STATE OF WISCONSIN
SUPREME COURT

CLEAN WISCONSIN, INC.
p/k/a Wisconsin's Environmental
Decade Institute, Inc.,
SC JOHNSON & SON, INC. and
CALPINE CORPORATION
Petitioners-Respondents-Cross-
Appellants-Cross-Respondents,

Appeal No. 04-3179

TOWN OF CALEDONIA,
Petitioner-Cross-Respondent,

v.

Circuit Court Case Nos.
03CV003478, 03CV003731,
04CV000133, 04CV000149,
04CV000530, 04CV000533

PUBLIC SERVICE COMMISSION OF
WISCONSIN and WISCONSIN
DEPARTMENT OF NATURAL RESOURCES,
Respondents-Co-Appellants-
Cross-Respondents,

WISCONSIN ELECTRIC POWER
COMPANY, W.E. POWER, LLC and
WISCONSIN ENERGY CORPORATION,
Interested Parties-Appellants-
Cross Respondents,

(Caption continued on following pages)

APPEAL FROM A DECISION OF THE CIRCUIT COURT OF DANE
COUNTY, THE HONORABLE DAVID FLANAGAN, PRESIDING

RESPONSE BRIEF OF INTERESTED PARTIES-APPELLANTS-CROSS RESPONDENTS WISCONSIN ELECTRIC POWER COMPANY, W.E. POWER, LLC AND WISCONSIN ENERGY CORPORATION

DAIRYLAND POWER COOPERATIVE,
Interested Party-Cross-Respondent,

MADISON GAS & ELECTRIC COMPANY
AND WISCONSIN PUBLIC POWER, INC.,
Interested Parties-Co-Appellants-
Cross-Respondents,

CITY OF OAK CREEK,
Interested Party-Respondent-
Cross-Appellant,

ROBERT H. OWEN,
Interested Party-Respondent-
Cross-Respondent.

CALPINE CORPORATION,
Petitioner,

v.

PUBLIC SERVICE COMMISSION OF
WISCONSIN and WISCONSIN
DEPARTMENT OF NATURAL RESOURCES,
Respondents,

WISCONSIN ELECTRIC POWER
COMPANY, W.E. POWER, LLC and
WISCONSIN ENERGY CORPORATION,
DAIRYLAND POWER COOPERATIVE,
MADISON GAS & ELECTRIC COMPANY,
ROBERT H. OWEN, JR., and
CITY OF OAK CREEK,
Interested Parties.

CLEAN WISCONSIN, INC.
p/k/a Wisconsin's Environmental
Decade Institute, Inc.,
SC JOHNSON & SON, INC. and
CALPINE CORPORATION,
Petitioners,

v.

WISCONSIN DEPARTMENT OF
NATURAL RESOURCES,
Respondent,

WISCONSIN PUBLIC POWER, INC.,
CITY OF OAK CREEK, DAIRYLAND
POWER COOPERATIVE, MADISON
GAS & ELECTRIC COMPANY,
WISCONSIN ELECTRIC POWER
COMPANY, WISCONSIN ENERGY
CORPORATION and W.E. POWER, LLC,
Interested Parties.

CALPINE CORPORATION,
Petitioner,

v.

WISCONSIN DEPARTMENT OF
NATURAL RESOURCES,
Respondent,

CITY OF OAK CREEK, DAIRYLAND
POWER COOPERATIVE, MADISON GAS
& ELECTRIC COMPANY, WISCONSIN
PUBLIC POWER, WISCONSIN ELECTRIC
POWER COMPANY, WISCONSIN ENERGY
CORPORATION and W.E. POWER, LLC,
Interested Parties.

CITY OF OAK CREEK,
Petitioner,

v.

PUBLIC SERVICE COMMISSION OF
WISCONSIN,
Respondent.

TOWN OF CALEDONIA,
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v.

PUBLIC SERVICE COMMISSION OF WISCONSIN,
Respondent,

WISCONSIN ELECTRIC POWER COMPANY, WISCONSIN ENERGY CORPORATION, W.E. POWER, LLC, DAIRYLAND POWER COOPERATIVE, MADISON GAS & ELECTRIC COMPANY, ROBERT H. OWEN, JR., and WISCONSIN PUBLIC POWER, INC.,
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ISSUES PRESENTED FOR REVIEW

1. Whether the Commission properly used econometric computer modeling as one tool to assist in determining whether ERGS is "in the public interest" under § 196.491(3)(d)3, Wis. Stats.

   Answered by the Circuit Court: Yes.

2. Whether the Commission properly determined that ERGS will not have an undue adverse impact on other environmental values in accordance with § 196.491(3)(d)4, Wis. Stats.

   Answered by the Circuit Court: Yes.

3. Whether the Commission properly determined that ERGS will not have a material adverse impact on competition in the relevant wholesale electric service market in accordance with § 196.491(3)(d)7, Wis. Stats.

   Answered by the Circuit Court: Yes.

4. Whether the Commission and the Department of Natural Resources ("DNR") properly determined that the joint Environmental Impact Statement was adequate and complied with the Wisconsin Environmental Protection Act ("WEPA"), § 1.11, Wis. Stats.

   Answered by the Circuit Court: Yes.

STATEMENT REGARDING ORAL ARGUMENT AND PUBLICATION

Oral argument has been scheduled for March 30, 2005. Publication of the opinion is appropriate because the decision will clarify Wisconsin law regarding the regulatory process for approval of a Certificate of Public Convenience and Necessity ("CPCN") and the discretion appropriately accorded the technical expertise of the Wisconsin Public Service Commission with respect to that highly complex process.

INTRODUCTION

Cross-Appellants do not challenge the Commission's fundamental determination that the new-technology, coal-fired facilities approved by the Commission are necessary to "satisf[y] the reasonable needs of the public for an adequate supply of electric energy." *Final Dec.* at 5. SC Johnson & Son and Clean Wisconsin ("SCJ/CW") concede that "[t]he issues before the Court do not turn on whether the new power plants are needed." SCJ/CW Brief at 2. As the Commission unanimously found, the evidence conclusively demonstrates that construction of the Elm Road Generating Station ("ERGS") is necessary to meet the State's baseload energy needs in the next decade. *Final Dec.* at 20, 22, 24, 27.

Instead, the cross-appeal challenges isolated, and particularly fact-intensive, aspects of the Commission's § 196.491(3)(d), Wis. Stats., inquiry. SCJ/CW challenges one component of the § 196.491(3)(d) criteria—the "public interest" inquiry under (3)(d)3—and focuses its criticisms on various inputs selected by the PSC for inclusion in a complex, econometric computer model used to facilitate the Commission's assessment of certain aspects of a proposed facility. Calpine Corporation ("Calpine") asserts that the Commission must mandate the "least cost" proposal derived from such computer modeling, and challenges two additional aspects of § 196.491(3)(d): (1) the "other environmental values" determination under (3)(d)4; and (2) the "impact on competition in the relevant wholesale electric service market" assessment under (3)(d)7.

As set forth below, the Commission properly exercised its delegated authority to weigh the conflicting evidence presented on each of these issues and rendered sound determinations "supported by substantial evidence in the record." § 227.57(6), Wis. Stats. There is no ground for judicial reversal of the appropriate judgments of the agency on these factual issues that are well within the discretion and institutional expertise of the Commission.

SCJ/CW and Calpine also independently challenge the PSC and DNR determinations of the adequacy of the joint Environmental Impact Statement ("EIS"). The EIS was the product of comprehensive proceedings under the Wisconsin Environmental Protection Act ("WEPA"), § 1.11, Wis. Stats., and comprises approximately 900 pages, including highly technical analyses.[1] The Commission and DNR have independently determined that the EIS was adequate to address the respective agency actions and complies with the requirements of WEPA. Under applicable principles of judicial review, the EIS prepared here readily comports with WEPA and provided an appropriate "hard look" at the potential environmental impacts of the proposed project.

STANDARDS OF REVIEW

SCJ/CW begins its discussion of the standards of review with a misleading citation. SCJ/CW cites *Kegonsa Joint Sanitary District v. City of Stoughton*, 87 Wis. 2d 131, 274 N.W.2d 598 (1979) for the purported proposition that "broad deference in lieu of careful analysis is inconsistent with the legislative policy favoring judicial review." SCJ/CW Brief at 8. The case contains no such statement. The decision addresses *jurisdiction* to review agency actions. *See Kegonsa*, 87 Wis. 2d at 145. To the extent the decision touches upon standards of review, it merely confirms that Chapter 227 "outlines the scope of judicial review" and reiterates that the "court has often pointed out that 'a court cannot compel that discretion be exercised in a particular way.'" *Id.* at 151-52 & 153 n.14 (citing *State ex rel. Knudsen v. Board of Education*, 43 Wis. 2d 58, 70, 168 N.W.2d 295 (1969)).

The deference properly accorded to administrative determinations of the fact-intensive matters at issue in this cross-appeal is well settled and statutorily defined:

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[1] The EIS (R.18-119) has been submitted as a supplemental appendix. Thus, references to the EIS in this brief cite directly to the EIS page designations.

> If the agency's action depends on any fact found by the agency in a contested case proceeding, the court shall not substitute its judgment for that of the agency as to the weight of the evidence on any disputed finding of fact. The court shall, however, set aside agency action or remand the case to the agency if it finds that the agency's action depends on any finding of fact that is not supported by substantial evidence in the record.

§ 227.57(6), Wis. Stats. A reviewing court may not overturn an agency's finding of fact "even if it may be against the great weight and clear preponderance of the evidence." *Holtz & Krause, Inc. v. DNR*, 85 Wis. 2d 198, 204, 270 N.W.2d 409 (1978).

The Commission's determination that an EIS is adequate for purposes of assessing the action at issue has been accorded "great weight deference." *See Citizens' Utility Board* v. *PSC*, 211 Wis. 2d 537, 553, 565 N.W.2d 554 (Ct. App. 1997). Recognizing the Commission's "'particular competence or expertise' in determining whether an EIS complies with § 1.11, Stats.," *id.* at 550, the Court of Appeals held:

> The PSC's determination of EIS adequacy will be sustained if it is "merely . . . reasonable," and the burden of proof is on the challenger to show that the PSC's determination of adequacy is unreasonable. An interpretation is unreasonable only if it directly contravenes the words of a statute, if it is clearly contrary to legislative intent or it is without a rational basis.

Id. at 552-53 (citation omitted). A reviewing court should "sustain the PSC's determination of [EIS] adequacy unless [the challenger] persuades [the Court] that there is no rational basis for that determination." *Id.* at 553. *See also State ex rel. Boehm* v. *DNR*, 174 Wis. 2d 657, 677, 497 N.W.2d 445 (1993) ("In determining the reasonableness of the DNR's decision that an EIS is not required, we defer to the technical

expertise of the department."); *accord Baltimore Gas & Electric Co. v. NRDC*, 462 U.S. 87, 97-98 (1983) (National Environmental Policy Act ("NEPA") requires "only that the agency take a 'hard look' at the environmental consequences before taking a major action. The role of the courts is simply to ensure that the agency has adequately considered and disclosed the environmental impact of its actions and that its decision is not arbitrary or capricious.").[2]

ARGUMENT

I. The Commission Properly Determined that ERGS is "In The Public Interest" Pursuant to the Factors Set Forth in § 196.491(3)(d)3, Wis. Stats.

Section 196.491(3)(d)3, Wis. Stats., provides that the Commission shall determine whether a proposed facility's

> design and location . . . is in the public interest considering alternative sources of supply, alternative locations . . ., individual hardships, engineering, economic, safety, reliability and environmental factors. . . . In its consideration of environmental factors, the commission may not determine that the design and location . . . is not in the public interest because of the impact of air pollution if the proposed facility will meet the requirements of ch. 285.[3]

The "public interest" determination does not turn upon any one of these statutory factors in isolation; rather, it requires that the Commission exercise its expertise and judgment to balance the various, often-conflicting considerations. As the Commission noted:

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[2] Federal cases interpreting NEPA are persuasive authority in interpreting WEPA. *State ex rel. Boehm*, 174 Wis. 2d at 675 n.4.

[3] The full text of relevant statutes and regulations is appended to this brief.

> The Commission must consider the extent to which a proposal may cause individual hardships, as well as concerns about its engineering, economics, safety, reliability, environmental impacts, interference with local land use plans, and impact upon wholesale competition. ***The Commission is required to balance all of these competing elements, which frequently lead in different directions; no single primary factor is the measure of a CPCN project.***

Final Dec. at 15 (emphasis added).

The Commission appropriately weighed the extensive evidentiary record developed through the contested case proceedings and balanced this array of factors to render a rational judgment that the design and location of ERGS is in the public interest. Cross-Appellants' disagreement with the agency's judgment in balancing these factors and weighing the evidence on disputed issues of fact provides no grounds for judicial reversal of the Commission's considered decision. § 227.57(6), Wis. Stats.; *see generally Westring v. James*, 71 Wis. 2d 462, 470, 238 N.W.2d 695 (1976) (holding with respect to an analogous "in the public interest" analysis that "it is within the legislative delegation to the administrative director to determine in which respects the enumerated considerations are pertinent to the effectuation of the broad legislative standards.").

A. The Commission fully understood the requirements of § 196.491(3)(d)3 and rendered appropriate findings that ERGS is "in the public interest."

SCJ/CW asserts, without citation to authority, that PSC "fail[ed] to perform th[e] statutorily required analysis" under § 196.491(3)(d)3. *See* SCJ/CW Brief at 10. No precedent defines a specific manner by which the Commission must "perform" the balancing of the competing qualitative and quantitative factors necessary to assess whether the design or location of a facility is "in the public interest." Nor is it the province of the judiciary to direct how the Commission

should exercise its delegated responsibilities in balancing these various, and often competing, factors. *See, e.g., Westring*, 71 Wis. 2d at 469; *Town of Ashwaubenon v. State Highway Commission*, 17 Wis. 2d 120, 130-31, 115 N.W.2d 498 (1962). Here, there can be no dispute that the Commission fully understood its responsibilities under § 196.491(3)(d)3—it specifically referenced the statutory factors on multiple occasions. *Final Dec.* at 5, 6, 15, 21, 44, 47, 51.

SCJ/CW's challenge is thus not legal, but rather a factual dispute over the agency's weighing of the evidence. As to these evidentiary matters, SCJ/CW asserts that the Commission "failed to make findings that would support its conclusory determination that the project is in the 'public interest' and meets other statutory criteria." SCJ/CW Brief at 9-11. The argument is meritless. The Commission's 62-page Final Decision sets forth in more than adequate detail the bases on which the Commission determined that ERGS is in the public interest.

Section 227.47(1), Wis. Stats., specifies the manner by which findings of fact should be set forth in final agency decisions:

> [E]very final decision of an agency shall be in writing accompanied by findings of fact and conclusions of law. The findings of fact shall consist of a concise and separate statement of the ***ultimate conclusions*** upon each material issue of fact ***without recital of evidence***.

Id. (emphasis added). *See also State ex rel. Harris v. Annuity & Pension Board*, 87 Wis. 2d 646, 661, 275 N.W.2d 668 (1979) (no requirement for "recitation of what evidence was believed and what was rejected" or an "elaborate opinion"); *Wisconsin's Environmental Decade, Inc. v. PSC*, 98 Wis. 2d 682, 701, 298 N.W.2d 205 (Ct. App. 1980) ("*WED*") ("It is sufficient if the findings of fact and conclusions of law are specific enough to inform the parties and the courts on appeal of the basis of the decision.").

Consistent with § 227.47(1), the Commission identified the following "ultimate conclusions" regarding the "public interest" requirement of § 196.491(3)(d)3:

> 5. The two SCPC units are reasonable and in the public interest after considering alternative sources of supply, individual hardships, engineering, economic, safety reliability, and environmental factors. The IGCC unit does not meet this standard.
>
> 6. The North Site—CUP alternative is in the public interest after considering alternative locations, individual hardships, engineering, economic, safety, reliability, and environmental factors.

Final Dec. at 5. These "ultimate conclusions" are supported throughout the Final Decision, which addresses various underlying bases for the determination that the "design and location" of the ERGS facility are "in the public interest," including, *inter alia*:

- Computer modeling demonstrates that new, high-technology, coal-based facilities are necessary to meet the State's baseload generation needs in the coming decade. *Id.* at 20, 27.

- "[T]he evidence presented demonstrates that WEPCO's existing fleet of baseload plants is aging." *Id.* at 21.

- The evidence "demonstrates the advantages of using cleaner burning coal technologies like SCPC as a baseload resource over gas-fired generation." *Id.* at 21.

- The evidence demonstrates that "relying on natural gas to meet WEPCO's baseload needs as well as intermediate and peaking requirements would raise

the risk of not properly diversifying the utility's fuel mix." *Id.* at 31.

- "[B]ased on a number of qualitative and quantitative factors . . . coal-fired generation provides the most cost-effective, prudent and practical means of meeting WEPCO's baseload capacity needs over the next decade." *Id.* at 22.

- And, although "any of the four sites proposed would meet the standards established under Wis. Stat. § 196.491," a number of qualitative factors point toward "the North Site—CUP alternative as the proper location for ERGS." *Id.* at 47-48.

B. The Commission properly used EGEAS modeling as one tool to assist in assessing need, source, and timing issues.

SCJ/CW devotes much of its brief to various criticisms of the EGEAS (Electrical Generation Expansion Analysis System) econometric modeling used by the Commission to assist in its assessment of timing, cost, and source issues. As the Commission notes, EGEAS modeling is "the primary tool to consider optimal resource options on a quantitative basis for [] future electric demand." *Final Dec.* at 23. This computer model requires "three forms of inputs: data about the utility's existing generating system; economic and engineering data for proposed new generating units; and a variety of base forecasts for demand and fuel prices." *Id.* PSC staff use different model runs, with differing inputs, as a quantitative basis to assist in assessing need, source, and timing considerations. *Id.* at 23-24.

The EGEAS model has inherent limitations and is just one tool used by the Commission in its broader consideration of whether a given facility is "in the public interest." "The EGEAS model . . . depends upon a great deal of numerical data inputs, assumptions, and forecast uncertainty. Although its results are complex estimates, EGEAS is a useful tool—albeit one important quantitative tool—for the Commission

to use in deciding the timing of the proposed facilities." *Final Dec.* at 25. EGEAS projections do not mandate the Commission's final decision. Nothing in the CPCN statute mentions EGEAS modeling, or suggests that results of that or any other econometric tool should dictate the Commission's decision making under § 196.491(3)(d)3. Rather, "[d]etermining what resource options will ensure low cost, reliability and environmental sensitivity for the consuming public requires the exercise of judgment and consideration of a wide variety of qualitative factors." *Id.*

SCJ/CW seeks to have this Court ignore the Commission's "consideration of a wide variety of qualitative factors" and reverse the Commission's Final Decision based on SCJ/CW's contention that the Commission "arbitrarily ignored undisputed categories of costs in its EGEAS modeling." SCJ/CW Brief at 16. Presumably, and without any basis in specific statutory language or administrative rule, SCJ/CW seeks to have this Court mandate, ***as a matter of law***, the different inputs that must be used in EGEAS modeling undertaken by the Commission. No precedent or principle of law would support such judicial intervention and micromanagement of the evidentiary considerations and decision processes of the PSC. *See generally Westring*, 71 Wis. 2d at 469-70 (the administrative body, not the courts, "determine[s] in which respects the enumerated considerations are pertinent" to deciding what is "in the public interest"); *City of New Richmond v. DNR*, 145 Wis. 2d 535, 548, 428 N.W.2d 279 (Ct. App. 1988) ("We must rely on the department for its expertise in making such technical scientific determinations as long as it acts reasonably based on an adequately developed record."); *WED*, 98 Wis. 2d at 701 ("[T]he methods for computing precise cost allocation and differential figures are complex, and this court cannot say that the PSC abused its discretion in choosing one figure over another."); *accord Vermont Yankee Nuclear Power Corp. v. NRDC*, 435 U.S. 519, 543-544 (1978).

SCJ/CW asserts that "cost-inputs" selected by PSC staff for the EGEAS modeling were flawed in three respects: (1) EGEAS models did not include "health-related costs from

ERGS' planned air emissions"; (2) EGEAS models did not include Oak Creek mitigation costs; and (3) EGEAS models did not include "other local community impacts." SCJ/CW Brief at 18, 21, 22. SCJ/CW also alleges that PSC did not model a "natural gas . . . alternative" to the ERGS facility. *Id.* at 24. Finally, SCJ/CW alleges sundry "inconsistencies and flaws" in the modeling. *Id.* at 25. As set forth below, each of these arguments is meritless.

More troubling, SCJ/CW plainly misrepresents the record throughout its argument. For instance, SCJ/CW goes so far as to suggest that "PSC uncritically accepted WEC's biased assumptions in its own EGEAS modeling." SCJ/CW Brief at 30. This is false. The Commission prepared various different model runs "us[ing] different data inputs." *Final Dec.* at 24. Indeed, although SCJ/CW fails to mention the fact anywhere in its brief, the Commission staff ***specifically took into account*** SCJ/CW's criticisms of the modeling inputs and prepared additional EGEAS runs reflecting revised inputs. *Id.* at 26-27. The matter is ***explicitly*** addressed in the Final Decision, *id.*, and the results of the "SC Johnson Blended" EGEAS runs were the subject of testimony in the contested proceedings. (R.18-158:Exh. 273; R.18-157:4706-4718).

The Commission determined that all EGEAS runs, even those reflecting the SCJ/CW concerns, pointed to the same conclusion: baseload, coal-fired capacity is needed to meet Wisconsin's energy needs. *Id.* at 24, 27. "After considering the quantifiable evidence presented in the EGEAS runs, the key question in this docket is not ***whether*** additional coal-fired baseload generation should be approved, but ***when*** it should be installed." *Id.* at 24 (emphasis supplied). Exercising its technical expertise, and taking into account the "paramount" concerns over "electric reliability" and the "five-year" process involved in construction and permitting of baseload facilities, the Commission concluded that approval was necessary now so that the facilities could be operational in 2009 and 2010. *Id.* at 22, 25.

As set forth below, each of Cross-Appellants' arguments relating to the EGEAS computer modeling are misplaced factually and legally.

1. SCJ/CW's claim that speculative "health costs" related to air pollution should have been included in the EGEAS model is incorrect and was properly rejected by the Commission.

Without citation to any supporting authority, SCJ/CW argues that the Commission erred by not including alleged "health-related costs from ERGS' planned air emissions" as an input in the EGEAS modeling. SCJ/CW Brief at 18-19. This argument fails on multiple grounds.

First, the Legislature made clear that environmental and health factors relating to the "impact of air pollution" are the jurisdiction of DNR and are ***not*** to be the subject of the Commission's CPCN decision:

> **§ 196.491(3)(d)3, Wis. Stats.**
>
> In its consideration of environmental factors, the commission ***may not determine that the design and location or route is not in the public interest because of the impact of air pollution*** if the proposed facility will meet the requirements of ch. 285.
>
> **§ 196.491(3)(d)4, Wis. Stats.**
>
> In its consideration of the impact on other environmental values [which expressly include public health and welfare], the commission ***may not determine that the proposed facility will have an undue adverse impact on these values because of the impact of air pollution*** if the proposed facility will meet the requirements of ch. 285.

(Emphasis supplied.)

The Commission was well aware of this statutory delegation of agency responsibility:

> [I]f DNR declares that a project will meet the agency's air pollution requirements under Wis. Stat. Ch. 285, the Commission loses its authority under Wis. Stat. §§ 196.491(3)(d)3 and 4 to determine that a project would have undue adverse air pollution impacts.

Final Dec. at 51. The Commission understood ERGS would "meet the requirements of ch. 285," as DNR had "issued preliminary determinations that both the North Site and North Site—CUP alternative should meet applicable criteria for permit approval." *Id.*

SCJ/CW seeks to circumvent this plain legislative mandate by recasting purported adverse "impact[s] of air pollution" into "health-related costs" that it claims should be monetized and factored into the EGEAS model. That result cannot be squared with the statutory directive that air-impact issues be addressed and handled within the specialized expertise and competence of the DNR. If the Commission were to deny the CPCN due to alleged external costs of air pollution, it would—quite obviously—be rendering a decision based on the "impact of air pollution" in contravention of the plain language of § 196.491(3)(d)3 and 4.

Second, even assuming *arguendo* that it would be jurisdictionally appropriate for the Commission to address "impact[s] of air pollution" in determining whether a facility was "in the public interest," nothing in § 196.491(3)(d), or in precedent, could plausibly be construed to ***mandate*** that the Commission quantify such impacts and include them as inputs in the EGEAS model. As the Commission recognized, it would have been inappropriate to do so here given the highly speculative and uncertain nature of the expert testimony on the issue. *Final Dec.* at 52-53; *see generally WED*, 98 Wis. 2d at 694-96 (PSC's decision not to

incorporate "unreliable" and "speculative" data into an econometric analysis was reasonable).

The Commission heard sharply conflicting expert testimony regarding the controversial endeavor of attempting to translate health-related air pollution impacts into cost figures. With respect to fine particulate matter ("$PM_{2.5}$"), which SCJ/CW discusses at length, expert testimony before the Commission demonstrated: (1) there is great uncertainty in the epidemiology and laboratory studies about whether there is any causal relationship between $PM_{2.5}$ and human health effects (R.18-157:4222-4224, 2379, 4253); and (2) the particular species of $PM_{2.5}$ emitted by these high-technology coal plants has not been shown to have adverse health impacts (R.18-157:2397-2398, 2383-2386). SCJ/CW's own experts conceded that the dose-response function they used to generate cost calculations is "quite uncertain." (R.18-157:4253-4254). Economist testimony also established that, even assuming *arguendo* some level of health impacts, the cost-quantification numbers set forth by SCJ/CW were grossly exaggerated. (R.18-157:2462-2488).

Given this conflicting expert testimony, the Commission was well within its discretion to conclude it did not have appropriate "expertise to render an independent judgment on this topic." *Final Dec.* at 52. As the Commission explained,

> [t]o do so would require the Commission to pick appropriate methods for modeling emission dispersion, determine if a causal relationship exists between emissions and adverse health impacts, decide whether a threshold level exists below which no impacts occur, and establish how to translate any identified impacts into dollars. These are primarily the functions of the EPA and DNR. . . .

Id. at 52-53. *See generally Sierra Club v. U.S. Department of Transportation*, 310 F. Supp. 2d 1168, 1188 (D. Nev. 2004)

(rejecting similar challenge based upon alleged impacts of $PM_{2.5}$).

In fact, DNR, applying its superior expertise, concluded in its decision granting the Chapter 285 air permit that "ERGS would not likely pose a significant inhalation risk if operated according to required standards." (WE App. 272, ¶ 41). DNR also "determined that the benefits of construction of ERGS significantly outweighed the environmental and social costs imposed as a result of its location and construction." *Id.* ¶ 34.[4]

Finally, the evidence establishes that ambient concentrations from the ERGS facility will not exceed the national ambient air quality standards ("NAAQS"), *see* EIS at 169-171, which are specifically designed to prevent adverse impacts on public health. *Id.* at 146. Indeed, viewing the question from a broader perspective, the Commission noted that the Power The Future ("PTF") project as a whole ***improves*** air quality in the state. Given the newer technology used in these modern coal facilities, consent agreements, and voluntary emission reductions, the evidence "demonstrates that ***total air emissions will decrease substantially from current levels*** after completion of all PTF projects." *Final Dec.* at 22 (emphasis supplied).[5]

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[4] The final air permit decision also notes the uncertainty and current lack of regulatory acceptance of these "emergen[t]" techniques "that attempt to quantify the adverse health impacts from a particular source." WE App. 285-286. Based on prior "DNR analyses," the DNR "'found that, from an inhalation perspective, the risks resulting from well controlled facilities with tall stacks are low.'" *Id.* (quoting EIS Vol. 3 at 20).

[5] In its Agreement with Oak Creek, WE agreed to limit total air emissions from ERGS and the existing Oak Creek facilities to a "baseline" level established in 2000. EIS Vol. 1, Appx. E ¶¶ I(A)-(B).

2. Mitigation costs and local community impacts need not be part of EGEAS modeling and were independently considered by the Commission.

SCJ/CW argues that the Commission erred by not incorporating mitigation costs and "other local community impacts" as inputs in the EGEAS modeling. Again, SCJ/CW cites no authority for the proposition. Nothing requires either cost to be made part of the EGEAS modeling process. The Commission addresses each issue through other means.

The Commission discusses mitigation payments in its Final Decision, ultimately authorizing payments of approximately $10 million. *Final Dec.* at 48-51. SCJ/CW ignores this finding and, focusing solely on the EGEAS modeling, suggests that "PSC erred as a matter of law by ignoring this substantial cost, without explanation." SCJ/CW Brief at 21. As the Final Decision demonstrates, the Commission obviously took mitigation payments into account. There is no requirement that this cost be input into the EGEAS model rather than assessed independently.

Similarly, there is no need to include the alleged external costs of "other local community impacts" in EGEAS modeling. Local community impacts of utility projects are addressed instead by identifying the likely impacts and requiring that project sponsors take reasonable steps to mitigate them. The Commission expressly ordered WE to "work with the neighboring communities to mitigate valid impacts and concerns." *Final Dec.* at 58. WE and Oak Creek negotiated and agreed to a variety of mitigation measures, and the City approved a conditional use permit ("CUP") for the project detailing specific mitigation measures. *See* EIS Appx. E, R.18-157:2632-2634. To the extent residual impacts remain, they are balanced against the external *benefits* of such projects (R.18-157:1162-1167) and by devices such as the state's shared revenue program for host communities. *See generally Final Dec.* at 49-50.

3. The Commission's EGEAS modeling expressly addressed the criticisms of SCJ/CW.

SCJ/CW further asserts various alleged "inconsistencies and flaws" in the Commission's EGEAS modeling, and suggests that modeling assumptions "artificially reduced the availability of existing facilities," ignored "hidden costs," "shifted costs," and rested on "unduly optimistic assumptions." SCJ/CW Brief at 25-30.

During its discussion of these purported "flaws," SCJ/CW does not once cite the Final Decision of the Commission. Instead, SCJ/CW variously asserts, without citation, that "PSC's decision . . . ignores these issues," *id.* at 27, PSC "did not account for these inconsistencies in its model runs," *id.* at 28, and PSC "uncritically accepted WEC's biased assumptions," *id.* at 30. SCJ/CW's representations to this Court are disturbing. These assertions flatly misstate the Commission's work and the Final Decision itself.

The Commission ***expressly*** addressed and considered the purported "flaws" now alleged by SCJ/CW:

> S.C. Johnson criticizes a number of modeling inputs, alleging that WEC is using improper engineering and fuel data for existing WEPCO units, an improper common systems cost allocation to the OCPP units, a demand and energy forecast that is too high, an improper addition of 200 MW of demand obligations for WPPI and MEUW, overly favorable engineering assumptions for the proposed SCPC units, and an improper early retirement of certain OCPP and Presque Isle units, while it is also ignoring the likely availability of additional energy efficiency efforts that would reduce the growth in electric demand. ***Commission staff evaluated these concerns, revised some of its assumptions, and prepared an EGEAS run to demonstrate how these***

> ***changes would affect the optimal expansion plan.***

Final Dec. at 26 (emphasis supplied). Even accounting for the criticisms raised by SCJ/CW, "the EGEAS model results are not significantly different" and new-technology coal plants remain necessary to meet baseload needs in the next decade. *Id.* at 27.

Various factual assertions set forth in the SCJ/CW Brief are also inaccurate. For instance, SCJ/CW asserts that it is "[p]erhaps most significant[]" that WE selected a "performance efficiency" of 8,700 Btu/kWh even though the "contractually guaranteed heat rate for the SCPC units is 8,850 Btu/kWh." SCJ/CW Brief at 30 & n.7. SCJ/CW fails to advise the Court that PSC staff ***did not*** "uncritically accept" WE's heat rate, but rather, in fact, used the rate guaranteed by the contractor—8,850 Btu/kWh. (R.18-157:4655).

Although SCJ/CW fails to bring these matters to the Court's attention in its brief, the law is clear: Where, as here, an agency has expressly addressed the factual matters at issue, weighed the evidence, and rendered a determination within its delegated discretion and expertise, the Court may not "substitute its judgment" for that of the agency. § 227.57(6), Wis. Stats.

Moreover, abundant evidence in the record rebuts the "flaws" alleged by SCJ/CW. Various witnesses testified on these matters, and presented evidence that: (1) modeling assumptions for existing capacity were reasonable (R.18-157:1772-1780); (2) the allocation of site common costs was reasonable (R.18-157:1225-1226); (3) the performance assumptions were reasonable (R.18-157:1772-1774); (4) WE's base case EGEAS analysis did not unreasonably presume the early retirement of Oak Creek Units 5 and 6; and (5) WE did not use unrealistically low equivalent forced

outage assumptions or unreasonably high unit efficiency assumptions (R.18-157:1755-1757).[6]

PSC's weighing of this competing evidence, its determination as to which assumptions were reasonable and appropriate for input into the EGEAS model, and its assessment of the various different modeling runs, are fact-intensive inquiries within the unique expertise and discretion of the Commission. There are no grounds for judicial reversal of such matters. *See* § 227.57(6), Wis. Stats.; *see also Liberty Homes, Inc. v. DILHR*, 136 Wis. 2d 368, 391-93, 401 N.W.2d 805 (1987); *WED*, 98 Wis. 2d at 701.

4. The Commission's EGEAS modeling considered alternatives to coal.

SCJ/CW argues that "PSC failed to run a comparable modeling analysis for a non-coal alternative to the two ERGS SCPC units" and specifically asserts that the Commission "did not evaluate the cost of relying upon natural gas units (or a combination of higher priority alternatives) as a substitute for coal-fired generation from ERGS." SCJ/CW Brief at 24. This is also a misrepresentation of the record.

The Final Decision expressly states: "The Commission also considered whether gas-fired generation is a cost-effective or technically feasible alternative that could replace the need for new baseload generation facilities." *Final Dec.* at 19. It was not. *Id.* Specifically addressing its computer modeling, the Commission explained: "Commission staff did conduct an 'integrated alternative' EGEAS analysis that examines the feasibility of combining renewable resources with natural gas, while also reflecting a more aggressive energy efficiency approach. . . . Even this integrated alternative run shows that an SCPC unit is needed during the

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[6] WE also disputed certain modeling assumptions by the Commission that skewed the analysis *against* ERGS. (R.18-157:749-755, 848-851). Moreover, as to the "admitted" error discussed in the SCJ/CW Brief at 40, this issue was first identified by WE, was corrected by PSC staff, and did not undermine the utility of prior EGEAS runs for comparative purposes. (R.18-157:4706, 4716-4717, 4730).

forecasting period." *Id.* at 20. Moreover, the EIS expressly sets forth EGEAS modeling that "rel[ies] exclusively on natural gas" as a substitute for coal-fired generation from ERGS. EIS at 66-73. That EGEAS run found that relying upon natural-gas units "would cost ratepayers $1.9 billion more than a balanced plan using optimally timed gas- and coal-fired electric generation, as well as some wind generation development." *Id.* at 73.

The Commission determined that, under any plausible scenario accounting for the State's impending energy needs, the advanced coal-technology of the SCPC units was necessary. *Final Dec.* at 20. The issue was timing, and the Commission found that "it is in the public interest to have more reliable baseload generation in place sooner rather than later as a matter of public policy." *Id.* at 22.

5. Calpine's "least cost" argument is without valid basis.

Calpine is an independent wholesale power producer that sought to have the Commission mandate that WE purchase power from Calpine to meet the baseload energy needs at issue. The Commission fully considered and ultimately rejected Calpine's proposal. The Final Decision identifies two principal bases for the Commission's determination that the Calpine proposal could not displace the need for ERGS:

> (1) "Calpine's projects are natural-gas fired, combined-cycle units. Ordinarily, such units are considered intermediate load generating stations, with capacity factors up to 50 percent. Almost without exception, though, EGEAS model runs in this record show that WEPCO needs additional baseload capacity within the next decade, in which generating stations must operate between 70 and 90 percent capacity factors." *Final Dec.* at 30.
>
> (2) Although "some EGEAS runs identify a $57 million cost reduction if a 523 MW,

> combined-cycle Calpine plant is included in 2006 or 2007, [] the EGEAS models demonstrate that approving such units ***would not replace the need for additional coal-fired baseload generation. In addition, relying upon natural gas to meet WEPCO's baseload needs as well as its intermediate and peaking requirements would raise the risk of not properly diversifying the utility's fuel mix***." *Id.* at 30-31 (emphasis supplied).

Calpine does not challenge these conclusions. Instead, Calpine advances an unprecedented, and ultimately groundless, legal argument that the Commission was ***required*** "to include Calpine's proposal as part of the authorized expansion plan" because § 196.491(3)(d)3 purportedly mandates that the Commission "implement the least cost requirement." Calpine Brief at 15. This argument fails on multiple bases.

First, and most obviously, nothing in § 196.491(3)(d)3 requires that the Commission "implement the least cost requirement." To the contrary, the statutory provision expressly requires that the Commission assess whether the "design and location" of a facility "is in the public interest considering" multiple factors: "alternative sources of supply, alternative locations[,] . . . individual hardships, engineering, economic, safety, reliability and environmental factors." *Id.* Calpine's "least cost requirement" argument would render ***one*** economic consideration dispositive, nullifying the breadth of remaining factors the Commission is directed to take into account in assessing the "public interest."[7] As the Commission correctly noted: "The Commission is required to balance all of these competing elements, which frequently lead in different directions; ***no single primary factor is the measure of a CPCN project***." *Final Dec.* at 15 (emphasis supplied).

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[7] Even the "economic" component of the multi-factor § 196.491(3)(d)3 inquiry is broader than "least cost" (*e.g.*, price volatility, risk of default, etc.).

Second, Calpine's references to prior PSC Orders do not support its claim. As a legal matter, such prior orders do not establish a binding "rule," as Calpine suggests. *See* §§ 227.01(13)(b) and 227.10(1), Wis. Stats. Regardless, Calpine misstates the Commission's prior decisions. The *112 Order* (which addressed a bidding process to select among independent power producers) did not impose a "least cost" requirement. The order expressly states that the Commission considers "a number of factors which are important, but defy a reasonable assignment at dollar costs, such as performance guarantees and community support/opposition." Calpine App. 209. So too, none of the remaining cited orders rested upon a "least cost requirement." *See, e.g.*, *Repap Order*, Calpine App. 152 ("The Commission chose the LS Power Whitewater project based on a balanced consideration of costs and intangible factors of all the bids."); *Rhinelander Order*, Calpine App. 243 (same); *MGE Order*, Calpine App. 462 ("[P]lans with the WCCF were either superior to or virtually tied with plans without the WCCF.").

Notably, the Commission's Order approving the first Phase of PTF (not cited by Calpine) recognizes that enactment of the leased generation law (under which these facilities are financed) underscores the importance of "qualitative factors" such as "reliability" and "long-term price certainty" in assessing whether a facility is "in the public interest":

> The enactment of this new law permits the Commission to consider leased generation through a non-utility affiliate as a new way to ensure greater reliability in Wisconsin and deliver greater long-term price certainty to ratepayers at a time of unprecedented price volatility in wholesale energy markets across the country.

In re W.E. Power, 2002 WL 32067560, at *11 (Wis. PSC Dec. 20, 2002).

Finally, although the Commission noted that "some EGEAS runs identify a $57 million cost reduction" (a

0.0028% difference in the context of the 30-year EGEAS projection)[8] under proposals that included both Calpine facilities ***and*** coal-fired facilities, *Final Dec.* at 30, a "gas-only" proposal "would cost ratepayers $1.9 billion more" than the ERGS plan ultimately approved. EIS at 73. Evidence before the Commission also addressed the substantial problems presented by the "extreme volatility of natural gas prices," *id.* at 62, R.18-157:4529-4530, and the significant uncertainties in the wholesale energy market. EIS at 45 ("[M]any independent power producers have been experiencing financial difficulties."). Indeed, at the time of the contested case hearings, Calpine's debt had been downgraded to "junk bond" status (R.18-157:1784), and its SEC filings stated that it "may be unable to secure additional financing in the future" and "may be unable to obtain an adequate supply of natural gas in the future." (R.18-158:Exh. 195, Tab 5 at 3, 5).

In sum, there is no "least cost requirement" by statute or rule. The Commission appropriately considered, and rejected, the Calpine proposal given the countervailing considerations and qualitative concerns regarding over reliance on gas-based generation.

II. The Commission Properly Determined that ERGS Will Not Have an Undue Adverse Impact on Other Environmental Values in Accordance with § 196.491(3)(d)4.

Calpine argues that the Commission's Final Decision violates § 196.491(3)(d)4's requirement that the Commission determine "[t]he proposed facility will not have undue adverse impact on other environmental values such as, but not limited to, ecological balance, public health and welfare, historic sites, geological formations, the aesthetics of land and water and recreational use." *Id.* Calpine bases this argument on two purported grounds: (1) "PSC inappropriately departed

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[8] The $57 million difference arose in the "Revised Staff Base" EGEAS run. (R.18-158:Exh. 273, Sch. 3 Revised). Various runs reflected different amounts. *Id.*

from its past interpretation of its mandate under Wis. Stat. § 196.491(3)(d)4 . . . ."; and (2) "The Final Decision confirms that ERGS's once through cooling system will not comply with applicable numeric environmental performance standards." Calpine Br. at 30. Neither argument is correct.

First, nothing in the Commission's prior rulings establishes any "mandate" under § 196.491(3)(d)4 that differs from the Commission's appropriate treatment of the issue here. Calpine references ***two*** proceedings as purported support for this legal proposition—namely, Calpine's own CPCN proceedings regarding the Fond du Lac Energy Center and a proposed "Sherry plant." Calpine Brief at 31. Nothing in either proceeding "mandates" how the Commission must exercise its discretion under § 196.491(3)(d)4. Indeed, the Commission's decision process in those proceedings is analogous to the process applied here, as the Final Decision approving the Fond du Lac application demonstrates. There, the Commission similarly rendered an "ultimate conclusion" that "[t]he Fond du Lac Energy Center will not have undue adverse impact on other environmental values," directed that Calpine be "responsible for obtaining, maintaining, and complying with the water diversion permit associated with plant use," and required that Calpine "be responsible for obtaining a Wisconsin Pollutant Discharge Elimination System (WPDES) Permit from the DNR in order to discharge its cooling water" into Lake Winnebago. *In re Fond du Lac Energy Center, LLC*, 2003 WL 21673685, at *2, 5 (Wis. PSC May 5, 2003). As here, the specific parameters of the WPDES permit had not been resolved by the DNR at the time of the CPCN decision.[9]

Second, contrary to Calpine's argument, PSC required and considered extensive evidence relating to the ERGS water intake structure and discharge. The EIS devotes extensive discussion to these matters. EIS at 179-221; EIS Vol. 3 at 34-35. Moreover, testimony on the matter was presented at the contested hearings by multiple witnesses. (R.18-157:1514-

[9] The WPDES permit (which relates to the water intake structure and discharge) is not a permit deemed necessary prior to issuance of a CPCN. WE Brief, at 37; PSC/DNR Brief at 28 n.9.

1545 (Krause); 3319-3361 (Goodwin); 3529-3588 (Jude); 4280-4332 (Henderson); 4337-4348 (Ehlinger); 4461-4503 (Schuettpeltz)). Initial entrainment studies indicated that, in fact, the proposed off-shore intake structure, if in compliance with "Best Technology Available" requirements, would, in fact, greatly ***reduce*** fish entrainment compared to the existing on-shore intake canal currently in use at the Oak Creek facility. (R.18-157:1516).

With the understanding that "ERGS could utilize once-through cooling, as [the existing Oak Creek Power Plant] does now, if applicants can demonstrate that the intake structure represents Best Technology Available for controlling impingement and entrainment of aquatic organisms," *Final Dec.* at 53, and in light of the evidence presented, the Commission appropriately deferred to the superior institutional expertise of DNR and EPA to ensure that these "Best Technology Available" requirements were, in fact, met. *Id.* The Commission's Order also specified: "If the EPA or DNR determine that once-through cooling is not permittable, WEC shall submit a revised project application for the Commission's approval that redesigns or relocates ERGS as needed." *Id.* at 58. *See State ex rel. Boehm*, 174 Wis. 2d at 676 ("[A]n agency may control potential adverse environmental consequences through conditions that must be complied with to obtain approval [and] . . . may assume that any environmental consequences will be controlled through compliance with the applicable administrative code provisions.").

Calpine's argument that the ERGS facility "does not comply with water intake standards" is wrong and incorrectly states that the proposed intake structure will have "a velocity of 1.0 feet/second." Calpine Br. at 35. On January 12, 2005, DNR published notice of its intent to issue the WPDES permit for the ERGS facility and found to the contrary. *See DNR Public Notice of Intent to Reissue a WPDES Permit No. WI-0000914-07-0* (WE Supp. App. 101-104).[10] That notice

[10] The DNR Notice is attached to this brief. WE requests judicial notice of this formal agency notice for the reasons set forth in the PSC/DNR's Motion for Judicial Notice.

specifies that WE has "proposed an array of submerged wedge-wire screens and a design through-screen ***velocity of 0.5 feet per second or less***," which DNR "tentatively determined . . . meets the [Best Technology Available] requirement with regard to reduction in fish impingement." (WE Supp. App. 101) (emphasis supplied). Calpine's claim that ERGS will not meet "thermal plume requirements" is also incorrect. DNR preliminarily concurred that the "thermal discharges will assure the protection and propagation of a balanced indigenous population of shellfish, fish, and aquatic life in Lake Michigan." (WE Supp. App. 101). Finally, the Chapter 30 permit issued by DNR concludes that construction of the intake structure "will not cause environmental pollution," and "impacts of the construction dredging will be short-lived and minor." (WE App. 296, ¶¶ 10-11).

With respect to wetlands, Calpine's arguments are similarly misplaced. The EIS addresses wetlands issues at length, *see* EIS at 197-200, 216-217, and testimony was presented relating to wetlands. (R.18-157:4400-4402, 4409-4429). Moreover, "DNR would have advised the PSC if DNR considered any of the sites to be unpermittable, but did not do so because DNR did not consider any of the four sites to be unpermittable." (WE App. 299, ¶ 29). DNR has, in fact, found that ERGS complies with wetlands requirements, noting "the two highest quality wetlands . . . will not be impacted by the project" and "the North Site—CUP avoids detrimental impacts to wetland functional values to the maximum extent possible." (WE App. 300, ¶¶ 35-36).

In sum, substantial evidence supports the Commission's reasoned determination that, provided WE complies with DNR's environmental permitting requirements, ERGS will not have "an undue adverse impact on other environmental values." That evidence included the materials presented through the EIS, which devoted hundreds of pages to a broad array of potential environmental impacts, *see* EIS at 133-390, and testimony and evidence offered at the technical hearings regarding potential impacts on environmental values and how such impacts would be

mitigated. (*e.g.*, R.18-157:1162-1167, 1505-1547, 2812-2841, 2187-2192).

The Commission's judgment on these fact-intensive issues is supported by substantial evidence in the record and borne out by DNR's permitting decisions. § 227.57(6), Wis. Stats.

III. The Commission Properly Determined that ERGS Will Not Have a Material Adverse Impact on Competition in the Relevant Wholesale Electric Service Market in Accordance with § 196.491(3)(d)7.

Calpine argues that the Commission undermined wholesale electric competition by approving ERGS but rejecting Calpine's efforts to have the Commission mandate that power be purchased, in part, from Calpine's own facilities. The argument is without basis. Acting well within its delegated expertise, and after evaluating substantial evidence regarding the impact of ERGS on the relevant wholesale market, the Commission properly found that the proposed project will have no material adverse impact on competition. *Final Dec.* at 5, 27-29.

The Commission was presented with extensive evidence regarding market effects through both the EIS and expert testimony during the contested hearings. Chapter 3 of the EIS addresses the potential impacts of ERGS on the wholesale market. As the EIS states, market power is defined as "the ability of a firm to charge prices for its product above what a competitive market would allow." EIS at 44. The EIS notes that the leased generation structure approved by the Wisconsin Legislature impacts pricing mechanisms and requires that any rate changes be regulated by the PSC through its ongoing "review of the lease's economic terms and conditions. Essentially, ***PSC economic regulation prevents any material adverse impact on competition***." *Id.* (emphasis supplied).

At the hearings, Dr. Gary Roberts, who served as Associate Director for Antitrust in the Bureau of Economics of the Federal Trade Commission, testified that "the proposed generating plants will have no material impact on competition in any relevant wholesale market." (R.18-157:2137). In reaching that conclusion, Dr. Roberts employed standard analytical techniques for evaluating competitive impacts. *Id.* at 2159. Dr. Roberts also developed an economic model that allowed him to evaluate whether ERGS would afford WE either the ability or the incentive to exercise market power. *Id.* at 2149-2152. He determined it would not. *Id.* at 2149.

Although Calpine would certainly prefer that the Commission mandate that power be purchased from its facilities, there is no basis in this record for the Court to substitute its judgment for that of the Commission regarding the expert testimony and evidence presented. § 227.57(6), Wis. Stats. The Commission fully understood its responsibility to ensure that ERGS would not "have a material adverse impact on competition in the relevant wholesale electric service market" and exercised its delegated authority on the basis of an appropriate record addressing the issue.

IV. The Commission and DNR Properly Determined that the Environmental Impact Statement was Adequate and Complied with WEPA.

The purpose of an EIS is to enable agencies to take a "hard look" at the environmental impacts of proposed actions. *See, e.g., Milwaukee Brewers Baseball Club v. DHSS*, 130 Wis. 2d 56, 72, 387 N.W.2d 245 (1986). "NEPA itself does not mandate particular results, but simply prescribes the necessary process." *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 350 (1989). "The role of the courts is simply to ensure that the agency has adequately considered and disclosed the environmental impact of its actions and that its decision is not arbitrary or capricious." *Baltimore Gas & Electric Co.*, 462 U.S. at 97-98. "Neither [NEPA] nor its legislative history contemplates that a court should substitute its judgment for that of the agency as to the environmental

consequences of its actions." *Kleppe v. Sierra Club*, 427 U.S. 390, 410 n.21 (1976).

The final EIS prepared jointly by PSC and DNR in this case fills approximately 900 pages and represents the collective efforts of 38 agency staff members. EIS at xv-xvi. It contains three volumes, which include separate chapters addressing: "Background and Regulatory Requirements," "PTF Costs and Financing Mechanism," "Need for Baseload Capacity in Southeastern Wisconsin," "Alternatives to the Proposed Project," "Overview of Proposed Sites and Technologies," "Air Emissions," "Water Resources," "Solid and Hazardous Waste Disposal and Remediation," "Land Resources," "Community Impacts," "The Conditional Use Permit (CUP) Option," and "Overview of the Required Decisions and Summary of Impacts." EIS at iii-vii. Volume 3 of the EIS reflects statements received during the public comment process (more than 270 individuals provided comments on the draft EIS) and sets forth a 43-page response discussing the manner by which the final EIS incorporates and addresses the issues raised. *See* EIS Vol. 3.

As with all EIS's addressing complex and dynamic projects (which necessarily and appropriately undergo modification in response to public and regulatory comments), this EIS is comprehensive, but it also recognizes and acknowledges various limitations inherent in its early-stage analysis. *See, e.g., Izaak Walton League of America v. Marsh*, 655 F.2d 346, 377 (D.C. Cir. 1981) ("So long as the environmental impact statement identifies areas of uncertainty, the agency has fulfilled its mission under NEPA. . . . 'If we were to impose a requirement that an impact statement can never be prepared until all relevant environmental effects were known, it is doubtful that any project could ever be initiated.'") (citations omitted); *Inman Park Restoration, Inc. v. Urban Mass Transportation Association*, 414 F. Supp. 99, 117-118 (N.D. Ga. 1975), *aff'd*, 576 F.2d 573 (5th Cir. 1978) ("The early stages at which the EIS must be done of necessity contemplates that all detailed planning for each component of the project unit will not have been completed at that time."). Indeed, if a project were not

allowed to be modified, it would undermine a fundamental purpose of the EIS and regulatory process.

Courts recognize that no EIS could ever be perfect. "No matter how exhaustive the discussion of environmental impacts in a particular EIS might be, a challenger can always point to a potentiality that was not addressed." *Citizens' Utility Board*, 211 Wis. 2d at 554; *accord Mason County Medical Association v. Knebel*, 563 F.2d 256, 265 (6th Cir. 1977) ("[N]o matter how well the EIS has been written, someone later can always find fault with it. We would question whether a perfect EIS has ever been prepared."). Accordingly the adequacy of an EIS is "to be construed in light of reason." *Milwaukee Brewers*, 130 Wis. 2d at 72. *See also Swanson v. United States Forest Service*, 87 F.3d 339, 343 (9th Cir. 1996) ("[T]his court need not 'fly-speck' the document . . ., but will instead employ a 'rule of reason' to determine whether it contains 'a reasonably thorough discussion of the significant aspects of the probable environmental consequences.'" (citation omitted)).

Both DNR and the Commission independently found the EIS to be adequate for purposes of their respective responsibilities and to comport with the requirements of WEPA. *Final Dec.* at 56; WE App. 301, ¶ 41. In its Final Decision, the Commission recounted the procedural history of the EIS, addressed the Respondents' challenges, and concluded:

> After hearing these concerns and reviewing the detailed record prepared in this case, much of which concerns environmental impacts, the Commission finds that this EIS properly discusses the significant aspects of probable environmental consequences. In those areas where the likely environmental consequences associated with ERGS are unknown, the EIS identifies these uncertainties.

Final Dec. at 56.

Despite the breadth of the EIS prepared for this project, and the independent findings by both the PSC and DNR that the EIS was adequate, SCJ/CW and Calpine both isolate components of the EIS for challenge. Viewed in its totality under the "rule of reason," and according appropriate great weight to the agency decisions, *see, e.g., Citizens' Utility Board*, 211 Wis. 2d at 552, *City of New Richmond*, 145 Wis. 2d at 548, the EIS fully satisfies WEPA.

A. The EIS appropriately addresses the cost-effectiveness of lower-emitting alternatives.

Simply recasting its EGEAS modeling complaints within the context of an attack on the EIS, SCJ/CW asserts that "PSC committed legal error by failing to do any modeling or analysis of less-polluting alternatives to ERGS." SCJ/CW Brief at 40. Aside from the lack of any legal authority that would dictate that EGEAS modeling be conducted in any particular manner, SCJ/CW's argument simply misstates the content of the EIS.

Chapter 4 of the EIS is devoted to "Alternatives to the Proposed Project." EIS at 47-77. Contrary to SCJ/CW's assertion, that chapter addresses, analyzes, and models various alternatives to ERGS. In particular, the chapter discusses the feasibility of energy efficiency measures, renewable resources (including wind, biomass, solar, and fuel cell alternatives), and natural gas-fired plants as alternatives to ERGS. *Id.* Neither energy efficiency measures nor renewable resources were viable means to address the energy needs at issue. *Id.* Modeling runs based on natural gas-only options increased costs by $1.9 billion, and those based on a combination of natural-gas and biomass were $1.4 billion more expensive. *Id.* at 48. The EIS also notes concerns relating to "the high cost of natural gas on a Btu-adjusted basis, and also the extreme volatility of natural gas prices." *Id.* at 62.

The EIS analysis—which considers, analyzes and models these various alternatives in a technically dense chapter dedicated to the subject—demonstrates that new-

technology, coal-fired generation is necessary to meet the state's baseload energy needs in a cost-effective and reliable manner. While SCJ/CW may take issue with this result, it is simply a misrepresentation to suggest that the EIS "fail[ed] ***to do any*** . . . analysis of less-polluting alternatives." SCJ/CW Brief at 40. As Chapter 4 of the EIS evidences, it unquestionably did.

B. The EIS appropriately addresses water-related impacts.

Cross-Appellants suggest that the EIS is inadequate because it did not "include sufficient information on once-through technology" or "alternative" cooling mechanisms. SCJ/CW Brief at 40-42; Calpine Brief at 39-40. SCJ/CW and Calpine also suggest that the EIS does not appropriately address wetlands issues, and Calpine suggests generally that the EIS does not adequately address the "cumulative impacts" on "water-related resources." SCJ/CW Brief at 47-48; Calpine Brief at 40-41. As both DNR and PSC concluded, the criticisms are misplaced.

Chapter 8 of the EIS sets forth a nearly 50-page, detailed analysis of water resource impacts associated with ERGS. Contrary to Cross-Appellants' assertion, the EIS contains an extensive discussion of the anticipated impacts of "once-through cooling" (a cooling system already in use at the existing Oak Creek Power Plant) and evaluates the expected aquatic impacts of the ERGS cooling system, including impacts on reproduction and spawning, *see* EIS at 188-189; effects of impingement and entrainment of fish and ichthyoplankton, *id.* at 190, 193-195; and impacts on benthic macroinvertebrates and zooplankton. *Id.* at 190-191. Efforts to mitigate aquatic impacts using the "Best Technology Available" for existing facilities and the treatment of water discharge are also addressed. *Id.* at 203-208, 217-224.

DNR and PSC possessed substantial information relating to the potential impacts of once-through cooling because the Oak Creek Power Plant has used once-through cooling for decades and it has been the subject of extensive

study. EIS at 192-193. Such studies have demonstrated that "the impacts of entrainment and impingement were inconsequential to aquatic life in Lake Michigan," *id.* at 193, and "have consistently indicated a lack of significant impact" from thermal discharge. *Id.* at 195. The EIS addresses DNR's determination that ERGS would be required to meet the "Best Technology Available" requirements for purposes of modifying the existing facilities. *Id.* at 204.

Cross-Appellants' criticism that the EIS should have more fully addressed alternative technologies to the once through cooling system is misplaced. The purpose of the alternatives analysis is to consider reasonable alternatives "to the proposed action," § 1.11(2)(c)3, Wis. Stats., not alternatives to each and every technical component of an engineering plan. *See, e.g., Seacoast Anti-Pollution League v. NRC*, 598 F.2d 1221, 1230 (1st Cir. 1979) ("[T]he process of studying alternatives is not endless.").[11] Here, the EIS properly examined, in detail, several reasonable alternatives to the "proposed action," including "taking no action," *see* EIS at 47, reducing energy load and peak demand, *id.* at 48-53, and employing different fuel sources to meet the identified energy needs. *Id.* at 53-77. With respect to the proposed once-through cooling technology, the EIS properly explained the process and its efficiencies, *see* EIS at 92, 95-96, 103, 200-208, and responded to comments concerning other cooling technologies, *id.* at Vol. 3, 34-35.

The EIS also addresses mitigation efforts with respect to the intake structure, noting that EPA and DNR regulations will mandate that "the proposed offshore intake structure must be designed to minimize environmental impacts" and that the specific details of such mitigation would be refined through the WPDES process. EIS at 204. An EIS does not impose a "substantive requirement that a complete mitigation plan be actually formulated and adopted." *Robertson*, 490 U.S. at 352. "[I]t is not necessary, nor is it possible, that every detail be contained in an FEIS. General commitments

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[11] As the Supreme Court noted, "the term 'alternatives' is not self-defining." *Vermont Yankee,* 435 U.S. at 551.

to future action suffice to meet mitigation requirements." *County of Bergen v. Dole*, 620 F. Supp. 1009, 1061 (D. N.J. 1985), *aff'd*, 800 F.2d 1130 (3rd Cir. 1986). Indeed, the EIS notes that ERGS is "an opportunity to attain the [Best Technology Available] requirements." *Id.* at 204. Testimony indicated that such "Best Technology Available" structures would ***improve*** present impacts on Lake Michigan, and that fish entrainment would be ***reduced*** compared to the existing intake system. (R.18-157:1516, 3559). After thorough and detailed consideration of the issue, DNR has issued a public notice setting forth its preliminary determination that the proposed once-through cooling system will not cause undue impacts from impingement or entrainment. (WE Supp. App. 101-104).[12]

As to wetlands issues, SCJ/CW's arguments are similarly misplaced. The "Water Resources" Chapter of the EIS (Chapter 8) addresses wetlands at length, describing the implicated wetlands by acreage, type, and significance, *see* EIS at 197-200; outlining anticipated impacts, *id.* at 216-217; and noting the independent DNR requirements that must be satisfied. *Id.* at 217, 226. The "Land Resources" Chapter of the EIS (Chapter 10), further addresses the "potential impacts on the natural resources that are part of [the] landscape," including wetlands and wildlife issues relating to development on this "brownfield" land. *Id.* at 247-283. The "Conditional Use Permit (CUP) Option" Chapter of the EIS (Chapter 12) addresses wetlands modifications based on the North Site—CUP alternative. *Id.* at 400-401. Through the Chapter 30 permitting process, DNR has, in fact, concluded that ERGS complies with wetlands requirements, will not cause any undue adverse environmental impacts, and "avoids detrimental impacts to wetland functional values to the maximum extent possible." (WE App. 300, ¶¶ 35-36). SCJ/CW's suggestion of vast degradation to wetlands from development of ERGS is simply inaccurate. The EIS appropriately addressed wetlands issues, and DNR has

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[12] Notably, one of the major requests during the CPCN public comment period was for a public fishing dock located near the discharge because of the excellent fishing opportunities. EIS at 345.

conclusively determined that development of ERGS will not compromise important wetlands needs.

Finally, Calpine's suggestion that the EIS is inadequate because it did not make a direct comparison between "water-related impacts" from the ERGS facilities and those at Calpine's facilities has no basis. The EIS did, in fact, include a discussion of Calpine's proposed Fond du Lac facility and the environmental impacts from that facility. EIS at 417-430. Moreover, as set forth above, the EIS thoroughly analyzed the alternative of using natural gas-fired facilities, including Calpine's proposed facility, as a substitute for ERGS.

C. The EIS appropriately addresses site alternatives.

SCJ/CW asserts that "the EIS fails to include any analysis of alternative sites." SCJ/CW Brief at 43. SCJ/CW attempts to redefine the record and substitute its own judgment for the factual determinations of PSC and DNR. Indeed, SCJ/CW seeks to dictate the conclusion of its argument by simply asserting, without citation to the record, that "WEC proposed a single site for the new units: the OCPP." SCJ/CW Brief at 6. This misstates the record. As the CPCN application itself plainly sets forth, and as both DNR and PSC understood and found:

> Three sites for the proposed ERGS were identified in the CPCN application. One of the proposed sites is in the city of Oak Creek in Milwaukee County at the east end of Elm Road, north of the existing OCPP. This site is referred to as the North Site throughout this EIS. A second site, the South Site, is located south of the existing OCPP along the lakeshore. A variation of the South Site was proposed as the applicant's third site alternative. . . . Since the draft EIS was issued, WEPCO and the city of Oak Creek agreed upon another site layout plan for the North Site. This site layout was negotiated as part of the Conditional Use Permit (CUP) process that the applicants agreed to follow

> in their agreement with the city of Oak Creek.

EIS at 2-3.

The EIS assessed the differences among these site alternatives throughout its analysis, including differences with respect to "Land Resources," *see* EIS at 247; "Water Resources," *id.* at 216; and "Air Emissions," *id.* at 162.

Chapter 6 of the EIS is entitled "Overview of Proposed Sites and Technologies," *see* EIS at 95-132, and explains that the site selection process "started with over 140 potential sites . . . reduced through a process that evaluated the sites on various social, environmental, and technical/economic parameters that were embodied in 55 screening criteria." *Id.* at 95. *See, e.g., Custer County Action Association v. Garvey*, 256 F.3d 1024, 1041 (10th Cir. 2001) (noting that alternatives that do not accomplish the goals of the project being proposed need not be addressed); *Laguna Greenbelt, Inc. v. U.S. Department of Transportation*, 42 F.3d 517, 524 (9th Cir. 1994) ("[T]here is no minimum number of alternatives that must be discussed.").

As to the final sites selected for ultimate comparison in the EIS, Chapter 6 notes:

> Although the sites would share the use of some of the common existing OCPP infrastructure such as the coal-handling equipment, rail lines and ash landfills, there are several ways in which the sites can be differentiated as alternative sites. These differences include: 1) having building footprints in different municipalities and counties resulting in different entities receiving shared-revenue payments if the ERGS proposal is approved, 2) separate [surface] water discharge locations, and 3) significant differences in the amount of excavation to build and safely operate the facilities.

Id. at 96.

SCJ/CW's simple re-labeling of these alternative sites as "the OCPP site" provides no grounds to cast aside the factual findings and exercise of delegated discretion of the agencies that "alternative sites" were presented and analyzed. § 227.57(6), Wis. Stats.

Moreover, it bears emphasis that despite the repeated suggestions by SCJ/CW that grave adverse environmental consequences attend the site ultimately approved for ERGS, the findings of DNR rendered throughout the environmental permitting process are squarely to the contrary: By its air permit, "DNR determined that ERGS would not likely pose a significant inhalation risk if operated according to required standards" and that "the benefits of construction of ERGS significantly outweighed the environmental and social costs imposed as a result of its location and construction" (WE App. 272, ¶¶ 34, 41); by its Chapter 30 permit, DNR concluded that dredging and grading activities at the location "will not cause environmental pollution," that the site "avoids detrimental impacts to wetland functional values to the maximum extent possible," and that "the most important wetlands have largely been preserved and will be protected and enhanced by the plan to minimize secondary impacts," *id.* at 296-301, ¶¶ 10, 24, 36, 39; by its public notice on the WPDES permit, DNR has preliminarily concluded that the cooling system will have no undue adverse impact on aquatic life and "assure[s] the protection and propagation of a balanced indigenous population of shellfish, fish, and aquatic life in Lake Michigan." (WE Supp. App. 102).

D. The EIS appropriately addressed potential adverse impacts and appropriately responds to public comments.

Despite the 53-page Chapter 7 of the EIS dedicated to the subject of "Air Emissions," *see* EIS at 133-178, SCJ/CW argues that the EIS fails to competently address the potential impacts of air pollution. SCJ/CW Brief at 44-45. It does so

on the grounds that the testimony proffered by its retained expert warranted further examination of health impacts. *Id.* The argument is unavailing.

First, the discussion of air emissions in the EIS is extensive. The EIS discusses the "criteria" air pollutants involved, *see* EIS at 133-140, 146, as well as other potentially hazardous air pollutants and mercury, *id.* at 141-42, greenhouse gases, *id.* at 138, and ozone and ozone precursors. *Id.* at 139. The EIS includes estimates of emissions expected at ERGS and National Ambient Air Quality Standards (NAAQS). *Id.* at 169-171, 457-62. The effects of these emissions are considered with respect to the federal acid rain program, *id.* at 152; the Wisconsin ambient air quality requirements, *id.* at 154; and the program for prevention of significant deterioration, *id.* at 161-62. The EIS discusses mitigation of these emissions using the "Best Available Control Technology" throughout construction and operation of ERGS. *Id.* at 168-170, 447-456.

Second, as set forth above with respect to SCJ/CW's arguments regarding EGEAS modeling, and as noted in the EIS, the purported adverse health impacts presented by SCJ/CW's expert are highly controversial and speculative. Volume 3 of the EIS notes: (1) there is no clear threshold defining a safe versus an unsafe exposure to $PM_{2.5}$; (2) initial air modeling showed that $PM_{2.5}$ emissions would be below the limits promulgated by EPA; and (3) given the current state of scientific knowledge, it is not possible to quantify the effects of mercury. EIS at 20-23. *See also Sierra Club*, 310 F. Supp. 2d at 1188 (rejecting similar challenge to EIS because of scientific uncertainty); *Laguna Greenbelt*, 42 F.3d at 526 ("NEPA does not require us to decide whether an EIS is based on the best scientific methodology available or to resolve disagreements among various experts."); *accord Baltimore Gas & Electric*, 462 U.S. at 103 ("When examining this kind of scientific determination, . . . a reviewing court must generally be at its most deferential.").

In issuing the air permit, DNR ultimately concluded that ERGS is not likely to pose a significant inhalation risk if

operated according to required standards. (WE App. 272, 285-286).

SCJ/CW also asserts that the EIS fails to appropriately address impacts from required upgrades to transmission facilities. SCJ/CW Brief at 45-47. The argument is factually incorrect. The EIS does, in fact, address potential transmission upgrades and contains preliminary estimates of ERGS-related transmission costs. Chapter 6 discusses "electric transmission" issues, including "interconnection," "substation changes," "possible system-wide transmission impacts," "stability issues," and "projected costs." EIS at 126-132. Chapter 11 of the EIS also contains a section entitled "Electric Transmission Proposals and Impacts" further addressing the design, location, and potential environmental impacts of "electric transmission needs" for ERGS. EIS at 381-89.

Calpine's conclusory and unsupported assertion that the EIS does not address "cumulative impacts on water related resources" is wrong. Calpine Brief at 40-41. Chapter 8 of the EIS provides just such a comprehensive, cumulative 47-page analysis of the potential impacts of ERGS on "water-related resources." EIS at 179-226.

Finally, SCJ/CW's argument that the "responsiveness summary is inadequate" is belied by the record. PSC staff produced a 43-page "responsiveness summary" responding to comments on the draft EIS and explaining whether and how comments were used to prepare the final EIS. As the EIS states: "The staff of PSC and DNR have given careful consideration to all of the comments received and have attempted to reflect as many of the comments as possible in the text of the final EIS as well as this volume." EIS Vol. 3, at 2. WEPA does not require that the agency adopt every request made during the comment period. *See WED*, 98 Wis. 2d at 702 ("[A]n agency has no duty to justify the rejection of figures or methods urged by other interested parties."); *accord Vermont Yankee*, 435 U.S. at 551.

Viewed under an appropriate "rule of reason" and according appropriate great weight deference to the independent determinations of both DNR and the Commission that the EIS was adequate for purposes of the decision at issue, Cross-Appellants' isolated challenges provide no basis for reversal. *See, e.g., Citizens' Utility Board*, 211 Wis. 2d at 551-53.

CONCLUSION

For the foregoing reasons, WE respectfully requests that the Court deny the issues raised on this cross appeal and promptly reinstate the Commission's November 10, 2003 Final Decision and Order.

Dated this 24th day of February, 2005.

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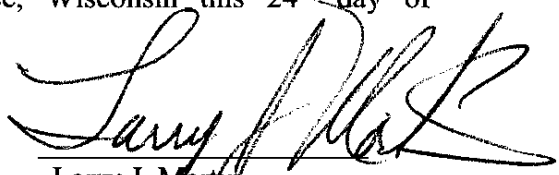
CERTIFICATION PURSUANT TO
§ 809.19(8)(b), WIS. STATS.

I hereby certify that this brief conforms to the rules contained in § 809.19(8)(b) and (c) for a brief produced with a proportional serif font. The length of this brief is 10,943 words.

Dated at Milwaukee, Wisconsin this 24th day of February, 2005.



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CPCN Statute - § 196.491(3), Wis. Stats. (2002)

(3) CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY. (a) 1. No person may commence the construction of a facility unless the person has applied for and received a certificate of public convenience and necessity from the commission as provided in this section. An application in the form and containing the information required by commission rules for such certificate shall be filed with the commission not less than 6 months prior to the commencement of construction of a facility. Within 10 days after filing the application, the commission shall send a copy of the application to the clerk of each municipality and town in which the proposed facility is to be located and to the main public library in each such county.

2. The commission shall determine whether an application filed under subd. 1. is complete and, no later than 30 days after the application is filed, notify the applicant about the determination. If the commission determines that the application is incomplete, the notice shall state the reason for the determination. An applicant may supplement and refile an application that the commission has determined to be incomplete. There is no limit on the number of times that an applicant may refile an application under this subdivision. If the commission fails to determine whether an application is complete within 30 days after the application is filed, the application shall be considered to be complete.

3. a. At least 60 days before a person files an application under subd. 1., the person shall provide the department with an engineering plan showing the location of the facility, a description of the facility, including the major components of the facility that have a significant air, water or solid waste pollution potential, and a description of the anticipated effects of the facility on air and water quality. Within 30 days after a person provides an engineering plan, the department shall provide the person with a listing of each department permit or approval which, on the basis of the information contained in the engineering plan, appears to be required for the construction or operation of the facility.

b. Within 20 days after the department provides a listing specified in subd. 3. a. to a person, the person shall apply for the permits and approvals identified in the listing. The department shall determine whether an application under this subd. 3. b. is complete and, no later than 30 days after the application is filed, notify the applicant about the determination. If the department determines that the application is incomplete, the notice shall state the reason for the determination. An applicant may supplement and refile an application that the department has determined to be incomplete. There is no limit on the number of times that an applicant may refile an application under this subd. 3. b. If the department fails to determine whether an application is complete within 30 days after the application is filed, the application shall be considered to be complete. The department shall complete action on an application under this subd. 3. b. for any permit or approval that is required prior to construction of a facility within 120 days after the date on which the application is determined or considered to be complete.

(b) The commission shall hold a public hearing on an application that is determined or considered to be complete in the area affected pursuant to s. 227.44. A class 1 notice, under ch. 985, shall be given at least 30 days prior to the hearing.

(d) Except as provided under par. (e) and s. 196.493, the commission shall approve an application for a certificate of public convenience and necessity only if the commission determines all of the following:

2. The proposed facility satisfies the reasonable needs of the public for an adequate supply of electric energy. This subdivision does not apply to a wholesale merchant plant.

3. The design and location or route is in the public interest considering alternative sources of supply, alternative locations or routes, individual hardships, engineering, economic, safety, reliability and environmental factors, except that the commission may not consider alternative sources of supply or engineering or economic factors if the application is for a wholesale merchant plant. In its consideration of environmental factors, the commission may not determine that the design and location or route is not in the public interest because of the impact of air pollution if the proposed facility will meet the requirements of ch. 285.

3m. For a high-voltage transmission line, as defined in s. 30.40 (3r), that is to be located in the lower Wisconsin state riverway, as defined in s. 30.40 (15), the high-voltage transmission line will not impair, to the extent practicable, the scenic beauty or the natural value of the riverway. The commission may not require that a high-voltage transmission line, as defined in s. 30.40 (3r), be placed underground in order for it to approve an application.

3r. For a high-voltage transmission line that is proposed to increase the transmission import capability into this state, existing rights-of-way are used to the extent practicable and the routing and design of the high-voltage transmission line minimizes environmental impacts in a manner that is consistent with achieving reasonable electric rates.

3t. For a high-voltage transmission line that is designed for operation at a nominal voltage of 345 kilovolts or more, the high-voltage transmission line provides usage, service or increased regional reliability benefits to the wholesale and retail customers or members in this state and the benefits of the high-voltage transmission line are reasonable in relation to the cost of the high-voltage transmission line.

4. The proposed facility will not have undue adverse impact on other environmental values such as, but not limited to, ecological balance, public health and welfare, historic sites, geological formations, the aesthetics of land and water and recreational use. In its consideration of the impact on other environmental values, the commission may not determine that the proposed facility will have an undue adverse impact on these values because of the impact of air pollution if the proposed facility will meet the requirements of ch. 285.

5. The proposed facility complies with the criteria under s. 196.49 (3) (b) if the application is by a public utility as defined in s. 196.01.

6. The proposed facility will not unreasonably interfere with the orderly land use and development plans for the area involved.

7. The proposed facility will not have a material adverse impact on competition in the relevant wholesale electric service market.

(dm) In making a determination required under par. (d), the commission may not consider a factual conclusion in a strategic energy assessment unless the conclusion is independently corroborated in the hearing under par. (b).

(e) If the application does not meet the criteria under par. (d), the commission shall reject the application or approve the application with such modifications as are necessary for an affirmative finding under par. (d). The commission may not issue a certificate of public convenience and necessity until the department has issued all permits and approvals identified in the listing specified in par. (a) 3. a. that are required prior to construction.

(g)1. The commission shall take final action on an application within 180 days after the application is determined or considered to be complete under par. (a) 2. If the commission fails to take final action within the 180-day period, the commission is considered to have issued a certificate of public convenience and necessity with respect to the application, unless the commission, within the 180-day period, petitions the circuit court for Dane County for an extension of time for taking final action on the application and the court grants an extension. Upon a showing of good cause, the court may extend the 180-day period for no more than an additional 180 days. If the commission fails to take final action within the extended period, the commission is considered to have issued a certificate of public convenience and necessity with respect to the application.

1m. Subdivision 1. does not apply to an application for a certificate of public convenience and necessity if another state is also taking action on the same or a related application.

(gm) The commission may not approve an application filed after October 29, 1999, under this section for a certificate of public convenience and necessity for a high-voltage transmission line that is designed for operation at a nominal voltage of 345 kilovolts or more unless the approval includes the condition that the applicant shall pay the fees specified in sub. (3g)(a). If the commission has approved an application under this section for a certificate of public convenience and necessity for a high-voltage transmission line that is designed for operation at a nominal voltage of 345 kilovolts or more that was filed after April 1, 1999, and before October 29, 1999, the commission shall require the applicant to pay the fees specified in sub. (3g)(a). For any application subject to this paragraph, the commission shall determine the cost of the high-voltage transmission line, identify the counties, towns, villages and cities through which the high-voltage transmission line is routed and allocate the amount of investment associated with the high-voltage transmission line to each such county, town, village and city.

(h) The commission may waive compliance with any requirement of this section to the extent necessary to restore service which has been substantially interrupted by a natural catastrophe, accident, sabotage or act of God.

(i) If installation or utilization of a facility for which a certificate of convenience and necessity has been granted is precluded or inhibited by a local ordinance, the installation and utilization of the facility may nevertheless proceed.

(j) Any person whose substantial rights may be adversely affected or any county, municipality or town having jurisdiction over land affected by a certificate of public convenience and necessity may petition for judicial review, under ch. 227, of any decision of the commission regarding the certificate.

(k) No person may purchase, or acquire an option to purchase, any interest in real property knowing that such property is being purchased to be used for the construction of a high-voltage transmission line unless the person gives written notice to the prospective seller of the size, maximum voltage and structure type of any transmission line planned to be constructed thereon and the person by whom it will be operated. Contracts made in violation of this paragraph are subject to rescission by the seller at any time prior to the issuance of a certificate of public convenience and necessity for the high-- voltage transmission line by the commission.

(3c) COMMENCEMENT OF CONSTRUCTION OF LARGE ELECTRIC GENERATING FACILITIES. (a) Except as provided in par. (b), an electric utility that has received a certificate of public convenience and necessity under sub. (3) for constructing a large electric generating facility shall commence construction no later than one year after the latest of the following:

1. The date on which the commission issues the certificate of public convenience and necessity.

2. The date on which the electric utility has been issued every federal and state permit, approval, and license that is required prior to commencement of construction.

3. The date on which every deadline has expired for requesting administrative review or reconsideration of every federal and state permit, approval, and license that is required prior to commencement of construction.

4. The date on which the electric utility has received the final decision, after exhaustion of judicial review, in every proceeding for judicial review described in sub. (3)(j).

(b) Upon showing of good cause, the commission may grant an extension to the deadline specified in par. (a).

(c) If an electric utility does not commence construction of a large electric generating facility within the deadline specified in par. (a) or extended under par. (b), the certificate of public convenience and necessity is void, and the electric utility may not commence construction of the large electric generating facility.

WEPA - § 1.11, Wis. Stats.

§ 1.11. Governmental consideration of environmental impact. The legislature authorizes and directs that, to the fullest extent possible:

(1) The policies and regulations shall be interpreted and administered in accordance with the policies set forth in this section and chapter 274, laws of 1971, section 1; and

(2) All agencies of the state shall:

(c) Include in every recommendation or report on proposals for legislation and other major actions significantly affecting the quality of the human environment, a detailed statement, substantially following the guidelines issued by the United States council on environmental quality under P.L. 91-190, 42 USC 4331, by the responsible official on:

1. The environmental impact of the proposed action;

2. Any adverse environmental effects which cannot be avoided should the proposal be implemented;

3. Alternatives to the proposed action;

4. The relationship between local short-term uses of the human environment and the maintenance and enhancement of long-term productivity;

5. Any irreversible and irretrievable commitments of resources that would be involved in the proposed action should it be implemented; and

6. Such statement shall also contain details of the beneficial aspects of the proposed project, both short term and long term, and the economic advantages and disadvantages of the proposal.

(d) Prior to making any detailed statement, the responsible official shall consult with and obtain the comments of any agency which has jurisdiction or special expertise with respect to any environmental impact involved. Copies of such statement and the comments and views of the appropriate agencies, which are authorized to develop and enforce environmental standards shall be made available to the governor, the department of natural resources and to the public. Every proposal other than for legislation shall receive a public hearing before a final decision is made. Holding a public hearing as required by another statute fulfills this section. If no public hearing is otherwise required, the responsible agency shall hold the hearing in the area affected. Notice of the hearing shall be given by publishing a class 1 notice, under ch. 985, at least 15 days prior to the hearing in a newspaper covering the affected area. If the proposal has statewide significance, notice shall be published in the official state newspaper;

(e) Study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources;

(h) Initiate and utilize ecological information in the planning and development of resource-oriented projects.

(j) Annually, no later than September 15, submit a report to the chief clerk of each house of the legislature for distribution to the legislature under s. 13.172(2), including the number of proposed actions for which the agency conducted an assessment of whether an impact statement was required under par. (c) and the number of impact statements prepared under par. (c).

(4) Nothing in this section affects the specific statutory obligations of any agency:

(a) To comply with criteria or standards of environmental quality;

(b) To coordinate or consult with any other state or federal agency; or

(c) To act, or refrain from acting contingent upon the recommendations or certification of any other state or federal agency.

(5) The policies and goals set forth in this section are supplementary to those set forth in existing authorizations of agencies.

Wis. Admin. Code § PSC 4.30

PSC 4.30 Environmental impact statement procedures.

(1) General information. (a) An EIS shall inform the commission and the public of significant environmental impacts of a proposed action and its alternatives, and reasonable methods of avoiding or minimizing adverse environmental effects. The environmental analysis shall be consistent with the regulations issued by the U.S. council on environmental quality, 40 CFR Parts 1500 to 1508.

(b) Each EIS shall evaluate reasonably foreseeable, significant effects to the human environment and significant socioeconomic effects of the proposal and its alternatives. If information relevant to evaluating these effects is incomplete or unavailable, the EIS shall:

1. Indicate the availability of the information.

2. Describe the information's relevance.

3. Summarize available, credible scientific evidence that is relevant to the evaluation.

4. Evaluate effects based upon theoretical approaches or research methods generally accepted in the scientific community.

(c) For each action requiring an EIS, the commission shall prepare both a draft EIS and a final EIS.

(2) Scoping. Scoping shall begin early in the process of preparing an EIS. The commission shall request any person it believes is interested in a proposed action to participate in scoping the proposed action. Scoping is an aid to help the commission identify all of a project's relevant environmental concerns and reasonable alternatives. Scoping may be achieved by means of meetings, hearings, workshops, surveys, questionnaires, interagency committees, requests for written comments, and other methods and combinations of methods that the commission considers appropriate. The commission may also integrate scoping with other public participation requirements.

(3) Content. Based on information obtained from the project applicant, scoping, site inspection, commission research, governmental agencies and other relevant sources, an EIS shall include:

(a) A description of the proposed action and the affected environment and other relevant information.

(am) A description of the purpose of the proposed action and of the need for the proposed action.

(b) An analysis of the probable impact of the proposed action on the environment, including:

1. An evaluation of positive and negative effects on the affected local and regional environments, including the proposed action's direct, indirect and cumulative environmental effects.

2. An analysis of any probable adverse environmental effects that would be unavoidable if the action is approved. This analysis shall consider:

a. The proposed action's short-term and long-term effects.

b. Any irreversible and irretrievable commitments of resources.

3. A statement of how other adverse effects could be mitigated or prevented if the commission approves a proposed action.

(c) An evaluation of the reasonable alternatives to the proposed action and significant environmental consequences of the alternatives, including those alternatives that could avoid some or all of the proposed action's adverse environmental effects and the alternative of taking no action.

(d) A proposed action's socioeconomic effects.

(e) A proposed action's effect on energy usage, including an evaluation of the technical feasibility of alternatives, pursuant to s. 1.12, Stats.

(f) An evaluation of the archeological, architectural and historic significance of any affected resources. This evaluation shall include consultation with the state historical society of Wisconsin.

(g) An evaluation of the effects of a proposed action on agriculture. If the proposed action may result in condemnation of farmland, the commission shall coordinate preparation of an EIS with the Wisconsin department of agriculture, trade and consumer protection. To the extent possible, an EIS for a proposed action that affects agriculture shall incorporate the provisions of an agricultural impact statement under s. 32.035 (4), Stats., so the EIS can also serve the functions of an agricultural impact statement under s. 32.035 (3), Stats.

(h) A summary of the scoping process used and the major issues identified for analysis in the EIS.

(4) Draft environmental impact statements. (a) A draft EIS is a preliminary document, clearly describing a proposed project and the alternatives being considered so that other persons can begin assessing the environmental effects of the proposal.

(b) Each draft EIS shall include a preliminary evaluation of the information described in sub. (3).

(c) The commission shall distribute a copy of each draft EIS to:

1. The governor.

2. Each county, state or federal agency and each Indian tribe the commission knows has special expertise or interest in the proposed project.

3. The state historical society of Wisconsin library.

4. The Wisconsin legislative reference bureau.

5. Each of the regional depository libraries.

6. The Wisconsin department of natural resources.

7. The project applicant.

8. Any person who requests a copy.

9. For a proposed action affecting a local area:

a. The public library nearest to the proposed project.

b. The county and the town or municipality chief executive officer for the project area.

c. Each regional, county and town or municipal planning agency with jurisdiction over the project area.

d. The Wisconsin department of natural resources field office with jurisdiction over the project area.

10. For a proposed action affecting a region of the state or the state as a whole:

a. One or more public libraries whose geographic distribution provides public access without undue travel.

b. The chief executive officer of each county in the project area.

c. Each regional planning commission and each county planning or zoning agency with jurisdiction over the project area.

d. Each Wisconsin department of natural resources field office with jurisdiction over the project area.

(d) The commission shall notify the public about the availability of the draft EIS. The notice shall include a description of the proposed action and of the administrative procedures to be followed, the last date to submit comments on the draft EIS to the commission, the locations where copies of the draft EIS are available for review, the commission's contact person and, if known, the date of the public hearing. The commission shall deliver a copy of the notice to:

1. Any person with a demonstrated interest in the draft EIS or who has requested to receive this type of information.

2. Any person who participated in scoping the EIS.

3. For a proposed action affecting a local area:

a. The nearest public library.

b. The county clerk and the town or municipal clerk for the project area, with a request that the clerks post the notice publicly.

c. The county, town, village or city chief executive officer in the project area.

d. Local news media.

e. The regional planning commission.

4. For a proposed action affecting a region of the state or the state as a whole:

a. The public libraries specified in par. (c) 10.

b. The county clerks in the proposed project area, with a request that the clerks post the notice publicly.

c. The county chief executive officers in the proposed project area.

d. Regional news media.

(e) 1. Except as provided in subd. 2., the commission shall allow the public at least 45 days, commencing with the date the draft EIS is mailed or personally served, to comment on the draft EIS.

2. The commission may shorten the public review period under subd. 1. for cause. If so, the commission shall include in its notice under par. (d) a statement calling attention to the reduced review period, specifying the date comments on the draft EIS are due to the commission in order to be considered in developing a final EIS, and describing the reasons why the commission decided to shorten the review period. The commission may also grant reasonable requests to extend the comment period.

(5) Final environmental impact statements.

(a) Following the public review period on a draft EIS, the commission shall prepare a final EIS. The final EIS may vary from the draft EIS in scope, based on comments received on the draft EIS or other pertinent information that becomes known to the commission. The final EIS shall contain the information described in sub. (3).

(b) The commission shall distribute a copy of the final EIS to the same persons who received a copy of the draft EIS under sub. (4) (c), and to any other person who requests a copy of the draft EIS or comments on the draft EIS.

(c) The commission shall notify the public about the availability of the final EIS in the manner specified for a draft EIS under sub. (4) (d), or by including a statement in a notice of hearing.

(d) 1. Except as provided in subd. 2., the commission shall distribute copies of the final EIS to the public and announce its availability at least 30 days before it holds a public hearing on the proposed action. The review period required under this paragraph commences with the date a final EIS is distributed.

2. The commission may shorten the public review period under subd. 1. for cause. If so, the commission shall include in its notice under par. (c) a statement calling attention to the reduced review period, and describing the reasons why the commission decided to shorten the review period. The commission may also grant reasonable requests to extend the public review period.

History: Cr. Register, July, 1995, No. 475, eff. 8-1-95.
Current through Reg. No. 586 (October 2004)

§ 227.57, Wis. Stats. (2002)

§ 227.57. Scope of review.

(1) The review shall be conducted by the court without a jury and shall be confined to the record, except that in cases of alleged irregularities in procedure before the agency, testimony thereon may be taken in the court and, if leave is granted to take such testimony, depositions and written interrogatories may be taken prior to the date set for hearing as provided in ch. 804 if proper cause is shown therefor.

(2) Unless the court finds a ground for setting aside, modifying, remanding or ordering agency action or ancillary relief under a specified provision of this section, it shall affirm the agency's action.

(3) The court shall separately treat disputed issues of agency procedure, interpretations of law, determinations of fact or policy within the agency's exercise of delegated discretion.

(4) The court shall remand the case to the agency for further action if it finds that either the fairness of the proceedings or the correctness of the action has been impaired by a material error in procedure or a failure to follow prescribed procedure.

(5) The court shall set aside or modify the agency action if it finds that the agency has erroneously interpreted a provision of law and a correct interpretation compels a particular action, or it shall remand the case to the agency for further action under a correct interpretation of the provision of law.

(6) If the agency's action depends on any fact found by the agency in a contested case proceeding, the court shall not substitute its judgment for that of the agency as to the weight of the evidence on any disputed finding of fact. The court shall, however, set aside agency action or remand the case to the agency if it finds that the agency's action depends on any finding of fact that is not supported by substantial evidence in the record.

(7) If the agency's action depends on facts determined without a hearing, the court shall set aside, modify or order agency action if the facts compel a particular action as a matter of law, or it may remand the case to the agency for further examination and action within the agency's responsibility.

(8) The court shall reverse or remand the case to the agency if it finds that the agency's exercise of discretion is outside the range of discretion delegated to the agency by law; is inconsistent with an agency rule, an officially stated agency policy or a prior agency practice, if deviation therefrom is not explained to the satisfaction of the court by the agency; or is otherwise in violation of a constitutional or statutory provision; but the court shall not substitute its judgment for that of the agency on an issue of discretion.

(9) The court's decision shall provide whatever relief is appropriate irrespective of the original form of the petition. If the court sets aside agency action or remands the case to the agency for further proceedings, it may make such interlocutory order as it finds necessary to preserve the interests of any party and the public pending further proceedings or agency action.

(10) Upon such review due weight shall be accorded the experience, technical competence, and specialized knowledge of the agency involved, as well as discretionary authority conferred upon it. The right of the appellant to challenge the constitutionality of any act or of its application to the appellant shall not be foreclosed or impaired by the fact that the appellant has applied for or holds a license, permit or privilege under such act.

INDEX TO WE SUPPLEMENTAL APPENDIX

January 12, 2005 Wisconsin Department of Natural Resources Notice of Intent to Reissue a Wisconsin Pollutant Discharge Elimination System (WPDES) Permit 101-04

July 2003 Final Environmental Impact Statement (R.18-119) ..... Submitted Separately

STATE OF WISCONSIN DEPARTMENT OF NATURAL RESOURCES
PUBLIC NOTICE OF:

- **INTENT TO REISSUE A WISCONSIN POLLUTANT DISCHARGE ELIMINATION SYSTEM (WPDES) PERMIT No.WI-0000914-07-0**
- **RECEIPT OF AN APPLICATION FOR A WATER LOSS APPROVAL**
- **INFORMATIONAL HEARING TO ADDRESS THE ABOVE ITEMS**

INTENT TO REISSUE PERMIT

Permittee: **Wisconsin Electric (WE) Power Company**
Discharge Facility Location: **4801 EAST ELM ROAD, OAK CREEK, WI 53154**
Receiving Water: **LAKE MICHIGAN, MILWAUKEE COUNTY**

Brief Facility Description:
The existing Oak Creek Power Plant (OCPP) is a coal fired steam electric power generating station located on the shore of Lake Michigan. It is comprised of four operating boilers supplying steam to individual turbine generators with a total capacity of about 1,170 megawatts (MW). The power plant generating units are identified as 5, 6, 7, and 8. Units 1, 2, 3, and 4 were retired in 1989. WE is proposing to construct two new coal fired generating units to be located immediately north of retired units 1-4. Each unit is to have a rated capacity of 615 MW. The proposed two new units are known as the Elm Road Generating Station (ERGS), and the combined existing and new generating units are known as the Oak Creek/Elm Road (OCER) Power Plant. The proposed reissued WPDES permit is intended to regulate the wastewater discharges from the entire OCER Power Plant.

In conjunction with the construction of the ERGS, WE is proposing to construct a new offshore intake structure in Lake Michigan that will supply water for the service water and condenser cooling water needs of the OCER Power Plant. The existing on-shore intake channel will be modified to serve as a back-up intake.

Section 316(b) of the Clean Water Act and s. 283.31(6), Wis. Stats., require that the location, design, construction, and capacity of cooling water intake structures (CWIS) reflect the best technology available (BTA) for minimizing adverse environmental impacts. WE has proposed that the new intake structure be located approximately 7,900 feet off-shore from the existing OCPP, that it consist of an array of 24 submerged wedge-wire screens with a screen slot-width of 9.5 millimeters, and that the through-screen velocity be no greater than 0.5 feet per second.

The Department has tentatively determined that the proposed intake structure meets the BTA requirement with regard to reduction in fish impingement, by virtue of having proposed an array of submerged wedge-wire screens and a design through-screen velocity of 0.5 feet per second or less.

WE has conducted two years of sampling for ichthyoplankton at the existing intake and at the site of the proposed off-shore intake. The purpose of the sampling program is to demonstrate that the national performance standard of a minimum of 60% reduction in ichthyoplankton entrainment can be met. Following an analysis of the sampling results, the Department has tentatively determined that the entrainment performance standard in the U.S. EPA regulation will be attained. The modified existing shoreline intake structure will serve as a back-up intake that will be used only for emergency purposes. WE has projected that use of this

emergency intake will occur only 3% of the time. The reissued permit authorizes use of the existing intake for the OCPP until the new CWIS is constructed.

The proposed permit includes a compliance schedule for the additional submittals required by the U.S. EPA regulation for CWIS, including a Verification Monitoring Plan to evaluate the efficacy of the new intake.

The proposed permit contains limitations regulating the discharge of mercury from the ERGS portion of the plant. Part of the air quality system WE is required to install is a flue gas desulfurization (FGD) system. Mercury is present in the FGD system wastewater. This wastewater is treated by a system representing best available technology. The effluent limitation for the combined cooling water and ERGS wastewater system is equal to the most stringent criterion for mercury (1.3 ng/L).

The OCER facility will be discharging heat to Lake Michigan via the condenser cooling water outfalls. Presently, the OCPP facility is not subject to thermal effluent limitations under ss. 283.13 or 283.19, Wis. Stat. WE has proposed thermal effluent limitations, and has filed a petition with the Department under s. 283.17, Wis. Stat., and NR 209, Wis. Adm. Code, for alternative effluent limitations. WE also submitted evidence in support of its request for alternative effluent limitations and requested the establishment of alternative thermal effluent limitations based on the maximum increase in temperature of the cooling water. The report concludes that the existing (OCPP) and proposed (ERGS) thermal discharges will assure the protection and propagation of a balanced indigenous population of shellfish, fish and aquatic life in Lake Michigan. The Department has tentatively concurred with this conclusion and is placing in the proposed permit alternative limitations expressed as 1500 MBTU/hr for outfalls 003 and 004, 1700 MBTU/hr for outfalls 005 and 006, and 6,200 MBTU/hr for outfall 013.

The petition, technical report, and other information are available for public inspection during normal office hours at the permit drafter's office at the address listed below. Any interested party may comment on WE's proposed alternative effluent limitations during the public comment period or by participating in the hearing (as described in this public notice). There may be a further opportunity to address alternative effluent limitations if a valid petition for a contested case hearing pursuant to s. 283.63, Wis. Stats., is filed with the Department.

The Department has tentatively determined that the WPDES permit for the WE OCER plant should be reissued subject to the limitations, monitoring requirements and other terms and conditions contained in the proposed permit.

APPLICATION FOR WATER LOSS APPROVAL

Under the provisions of s. 281.35, Wis. Stats., any water withdrawal that results in a water loss of greater than 2 million gallons per day of water from waters of the Upper Mississippi River or Great Lakes basins is subject to a water loss review by the Department. The OCER power plant is expected to have a water loss that averages in excess of 2 million gallons per day over a 30-day period. As a consequence, WE has applied to the Department for a water loss approval. The grounds for a water loss approval are specified at s. 281.35(5)(d), Wis. Stats., and NR 142.06(3), Wis. Adm. Code, and the approval of the water loss is subject to the review process provided under s. NR 142.06(5), Wis. Adm. Code. The Department has determined that WE has submitted a complete application.

Facility Where Water Loss Will Occur: The OCER power plant, as previously described.

Source of Water Withdrawal and Location: All of the water withdrawn by the OCER power plant comes directly from Lake Michigan. A relatively small amount of water (about 0.6 million gallons per day)is supplied by the City of Oak Creek public water supply that is also drawn from Lake Michigan.

Brief Description of Facility and Water Loss:
The existing OCPP uses Lake Michigan water for cooling water and various other process purposes. The proposed ERGS will also use Lake Michigan water for cooling water, process uses, and air pollution control purposes.

When all condenser cooling water pumps are in operation, the OCPP withdraws 1.177 billion gallons of water per day from Lake Michigan. Nearly all of this water is used for once through condenser cooling and is returned to Lake Michigan. Not all condenser cooling water pumps are in operation all year. On an annual average basis, the flow rate is 0.08718 billion gallons per day. Actual consumptive water use (i.e., water not returned to Lake Michigan), is 36,648 gallons per day. The consumption is a result of steam losses to the atmosphere (14,434 gallons per day) and water contained in byproduct ash and wastewater treatment plant sludge (22,214 gallons per day). The consumptive water loss from the OCPP is, therefore, 0.0042% of the water withdrawn.

When all condenser cooling water pumps are in operation, the ERGS is expected to withdraw 1.0648 billion gallons of water per day from Lake Michigan. Nearly all of this water is used for once-through condenser cooling and is returned to Lake Michigan. Not all condenser cooling water pumps will be in operation all year. On an annual average basis, the expected flow rate is 1.0636 billion gallons per day. Actual consumptive water use is designed to be 2.53 million gallons per day (annual average). The consumption is a result of the following losses:

Bottom ash system evaporative losses	11,520 gallons per day
Water removed with bottom ash solids	8,640 gallons per day
Deaerator & cycle misc. losses	63,360 gallons per day
Soot blowing losses	460,800 gallons per day
Fly ash conditioning	57,600 gallons per day
Water loss at scrubber	1,823,040 gallons per day
Water with gypsum	102,240 gallons per day
Water loss with filter cake	5,760 gallons per day

The total consumptive loss from the combined OCER facility is, therefore, approximately 2.57 million gallons per day. The 0.6 million gallons per day that is withdrawn from the City of Oak Creek public water supply is used primarily as the water source for the demineralizers serving the OCPP and for domestic and miscellaneous potable water uses. The OCPP boiler blowdown and demineralizers regenerant wastes all discharge to the OCPP wastewater treatment plant and consumptive losses from these activities are accounted for in the aforementioned treatment plant sludge. Used domestic and potable water goes to the sanitary sewer and is discharged to Lake Michigan via the Milwaukee Metropolitan Sewerage District South Shore wastewater treatment facility in Oak Creek. Therefore, there is no consumptive loss associated with domestic/potable water uses.

Department's River Basin Contact Name, Address, and Phone: Mike Luba, 9531 Rayne Rd., Suite 4, Sturtevant, WI 53177, 262-884-2369
Permit Drafter's Name, Address and Phone: Daniel Joyce, 101 S. Webster St. PO Box 7921, Madison, WI, 53707-7921, (608) 266-0289

Basin Engineer's Name, Address, and Phone: Jason Chappelle, 9531 Rayne Rd., Suite 4, Sturtevant, WI 53177, 262-884-2362

NOTICE OF INFORMATIONAL HEARING

The Department has scheduled an informational hearing, pursuant to s. 283.49, Wis, Stats., for the purpose of giving all interested persons an opportunity to provide comments to the Department with respect to the above issues. The informational hearing shall be held on February 16, 2005 - 12:30 - 4:00 p.m. at the courtroom of the Oak Creek Police Department, 301 West Ryan Road, Oak Creek, WI.

A hearing officer will conduct the hearing in an orderly and speedy way and will use procedures necessary to insure broad public participation in the hearing. The hearing officer will open the hearing and make a concise statement of the scope and purpose of the hearing and shall state what procedures will be used during the course of the hearing. The hearing officer shall explain the method of notification of the final decision to grant or deny the permit and the methods by which the decision may be reviewed in a public adjudicatory hearing. The hearing officer may put limits on individual oral statements to insure an opportunity for all persons present to make statements in a reasonable period of time and to prevent undue repetition. The hearing officer may also limit the number of representatives making oral statements on behalf of any person or group. Informational and clarifying questions and oral statements shall be directed through the hearing officer. Cross-examination shall not be allowed.

Persons wishing to comment on or object to the proposed permit action, or persons wishing to comment on the application for a water loss approval, are invited to do so by attending the public hearing or by submitting any comments or objections in writing to the Department of Natural Resources, at the above named permit drafter's address. All written comments or suggestions received from members of the public no later than 7 days following the date of this public hearing will be used, along with other information on file and testimony presented at the hearing, in making a final determination.

Information on file for this permit action may be inspected and copied at either the above named permit drafter's address or the above named basin engineer's address, Monday through Friday (except holidays), between 9:00 a.m. and 3:30 p.m. Information on this permit action may also be obtained by calling the permit drafter at (608)266-0289 or by writing to the Department. Reasonable costs (usually 20 cents per page) will be charged for copies of information in the file other than the public notice and fact sheet. Permit information is also available for downloading from the internet using a world wide web browser at: http://www.dnr.state.wi.us/org/water/wm/ww. Pursuant to the Americans with Disabilities Act, reasonable accommodation, including the provision of informational material in an alternative format, will be made to qualified individuals upon request.

FOR THE SECRETARY:
By Charles Hammer, Hearing Officer

PUBLISHING NEWSPAPERS:
Racine Journal-Times – January 14, 2005
Oak Creek Pictorial – January 13, 2005
Milwaukee Journal-Sentinel – January 12, 2005
Wisconsin State Journal – January 13, 2005

APPENDIX

(Supplemental appendix, *Final Environmental Impact Statement: Elm Road Generating Station – Volume 1*, accepted per court order dated 2/24/05)
WI Elec. Power Co., W.E. Power, LLC and WI Energy Corp

July
2003

PUBLIC SERVICE COMMISSION OF WISCONSIN
DEPARTMENT OF NATURAL RESOURCES

Final Environmental Impact Statement

Elm Road Generating Station – Volume 1

Docket 05-CE-130
Date Issued, July 2003

PUBLIC SERVICE COMMISSION OF WISCONSIN

DEPARTMENT OF NATURAL RESOURCES

Elm Road Generating Station

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This is the Publlic Service Commission's Final Environmental Impact Statement for the Elm Road Generating Station project in docket 05-CE-130.

By: Kathleen J. Zuelsdorff

Kathleen J. Zuelsdorff
WEPA Coordinator
Public Service Commission

July 23, '03
Date

Questions about information provided in this Environmental Impact Statement should be directed to:

Kathleen J. Zuelsdorff (Environmental)
Public Service Commission
(608) 266-2730

Or

Kenneth J. Detmer (Engineering)
Public Service Commission
(608) 267-9509

Michael Thompson
Department of Natural Resources
(414) 263-8648

To the Reader:

This final Environmental Impact Statement (EIS) for the Elm Road Generating Station (ERGS) fulfills part of the requirements of the Wisconsin Environmental Policy Act (WEPA) Wis. Stat. § 1.11. WEPA requires state agencies to consider environmental factors when making major decisions. The purpose of this EIS is to provide the decision makers, the public, and other stakeholders with an analysis of the economic, social, cultural, and environmental impacts that could result from the construction of three new coal-fired power plants and their associated facilities. This document has been prepared jointly by the Public Service Commission of Wisconsin (Commission or PSC) and the Wisconsin Department of Natural Resources (DNR).

Many changes have been made to the draft EIS. These modifications have been made in response to written and oral comments received on the draft EIS, new information and proposed changes to the project made by the applicants, and as a result of additional analyses by PSC and DNR staff. Some of the major modifications include:

- A new chapter has been added to describe the new site layout for the proposed ERGS facilities brought forward by the applicants in their direct testimony in late May 2003. To the extent known, the potential environmental and social effects related to the new layout for the North Site have been presented.

- The cost of the ERGS proposal has increased based on information provided by the applicants. This new cost information has been used in the economic analysis of alternatives to this project.

- Additional EGEAS modeling has been performed that includes assumptions about monetization of major pollutants, further consideration of conservation potentials, unlimited wind potential, and retirement of Oak Creek Units 5 and 6 in 2012.

- A new analysis of the thermal pollution effects related to the SCPC and IGCC discharge water has been conducted.

- Additional information about air pollutants such as CO_2 and $PM_{2.5}$ has been added to the Air Emissions chapter.

- A third volume has been prepared to respond to comments, questions, and concerns raised by members of the public and parties to this case.

Alternatively, there are analyses and information that PSC and DNR staff have not been able to present in this document due to insufficient information and the press of time imposed by statutory deadlines. Some of these items include:

- The Department of Natural Resources (DNR) has been unable to complete its air modeling analysis for inclusion in the final EIS due to incomplete air permit applications, continuing changes made to the air modeling parameters by the applicants, and an additional air permit application for the new site layout.

- A comprehensive evaluation of the environmental effects of the new site layout brought forward by the applicants has not been completed. The information provided was incomplete with respect to several of the site features and inconsistent with the information submitted for the original site alternatives. A comparative analysis of the site alternatives, including the new site layout, has not been completed.

- No mitigation plans or strategies have been proposed by the applicants to avoid or minimize the potential adverse effects of the water intake structure, the thermal discharge from the plant, placing fill in wetlands, or the loss of important biological resources. The new site layout brought forward by the applicants in May would result in more wetland filling and greater loss of natural resources and habitat than the original site layouts, if evaluated on a consistent basis.

- The analysis of the proposed IGCC unit could not be completed because the information provided by the applicants was preliminary and is subject to change as technologies mature. PSC staff did supplement the applicants' information with its own analysis, but the applicants declare that the design for their proposed IGCC unit may change.

- Due to the continuing redesign of the project, some of the text and several of the maps and diagrams presented in this final EIS may not be up-to-date.

It is the agencies' intent to provide as much of this information and analysis as possible by the time of the public hearing for this project. The Commission decision on the merits of this project will be based on the record of public hearings, which are scheduled for August and September 2003 in Oak Creek, Caledonia, and Madison, Wisconsin. The Commission will issue the Notice of Hearing for this project in July 2003. The EIS, as well as testimony from the public hearings, will be included in the hearing record. A Commission decision on the proposed project is expected in October 2003.

As necessary the DNR will hold a separate hearing on the application for an air pollution control permit and other water-related permits for this project.

Please use the PSC docket number 05-CE-130 on all e-mail and correspondence. Specific questions on the EIS should be addressed to:

Kathleen J. Zuelsdorff
Public Service Commission
(608) 266-2730
e-mail address: kathleen.zuelsdorff@psc.state.wi.us

Michael Thompson
Department of Natural Resources
(414) 263-8648
e-mail address: michael.thompson@dnr.state.wi.us

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Executive Summary

Wisconsin Energy (WEC); Wisconsin Electric Power Company (WEPCO); and WE Power, LLC (WE Power), a non-utility affiliate are proposing to build approximately 1,830 MW of advanced technology coal-based generating capacity.

The applicants have applied to the Public Service Commission of Wisconsin (Commission or PSC) for a Certificate of Public Convenience and Necessity (CPCN) under Wis. Stat. § 196.491(3), and Wis. Admin. Code PSC ch. 1.11, and for any additional approvals required from the Commission to construct and operate a large electric power generating facility under Wisconsin's leased generation law, Wis. Stat. § 196.52(9).

The new facility, the Elm Road Generating Station (ERGS), would consist of two super-critical pulverized coal (SCPC) units and one integrated gasification combined-cycle (IGCC) unit, all constructed on or adjacent to a site containing WEPCO's existing Oak Creek Power Plant (OCPP). The proposed in-service dates for the two SCPC units are 2007 and 2009. The IGCC is proposed to begin commercial operation in 2011.

Bituminous coal from Pennsylvania would be the primary fuel for the SCPC and IGCC generating units. The assumed capacity factor for the SCPC facility is in the range of 85 to 90 percent and the assumed capacity factor for the IGCC facility would range from 75 to 80 percent. The applicants expect the plant to be operated, for the majority of the year, as a base-load facility over a life time of 40 to 45 years. The plants are expected to operate 24 hours per day. Each unit would be expected to operate about 10.5 to 11.0 months per year.

Under the leased generation approach, WEPCO would enter into a long-term facility lease with two wholly owned subsidiaries of its non-utility affiliate company known as WE Power. These subsidiaries of WE Power are ERGS Supercritical LLC and ERGS IGCC LLC. The WE Power subsidiaries would construct and have major ownership interest in the facilities, but lease the generating units to WEPCO at economic terms and conditions reviewed, regulated, and approved by the PSC. Other interest utilities might have ownership interests in the facilities as well, but WE Power companies would own no less than 83 percent of each of the new generating units. WEPCO would operate the coal facilities at the ERGS. Operation would include staffing, maintenance, and fuel procurement.

Proposed sites

The proposed sites for the ERGS are on a large parcel of land located along the shore of Lake Michigan near the existing Oak Creek Power Plant (OCPP). The entire parcel of land owned by WEPCO is approximately 1,000 acres in size. Much of the land currently functions as buffer area around the existing OCPP.

Three sites for the proposed ERGS were identified in the CPCN application. One of the proposed sites is in the city of Oak Creek in Milwaukee County at the east end of Elm Road, north of the existing OCPP. This site is referred to as the North Site throughout this EIS. A second site, the South Site, is located on a portion of the property that is south of the existing OCPP, along the lakeshore in Racine County. A variation of the South Site was proposed as the applicants' third site alternative. In this variation, the SCPC units would be

placed in the same location as for the South Site, but the IGCC facility would be built on land that is currently state and federally owned and used as a shooting range. For purposes of description and analysis in this document, this variation is referred to as the South Site-Exp option.

After the draft EIS was issued, WEPCO designed another site layout plan for use at the North Site. This site layout was negotiated as part of the Conditional Use Permit (CUP) process that the applicants agreed to follow in their agreement with the city of Oak Creek. The applicants have stated that they would be willing to build the ERGS facilities as proposed in their CPCN application (with some exceptions), but that they would like to have the new site layout considered by the Commission in its final decision on the project. In order to have this option, hereafter referred to as the CUP Option, available for consideration by the Commission, PSC and DNR staff have reviewed the new site layout for the CUP Option and assessed its environmental effectsto the extent possible. In the CUP Option, the two SCPC units and the IGCC unit would be placed at approximately the same location as in the original North Site layout. The new option involves relocating the coal storage area, splitting and relocating the existing 138/345 kV substation, adding a new access road, and altering the location and configuration of soil deposition areas. A detailed description of the new layout and some of its potential environmental effects are described in Chapter 12 of this final EIS.

Cost of the ERGS project

The cost to construct two SCPC units and the IGCC plant would be approximately $4.15 billion. Estimated costs for the ERGS project on a per unit basis are listed in Table ES-1.

Table ES-1 ERGS estimated construction costs on a per unit basis

Item	Unit 1 SCPC (2003)	Unit 2 SCPC (2003)	Unit 3 IGCC (2003)
Generating Unit (2003 $)	922,140,000	623,470,000	843,394,000
Shared Facilities	335,750,000	28,220,000	59,171,000
Escalation	125,412,000	78,594,000	147,118,000
Carrying Cost	261,300,000	275,200,000	298,900,000
Retirement Cost	138,330,000	73,028,000	104,968,000
TOTAL	1,782,932,000	1,078,512,000	1,453,551,000
TOTAL, 3 UNITS	4,314,995,000		

* Each unit has $13 million included for additional train costs.
** Escalation is for general inflation as measured by the GDP price deflator.
*** Carrying costs represent the interest on the capital invested in the project.
**** Retirement costs include amounts necessary to tear down the facility.

The costs provided to the PSC for the ERGS are not as certain as those provided for the Port Washington units.[1] The estimated costs for the ERGS are on a "cost-up to 10 percent cap" basis, rather than a "firm" basis like the Port Washington costs.[2] In May 2003 diect testimony filed by WEPCO, it indicates that

[1] Introduction and Application booklet, p. 12 of the CPCN application and Volume 1, Enclosure 8, page 1
[2] In the Port Washington CPCN, WE Power indicated that it would bear the risk of cost overruns unless the overruns were due to unpredictable occurrences beyond WE Power's control or changes in the general inflation level. The Commission accepted and approved such a "hold-to" treatment for the Port Washington combined-cycle units. Examples of unpredictable occurrences beyond WE Power's control included changes in laws or government regulations and Act-of God or similar events.

project costs would be capped at no more than 10 percent above the construction estimates in this proceeding.

In the present ERGS docket, WE Power has indicated that a strong "hold-to" cost treatment such as that for the Port Washington facilities is not possible, thus placing some of the risk of any cost overruns on ratepayers. However, in its direct testimony WEPCO now indicates that any cost overrun would be capped at 10 percent. The implication of the estimated project costs, including the cost uncertainties, on ratepayers is discussed below.

WEPCO has indicated that the construction cost of each SCPC unit would be $1,400,000 per MW in 2003 dollars. The estimated construction costs and WEPCO's portion of the coal plant's output translate into a $721,000,000 lease obligation in 2001 dollars for each of the SCPC units.[3] Allowing for expected annual inflation of about 2.32 percent per year, turns that obligation into a $808.6 million value, measured in 2008 dollars to reflect the year the first unit is expected to begin commercial operation.[4] This $808.6 million represents the principal amount on average per SCPC unit used in the facility lease. This value does not include retirement or management costs. It also excludes carrying costs incurred during construction. Using lease terms that were approved for the Port Washington Generating Station docket, which included a return on equity of 12.7 percent, a capital structure containing 53 percent common equity, a debt cost of 5.00 percent (based on long-term utility debt with an "A" credit rating) and a 30-year lease term, the annual lease payment from WEPCO to WE Power would be $111.25 million on average for each SCPC unit.

In the affiliated interest portion of this proceeding, docket 05-AE-118, PSC staff has suggested that a return on equity of between 11.0 and 11.4 percent would be more appropriate for the proposed facility lease for the SCPC plants should the Commission decide to use that form of financing. Using the midpoint of this range, or a 11.2 percent return on equity, would reduce the estimated annual rent from $111.25 million to $101.28 million.

Together, the annual lease payments for the two SCPC units would equal about $222.5 million. By 2010, the retail electric revenue requirement for WEPCO could be $2.15 billion. This means that the additional lease payments for the first two SCPC plants at Elm Road would increase retail electric revenue requirement by about 10.3 percent by the end of 2010. For a residential customer paying about $40 per month, this means that the average customer bill would increase about $4.12 per month. This estimated effect covers the construction cost component only, and represents a proportionate increase across all customer classes, and does not include the IGCC unit.

One of the reasons a leasing approach for the coal plants was pursued, according to WEC, is that WEPCO would unlikely be allowed sufficient return on a traditional rate-base investment to compensate investors for the risks associated with the coal plants. Commission staff compared the cost of rate-based ERGS project to the proposed leased generation proposal and assumed all lease terms were the same as for the leasing method except for the return on equity and the project life.

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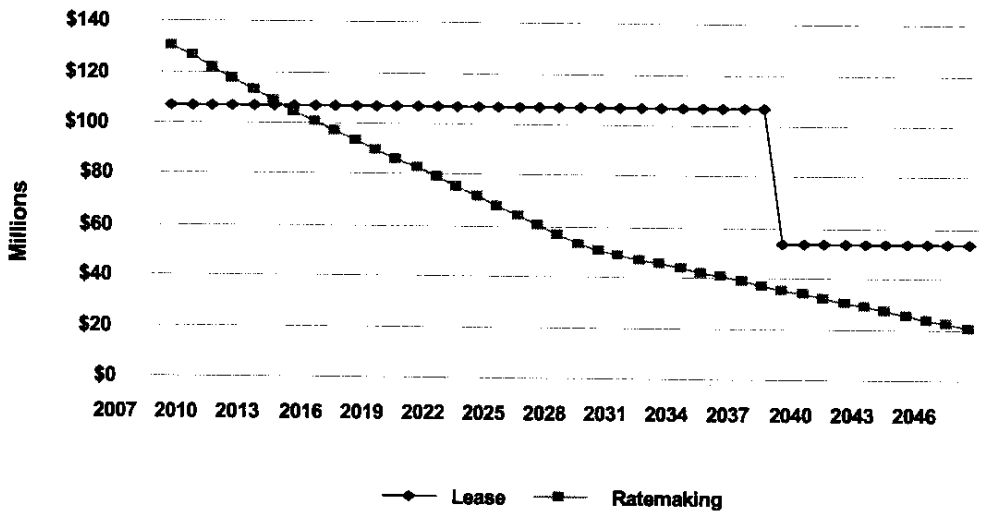
[3] The calculation is $1,400,000\MW X 515 MW = $721,000,000.

4 Calculated as $650,445,000 in 2001 dollars X six years compounded 2.32 percent annual inflation or $650,445,000 * [(1+.0232) ^ 6] = $746,404,000 in 2007 dollars.

Staff's analysis indicates that a traditional rate-making approach would cost ratepayers about 14 percent less on a present value basis than using the proposed lease financing mechanism. For example, for 40 years of operation, the present value of the lease approach for one SCPC unit is $868 million in 2003 dollars as compared to $753 million using traditional rate-making procedures. This difference would occur if the rate-based coal generation projects could be financed at a common equity rate of 13.7 percent assumed in the analysis.

While the rate-base calculation is less cost than the facility lease method on a present value basis, there are important intergeneration equity aspects that may favor the lease. Under the facility lease, the annual rent would be $111.25 million on average per year per SCPC unit over the 30-year lease; whereas, under traditional rate making procedure the revenue requirement would start out much higher at $137 million and then gradually decline to around $22 million after 40 years. This means that under traditional rate-making, current customers would pay relatively more for the plant than future customers would. The following chart depicts the required revenue streams under the facility lease approach and traditional rate making:

Figure ES-1 Comparison of facility lease and ratemaking annual cost streams for a SCPC unit



On March 25, 2003, the city of Oak Creek and WEPCO entered into an agreement by which WEPCO agrees to annually pay the city of Oak Creek $1.5 million at the start-up of ERGS unit 1, $750,000 at the start-up of ERGS unit 2, and $250,000 at the start-up of ERGS unit 3.[5] Under this arrangement, the city of Oak Creek would drop its opposition to the ERGS project, and WEPCO would seek Commission approval for ratepayer recovery associated with the annual community impact payments. The first annual payment of $1.5 million would increase the cost of the facility lease for the first SCPC unit by about 1.3 percent based on an annual estimated lease payment of nearly $107 million. The effect of such payment would be less than $0.54 per month for an average residential customer. The Commission approved such payments to the city

[5] In addition to the annual payments, this agreement contains language about capping emissions. At this time, neither PSC nor DNR staff have been provided detailed information about these emission caps.

of Port Washington for the two recently approved 545 MW gas-fired combined-cycle generating plants to be constructed in that city. Whether these payments should be recovered and what is the appropriate level may be key issues at hearing in this case.

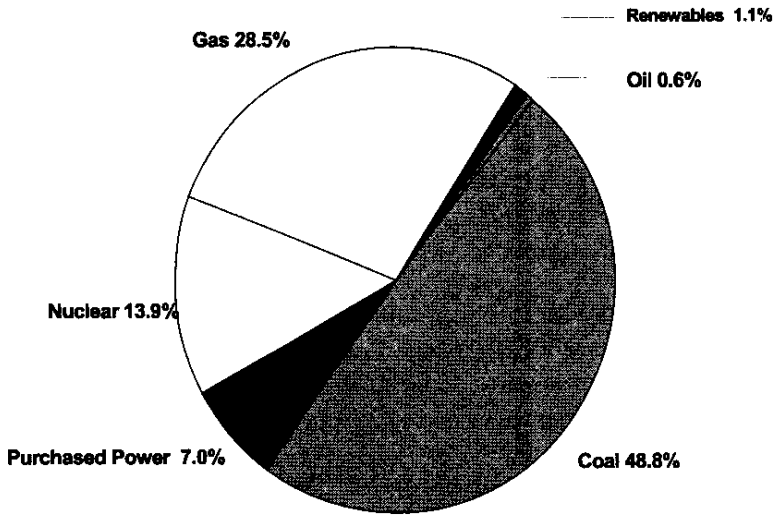
Need for the ERGS project

Planning at least five years into the future is required for large generating units because of the construction lead-time necessary. The need for one, two, or three units is examined.

WEPCO currently maintains sufficient peaking capacity and/or purchase power arrangements to cover unscheduled or planned outages from its generation supply during peak demand. WEPCO's peak load for 2002 was 5,479 MW [6] with an estimated peak at 5,624 MW, as reported in its 2002 Wisconsin Strategic Energy Assessment (SEA) filing for 2003. Available WEPCO-owned capacity at peak, for 2003, is 5,053 MW. In addition, WEPCO has 948 MW contracted from merchant power plants and expects 411 MW of purchases without reserves. Adjusting for its Upper Michigan load of 98 MW, yields a total supply of 6,430 MW in 2003, as reported in the SEA. This results in a 20.56 percent reserve margin for WEPCO in 2003.

Although its reserve margin for 2003 is quite sufficient, WEPCO is becoming increasingly dependent on power purchases to meet its needs. Figure ES-2 indicates that seven percent of its capacity to meet the anticipated peak demand will be power purchases. This does not include merchant plants under contract to WEPCO which are included in the gas portion.

Figure ES-2 WEPCO's summer capacity available for 2003 peak demand



[6] Peak load not weather normalized and for Wisconsin only load of WEPCO.

To obtain the required 18 percent planning reserve margin,[7] WEPCO has increased its reliance on interruptible load, load control, and increased purchases with reserves to reduce its peak load. On the supply side, WEPCO has increased its reliance on merchant plant capacity purchases and purchases without reserves, some of which are located outside of Wisconsin.[8]

Figure ES-3 shows the increase in power purchases and merchant plant generating capacity. These purchases have, in turn, increased the strain on a transmission system that is already viewed as overloaded; it is unlikely that this trend can continue. This trend implies that there may be a need for more baseload capacity in Wisconsin and more transfer capability.

Figure ES-3 WEPCO's power purchases and merchant plant capacity

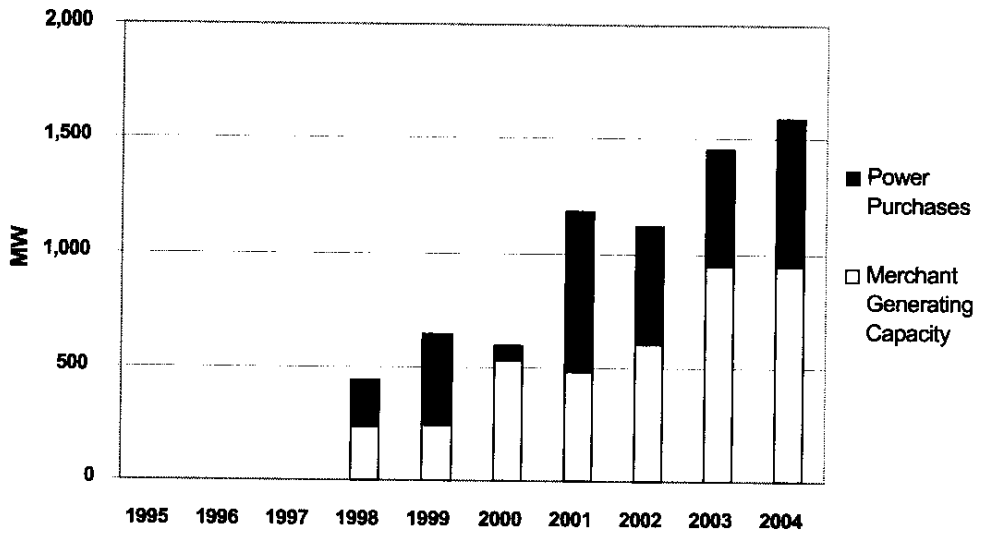


Table ES-2 shows WEPCO's forecast for growth in electric demand and energy use forecast through 2030 and the lower growth rates used by the Energy Information Administration (EIA) in its estimates of energy growth rates for the Mid-America Interconnected Network (MAIN) through 2020.

WEPCO's forecasted growth rates from 2002 through 2011, in this case, are very close to those it used for the Port Washington case. Commission staff completed a detailed analysis of WEPCO's forecast, analyzing the residential, commercial and industrial sectors. Staff's analysis indicates that WEPCO's electric demand and energy forecast is reasonable although it may have a slight upward bias.

As in the Port Washington case, Commission staff applied the forecasted growth rates estimated by the EIA for the MAIN region for 2002 to 2020. Commission staff used also the EIA MAIN forecasted increase for

[7] The North American Electric Reliability Council (NERC) recommends a 15 percent reserve margin, but the Commission has added an additional 3 percent in order to allow for transmission constraints and other reliability issues in Wisconsin and the Upper Midwest.
[8] The distinction between purchases with reserves and purchases without reserves pertains to the power seller's responsibility for planning reserves. A purchase with reserves means the seller is required to have sufficient capacity to back up the sale as if the seller were delivering the power for use by its own native load customers.

2019 to 2020 for the period 2020 through 2030. The EIA forecast is for energy use only. Commission staff assumed that the growth rate in peak demand would be the same as the growth rate in energy during this period. The difference between the two forecasts is an increase in peak demand of 500 MW in the WEPCO forecast by the year 2015. Under the EIA MAIN forecast, WEPCO would not need the capacity represented by the third coal plant until much later.

Table ES-2 Summary of peak and energy forecasts: WEPCO and MAIN Region

Year	Peak Demand (MW)			Energy Use (GWh)	
	WEPCO	MAIN		WEPCO	MAIN
2002	5,778	5,778		30,877	30,877
2005	6,276	6,223		33,379	33,254
2010	7,258	6,971		37,920	37,250
2015	8,166	7,665		42,024	40,958
2020	9,175	8,321		46,345	44,464
2025	10,295	8,925		48,974	47,689
2030	11,280	9,515		52,735	50,845
Growth Per Year					
2002-2005	2.8%	2.5%		2.6%	2.5%
2005-2010	3.0%	2.3%		2.6%	2.3%
2010-2015	2.4%	1.9%		2.1%	1.9%
2015-2020	2.4%	1.7%		2.0%	1.7%
2020-2025	2.3%	1.4%		1.1%	1.4%
2025-2030	1.8%	1.3%		1.5%	1.3%

Figure ES-4 displays the WEPCO peak load demand forecast compared to the electric supply resources available to the utility if there is no expansion in existing generating capacity, if the 1,090 MW of Port Washington capacity is added to WEPCO's existing system, and if both the Port Washington and 1,800 MW of ERGS capacity is added to the existing system using the implementation schedule set forth by the utility. Figure ES-4 demonstrates that without some type of significant capacity addition after 2007, WEPCO would not be able to meet its expected peak load obligation. Data in Figure ES-4 assume that WEPCO continues to purchase as part of its existing capacity about 1,200 MWs from merchant power plants and other suppliers during the 2005 to 2015 time frame.

Currently, coal-fired generation accounts for the majority of WEPCO's energy produced, as shown in Figure ES-5. The question of what technology should be used to supply needed baseload generation is a major issue of interest in this case. Natural gas use carries the potential for high-priced fuel and increased price volatility, but it has a lower emission profile, less intensive resource use related to land and water, and a significantly lower, more consistent capital cost than coal-based generation.

Figure ES-4 WEPCO peak load compared to generation supply with and without the Port Washington and ERGS units

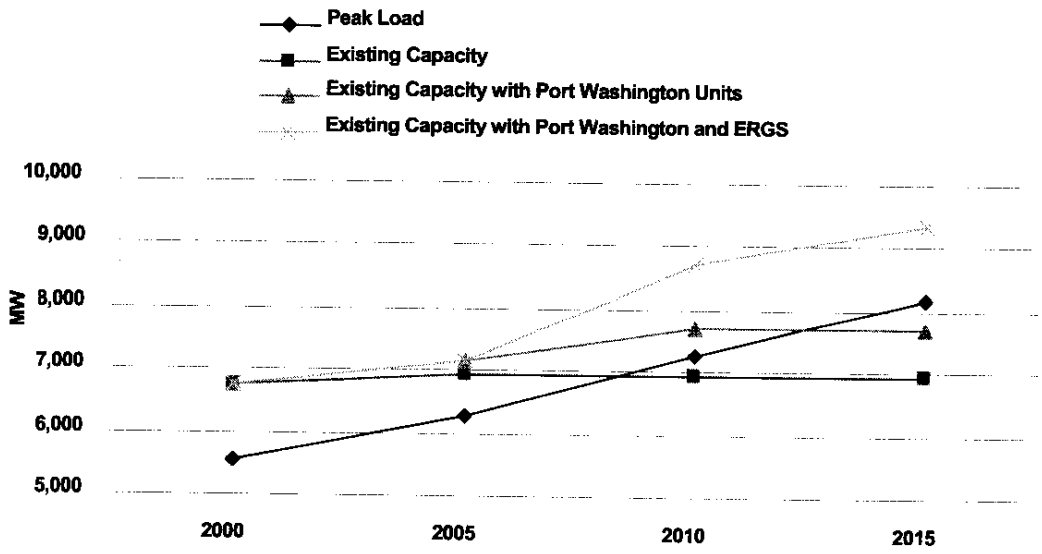
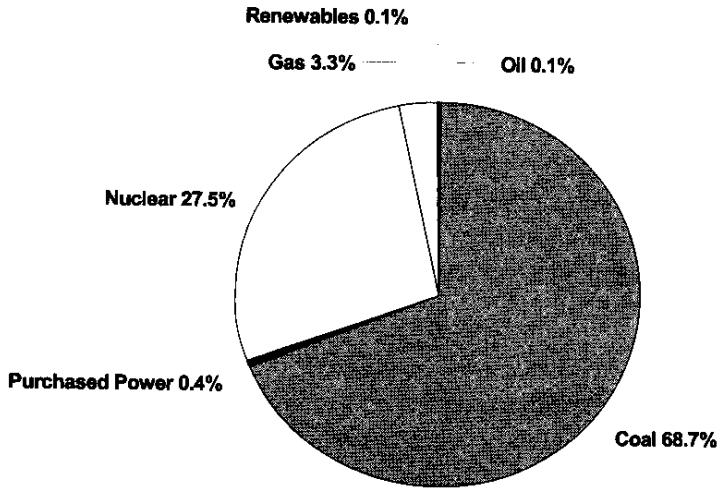


Figure ES-5 WEPCO's energy production by fuel for 2001 in MWh



Alternatives to the ERGS project

A range of alternatives, which includes taking no action, reducing energy load and peak demand, considering other energy supply sources, and approving all or part of the proposed project were analyzed with respect to cost, technical feasibility and environmental soundness.

Commission staff used EGEAS (Electric Generation Expansion Analysis System) to determine the alternative generation expansion plans, the cost of the plans and the projected timeframe that various units of capacity would be needed. Commission staff addressed the following scenarios when performing its EGEAS analyses: 1) Base Case; 2) DSM-EIA Load Growth; 3) High Gas Prices; 4) Low Gas Prices; 5) High Coal Prices; 6) Low Coal Prices; 7) Coal Capital Costs plus 10 percent (this scenario addresses the potential for capital cost overruns); 8) CO_2 Monetization; 9) Monetization of NOx, Hg, and SO_2 Emissions; 10) Capacity of the SCPC at 615 MW; and 11) Retirement of All Coal at 60 Years. For each of these scenarios, Commission staff performed an EGEAS run assuming three different outcomes:

- Optimal operation (EGEAS picks the best combination of generating options)
- Optimal operation with a Calpine 523 MW combined-cycle unit by 2007. Calpine, LLC filed a proposal in early 2003 to have the Commission consider its Calpine Fond du Lac Energy Center, currently under review at the PSC, as a substitute for all or a portion of the proposed ERGS.
- Two SCPC units (2008 and 2009); no IGCC unit. This is the ERGS project without the IGCC.

Commission staff's EGEAS analysis resulted in several quantitative conclusions:

1. The IGCC unit, which is the third unit in the ERGS proposal, is not cost-effective.
2. The proposed timing of the SCPC units in 2007 and 2009, as WEPCO has proposed, is not least cost. This scenario is generally more than $100 million more expensive on a present value basis. Timing appears to be about two to three years premature.
3. The Calpine 523 MW CC proposal in Fond du Lac using natural gas is lower cost than the ERGS - w/o IGCC proposal. However, the Calpine proposal would not need to be put in-service until 2007. Selecting the Calpine proposal does not mean that coal plants would not be needed. Several scenarios suggest that a coal plant would not be needed until 2011, if not later, if the Calpine proposal is selected.
4. CO_2 monetization, as well as other emissions monetization scenarios, favors picking the Calpine proposal versus ERGS w/o IGCC.
5. If the coal plants were to have cost overruns of 10 percent, then the Optimal expansion plan does not select a coal plant until 2011.
6. Should lower demand and energy growth occur due to increased energy efficiency efforts and lower overall use of electricity than depicted by WEPCO in its base demand and energy forecast, then the earliest a new coal facility would be needed is 2012.
7. ERGS w/o IGCC could be made competitive with the Calpine Fond du Lac proposal by the Commission choosing an overall finanacing plan that would cost ratepayers between $50 million and $100 million less on a present value basis.
8. Substantial Lake Michigan wind development exceeding 2,500 MW by 2014 and 11,000 MW by 2023 would be effective in meeting demand and energy growth for WEPCO, but it would require a substantial federal transfer via a permanent wind tax creit of $18 MWh. If the federal government were to not renew the wind tax credit presently set to expire in 2004, then no new wind would be selected by EGEAS until 2017.
9. An expansion plan over the next 30 years relying exclusively on natural gas would cost ratepayers $1.9 billion more than a balanced plan using optimally timed gas- and coal-fired electric generation, as well as some wind generation development.

These results are based on a materiality threshold of $10 million. Using a $50 million materiality threshold still results in selecting the Calpine project over the ERGS without the IGCC proposal.

These results focus on quantitative effects. The Commission will need to consider impacts of qualitative factors as well, including both environmental and economic risks associated with the use of different fuels.

Environmental Effects of the ERGS project

Soil excavation and stockpiling

The proposed design would place the ERGS facilities below the existing grade level, so that once-through cooling technology could be used to operate the plants. This design would have major implications for altering the present OCPP property owned by WEPCO, both in terms of changing the topography along the lakefront, stockpiling the excavated soil at various locations on the property, and changing existing drainage patterns.

If only the two SCPC units are constructed, the amount of soil excavated would range from 5.8 to 7.3 million cubic yards, with the greater amount required for use of the North Site. If all three units are approved and built, between 7.3 and 10.0 million cubic yards of soil might be excavated and removed to make room for the facilities. Use of either the North Site (original site layout)or the South Site-Exp would require a greater amount of soil removal. Use of the Cup Option would require slightly less. In addition, the closed North Oak Creek Power Plant buildings would be demolished to make room for the plant if the facilities are built on the North Site.

The applicants preliminary designs included in the CPCN application identified several permanent soil stockpile locations where berms would be created to help in screening the plant from view and attenuating noise from plant operation. A number of vehicles and types of machinery would be needed to excavate and haul the soil to the deposition areas. The amount of diesel fuel needed and the size and location of diesel storage facilities required to operate the machinery on a nearly continuous basis for a period of about one year have not been determined at this time. Because of this, the potential for noise, fugitive dust and diesel fumes related to the soil excavation and hauling activities cannot be accurately assessed at this time.

The primary soil stockpile locations described in the application include:

- an area east of STH 32 south of the existing transmission line corridor;
- an area north of Elm Road across the railroad tracks from the Barton Oaks subdivision that is currently old field, wetlands, and the North Ash Landfill;
- a large area immediately south of Haas Park that currently supports the Oak Creek South Ash Landfill;
- an area that is currently farmed which is located north of Seven Mile Road and east of STH 32; and
- an area west of the proposed switchyard expansion and east of the railroad tracks.

The CUP Option entails some different locations and configurations for soil deposition sites. The berms north of Elm Road would be lengthened in a north-south direction and extend across the closed section of Elm Road east of the Union Pacific railroad tracks. The berms east of Haas Park would be pushed slightly

more to the east. Berms in both of these areas would have a wavy edge effect, steeper slopes, and would be slightly higher than in the original plans. In addition, use of the CUP Option would require relocating the shooting range further to the south adjacent to Seven Mile Road and Lake Michigan. Large berms would be constructed around ther perimeter of the new shooting range.

Proposed changes to the Lake Michigan shoreline and harbor

A new water intake system would be constructed regardless of the site selection or the number of generating units approved and built. The system would consist of a tunneled conduit or trenched-in pipes that would transport lake water that had been drawn in through velocity caps or an intake crib located approximately 3,500 to 9,000 feet off-shore.

Regardless of the final design selected, the construction of the new water intake system would involve dredging, with much more extensive dredging required for a trenched-in pipeline. Potential short-term impacts include localized increases in water turbidity, planktonic growth and nutrient levels, habitat disruption, and reductions in dissolved oxygen concentrations. Long-term effects could include modifications to the existing bathymetry, fish populations, and habitat quality. The final design of the water intake system must minimize impingement and entrainment of fish and other aquatic organisms in order to comply with new proposed rules for section 316(b) of the Clean Water Act under authority of the U.S. Environmental Protection Agency.

A new cooling water discharge structure, involving a seal well with concrete retaining walls and a rock-lined dredged channel, would also be constructed. Approximately 10 to 15 thousand cubic yards of material would be dredged from the Lake Michigan bed to create the channel. This material would also have to be stockpiled or hauled off-site. For use of the North Site, the structure would be located north of the existing coal dock along an area that currently supports a wide sand beach that provides good aquatic habitat for shore species. If the ERGS facilities are built on the South Site, the discharge structure would be located south of the coal dock in the vicinity of the existing discharge structure. Operation of the cooling water discharge structure would result in discharge of heated water causing a thermal plume that would extend into Lake Michigan waters. Based on modeling of the expected thermal plume, it appears that compliance with the acute and chronic criteria of the proposed Wisconsin thermal standards may be easily met.

To accommodate ship delivery of coal and limestone, the applicants have also proposed several major modifications to the existing harbor, including extension of the existing coal dock, construction of a new breakwater that would extend up to 1,900 feet into the lake, and dredging of a navigational channel. These harbor construction activities could result in extensive long-term impacts on the existing lakebed, creating dramatic changes in gradient between the coal dock, breakwater and channel. The diverse benthic habitat within the area would be reduced from a diverse mixture of micro-habitats to a uniform zone of sand and silt or large rock riprap.

At the present time, the applicants have stated that it is unlikely that they would construct facilities for delivering coal by both ship and rail, since the improvements needed for each option are very expensive and some railroad modifications would likely be necessary regardless of the coal transport method chosen. Because of these reasons, they have expressed a preference for coal delivery by rail, diminishing the possibility of constructing the new harbor facilities described above. (The water intake system and discharge structures would be needed regardless of the coal delivery option selected.)

Solid waste

WEPCO's two SCPC units would burn washed bituminous coal and the primary coal combustion by-products materials generated would include fly ash, bottom ash, and synthetic gypsum. Limestone used in the SCPC units to control and reduce SO_2 emissions would result in the gypsum by-product.

A total of 206,300 tons per year of fly ash and 51,600 tons of bottom ash would be produced each year by the two SCPC units. The respective volumes of the fly ash and bottom ash would be calculated at 171,900 cubic yards and 43,000 cubic yards. The total volume of fly ash and bottom ash together would be 214,900 cubic yards per year. Some of this volume will become part of the WEC's beneficial ash re-use plan and some of this waste is expected to be hauled to one of three area landfills: the Caledonia Landfill located about one mile west of the existing OCPP plant; the STH 32 Ash Landfill located in the town of Grafton about four miles southwest of the WEPCO Port Washington Power Plant; and the Pleasant Prairie Ash Landfill located in Kenosha County.

The primary by-products of the IGCC system would be slag produced by the coal gasification process and elemental sulfur or sulfuric acid, which results from the capture of sulfur containing gases during the IGCC process. Based on the proposed fuel, the sulfur content of the coal would yield about 33,200 tons/year of elemental sulfur. The quantity of sulfuric acid produced would amount to approximately 109,200 tons/year, or 50,700 gallons per day. This material may be considered hazardous waste. On-site liquid sulfuric acid storage would require a bulk liquid storage of 200,000 gallons.

WEPCO anticipates few changes in the hauling methods or routes for solid waste from the new facilities if the ERGS is built as proposed in its CPCN application; mostly existing OCPP roads would be used. Use of the CUP Option would require construction of new ash haul roads on-site. There would be an increase in truck traffic for transportation of ash and other by-products from the ERGS to other WEPCO-owned landfills. WEPCO is required to submit plan modifications to the DNR for any of the landfills they plan to use for disposal of newly generated by-products. WEPCO would also be required to update the design of these landfills to provide better protection for the groundwater.

The ERGS project includes the construction of access roads and temporary parking facilities over the majority of the footprint of the Oak Creek North Landfill. In addition, a significant amount of fill generated by the excavation for the construction of the two SCPC units would occur in this area.

The proposed modifications to the Oak Creek South Landfill involve compaction and grading of the newly deposited soil (from the site excavation) for a construction laydown area. Construction of access roads and development of short- and long-term stormwater management facilities would also occur in this area.

WEPCO has a beneficial ash re-use program in place. WEPCO is proposing, based on past experience and recent contacts with by-product marketers, to increase utilization of the ERGS by-products from zero percent to full utilization within 10 years on a straight line basis from the start of commercial operation of these new generating units.

Air quality impacts

Although the best available emissions reduction technologies would be installed on all emission-producing equipment at the ERGS, local air quality would be expected to decrease as a result of constructing and

operating the facility. Results of WEPCO's air modeling analyses indicate that the resultant concentration of total suspended particulates (TSP 24-hr) would be nearly 100 percent of the Wisconsin secondary (welfare-based) air quality standard. Concentrations of PM_{10} including the regional background, are expected to be about 80 percent of the health-based National Ambient Air Quality Standard (NAAQS).

WEPCO's air modeling analyses (presented in this EIS) for construction on the South Site options are incomplete due to redesign of the project and late submittals of air permitting information. The Department of Natural Resources (DNR) will be conducting its own air modeling analysis as soon as the air permit applications are complete.

Noise

A noise survey was conducted according to the PSC's Noise Assessment Measurement Protocol to determine the projected impact of the ERGS facilities on the existing noise levels in and around the OCPP property. Assessments were completed for both the North and South Sites. Results indicate that the sound profiles for the two sites would be very similar. However, the North Site would potentially have a greater noise impact on the Barton Oaks Subdivision, whereas, use of the South Site would shift some of the impact south to affect residences along STH 32 near Botting Road. Noise levels related to the CUP Option may be lower due to relocation of the coal storage areas and some coal handling equipment. However, the CUP Option and the South Site-Exp option would require relocating the shooting range, thereby increasing noise levels for residents near Seven Mile Road. The plant design which would require excavation for the generating units and create an embankment to the west and north of either site would tend to attenuate sound emissions from the SCPC units.

Other temporary noise sources are likely to be somewhat louder and more noticeable to nearby residences. Noise from the coal handling facilities and the coal trains entering and exiting the site and unloading coal would be transient and inconsistent, making them more noticeable. The most significant noise source is likely to be the earth-moving and plant construction activities which could last over a period of five to six years if the SCPCs only are built and up to eight years if the IGCC is also built. Between 6 and 10 million cubic yards of soil would need to be excavated and moved. Noise levels associated with large construction equipment and heavily-loaded dump trucks can be fairly intense with a low frequency component.

Recreation

The local public has expressed a great deal of interest in establishing public access to accommodate shoreline fishing on the site adjacent to the proposed water discharge structure near the North Site. To date, no discussion has been held regarding access for fishing further south along the shoreline near the location of a discharge structure built to accommodate use of the South Site or the South Site-Exp option. Several local meetings have been held by the applicants to get input from local fishing clubs and the DNR. Concerns about plant security and public safety are the primary disadvantages of allowing fishing access and would have to be addressed before a final decision is made.

In addition, there is a north/south bike trail that passes through Racine County and currently ends at Seven Mile Road. There is a similar trail that begins near the boat launching facilities in Bender Park north of WEPCO's property. The public has expressed interest in the potential for connecting these two trails via an asphalt path that would pass through the OCPP property near the western boundary of the site. Again, the applicants have held several meetings to receive input and ideas and are considering the possibility of

combining such a trail with a Visitor's Center on the property. No final routes or facility designs have been chosen.

Local concerns have been expressed about views of the plant from some of the nearby parks, such as Cliffside Park in Racine County, Haas Park adjacent to the proposed project, and Bender Park located along the lake, north of WEPCO's property. The city of Oak Creek is encouraging development of a championship golf course on the northern portion of Bender Park and thinks that the aesthetics of the course could be diminished by the proposed additional generating units at the OCPP site.

Vehicle traffic

Regional and local traffic would be expected to increase as a result of the construction and operation of the proposed ERGS facilities. During the construction phase (for two or three units) up to 4,180 vehicle trips per day (this includes vehicles entering and exiting the plant) could be expected during peak activities. This would be reduced to about 1,000 to 1,500 trips per day during plant operation. Employees, about 400 in number taking into account existing OCPP employees would enter the site via a new access road leading into the plant facilities from Oakwood Road. Trucks and vehicles traveling to the site for deliveries or equipment maintenance would access the plants off of STH 32.

Traffic is also likely to increase on nearby arterial roads such as Ryan Road, STH 32 and Seven Mile Road west of the plant site. County plans to widen STH 32 in the future would help to accommodate this increase in traffic.

Elm Road, which currently supports a large amount of traffic due to the location of the main plant entrance just east of Haas Park, is proposed to be permanently closed east of the Union Pacific (UP) rail corridor in order to accommodate construction activities, laydown areas, and haul roads.

Proposed railroad modifications

Rail delivery of coal for the new SCPC units and the IGCC plant would require increasing the number of cars per train or increasing the capacity of the coal cars. The applicants have assumed that train lengths would likely be increased from the current 125 cars per train to 135 cars per train and that the number of trains per week would increase from five (currently) to nine for two SCPC units and eleven for the entire ERGS project. Without substantial rail improvements, several local roads could be blocked for a substantial amount of time each day.

This road blockage would be unacceptable to residents and emergency services that would need to access areas east of the Union Pacific Railroad tracks.

The primary rail improvement proposed is construction of an underpass beneath the tracks at Six Mile Road. This proposal would include construction of a bike/pedestrian bridge parallel to the tracks over the roadway to accommodate the Racine County Recreational Trail described earlier. At the present time, a new alignment located slightly north of the exiting roadway is being considered for this short section of Six Mile Road. At Seven Mile Road, the applicants have proposed to close the road and provide a cul-de-sac just west of the UP railroad tracks. This would result in the loss of convenient access to their homes for several residents who live just west of the tracks on Seven Mile Road and a potentially longer emergency response time for those residents if emergency services are needed. However, this inconvenience must be weighed

against the potential for a frequent and longer duration road blockages of Seven Mile Road if no changes to the road are made and the ERGS facilities are approved and built.

The applicants are also planning to install a new rail sidings on WEPCO's property and further to the south to service rail cars needing maintenance and a new indexer system that would automatically line up coal cars for unloading, rather than manually starting and stopping the train numerous times during coal unloading. This equipment and the new sections of track could substantially reduce the existing noise and emission of diesel fumes caused by the trains starting and stopping on-site and adjacent to the site.

Vegetation

Although portions of the OCPP property are highly disturbed, the site contains several areas of exceptional resource quality. The Southeast Wisconsin Regional Planning Commission (SEWRPC) has designated some of the areas as "primary environmental corridors" (PECs) and "isolated natural resource areas" (INRAs). In addition, a mature beech/basswood woodland has been designated as "critical species habitat" (CSH) because it supports over 90 plant species, including the state-endangered blue-stemmed goldenrod. Old field, wet meadow, other woodlands, grasslands, farmed cropland and marsh and pond habitat comprise some of the other vegetative cover on the site. Many acres of this upland and wetland habitat would be temporarily or permanently destroyed due to plant construction and stockpiling and berm construction using the materials excavated from the bluffs. Approximately 100 acres of these special resource areas would be destroyed by construction of the ERGS facilities regardless of the site or layout design used.

Use of the North Site (original layout of the CUP Option) would also remove several old fields and about 700 feet of bluff and beach habitat, part of which is designated PEC. Use of either of the South Site options would result in the loss of little or no high quality old field or beach and bluff habitat.

Several of the existing large blocks of habitat present on the OCPP site function as bird migration stopover sites for over 300 species of birds that travel thousands of miles, using the Lake Michigan shoreline to guide their flight through this region. Long-term major construction activities along shoreline and destruction of the bluff and beach habitat, as well as areas of grasslands and woods would diminish the attractiveness of this area as a stopover site for migrants.

Based on surveys conducted in spring of 2002 and 2003, and observations in recent years, grasslands present on the area proposed for the North Site, harbor five of the state's seventeen grassland birds that depend on grasslands for most or all of their breeding cycles. These include the bobolink, dickcissel, eastern meadowlark, and savannah sparrow and Henslow's sparrow, a state-threatened species. These grasslands would be destroyed if the facilities were built on this site.

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Chapter 1 – Background and Regulatory Requirements

Description of the Proposed Project

Wisconsin Electric (WEC); Wisconsin Electric Power Company (WEPCO); and WE Power, LLC (WE Power), a non-utility affiliate, are proposing to build approximately 1,830 MW of advanced technology coal-based generating capacity.

The applicants have applied to the Public Service Commission of Wisconsin (Commission or PSC) for a Certificate of Public Convenience and Necessity (CPCN) under Wis. Stat. § 196.491(3), and Wis. Admin. Code PSC ch. 111.53, and for any additional approvals required from the Commission to construct and operate a large electric power generating facility under Wisconsin's leased generation law, Wis. Stat. § 196.52(9).

The new facility, the Elm Road Generating Station (ERGS), would consist of two super-critical pulverized coal (SCPC) units and a single integrated-coal gasification (IGCC) unit, all constructed on or adjacent to a site containing WEPCO's existing Oak Creek Power Plant (OCPP). The new generating units would be constructed and owned by WE Power. The units would be leased by WEPCO and other interested utilities. Employees of WEPCO would operate the new facilities.

The purpose of the project is to satisfy WEPCO's need for additional capacity over the coming years. WEPCO forecasts that its peak demand driven by population growth, new wholesale obligations, business expansion and increasing usage per customer, will grow at approximately 2.9 percent annually from 2002 through 2011, reaching 7,612 MW. In order to meet this need, plus an 18 percent reserve margin, it has proposed a package of generation capacity that includes 1,090 MW of natural gas-fired capacity at its existing Port Washington Power Plant site and 1,830 MW of coal-based generation that is the subject of this application. The portion of the new facilities at Port Washington and Elm Road expected to be available for use by WEC's utilities is 2,620 MW. It is anticipated that the remaining capacity, approximately 300 MW, would be leased by other Wisconsin-based utilities.

Proposed Facilities

SCPC units

Two SCPC units would be built on the selected site. One would commence construction in 2004 and begin operation in 2008[9] and the second would have an in-service date of 2009, with a similar construction period.

The SCPC technology is more advanced than conventional coal-combustion technologies currently in operation in Wisconsin. In the SCPC technology, water is heated to higher temperatures and pressure so that the energy content of the steam delivered to the turbines is much greater. Higher plant efficiencies result and less fuel is burned per unit of electrical output.

The combustion process and the equipment and components that comprise the power block are described in Chapter 6. All of the auxiliary facilities, such as the coal handling equipment and coal train unloading facilities are also discussed in Chapter 6.

IGCC unit

The proposed IGCC process is designed to break down coal into its basic constituents and produce a synthetic gas (syngas), separate out pollutants from the syngas, and use the syngas as fuel for the combustion turbines. Waste heat is also used to produce steam for steam turbine use.

The IGCC technology, which is described in detail in Chapter 6, is based on several existing facilities in the U.S. However, this technology is still in the early stages of development relative to conventional coal and SCPC combustion technologies. The IGCC plant is proposed to be in service in 2011 and it is expected that changes in the technology and estimated final cost could differ from what is presented in this application.

Proposed sites

The proposed sites for the ERGS are on a large parcel of land located along the shore of Lake Michigan near the OCPP. The parcel is approximately 1,000 acres in size, and is primarily owned by WEPCO. This land currently functions as buffer area around the existing OCPP. An 80-acre property within the WEPCO property is currently used as a shooting range, but is also being considered as a site for some of the facilities. This property consists of two parcels - a northerly parcel owned by the State of Wisconsin and a southerly parcel owned by the U.S. government.

Three sites for the proposed ERGS were identified in the CPCN application. One of the proposed sites is in the city of Oak Creek in Milwaukee County at the east end of Elm Road, north of the existing OCPP. This site is referred to as the North Site throughout this EIS. A second site, the South Site, is located south of the existing OCPP along the lakeshore. A variation of the South Site was proposed as the applicants' third site alternative. For purposes of description and analysis in this document, this alternative will be referred to as South-Exp Option.

[9] In WEPCO's direct testimony, May 2008 is listed as the start-up date for the first SCPC unit. This differs from the 2007 date provided in the CPCN application and used in the analyses for the draft EIS.

Selection of the South Site would place all three coal units (two SCPC units and one IGCC unit) on property currently owned by WEPCO. In the South-Exp Option, the two SCPC units would be placed on WEPCO property in the same location, but the IGCC unit would be built on the section of land that is currently federally-owned. Use of the South-Exp Option would require negotiations for a land purchase or swap between WEPCO and the federal government. Both the South Site and its variant, the South-Exp Option, are located in the town of Caledonia in Racine County.

Since the draft EIS was issued, WEPCO and the city of Oak Creek agreed upon another site layout plan for the North Site. This site layout was negotiated as part of the Conditional Use Permit (CUP) process that the applicants agreed to follow in their agreement with the city of Oak Creek. The applicants have stated that they would be willing to build the ERGS facilities as proposed in their CPCN application (with some exceptions), but that they would like to have the new site layout, hereafter reffered to as the CUP Option, considered by the Commission in its final decision on the project.

In the CUP Option, the two SCPC units and the IGCC unit would be placed at approximately the same location as in the original North Site layout. However, the new option involves relocating the active and reserve coal piles, splitting the existing substation into two sections and relocating the substations, adding a new access road and ash haul roads (and possibly a new ash reburn building), and altering the configuration of soil deposition areas. A description of the new layout and its potential environmental effects are described in Chapter 12 of this final EIS.

Both the North and South Sites are within WEPCO's service territory adjacent to a major and growing source of electric load. A description of the criteria used in identifying potential sites and the methodology and justification used by WEPCO to select the proposed sites is found in Chapter 6.

Ownership and operation

WEPCO is a public utility, as defined in Wis. Stat. § 196.01(5), engaged in the generation and distribution of electricity to customers in eastern Wisconsin and the upper peninsula of Michigan.

WEPCO owns, or would own (if it obtains the federal land), the site on which the proposed ERGS facilities would be located. WE Power would build and own the facility, and WEPCO would operate the facility.

Leased generation agreements

The leased generation statute was created recently to allow the formation of electric generating facilities by non-regulated entities and the use of leased generation contracts between the non-utility entity and the public utility. The addition of this subsection to Wis. Stat. §196.52 does not change the basic requirement that affiliated interest agreements (in this case, leased generation contracts) must be reasonable and in the public interest.

According to the application, an entity titled Elm Road Generating Station - SCPC Unit 1 LLC would be formed as another wholly owned subsidiary of WEC. WEPCO, WE Power, and ERGS - SCPC Unit 1 LLC are or will be affiliated interests as defined in Wis. Stat. § 196.52.

WEPCO would lease the land (the Ground Lease) to build the proposed facilities to ERGS - SCPC Unit 1 LLC. WE Power would lease its owned interest in the facility (the Facility Lease), and sublease its interest in the facility site (Ground Sublease) to WEPCO, who would operate the electric generation facility. Similar arrangements would occur for the second SCPC unit as well as the IGCC unit.[10]

Because WEPCO and WE Power are affiliated interests, the Facility Lease and Ground Sublease between WEPCO and WE Power must receive PSC approval under Wis. Stat. § 196.52(9). The completed facility would be owned by WE Power. WE Power would own assets that comprise a complete facility for the generation of electricity under the leased generation law. These relationships and facility leases related to the ERGS are shown in Figure 2-4 in Chapter 2.

Cost in brief

The cost to construct both SCPC units and the IGCC plant would be approximately $4.3 billion. A detailed discussion regarding the assumptions and uncertainties contained in the estimated costs, the structure of the financing and lease arrangements, and the potential long-term impact of the facility cost on WEPCO customers is discussed in Chapter 2.

Proposed Schedule

Draft EIS issued	April	2003
Public meetings	May	2003
Final EIS issued	August	2003
Technical hearings	August	2003
Public hearings	September	2003
PSC decision and order	November	2003
If the project is approved:		
Begin construction of initial SCPC unit	April	2004
Begin construction of the second SCPC unit	December	2005
Commence operation of the first SCPC	May	2008

PSC Construction Case Process

Application for PSC certification

Anyone proposing to build a power plant of 100 MW or more in Wisconsin must obtain approval from the PSC in the form of a CPCN before construction can begin. The Commission makes the final decision about whether a power plant is built and where it is sited. The Commission consists of three members, appointed by the governor for staggered six-year terms.

[10] Each subsequent unit of the ERGS, the second SCPC unit and the IGCC unit, would require the development of a separate Ground Lease, Ground Sublease, and Facility Lease.

Project developers must file a detailed CPCN construction application with the PSC. Once the PSC deems an application complete under Wis. Stat. § 196.491(3), it must complete its review process within 180 days. Court approval is needed to extend the review time to a maximum of 360 days. If the PSC does not obtain a court extension or issue a CPCN within this time period, the project is automatically approved as proposed by the applicant.

Because of the complexity of the ERGS proposal and the amount of public interest it has generated, the Commission applied to the Dane County Clerk of Court for a 180-day extension needed to complete the review of this project. A 180-day extension was granted. Thus, the Commission's final decision must be rendered by November 10, 2003.

DNR permitting authority

The developer of a proposed power plant must obtain several approvals and permits from the DNR. Some of these permits are designated as "pre-construction" permits or approvals. Construction may not begin until these permits and approvals are received by the applicants. The primary DNR approval needed before power plant construction may begin is the construction permit for a new source emitting significant[11] quantities of air pollutants. The DNR will also conduct a Prevention of Significant Deterioration (PSD) review and use the results in establishing permit conditions.

Because of the location of the proposed sites and potential for adverse effects to the lakeshore and water quality, several other permits have also been designated as pre-construction approvals. These include the permit for grading work for the generating facilities, the NR 103/NR 299 analysis and certification for wetland fill associated with the generating station site work, the approval of a plan for construction site stormwater runoff, and the threatened/endangered species review for construction associated with the generating station site work.

Some of the other important water-related permits and approvals would include modification of the WPDES permit, and a water withdrawal and loss approval. Other DNR permits would be required for various parts of the power plant project, depending on the final location, the type of shoreline protection measures implemented, the selected method of coal and limestone delivery for the new plant, and other expected impacts.

Wisconsin Environmental Policy Act

Environmental impact statement

The Wisconsin Environmental Policy Act (WEPA), Wis. Stat. § 1.11, requires all state agencies to consider the environmental impacts of major actions that could significantly affect the quality of the human environment. A proposal for a coal-fired power plant requires preparation of an environmental impact statement (EIS) under Wis. Admin. Code § PSC 4.10, regardless of whether it is located at an existing generating site or a green field site. The PSC and the DNR have prepared this EIS jointly with the PSC functioning as the lead agency. Based on the information provided, this EIS describes the proposed project

[11] "Significant" in this context means the level of pollutants that triggers the permitting process.

to the extent known, discusses possible alternatives to the proposed action, and evaluates the project need, cost, and impacts on the natural and human environment.

The EIS process has several stages: a draft EIS is produced and circulated for comment; all comments are considered in preparing a final EIS which is also distributed for review; and a public hearing is held in the project area.

Public participation opportunities

As part of agency scoping responsibilities under Wis. Admin. Code § PSC 4.30(2) and NR 150.21(3), the PSC and DNR, before preparing the draft EIS, solicit comments from any person interested in the proposed action. The PSC also distributes copies of the project application to local clerks and libraries for inspection by the public.

The applicant and the regulatory agencies may hold public information meetings in the project area early in the process. At these meetings, the public can learn more about the project, the applicant can improve its application, and the PSC and DNR staff can learn more about local concerns and interests before beginning to prepare the draft EIS.

The purpose of the EIS is to inform the Commissioners and the public of the potential effects of the proposed project. After the draft EIS is issued, there is a public comment period of 45 days. After the final EIS is issued, there is at least a 30-day review period to allow individuals to read the final EIS and prepare for the public hearing. The Commission provides notice to the public and holds a public hearing in the project area. The hearing is the opportunity for the public to make their views known to the Commissioners.

Process and public participation for this case

Application filed – PSC docket 05-CE-130

On February 1, 2002, WEPCO, WE Power, and WEC filed a CPCN application for authority to construct 1090 MW of natural gas-fired generation at the existing Port Washington Power plant site and 1830 MW of coal-fired generation on or adjacent to the existing OCPP site. The applicants also filed for other approvals related to the new leased generation law. The PSC subsequently bifurcated the process for reviewing the Port Washington Generating Station (PWGS) and the ERGS into two separate construction dockets. The PWGS application (PSC docket 05-CE-117) was reviewed and approved in 2002. The ERGS application was assigned PSC docket number 05-CE-130 and is the subject of this EIS.

After the company filed additional materials, the PSC found the application to be complete on November 15, 2002. The PSC distributed copies of the entire application to local clerks and county libraries in the project area. It also issued a public notification to interested and affected persons on January 13, 2003, to explain the PSC's review process, to solicit comments and questions about the proposed project, and to announce a public scoping meeting, which was jointly sponsored with the DNR and held on January 27, 2003. Applications for several permits were filed with the DNR at about the same time the CPCN application was filed.

PSC process

The PSC and the DNR prepared this draft EIS and held public meetings in the project area during the 45-day comment period to solicit comments on the draft EIS. Following the comment period, a final EIS was prepared taking into consideration the comments received and new information filed by the applicants in their direct testimony and in response to numerous data requests. A Notice of Hearing will be issued at least 30 days before the scheduled hearing date, possibly with the final EIS.

About 30 days after the final EIS is issued, the PSC will hold public hearings in the project area on the final EIS and the CPCN application. After the hearing is complete and transcripts of the hearing record are reviewed, the three Commissioners will meet to make a decision to approve, modify, or reject the proposed project based on information presented at the hearing. That meeting will be open to public observation. If one or more of the proposed coal-fired units are approved, the Commission will select the site for the unit(s) and add any conditions it determines necessary to be included in the construction order. After the Commission's decisions are made, an order to the applicants will be prepared and issued.

Public participation activities for this docket

Applicants

The applicants have prepared materials outlining the plans for the ERGS, issued news releases, sent letters to area residents, held several open house meetings, and conducted personal visits regarding the project. WEPCO representatives have also met with municipal government members of the nearby communities of Oak Creek and the town of Caledonia.

PSC and DNR

After reviewing the CPCN application and DNR permit applications, the PSC and DNR co-hosted a public scoping meeting with afternoon and evening sessions on January 27, 2003 in the Oak Creek Community Center on Howell Avenue in the city of Oak Creek. A press release was issued, and direct mail invitations were made to everyone on the project mailing list, including landowners near the project site and members of the public that had contacted the PSC about the project. About 200 members of the public participated in the afternoon session, and about 300 people attended the session in the evening.

Meetings to solicit comments on the draft EIS were held in Oak Creek and the town of Caledonia in May 2003. These meetings were well attended and staff received nearly 300 written and verbal comments during the 45-day comment period, many of them substantive in nature. The comment period on the draft EIS ended on June 12, 2003. Comments were used to prepare this final EIS.

The hearing and the Commission decisions

As described above, the final EIS will be distributed to all interested and affected persons who request a copy. A 30-day review period for the final EIS will be followed by a public hearing in which members of the public are encouraged to testify. The Commission meeting where final decisions on the project are made will be open to public observation.

Public involvement through other state agencies

An air pollution control permit is part of the project review, and anticipated air pollutant emissions are described in this EIS. The hearing on the air permit will likely be held separately in late September 2003.

The EPA has also delegated to DNR its determination regarding whether the ERGS facilities qualify as new or existing facilities under Section 316 (b) of the Clean Water Act. This determination could affect the applicant's ability to use once-through cooling technology for the ERGS facilities. More information about this determination is found in Chapter 9.

Other state level permits would be needed to build or operate the plant but are not required before plant construction can begin. Some permits are required before specific plant components are installed, constructed, or operated. State agency permits and approvals needed for this project are listed in Table 1-2.

Other Federal, State and Local Interests

Federal interests

Several federal government agencies also have regulatory interests in this project that they will act on directly or will delegate to state agencies. These interests can be varied, depending on the sites and the type of facilities proposed. Table 1-1 indicates the federal agencies involved in this project to date.

Table 1-1 Federal government agencies involved in the project

Agency	Interest or Permit	Contact
U.S. Environmental Protection Agency	Section 316(b) Clean Waters Act determination - delegated to DNR	
	Clean Air Act New Source Performance Standards - delegated to DNR	See DNR below in Table 1-2
	Clean Air Act Acid Rain Permit - delegated to DNR	See DNR below in Table 1-2
U.S. Army Corps of Engineers	s. 404 of the Clean Waters Act - wetland fill for generating station, coal storage, site work, rail improvements. Construction of railroad underpasses and/or overpasses	Tamara Cameron St. Paul District (651) 290-5197
	s. 10 of the Rivers and Harbors Act of 1899 - construction of breakwater and harbor facilities, including dock extension	
Federal Aviation Administration	Reviewing heights of proposed facilities; assessing impacts on aviation and clearance standards; and requiring facility alterations as needed.	Richard Farrell, III Great Lakes Regional Office (847) 294-7566

National Historic Preservation Act compliance

Under Section 106 of the National Historic Preservation Act, the Wisconsin Historical Society (WHS) must be consulted by each federal agency that has an interest in this project. These agencies must also contact any Native American peoples that may have an interest in the area affected by the project and any other individuals that may be affected by the loss or protection of historical, archeological, or traditional cultural properties as part of agency actions. Eventually, treatment of the area of potential affect would be the subject of a memorandum of agreement among all the interested parties.

The requirements of Section 106, when invoked early in a project review at the Commission, supersede the requirements of the corresponding state law on historic preservation. If Section 106 is invoked, it could cover all facets of this project, including the plant site, any new natural gas corridor, and any new water intakes, outflows, or pipeline corridors that are required by the proposed plant. Discussions of historical and archeological considerations are in Chapter 10 of this draft EIS under the heading "Historical and

Archeological Sites." Although the results of any negotiations or agreement under Section 106 can be incorporated into the final EIS, it is possible that they would occur during federal agency review processes after the project received PSC approval. If no historic properties were potentially affected, the Section 106 process could be completed before the CPCN were issued.

State interests

In addition to the substantial approval and permitting interests of PSC and DNR, several other state agencies must approve plans, designs, or specific components of the proposed generating facilities and auxiliary equipment.

Table 1-2 State agency approvals and permits required for construction of the proposed plant, electric transmission, and water supply and discharge structures

Agency	Approvals/Permits or Interests	Contact
Public Service Commission	s. 196.491 Wis. Stat. – Certificate of Public Convenience and Necessity for construction of large electric generating facility	Jeffrey Kitsembel 608-266-9658
	s. 196.49 Wis. Stat. - Certificate of Authority and s. 196.491 Certificate of Pubic Convenience and Necessity for transmission construction	
Department of Commerce	s. 101.12 Wis. Stat. - Plan and specification approval for construction of buildings and structures and installation of HVAC equipment, exhaust systems and elevators	Betty Wiese-Milwaukee. Co (414) 8523694 Larry Weede-Racine Co (262) 949-4300
	ch. DCOMM 41 and s. 101.17 Wis. Stat. - Safety requirements for installation of boilers, turbines, and related equipment	Terrence Walbillig (414) 303-8575
	ch. DCOMM 82.20 - Plan review and approval for construction of plumbing facilities	Robert Samuels (262) 424-3373
	ch. DCOMM 10 and s. 101.09 Wis. Stat. - Design requirements for installation of fuel or lubricating oil storage tanks	Vannessa Mouth (608) 267-5280
Department of Natural Resources	ch. NR 407 - Air quality operation permit and acid rain permit	Jeffrey Hanson (608)266-6876
	ch. NR 405, 406, 408 - Air construction permit	
	ch. NR 103 and 299 - Analysis/certification for wetland fill for the generating station coal storage, site work, and rail improvements	Heidi Hopkins (414) 263-8522
	s. 30.19 Wis. Stat. - permit for grading work in excess of 10,000 sq. ft. for generating facilities	
	s. 30.19 Wis. Stat. - permit for grading work for construction of railroad underpasses and./or overpasses	
	s. 30.21 Wis. Stat. - Approval for use of lakebed, dredging, and shoreline structures for construction of breakwater and harbor facilities.	
	s. 30.21 Wis. Stat. - Approval of use of lakebed for installation of the cooling water intake and discharge structures.	
	ch. NR 216 - WPDES Permit for stormwater discharges associated with construction activities and amendment of existing stormwater pollution prevention plan	Peter Woods (262) 884-2360
	ss. 281.35 and 281.41 Wis. Stat. and NR 142.06 – Approval for water withdrawal and water loss	Dan Joyce (608) 266-8736
	s. 283.31(6) Wis. Stat. and 316(b) CWA - BTA modification of WPDES permits and determination for cooling water intake structure	

Agency	Approvals/Permits or Interests	Contact
Department of Natural Resources (continued)	ch. NR 502 - Approval for storage of coal combustion byproducts	Bizhan Zia Sheikholeslami (414) 229-0852
	ch. NR 514 - Solid waste approval for landfill plan of operation modifications	Heidi Hopkins (414) 263-8522
	s. 29.604 Wis. Stat. and NR 27 - Incidental take for threatened and endangered species if necessary	Jennifer Bardeen (608) 266-0289
Department of Transportation	s. 114.135(6) Wis. Stat. - High structure permit for the stacks	Gary Dikkers (608) 267-5018
	Vehicle weight restrictions and oversize/overweight permits	
Department of Health and Family Services	s. 145 Wis. Stat. - Approval of plumbing and fire protection system for construction of plumbing facilities	TBD
Wisconsin Historical Society	s. 44.40 Wis. Stat. - Approval of archeological surveys	Richard Dexter (608) 264-6509

Local Interests

To date, the city of Oak Creek and the town of Caledonia have been very active in seeking information about the project and involving local citizens and residents in the project review. Many locally sponsored meetings and forums have been held in these communities to provide information to citizens and ensure that the applicants are aware of local interests. Milwaukee and Racine County governments are also involved in reviewing certain aspects of the proposed project. Table 1-3 indicates the local interests and approvals necessary for construction of the ERGS facilities.

Table 1-3 Local government approvals and interests

Agency or Office	Interest or Approval	Contact
Milwaukee County	Inventory of hazardous materials and toxic release	Carl Stenbol (414) 278-4709
Racine County	Conditional Use permit to incorporate requirements of local ordinances, including site plan approval, erosion control, drainage and noise.	Julie Anderson (262) 886-8470
	Inventory of hazardous materials and toxic release	David Maack (262) 242-4202
City of Oak Creek	Conditional Use Permit to incorporate requirements of local ordinances, including site plan approval, erosion control, drainage and noise	Doug Seymour (414) 768-6526
Town of Caledonia	Coordination with Racine County on conditional use permit	Fred Haerter (262) 835-8423
	Construction permit, including erosion control and stormwater control plans for construction of railroad underpasses and/or overpasses.	

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Chapter 2 – PTF Costs and Financing Mechanism

Expected Capital Costs

The Commission has an obligation to review the potential costs of a generation project proposed by a Wisconsin utility in order to examine the potential impact the project might have on utility customers or ratepayers. This chapter will describe the estimated cost of the ERGS project, the assumptions and uncertainties contained in those estimated costs, and the expected financial impact on WEPCO customers if the entire project or portions of it are approved. The estimated capital costs include the generating units, transmission interconnection (but no upgrades to the transmission system to facilitate power dispatch), and shared facility improvements (such as water supply and coal handling and delivery).

WEPCO provided the costs for the ERGS as part of its overall PTF application. However, the costs provided for ERGS are not as certain as those provided for the Port Washington units.[12] The costs provided for the SCPC units are somewhat uncertain and the cost for the IGCC unit is even less certain. Thus, the estimated costs for the ERGS are on a "cost-plus-up to 10 percent cap" basis, rather than a strong "firm" basis like the Port Washington costs.[13] In its May 2003 direct testimony, WEPCO indicates that projects would be capped at no more than 10 percent above the construction estimates for the coal facilities, thus placing some of the risk of any cost overruns on ratepayers, but not all of the risk. This represents an improvement for ratepayers over the initial proposed treatment which had no cap.

WE Power has indicated specifically that "because few comparable coal-based facilities have been built recently, the risk that actual costs may deviate from estimated costs is greater for the ERGS proposal than for the Port Washington project." In addition, labor costs make up a greater share of costs for the ERGS project, and equipment costs are inherently more difficult to estimate for coal-based units than for gas-based units.[14] The implication of these cost uncertainties for ratepayers is discussed later in this chapter.

WEPCO estimates that the costs for the SCPC units would range between plus or minus 10 percent from those estimated, with a higher uncertainty for the IGCC project costs.[15] In addition, IGCC cost estimates are

[12] Introduction and Application booklet, p. 12 of the CPCN application and Volume 1, Enclosure 8, page 1.
[13] In the Port Washington CPCN, WE Power indicated that it would bear the risk of cost overruns unless the overruns were due to unpredictable occurrences beyond WE Power's control or changes in the general inflation level. The Commission accepted and approved such a "hold-to" treatment for the Port Washington combined-cycle units. Examples of unpredictable occurrences beyond WE Power's control included changes in laws or government regulations and Act-of God or similar events.
[14] "Power the Future--Application to the Public Service Commission of Wisconsin," Application, page 13, February 15, 2002.
[15] Response to 1-SUP-156.

less certain because coal-based IGCC plants in the 500+ MW range have not been built anywhere in the world. Estimated costs for the ERGS project on a per unit basis are listed in Table 2-1. The total cost for the ERGS proposal is estimated to be about $4,314,995,000.

The cost estimates provided by WEPCO were utilized in the EGEAS modeling discussed in Chapter 4. For the SCPC and IGCC generating units, construction cost estimates of $1,415/kW and $1,739/kW were utilized respectively for the economic evaluation.[16]

Table 2-1 ERGS estimated construction costs on a per unit basis

Item	Unit 1 SCPC (2003)	Unit 2 SCPC (2003)	Unit 3 IGCC (2003)
Generating Unit (2003 $)	922,140,000	623,470,000	843,394,000
Shared Facilities	335,750,000	28,220,000	59,171,000
Escalation	125,412,000	78,594,000	147,118,000
Carrying Cost	261,300,000	275,200,000	298,900,000
Retirement Cost	138,330,000	73,028,000	104,968,000
TOTAL	1,782,932,000	1,078,512,000	1,453,551,000
TOTAL, 3 UNITS	4,314,995,000		

* Each unit has $13 million included for additional train costs.
** Escalation is for general inflation as measured by the GDP price deflator.
*** Carrying costs represent the interest on the capital invested in the project.
**** Retirement costs include amounts necessary to tear down the facility.

Production costs for electric generation consist of the capital dollars to build the plant, fuel procurement, and the Operating and Maintenance (O&M) expenses. Each of these costs is described in more detail below.

Financing mechanism

In its supply resource planning, WEPCO considered utility-owned generation (i.e. traditional rate-based generation), procurement from wholesale merchant plant suppliers (i.e. independent power producers), and leased generation from a public utility affiliate. After reviewing these three approaches, WEPCO decided to pursue the leased generation financing approach for both the combined-cycle units at Port Washington and the coal-fired facilities designated as the ERGS and located near the existing Oak Creek Power Plant.

The leased generation contract for the ERGS consists of three leases, a Facility Lease, a Ground Lease, and Ground Sublease. A set of these three leases would be required for each of the three units proposed for the ERGS. At this time, only the leases for the first SCPC unit have been provided to the PSC for review. These leases and their financial terms and ratepayer impacts are discussed later in this chapter.

Technology cost assumptions – SCPC units

WEPCO is proposing to use bituminous coal as the primary fuel source at an estimated cost premium of 3.5 percent more than if it burned sub-bituminous coal. The additional cost offers advantages of improved mercury collection and higher efficiencies[17] (thus less CO_2 production). Bituminous coals, from the eastern

[16] DR-006 provided original supporting documentation for levelized lease payments. Al Mihm's testimony provided the latest $/kW costs.
[17] Response to 1-SUP-013.

U.S., have higher heating values due to more fixed carbon. Subbituminous coals, from the western U.S., have higher ash and moisture content.

The technology for the SCPC units is considered mature and the estimated costs should be relatively stable. Roughly 1,000 units are operating with coal as a primary fuel source and it is estimated that 40 units within the U.S. have incorporated the SCPC technology since 1960.[18]

Since the PTF application was initially filed, WE Power has received bids for the Engineer, Procure, and Construct (EPC) contract for the SCPC units. Bechtel Power Corporation has been selected as the lowest evaluated bidder. WEPCO has indicated a change from the original cost estimates of $1,263/kW in 2001 dollars to $1,400/kW in 2003 dollars.

Items that impacted the original estimate provided by WEPCO include:

- The need to remove a portion of the bluff for plant siting.
- The additional cost for the water intake being tunneled 9,000 feet into bedrock.[19]
- The estimated cost for a fabric final filter after the electrostatic precipitator (if required).
- The estimated cost of $20 million for a coal shed over the active coal pile.[20]
- Construction of an underpass at Six Mile Road at a cost estimated at $5 million.[21]

Items that have not been considered part of the construction cost include:

- Recently negotiated annual payments to Oak Creek similar to that paid to Port Washington.[22]
- Transmission system impacts.

Technology cost assumptions - IGCC Unit

The estimated cost for the IGCC unit is not as refined as that for the SCPC units. A request for bids for an EPC contract for the IGCC plant has not been issued and likely will not be issued before a CPCN decision occurs. There is little historical information to determine the estimated IGCC cost and the 2011 commercial operation date is too far into the future to develop a more reliable estimate with increased price certainty.

IGCC technology has been demonstrated commercially at only two sites within the U. S., both for a nominal 250-MW size plant. The cost for one of those plants, the Wabash River Plant in Indiana, was $417 million for a 262-MW facility (in 1995 dollars) or $1,591/kW.

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18 http://www.fe.doe.gov/coal_power/special_rpts/market_systems/marketbased_systems_appendices.pdf page 11.

19 Response to 1-SUP-093.

20 WEPCO increased this cost from $5 million to $20 million in its comments on the draft EIS.

21 Grade Separation Feasibility Studies... by Benesch.

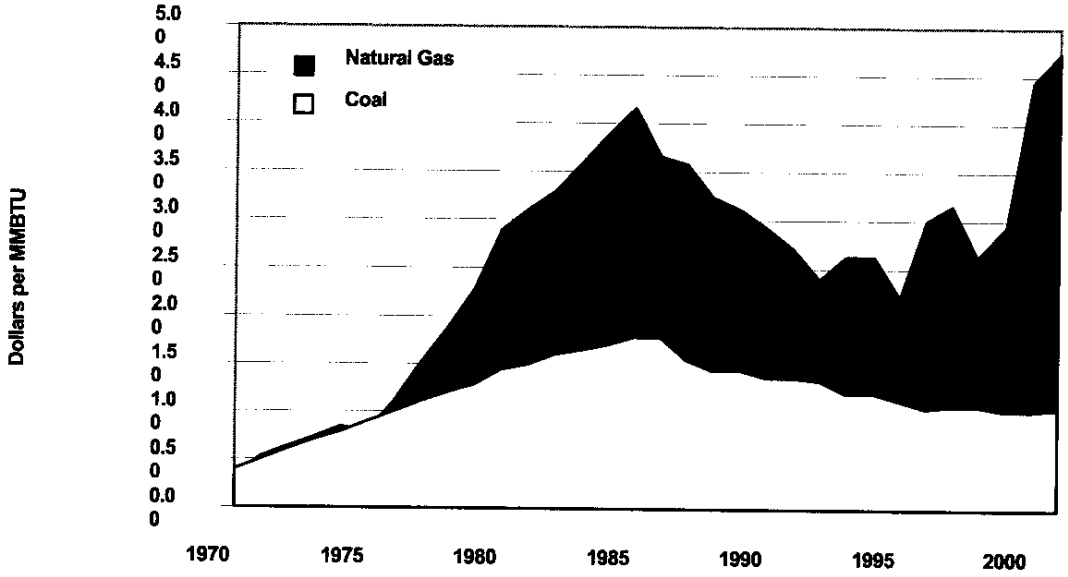
22 The Commission approved an annual payment of $500,000 to the city of Port Washington after it approved the construction of two 515 MW natural gas-fired combined-cycle plants to replace the existing 320 MW of coal-fired generation currently on-site. Recently WEC and WEPCO agreed to pay Oak Creek the following amounts: $1.5 million per year after the start-up of unit 1 (SCPC); an additional $750,000 at the start-up of unit 2 (SCPC); and an additional $250,000 at the start-up of unit 3 (IGCC).

Fuel cost assumptions

WEPCO forecasts coal prices at a cost of $1.35 per mmBtu (or $26.00 per ton) and expects that this cost would increase at an annual growth rate. In its coal price estimates, WEPCO applies nominal increases (near inflation levels) for 2004 and beyond. There is little price volatility in its forecast from year-to-year after 2004. Thus, WEPCO's forecasted coal prices appear to be conservative, and appear not to unduly favor coal over use of other fuels. Figure 2-1 shows that historically, the price of coal has been quite stable for Wisconsin utilities, especially compared to the price of natural gas. The volatility of natural gas prices is discussed in Chapters 4 and 5.

WEPCO assumes that the cost of coal delivered by rail or barge is comparable for bituminous coal.[23]

Figure 2-1 Price of coal versus natural gas for Wisconsin utilities



Operation and maintenance

Costs estimated by WEPCO are broken into fixed or variable operations and maintenance expenses (O&M). Fixed O&M expenses for the SCPC units are estimated at $20.07/kW/year. This includes plant staffing, insurance, and some other equipment and contract labor maintenance costs. Variable O&M expenses for the SCPC units are estimated at $ 2.01/MWH. This estimate includes the equipment, material, and contract labor costs associated with equipment maintenance.

Fixed O&M expenses for the IGCC unit are estimated at $33.44 /kW/year. This also includes plant staffing, insurance, and some other equipment and contract labor maintenance costs. Variable O&M expenses for

[23] Response to 1-SUP-206.

the IGCC units are estimated at $ 0.82/MWH. This estimate includes the equipment, material, and contract labor costs associated with equipment maintenance.

The O&M costs for the SCPC units are comparable with other coal-fired units operating in Wisconsin and are slightly lower than estimates from the Energy Information Administration (EIA), an office in the U.S. Department of Energy. The IGCC costs are similar to EIA estimates since limited experience is available from other plants.

Retirement costs

Future retirement costs for the proposed units would be collected as part of the annual lease payments. Net salvage factors of 10 percent of the estimated project cost for these coal-fired units was utilized as part of the lease payment.

Projected transmission costs

American Transmission Company (ATC) completed the Generation Interconnection Study Report for the ERGS facilities (IC012) in December 2001. The Final Summary Report Revision 1 was issued July 17, 2002. This report presented and summarized the results of the stability, thermal and fault duty studies for all three phases of the ERGS proposal. A detailed cost break down and description of the requirements for each stage can be found in Chapter 6.

The total transmission costs, associated with all three coal units, are expected to be $266,214,753 in 2007 dollars. WE Power would pay for the system improvements up to the point where the interconnections reach the common network side of the high voltage system, which is 345 kilovolts (kV) in this case. Beyond that point, the network transmission costs would be covered by ATC. ATC would recover its costs through transmission tariffs which are approved by the Federal Energy Regulatory Commission (FERC). The three phases of the ERGS proposal have associated transmission costs as follow:

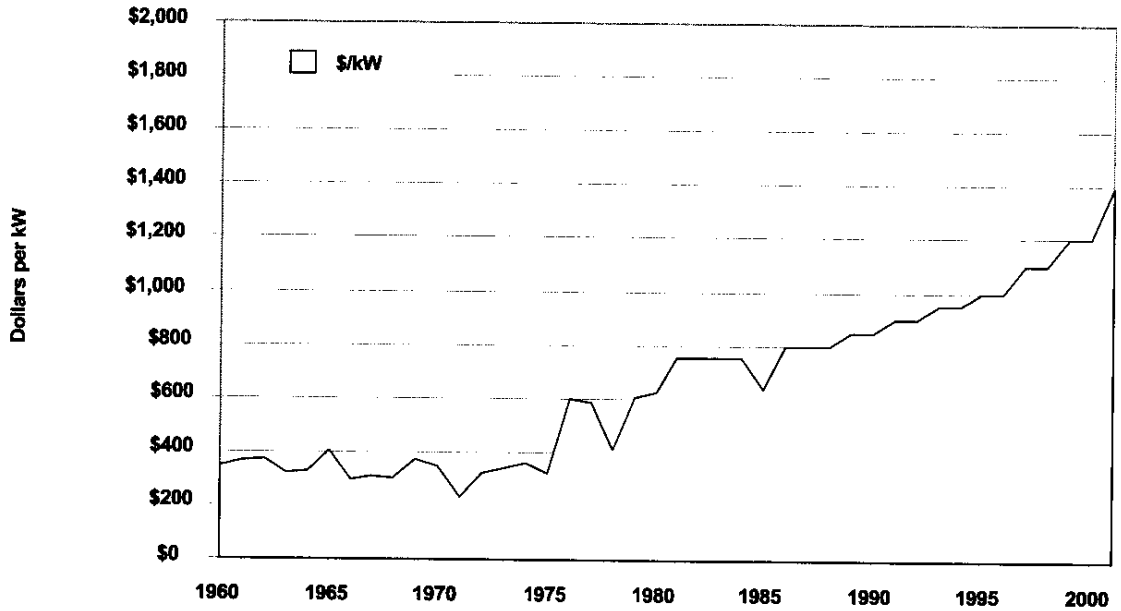
Phase 1 – 650 MW in 2007	Project Cost (2007 $)
System Reinforcements for Stability (Required)	94, 989,991
System Reinforcements for Short Circuit (Required)	2, 435,391
System Reinforcements for Thermal (Optional)	20, 288,167
Total Phase 1	**117,713,549**
Phase 2 – 1,300 MW total in 2009	
System Reinforcements for Stability (Required)	46,338,542
System Reinforcements for Short Circuit (Required)	0
System Reinforcements for Thermal (Optional)	0
Total Phase 2	**46,338,542**
Phase 3 – 1,950 MW total in 2011	
System Reinforcements for Stability (Required)	88,810,206
System Reinforcements for Short Circuit (Required)	7,654,086
System Reinforcements for Thermal (Optional)	5,700,370
Total Phase 3	**102,164,662**
Grand Total	**$266,216,753**

Uncertainties inherent in the estimated costs

ATC performs interconnection studies based on requests that are placed in a queue. When it performs a new generation interconnection study, ATC assumes that the facility interconnections requested prior to the case at hand, are in place. It assumes that the plants have been built and are interconnected to the primary transmission network.

In Wisconsin, several generation projects that preceded the ERGS proposal in the ATC queue have been cancelled, or indefinitely delayed. At the time that the initial interconnection study for the ERGS was completed, there were other units in the Midwest queue ahead of Elm Road, including IC001 (Midwest Power – Germantown), IC003 (Badger Gen – Kenosha), and four generating units in northern Illinois. These generating plants were all assumed to be interconnected and operating when the transmission studies for the ERGS were being done. Since that time IC001 and IC003 have dropped out of the queue or have been terminated, as well as three out of the four Illinois plants. Thus, the transmission improvements designated as needed for transmission service (thermal options) may no longer be required or may be somewhat different. More discussion about these transmission improvements and updated transmission studies can be found in Chapter 6.

Figure 2-2 **Construction cost per kW for Wisconsin coal plants since 1960 (cost increases after 1985 are based solely on inflation since no plants were actually built between 1985 and 2000)**



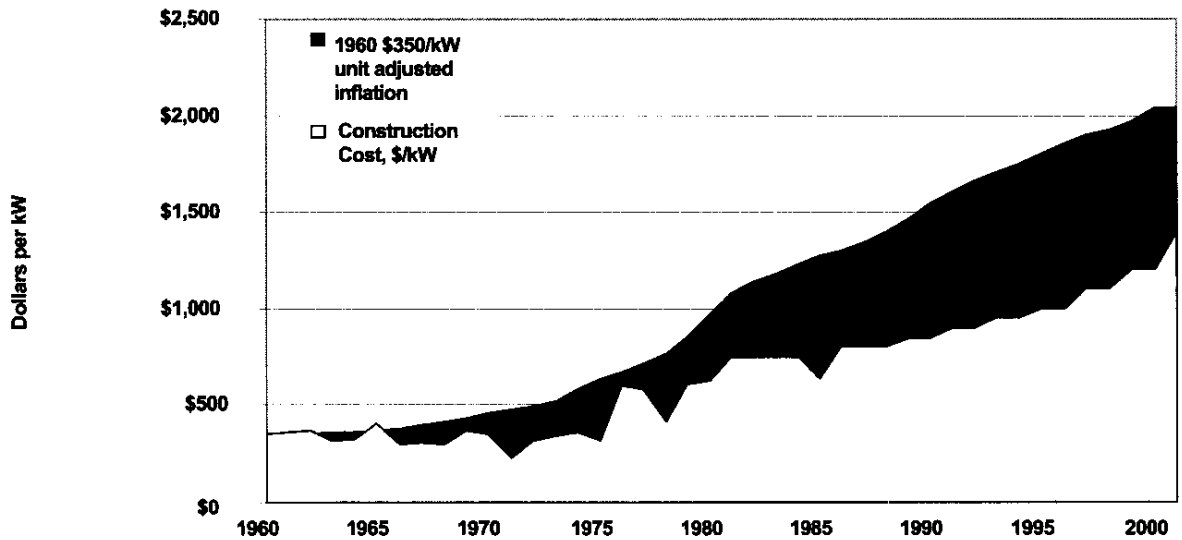
Costs of previous coal-fired generation plants

Estimated costs and actual costs for approximately 20 coal-fired generating units built in Wisconsin since 1960 were reviewed to determine the potential for cost overruns in the ERGS project. A comparison on a per unit basis for Wisconsin coal plants built since 1960 is shown in Figure 2-2. For power plants, the per

unit basis is construction cost per kW ($/kW). Costs over the past ten years, when no coal units were actually built in Wisconsin, were estimated based on inflation rates.

Costs have increased on a per unit basis but less than inflation. To further illustrate how costs have changed with time, the construction costs on a per unit basis are compared to the inflation rate as shown in Figure 2-3.

Figure 2-3 Comparison of construction costs of Wisconsin coal units versus inflation



The costs for Pleasant Prairie, WEPCO's most recently built coal-fired plant, along with Weston 3 and Edgewter 5, were reviewed and are shown in Table 2-2.

Table 2-2 Estimated and actual costs of recent coal-fired generating units

Plant	Estimated Cost	Actual Cost	Percent Variance
Pleasant Prairie Unit 1- 1980 (CA-5489)	$318,000,000	$411,000,000	29.2%
Pleasant Prairie Unit 2 - 1986 (CA-5489)	$264,900,000	$339,100,000	28.0%
Weston 3 - 1978 (6690-CE-1)	$240,000,000	$229,662,833	-4.2%
Edgewater 5 -1979 (6680-CE-3)	$294,600,000	$308,300,000	4.6%

Because construction costs for power plants have not increased as fast as the rate of inflation, costs on a per unit basis tend to decrease over time as the technology matures. Since 1960, advances have occurred with power technology including the ability to build larger units and the ability to obtain higher steam temperatures and pressures. During this period, emissions from coal-fired power plants have also been reduced through the burning of low sulfur Western coal, improved particulate collection, and improved combustion practices for NO_X reductions.

The cost overruns for Pleasant Prairie Unit 1 were the subject of a PSC investigation in 1981.[24] The report listed several of the factors above as reasons for the cost overrun along with the regulatory process that took 33 months to approve. The report also noted the unit was still less expensive than other units being built at that time. Factors cited for the cost overruns included:

- The time period during construction was one of high inflation and inflation was higher than anticipated.
- There was high demand for labor and materials for power plant construction.
- The costs were underestimated.
- Slippage in the planned start of construction.

The design of the Pleasant Prairie Power Plant was not finalized before the estimated costs were provided to the PSC for use in the Final Environmental Report.

PSC engineering staff believe, at this time, that the cost overrun potential for the ERGS is about 10 percent for the SCPC units and somewhat greater for the IGCC unit. Because of the recent historical trend toward cost overruns for coal-fired generation construction, staff has examined various cost overrun sensitivities when performing its analysis of the proposed ERGS project and other alternatives. A discussion of the financial and socioeconomic implications of cost overruns can be found in Chapter 4.

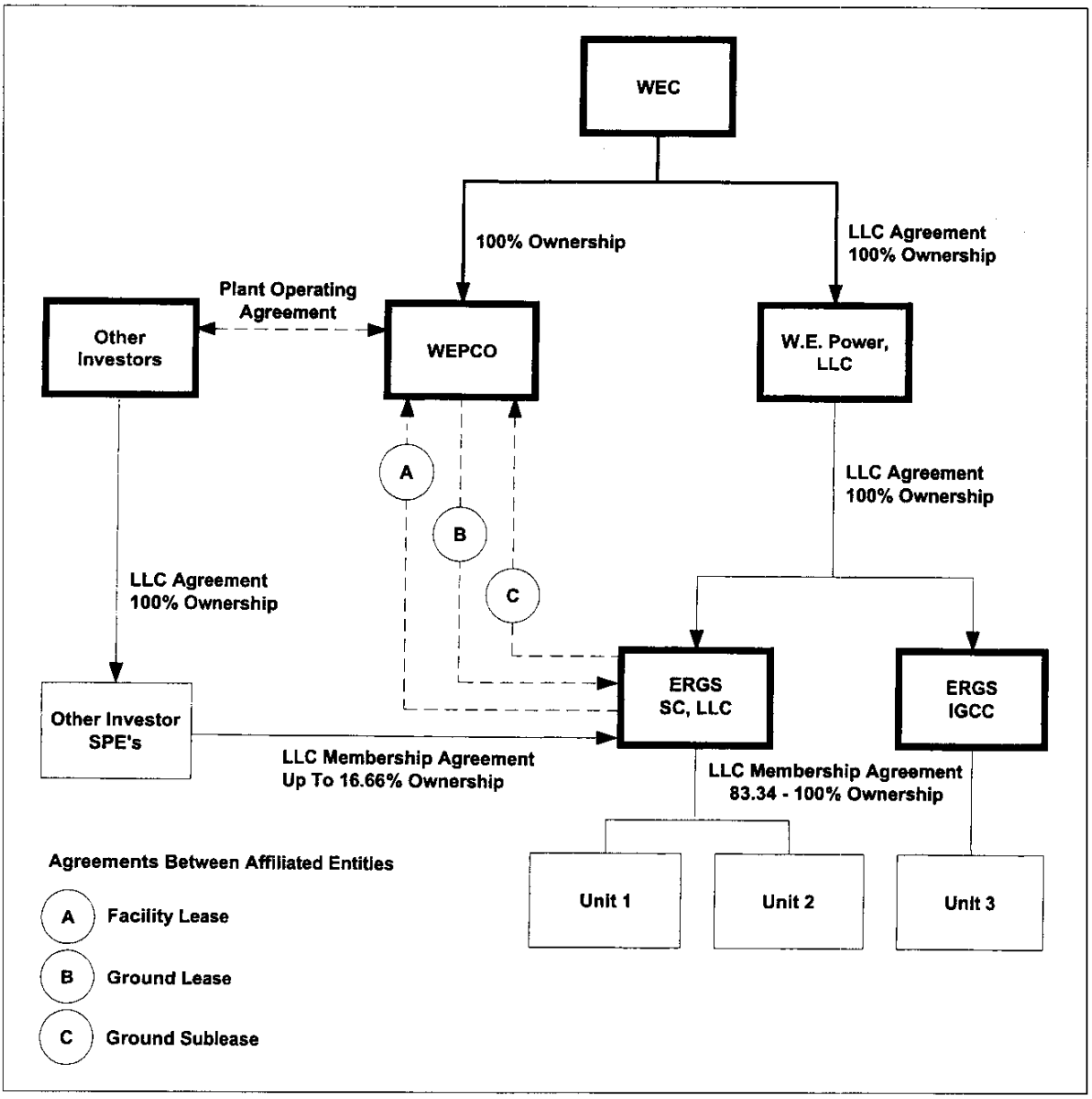
Lease Contracts

Facility lease financing

Under the leased generation approach, WEPCO would enter into long-term facility leases with two wholly owned subsidiaries of its non-utility affiliate company known as WE Power. These subsidiaries of WE Power are ERGS Supercritical LLC and ERGS IGCC LLC. The WE Power subsidiaries would construct and have major ownership interest in the facilities, but lease the generating units to WEPCO at economic terms and conditions reviewed, regulated, and approved by the PSC. Other interested utilities might have ownership interests in the facilities as well, but WE Power companies will own no less than 83 percent of each of the new generating units. WEPCO would also operate the coal facilities at the ERGS. Operation would include staffing, performing maintenance, as well as fuel procurement. The proposed facility lease for each of the proposed coal plants would have an initial term of 30 years, and WEPCO would have several options to extend the lease at a reduced rent. In addition to the facility lease there would also be several other leases covering use of the site. These other leases are referred to as ground leases and ground subleases and are discussed in sections below. The relationship between the companies and the required leases is shown in the following illustration.

[24] Final Report by Theodore Barry on Pleasant Prairie Unit 1 Cost Overruns.

Figure 2-4 Illustration of company relationships



In its May 2003 direct testimony supporting its application, WEPCO has indicated that the average construction cost of each SCPC unit would be $1,400,000 per MW in 2003 dollars. At present, WEPCO expects to take about 515 MW from each of the three 615 MW units. The remaining 100 MW of capacity for each unit is expected to be sold to Madison Gas & Electric Company (MGE) and Wisconsin Public Power Incorporated (WPPI). The estimated construction costs and WEPCO's portion of the coal plant's

output translate into a $721,000,000 lease obligation in 2003 dollars for each of the SCPC units.[25] Allowing for expected annual inflation of about 2.32 percent per year turns that obligation into a $808.6 million value measured in 2008 dollars to reflect the year the first unit is expected to begin commercial operation.[26] This $808.6 million represents the principal amount per SCPC unit used in the facility lease. This value does not include retirement or management costs. It also excludes carrying costs incurred during construction. These are listed in Table 2-1. Financing costs incurred once commercial operation begins are included in the analysis that follows.

Under the facility lease, the $808.6 million principal amount per unit must be financed. In the Port Washington CPCN docket, the Commission found that the appropriate lease financing parameters were a return on equity of 12.7 percent using a capital structure containing 53 percent common equity. As for long-term debt costs, the Commission indicated that costs associated with long-term utility debt credit that is rated "A" should be used. As of June 2003 that debt cost would be 5.00 percent. Using these financing costs and a 30-year lease term indicates that the annual lease payment from WEPCO to WE Power would be $111.25 million on average for each SCPC unit. This value is calculated using an ordinary annuity formula in the following table:

Table 2-3 Lease payment calculation for the first SCPC unit at the ERGS (2008 operation date)

515	MW capacity contracted to WEPCO
$1,400	Installed cost $/kW 2003 dollars
2.32%	Annual GDP escalation rate
	Lease Treatment Using PSC Approved Parameters From Port Washington CPCN Docket
53.00%	Equity Share
12.70%	After Tax Cost of Equity
1.66061	Fixed Tax Rate Gross Up Factor
47.00%	Debt Share
5.00%	Cost of 30-Year Debt Credit Rated A 6/13/03
50.00%	Lease Extension Renewal Rate Percentage
13.53%	Economic Cost of Capital Inclusive of Taxes
$808.608	Principal Amount of Project (millions) 2008$
30	Lease Term (years)
$111.258	**Annual Rent (millions) on an annuity payment basis including MARBA adjustment**

It is important to note that the table shown above uses the financing parameters approved by the Commission in the Port Washington CPCN docket rather than the parameters originally sought by the applicants in the ERGS application. Those parameters are an equity share for total capitalization of 58 percent earning a 12.9 percent return. Using those values in Table 2-3 would increase the annual rent to $118.9 million.

[25] The calculation is $1,400,000\MW X 515 MW = $721,000,000.

[26] Calculated as $721,000,000 in 2003 dollars X five years compounded 2.32 percent annual inflation or $721,000,000 * [(1+.0232) ^ 5] = $808,608,000 in 2008 dollars.

It is important to note that in a July 19, 2002, agreement with the Customers First Coalition, an intervener group representing some consumer groups and utilities, WEPCO agreed to seek financing for the gas facilities at Port Washington using a 12.9 percent return on equity and 55 percent common equity in the capital structure. In the current proceeding, certain financing parameters, particularly the appropriate return on equity, will be revisited.

In the affiliated interest portion of this proceeding, docket 05-AE-118, Commission staff has suggested that a return on equity of between 11.0 and 11.4 percent would be more appropriate for the proposed facility lease for the SCPC plants should the Commission decide to use that form of financing. Using the mid-point of this range, an 11.2 percent return on equity, as well as 53 percent common equity in Table 2-3 would reduce the estimated annual rent from $111.25 million to $101.28 million.

Lastly, because computer model simulation listed in Chapter 4 shows the IGCC unit to be non-economic, Table 2-3 has not been produced in the IGCC unit. This is the reason this section focuses on the SCPC units.

Effect of facility lease on retail electric customers

Given the facility lease payment calculation shown above, it is possible to estimate the effect on ratepayers for the two SCPC plants. Together, the annual lease payments would equal about $222.5 million. Presently, the retail electric revenue requirement for WEPCO is $1.7 billion. By 2010, WEPCO's retail revenue requirement may equal $2.15 billion. This means that the additional lease payments for the first two SCPC plants at Elm Road would increase retail electric revenue requirement by about 10.3 percent by the end of 2010. For a residential customer paying about $40 per month, this means that the average customer bill would increase about $4.12 per month. (Note: this rate impact does not take into account construction of the IGCC unit.)

This estimated effect covers the construction cost component only, and it represents a proportionate increase across all customer classes. The estimate does not include carrying costs or interest during construction. In addition, the estimate does not factor in fuel expenses associated with operating the units. This latter category is difficult to estimate because while fuel expenses would increase due to the new SCPC plants, system dispatch may reduce fuel expenses at other existing generating units. Demand growth also affects the calculation because increases in demand increase fuel expense. However, the increased demand also allows the extra fuel costs to be spread over the increased demand, thereby reducing the average effect on retail rates. Due to this complexity, the above price effect on customers focuses only on the capital component of the lease associated with construction.

As a final caveat, to the extent WEPCO is able to sell excess capacity from the unit when its native load customers do not require the power, revenue from the sales would be credited back to customers during ratemaking, thus reducing the above 10.3 percent electric rate increase estimate.

Facility lease versus a traditional rate-making approach

One of the reasons a leasing approach for the coal plants was pursued, according to WEC, is that WEPCO would unlikely be allowed sufficient return on a traditional rate-base investment to compensate investors for the risks associated with the coal plants. Under traditional rate-making procedures, the utility both owns and operates the plants. Under traditional rate-making, the value of the power plant put in service is 1) placed

into a utility's rate base representing accumulated capital investment in generation and distribution assets, 2) authorized a return on equity, and 3) depreciated over its estimated useful economic life. At present, WEPCO receives an authorized return of 12.2 percent for its rate-based generation and distribution assets. The useful life of a coal plant for accounting purposes is likely to be in the 40- to 50-year time frame.

In the Port Washington CPCN docket the Commission found that the historical rate-based approach was feasible, but that based on the evidence presented in that case, a leased generation financing approach was in the public interest.[27] The Commission's determination was based on the financial parameters it selected for the facility lease, other terms and conditions selected by the Commission, as well as the fact that under the Port Washington facility lease, WEPCO would operate and maintain the plant, thus remaining a regulated entity under the PSC's legal jurisdiction.

Whether this project should be financed through leases is an important issue. It is expected that the Commission will once again review whether the leasing approach or the traditional rate-base approach is the appropriate financing and ownership vehicle for the ERGS coal facilities. It is important to note recent developments favoring rate base treatment for new coal facilities. In May 2003, the Iowa Utilities Board approved a ratemaking approach for a new 790 MW coal facility for MidAmerican Energy Company to be located at Council Bluffs, Iowa. Also, as part of a requested declaratory ruling Wisconsin Public Service Corporation has indicated that it would use rate base treatment for a proposed new coal facility to be located at its Weston generating station.

The following analysis demonstrates cost streams associated with the proposed lease approach for the first SCPC unit at Elm Road versus using historical rate-making in which WEPCO would own the coal plants outright. In the rate-making example, all assumptions are the same as for the leasing method except for the return on equity and the project life. The modeled value for the traditional rate-making approach uses 13.7 percent for the rate of return on equity in order to reflect that the rate-based approach may be more expensive on a risk-adjusted basis due to potential variability of the authorized return on equity.[28] This is unlike the approach in the facility lease where the authorized 12.7 percent return on equity in the facility lease would be held fixed for the duration of the facility lease. In terms of project life, the facility lease uses the assumption of a 30-year initial term with a ten-year extension in which rent is only 50 percent of the original lease payment. In the rate-making method, the life of the project is 40 years and standard depreciation is used.

The following analysis also uses an 8.97 percent rate of discount. Under the assumption of 2.32 percent inflation, the implicit real rate of discount is 6.5 percent. This 6.5 percent value is somewhat higher than the 5.5 percent real rate of discount that the Commission had authorized for use in Advance Plan 8. A slightly higher rate favors current ratepayer and investor interests. Using a lower rate would better factor in future generations. However, the somewhat higher rate was used here to better taken into consideration potential investor interests since the Commission, as part of this proceeding, must also choose between either the facility lease or ratemaking finance method. Such a choice strongly affects the ability to finance a project.

[27] Page 25, Final Order in Docket 05-CE-117

[28] In a traditional rate-making approach, the utility's return of equity is periodically reviewed by the Commission and adjusted according to current financial trends.

Table 2-4 Comparison of cost streams using facility lease and traditional rate-making practice

515	**Contract Capacity to WEPCO in Megawatts**
$1,400	**Installed Cost $/kW 2003$ SCPC**
2.32%	**Annual GDP Escalation Rate**
8.97%	**Nominal Discount Rate**

	LEASE TREATMENT		**RATEBASE TREATMENT WITH 13.7% ROE**
53.00%	**Equity Share**	53.00%	**Equity Share**
12.70%	**After Tax Cost of Equity**	13.70%	**After Tax Cost of Equity**
1.66061	**Fixed Tax Rate Gross Up Factor**	1.66061	**Fixed Tax Rate Gross Up Factor**
47.00%	**Debt Share**	47.00%	**Debt Share**
5.00%	**Cost of 30-Year Debt Credit Rated A 6/13/03**	5.00%	**Cost of 30-Year Debt Credit Rated A 6/13/03**
50.00%	**Lease Extension Renewal Rate Percentage**	40	**Book Life (Years)**
		30	**Tax Life (Years)**
13.53%	**Economic Cost of Capital Inclusive of Taxes**	14.41%	**Economic Cost of Capital Inclusive of Taxes**
$808.608	**Principal Amount of Project (millions) 2008$**	$808.608	**Principal Amount of Project (millions) 2008$**
30	**Lease Term (years)**		
$9.279	**Monthly Rent Annuity Basis (millions)**		
$111.258	**Annual Rent (millions) with 99.915% MARBA Adjustment**		

First 30 Years Analysis

Year	Annual Rent Millions	Discount Factor	2003 Present Value	Year	Annual Revenue Requirement	Discount Factor	2003 Present Value
2008	$111.258	0.6508	$72.410	2008	$136.716	0.6508	$88.979
2009	$111.258	0.5973	$66.449	2009	$133.224	0.5973	$79.569
2010	$111.258	0.5481	$60.979	2010	$128.125	0.5481	$70.224
2011	$111.258	0.5030	$55.960	2011	$123.276	0.5030	$62.005
2012	$111.258	0.4616	$51.353	2012	$118.660	0.4616	$54.770
2013	$111.258	0.4236	$47.126	2013	$114.258	0.4236	$48.397
2014	$111.258	0.3887	$43.247	2014	$110.055	0.3887	$42.779
2015	$111.258	0.3567	$39.687	2015	$106.036	0.3567	$37.824
2016	$111.258	0.3273	$36.420	2016	$102.186	0.3273	$33.450
2017	$111.258	0.3004	$33.422	2017	$98.364	0.3004	$29.549
2018	$111.258	0.2757	$30.671	2018	$94.543	0.2757	$26.063
2019	$111.258	0.2530	$28.146	2019	$90.721	0.2530	$22.951
2020	$111.258	0.2322	$25.829	2020	$86.900	0.2322	$20.174
2021	$111.258	0.2130	$23.703	2021	$83.078	0.2130	$17.700
2022	$111.258	0.1955	$21.752	2022	$79.257	0.1955	$15.495
2023	$111.258	0.1794	$19.962	2023	$75.435	0.1794	$13.534
2024	$111.258	0.1646	$18.318	2024	$71.614	0.1646	$11.791
2025	$111.258	0.1511	$16.810	2025	$67.792	0.1511	$10.243
2026	$111.258	0.1387	$15.427	2026	$63.970	0.1387	$8.870
2027	$111.258	0.1272	$14.157	2027	$60.149	0.1272	$7.653
2028	$111.258	0.1168	$12.991	2028	$56.327	0.1168	$6.577

2029	$111.258	0.1072	$11.922	2029	$53.539	0.1072	$5.737	
2030	$111.258	0.0983	$10.941	2030	$51.785	0.0983	$5.092	
2031	$111.258	0.0902	$10.040	2031	$50.032	0.0902	$4.515	
2032	$111.258	0.0828	$9.214	2032	$48.278	0.0828	$3.998	
2033	$111.258	0.0760	$8.455	2033	$46.524	0.0760	$3.536	
2034	$111.258	0.0697	$7.759	2034	$44.770	0.0697	$3.122	
2035	$111.258	0.0640	$7.120	2035	$43.016	0.0640	$2.753	
2036	$111.258	0.0587	$6.534	2036	$41.262	0.0587	$2.423	
2037	$111.258	0.0539	$5.996	2037	$39.508	0.0539	$2.129	
		PV for 2008-2037	$849.225			PV for 2008-2037	$741.903	-12.6%

10 Year Lease Extension @50% of Prior Rent

Year	Rent	Discount Factor	2003 Present Value
2038	$55.629	0.0495	$2.751
2039	$55.629	0.0454	$2.525
2040	$55.629	0.0417	$2.317
2041	$55.629	0.0382	$2.126
2042	$55.629	0.0351	$1.951
2043	$55.629	0.0322	$1.791
2044	$55.629	0.0295	$1.643
2045	$55.629	0.0271	$1.508
2046	$55.629	0.0249	$1.384
2047	$55.629	0.0228	$1.270
		PV for 2038-2047	$19.267

40 Year Analysis

PV for 2008-2047	$868.492

Ongoing Ratebase Treatment for Next 10 Years

Year	Annual Revenue Requirement	Discount Factor	2003 Present Value
2038	$37.754	0.0495	$1.867
2039	$36.000	0.0454	$1.634
2040	$34.246	0.0417	$1.426
2041	$32.493	0.0382	$1.242
2042	$30.739	0.0351	$1.078
2043	$28.985	0.0322	$0.933
2044	$27.231	0.0295	$0.804
2045	$25.477	0.0271	$0.691
2046	$23.723	0.0249	$0.590
2047	$21.969	0.0228	$0.502
		PV for 2038-2047	$10.768

40 Year Analysis

PV for 2008-2047	$752.671	-13.3%

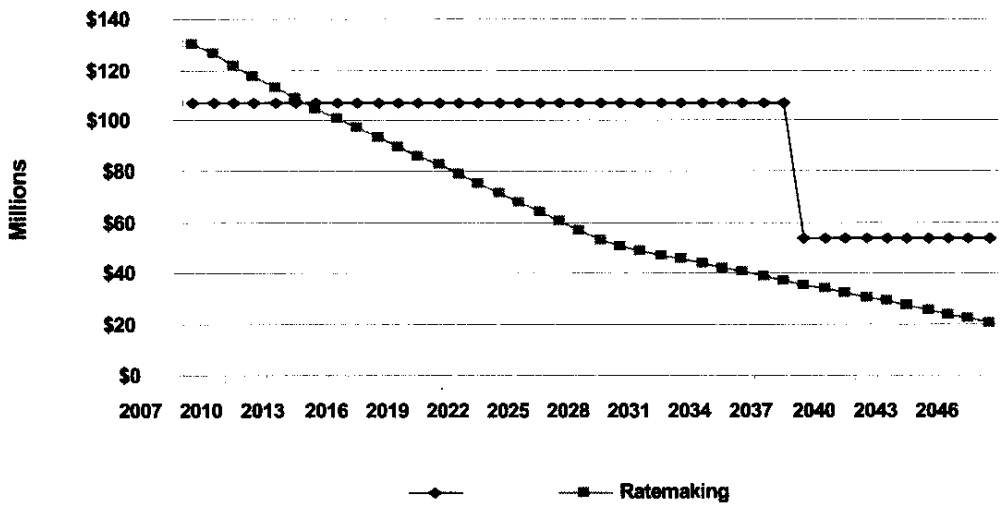
The analysis in the table above shows that a traditional rate-making approach would cost ratepayers about 13 percent less on a present value basis than using the proposed lease financing mechanism. For 40 years of operation, the present value of the lease approach is $868 million in 2003 dollars as compared to $753 million using traditional rate-making procedures. This difference would occur if the rate-based coal generation projects could be financed at a common equity rate of 13.7 percent assumed in the analysis. Whether this is the case will be examined during technical hearing in this docket, but it is important to note that the 13.7 percent rate assumed in the above analysis nearly matches the authorized rate of 13.75 percent granted to Alabama Power Company in 2002 by the Alabama Public Utility Commission. According to the utility trade publication, Public Utilities Fortnightly,[29] the 13.75 percent authorized return for Alabama Power Company was the highest authorized return for electric rate base assets in the country during 2002. However, such a value could be on the high side as MidAmerican Energy Company in Iowa in May 2003 agreed to accept a 12.29 percent return on equity in a traditional rate making financing approach for its

[29] "Return on Equity: Interest Rates Push Down Allowances," by Phillip S. Cross, Public Utilities Fortnightly, November 15, 2002.

proposed 790 MW coal facility in Council Bluffs, Iowa. Using such a value in the above table with traditional ratemaking for ERGS would save ratepayers about 19 percent on a present value basis over the facility lease.

While the rate-base calculation above is less cost than the facility lease method on a present value basis, there are important intergeneration equity aspects that may favor the lease. This is because under the facility lease, the annual rent would be $111.25 million per year on average per SCPC unit for the first 30 years, while under traditional rate making procedure using a 13.7 percent return on equity, the revenue requirement would start out much higher at $137 million and then gradually decline to around $39 million during the same period. This means that under traditional rate-making, current customers would pay relatively more for the plant than future customers would. The following chart depicts the required revenue streams under the facility lease approach and traditional rate making:

Figure 2-5 Comparison of facility lease and ratemaking annual cost streams for a SCPC unit



Cost Impact of Recent Agreement Between WEPCO and the City of Oak Creek

On March 25, 2003, the city of Oak Creek and WEPCO entered into an agreement by which:

1. Total emissions of all of the OCPP and ERGS power plants, old and new, are not to exceed year 2000 levels.
2. WEPCO agrees to install two new emissions monitoring stations.
3. WEPCO agrees to annually pay the city of Oak Creek $1.5 million at the start-up of ERGS unit 1, $750,000 at the start-up of ERGS unit 2, and $250,000 at the start-up of ERGS unit 3.
4. WisPark agrees to work with the city of Oak Creek to identify and develop areas for commercial/industrial parks and commits to investing $20 million.

5. WEPCO will work with the city on a conditional use permit basis to minimize concerns of the city of Oak Creek.[30]

Under this arrangement, the city of Oak Creek would drop its opposition to the ERGS project, and WEPCO would seek Commission approval to recover the costs of these annual community impact payments from ratepayers. Such payments would total $2.5 million after the third unit is commercially operational. The first annual payment of $1.5 million would increase the cost of the facility lease for the first SCPC unit by about 1.3 percent based on an annual estimated lease payment of $111.25 million. The effect of such payment would be less than $0.54 per month for an average residential customer. The Commission approved such payments to the city of Port Washington for the two recently approved 545 MW gas-fired combined-cycle generating plants to be constructed in that city. Whether these payments should be recovered and what is the appropriate level may be key issues at hearing in this case. In July 2003, the governor withed into law a new method for compensating communities that host new power plants. By the hearings the Commission will know the full implications of the new statute, and how it affects ERGS and the estimated ratepayer impacts.

Ground leases

Under the respective Ground Leases, WEPCO would lease land known as the Elm Road Site to ERGS, LLC, for the purpose of site access, construction, use, and operation and maintenance of each generating facility.

Upon completion of construction, the Elm Road Site would be subleased back to WEPCO to allow it to operate the completed facility as provided in the Facility Lease.

[30] The conditional use permit (CUP), signed on June ___, 2003, resulted in another proposed site layout for the ERGS facilities on the North Site. This layout and the potential environmental effects of the new layout are described in Chapter 12.

3

Chapter 3 – Need for Baseload Capacity in Southeastern Wisconsin

WEPCO proposes to build three additional units or 1,830 MW of coal-fired generation over the next eight years. The need for all or a portion of this capacity, particularly as baseload generation, is explored in this chapter.

In determining the need for a proposed power plant, peak demand, energy use, and implications on reliability are examined. Forecasts of future peak demand and energy use typically include a multi-year projection of the annual maximum demand for power in kilowatts and energy use, in kilowatt hours.

Planning at least five years into the future is required for large generating units because of the construction lead-time necessary. The further into the future demand and energy use are predicted, the more uncertain the data becomes. To avoid paying for plants before they are required, there is a need to accurately balance future supply and demand. Appropriate planning for additional generation to meet future needs requires accurate forecasting of the variables and is best accomplished by making incremental changes in the generation supply instead of large changes all at once.

In addition to balancing supply and demand, an analysis of the generating system reliability is required. Reliability is based on the demand for electricity and the operating and reliability characteristics for each individual plant in the system.

Reliable service typically is defined by a lack of power interruptions. WEPCO must maintain sufficient peaking capacity and purchase power arrangements to cover unscheduled or planned outages from its generation supply during peak demand. The Mid-America Interconnected Network (MAIN) guidelines typically require about 15 percent target reserves. The PSC has traditionally required Eastern Wisconsin utilities to maintain a higher 18 percent planning reserve margin due to concerns with issues such as transmission limitations.

The optimal choice for new generation is determined by examining all of the possible generation addition plans that would meet the projected peak demand and energy use with an adequate level of reliability. The need to have an adequate mix of fuel sources (coal, nuclear, gas, and renewables) is discussed in this chapter. Alternative plans that could potentially substitute for the ERGS proposal are discussed in Chapter 4 and compared on the basis of cost, reliability, and environmental impacts.

Recent History of Reliability in WEPCO's (EWU's) Service Territory

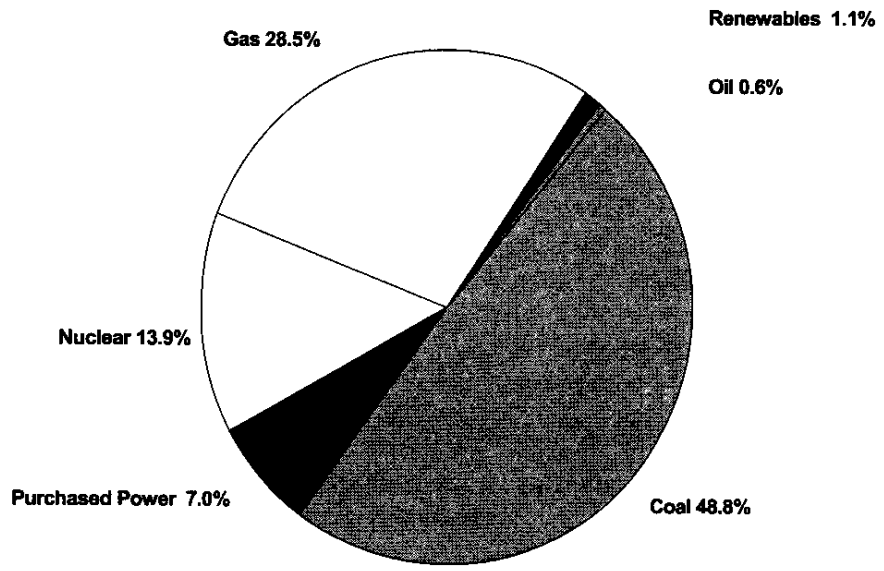
WEPCO's peak load for 2002 was 5,479 MW [31] with an estimated peak of 5,624 MW for 2003, as reported in its 2002 Wisconsin Strategic Energy Assessment (SEA) filing. Available WEPCO-owned capacity at peak, for 2003, is 5,053 MW. In addition, WEPCO has 948 MW contracted from merchant power plants and expects 411 MW of purchases without reserves. Adjusting for its Upper Michigan load of 98 MW results in a total supply of 6,430 MW in 2003, as reported in the SEA. The Mid-American Interconnection Network (MAIN) audit shows a 20.56 percent reserve margin in 2003 for WEPCO.

For planning future needs, it is desirable for WEPCO to maintain the 18 percent planning reserve margin recommended by the PSC. The 18 percent reserve is greater than some North American Electric Reliability Council (NERC) sub-region guidelines because it is meant to take into account transmission constraints within the Wisconsin Upper Michigan System (WUMS).

Adequacy of existing supply for peak demand

Although its reserve margin for 2003 is 20.56 percent, WEPCO is becoming increasingly dependent on power purchases to meet its needs. Figure 3-1 indicates that seven percent of its capacity will be power purchases to meet the anticipated peak demand. This does not include merchant plants under contract to WEPCO which are included as part of the gas section.

Figure 3-1 WEPCO's summer capacity available for 2003 peak demand

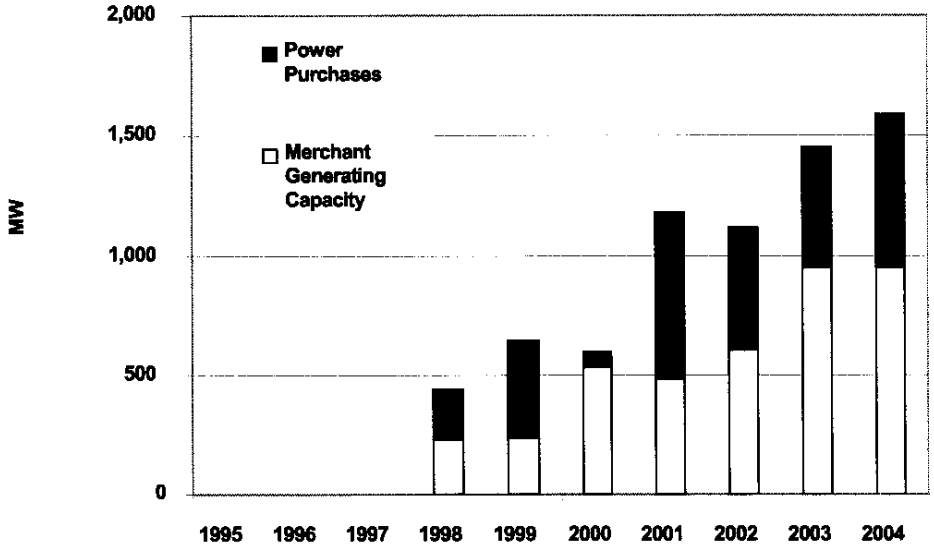


[31] Peak load not weather normalized and for Wisconsin only load of WEPCO.

No guidelines are specified for utilities on how to meet the PSC reserve margin; therefore, utilities have opted to pursue numerous options. To obtain the required 18 percent planning reserve margin, WEPCO has increased its reliance on interruptible load, load control, and increased purchases with reserves to reduce its peak load. On the supply side, WEPCO has increased its reliance on merchant plant capacity purchases and purchases without reserves, some of which are located outside of Wisconsin.[32]

Figure 3-2 shows the amount of WEPCO's capacity comprised of power purchases and merchant plant generating capacity. The additional three percent added to the reserve margin by the PSC was intended to allow for transmission constraints and other reliability issues. Three percent of WEPCO demand is approximately 150 MW, but the amount of purchase power WEPCO relies on is growing to levels well beyond this. Because these purchases have in turn increased the strain on a transmission system that is already viewed as overloaded, it is unlikely that this trend can continue. This implies that there may be a need for more baseload capacity in Wisconsin and more transfer capability.

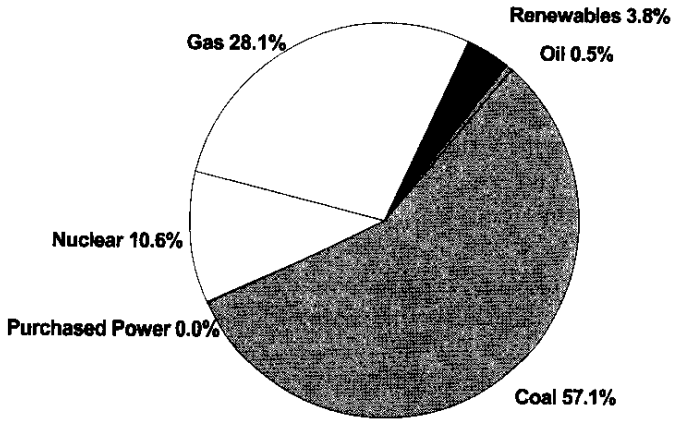
Figure 3-2 WEPCO's power purchases and merchant plant capacity



A mixture of baseload, intermediate load, and peaking load generation is required for an adequate generation mix as well as a mixture of fuel types. The baseload units in WEPCO's fleet consist of: Pleasant Prairie 1 and 2; Oak Creek 5, 6, 7, and 8; Point Beach 1 and 2; and WEPCO's 25 percent share of the Edgewater generating unit. Figure 3-3 presents the summer capacity in 2011 if all Port Washington and ERGS units are built.

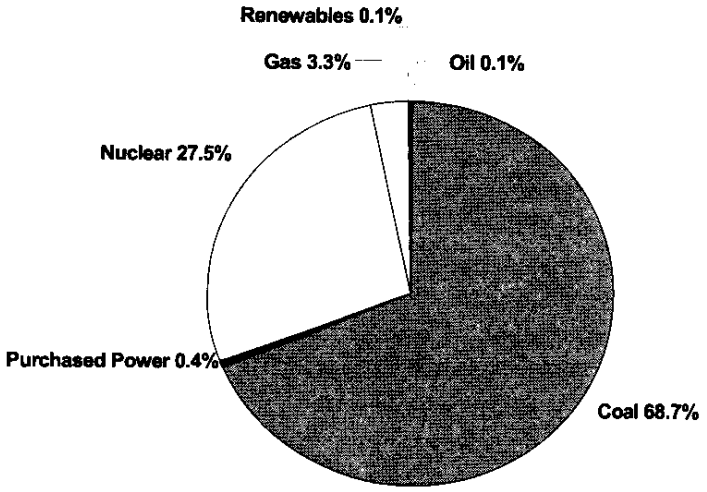
[32] The distinction between purchases with reserves and purchases without reserves pertains to the power seller's responsibility for planning reserves. A purchase with reserves means the seller is required to have sufficient capacity to back up the sale as if the seller were delivering the power for use by its own native load customers.

Figure 3-3 **WEPCO's summer capacity available for 2011 peak demand (if ERGS and PWGS are constructed as planned)**



Compared to the summer capacity chart for 2003, the percent of gas generation would remain the same, the percent of coal generation would increase, and the percent of nuclear would decrease. Figure 3-3 assumes that WEPCO would sign no purchased power contracts, which in all likelihood is false. However, at this point it is not possible to forecast the number of contracts or the capacity they would provide. If the purchases are gas-based, the coal percentage would be lower.

Figure 3-4 **WEPCO's energy production by fuel for 2001 in MWh**



Adequacy of existing supply for energy use

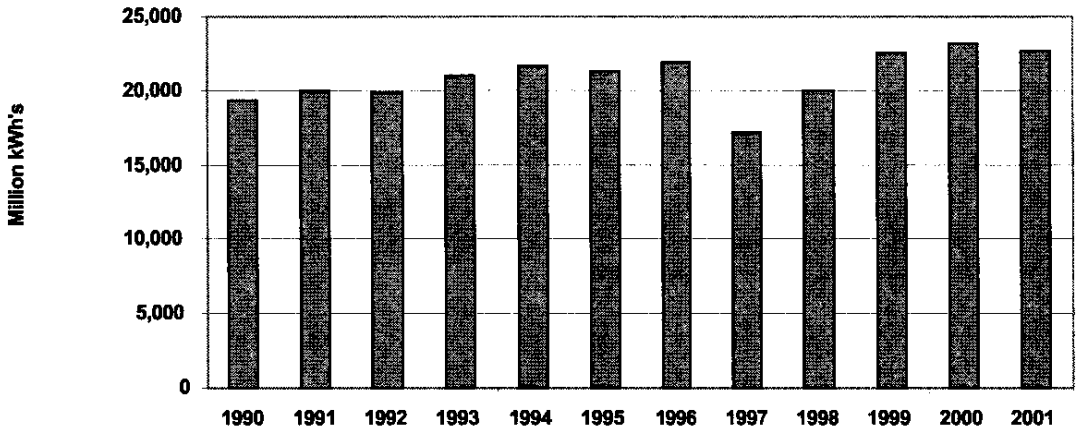
Coal-fired generation accounts for the majority of WEPCO's energy produced, as shown in Figure 3-4.[33] Nuclear power, which has represented greater than 25 percent of WEPCO's energy needs, will probably have a declining role if energy use continues to rise. Natural gas generation has increased to over 3 percent. The amount of future natural gas capacity will be highly dependent on the price of future fuel supplies. To meet the increase in energy use, there is a need for additional capacity with low fuel costs and high capacity factors to meet the changing energy needs. The different generating options and the changes that could result in the energy used to generate power are evaluated in Chapter 4.

Existing Generation Supply

Baseload generation of energy

The existing baseload plants are aging and at the same time have come under greater pressure to increase their output. The last baseload power plant constructed by WEPCO was Pleasant Prairie, Units 1 and 2 in 1985. While the growth in peak demand of the last decade was met by the installation of combustion turbines, the growth in energy use has been met in additional ways. The energy produced from WEPCO baseload generating units during the last decade increased by 15 percent as shown in Figure 3-5.

Figure 3-5 kWh production for WEPCO generating units built after 1960

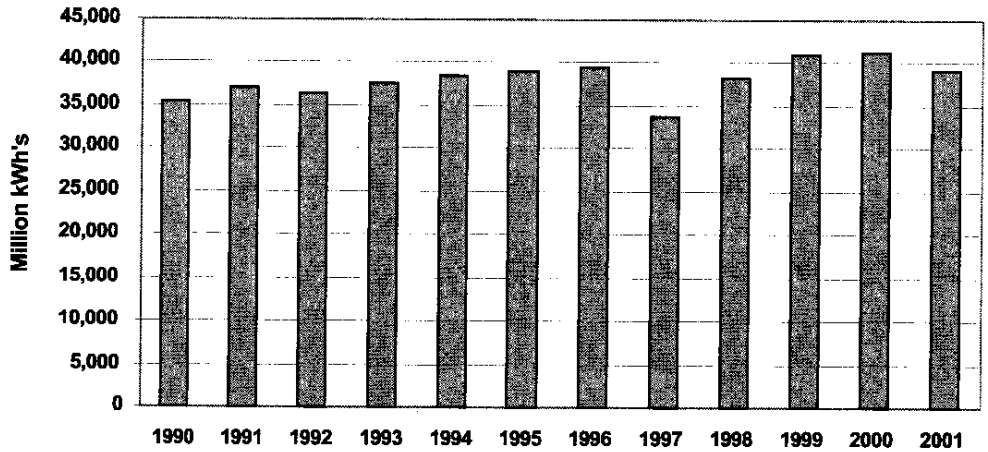


This increase is comparable to the trend seen in the rest of Wisconsin utilities where an increase of 9 percent has occurred (see Figure 3-6). The reduction in 1997 was due to the Point Beach and Kewaunee nuclear units being out of service for an extended period. The existing baseload plants have encountered higher capacity factors as production costs remained less than those for the newly installed combustion turbines.

[33] WEPCO purchases additional renewables amounting to between 2 and 5 percent of its sales that is not accounted for in its production.

Further production increases from the existing baseload generating units are not anticipated, and any shortfall in production would need to come from other sources.

Figure 3-6 kWh production for Wisconsin generating units built after 1960



Increased baseload energy use means the available time to work on multiple generating units during spring and fall maintenance seasons is further constrained. As a result, the outage "season" for Wisconsin is starting earlier and continuing later. As seen this past January, the need for maintenance at baseload facilities and unexpected forced outages during colder weather can force combustion turbine units into service during periods of high gas demand. As a planning issue, the implications of needing a large amount of gas generation to be available during the winter have been overlooked and requires further investigation, especially with the predicted increase in gas generation.

An increase in energy use has also been seen at the end of the outage "season" in May or the beginning of the fall season in September. Warm weather results in increased air conditioning load and a need to run gas turbines while baseload capacity is out of service.

In addition, the effect of peak demand reduction programs, such as direct load control and interruptibles, is contributing to reducing the time available for maintenance of existing baseload units. Summer peak demand reduction through active and passive kW programs, lessens the difference in demand between the spring and fall "shoulder" months and the summer peak month. In essence, this leaves less "room" to take multiple units out of service for routine maintenance.

As a market indicator, utilities have seen the forward-looking prices for purchased power in Wisconsin increase. This indicates that the costs for replacement generation are no longer based on the next available coal-fired baseload plants but on the next available gas generation plant.

Previous generation supply plans

WEPCO's 1976 long range expansion plan, developed to match the projected peak demand and projected energy demands, indicated 2,000 MW of coal-fired generation, 1800 MW of nuclear generation, and 213 MW of gas generation (see Table 3-1) would be required.

Table 3-1 WEPCO's proposed expansion plan in 1976

Year	Generating Units	Estimated MW	Actual MW
1979	Germantown combustion turbines	213	245
1980	Pleasant Prairie I	580	600
1982	Pleasant Prairie II	580	600
1984	A share of Koshkonong I coal-fired plant	440	
1985	A share of Koshkonong II coal-fired plant	400	
1987	A share of the Haven I nuclear plant	900	
1989	A share of the Haven II nuclear plant	900	

The Koshkonong and Haven power plants were never built as the energy demand discussed earlier never materialized until the late 1990s. Growth in energy and peak demand did, however, continue to increase. WEPCO met its generation needs accordingly by installing less costly combustion turbines at Paris and Concord as shown in Table 3-2.

Table 3-2 Generating units installed by or under contract to WEPCO since 1985

Year	Generating Units	Estimated MW	Actual MW
1993-94	Concord combustion turbines	344	382
1995	Paris combustion turbines	344	382
1997	Whitewater combined-cycle (purchase)	235	247
2000	Germantown 5 combustion turbine	95	95
2000	Neenah combustion turbines (purchase)	300	350
2004	Zion combustion turbines (Illinois purchase)	450	
2005	Port Washington combined-cycle	545	
2008	Port Washington combined-cycle	545	

In addition to the generating units it built, WEPCO arranged a 235 MW power purchase from the Whitewater combined-cycle generating unit and it expects to use up to 450 MW of capacity from Calpine's Zion Energy Center in Illinois by 2003. Advance Plan 7, filed in 1994, identified a future need for 500 MW of baseload facilities in 2011 and 2013. While use of 10- to 20-year Advance Plans has now been superceded by a two-year focused Strategic Energy Assessment, planning exercises over the past decade have identified a need for new baseload generation after 2007.

Other plants built or under construction within Wisconsin or that have ties to Wisconsin load are listed in Table 3-3.

Current generation supply plans

After the Advance Plan statute was repealed, the Strategic Energy Assessment (SEA) was created as its replacement. The SEA, issued every two years, has only a two-year outlook. Thus, large generation projects that require a longer lead time may not be disclosed or discussed.

Table 3-3 Other generating units greater than 50 MW installed or under construction in Wisconsin since 1998, or tied to Wisconsin load[34]

State	Year	Generating Units	Estimated MW	Utility Served
Wisconsin	1999	De Pere CT	175	WPSC
Wisconsin		Marinette CT		MGE
Wisconsin	2001	Rock Gen Christiana CT	450	WP&L
Wisconsin	2001	Elk Mound CT	96	DPC
Illinois	2001	Cordova CC	500	
Illinois	2002	Kendall Energy Center CC	1,000	
Wisconsin	2003	Pulliam CT	83	WPSC
Wisconsin	2004	Kaukauna CT	52	WPPI
Wisconsin	2004	Riverside CC	600	WP&L

Due to deregulation of wholesale power markets at both the state and federal levels, non-utility generation has been the supply area in which significant power plant construction has taken place in recent years. As late as 1996, there were no merchant power plants in the state. Beginning in 1997 with the operation of the LS Power (now Cogentrix) 235 MW cogeneration facility at the University of Wisconsin-Whitewater, there has been an expanded use of wholesale merchant power plants. In 1999, the 175 MW Polsky Energy Corporation combustion turbine unit in De Pere began commercial operation (the plant was subsequently purchased by WPSC). During the summer of 2000, SEI Wisconsin, the predecessor of Mirant, placed a 300 MW natural gas facility in Neenah into commercial operation (the plant subsequently was purchased by Alliant Generation). During 2001, the 450 MW RockGen combustion turbine project located in the town of Christiana in Dane County began full operation. All of these facilities are under contract to various state utilities. The sale of some of the merchant power plants to Wisconsin utilities reduces the amount of generation that merchant plants were predicted to supply toward the state's generation needs.

By the end of 2004, nearly 2,050 MW of electric generating supply being used by electricity providers for Wisconsin customers may come from merchant plants under contract to the states' utilities. Some of this power will come from merchant facilities located outside the state; such capacity plays an important part in maintaining electric reliability in the state. For instance, by 2003, WEPCO expects to use up to 450 MW of capacity from Calpine's Zion Energy Center in Illinois.

Power plants approved by the PSC but not expected to start construction in the near future include: a 1,050 MW combined-cycle unit in Kenosha County proposed by Badger Generating, LLC, a unit of Pacific Gas and Electric; a 900 MW facility in the Plover area of Portage County proposed by Mirant Corporation; and a 170 MW combustion turbine facility in Superior planned by Rainy River.

[34] The table does not include the Badger Gen, Rainy River, Fox Energy, or Mirant power plants which have PSC approval but have not been constructed. These projects have been placed on hold because they have been unable to sign contracts with Wisconsin electricity providers and because of the widespread financial difficulties in the IPP markets.

A shift toward a deregulated electricity market in the 1990s was supposed to allow merchant power plants the opportunity to compete with the electric utilities for providing wholesale power at competitive rates. Competitive alternatives for generation, however, have not fully materialized for several reasons:

- The financial standing of many IPPs is questionable. Financing is difficult without long-term power purchase agreements.
- Utilities have been reluctant to sign long-term contracts with IPP's because of their uncertain financial situation.
- A lack of available firm transmission services into Wisconsin hinders agreements with IPP's outside of Wisconsin.
- IPP projects are gas-fired, not coal, for the most part and natural gas prices have been higher than predicted.

Capacity needs in surrounding states

States surrounding Wisconsin have addressed capacity needs in different ways. Illinois, which was in the forefront of the deregulation movement a few years ago, has had over 10,000 MW of combustion turbines installed and 5,000 MW of combined-cycle generating units constructed since 1998. Much of this generation is located south and west of Chicago. Transmission constraints between northern Illinois and Wisconsin however, limit the options available to Wisconsin utilities beyond the merchant power plants listed in Table 3-3.

Iowa has not built a baseload power plant since the late 1970s and energy demands are expected to exceed supplies by 2003. Deregulation plans have been delayed. In May 2003, the Iowa Utility Board approved a 750 MW coal plant proposed by Mid American Energy Company. That plant would be located in Council Bluffs, Iowa.

Minnesota has not built a baseload power plant since the late 1980s and anticipates the need for two or three large coal or nuclear plants.

Recently approved transmission capacity

Existing transmission

The existing high voltage and extra high voltage (EHV 230 and 345 kV) systems in southeast Wisconsin have been just adequate to meet current generation and load serving requirements. Since the start of 2003, contracts for additional firm import power (beyond existing contracts) from northern Illinois have been mostly denied by the Midwest Independent System Operator (MISO). Recently, Alliant was granted a 100 MW contract for the summer of 2003.

The interstate transmission lines to the west and south have been in transfer-limiting condition for the past two years. When transmission lines can be overloaded with a single outage, the system operator issues a Transmission Loading Relief (TLR) order to mitigate the problem and reduce the chances of cascading power failures. Power flow issues are quite complex and can originate from several causes, including local

generation dispatch, line maintenance, generation maintenance, interstate power transfers, or inadvertent loop flow. Selected TLR incidents from the year 2001 are listed in Table 3-4 below.

MISO tracks the number of hours that its flowgates are in a TLR. MISO's footprint covers Wisconsin, Michigan, Minnesota, Dakota's, Nebraska, Iowa, Missouri, Kansas, Indiana, Ohio, and Kentucky. During 2001, only five months had "flowgate hours in TLR" (FG-HR) that exceeded 500 hours when considering the sum for each month. The largest monthly total was 800 FG-HR. This indicator of system transfer capability has steadily declined since 2001. From June 2002 to December 2002, no month has had less than 700 FG-HR. September 2002 had almost 1,400 FG-HR.

The levels of mitigation that involve curtailment of power transactions start at level 3. The definitions for each level are:

> **Level 3a:** Curtail transactions using Non-firm Point-to-Point transmission service to allow transaction using higher priority Point-to-Point transmission service.
>
> **Level 3b:** Curtail transactions using Non-firm Point-to-Point transmission service to mitigate operating security limit violations.
>
> **Level 4:** Reconfigure transmission system to allow transactions using Firm Point-to-Point transmission service to continue.
>
> **Level 5a:** Curtail transaction (pro rata) using Firm Point-to-Point transmission service to allow new transactions using Firm Point-to-Point transmission service to begin (pro rata).
>
> **Level 5b:** Curtail transactions using Firm Point-to-Point transmission service to mitigate operating security limit violations.

ATC has plans to improve the 138 kV problems noted in the above table. Work is now in progress in the Janesville area and in the Mukwonago area. ATC's 10-Year Assessment – Full Report – August 2002 notes other system performance limitations in the southeast portion of Wisconsin, which it designates as Zone 5. The other limitations include low voltages, overloads, and the accommodation of new generation.

Table 3-4 Selected 2001 transmission loading relief (TLR) incidents

Limiting element*	Contingent element	# days at level 3, 4, or 5
Albers - Paris 138 kV	Wempleton - Paddock 345 kV	21
Blackhawk Colley Road 138 kV	Paddock -Rock River 138 kV	12
Eau Claire – Arpin 345 kV		10
Mukwonago – Whitewater 138 kV	South Fond du Lac - Columbia 345 kV	2
Paddock - Blackhawk 138 kV	Paddock - Rock River 138 kV	4
Paddock - 345/138 kV Transformer	Paddock - Rockdale 345 kV	22
Pleasant Prairie - Racine 345 kV	Wempleton - Paddock 345 kV	1
Russell –Rockdale 138 kV	Paddock - Rockdale 345 kV	8
Wempleton - Paddock 345 kV		7

*Limiting element identifies the transmission segment that will become overloaded if the contingent element trips out of service unexpectedly.

Figure 3-7 shows the MISO curtailment flowgate-hours by TLR level for the months from January 2001 to December 2002.

Proposed transmission additions in southeastern Wisconsin

There are several transmission projects planned for Zone 5 (southeastern Wisconsin) that would address existing and near term reliability issues. Some of the larger projects planned by ATC are listed in Table 3-5 below. These items were selected from ATC's recent 10-Year Assessment Update, February 2003. This table does not include the additions that would be associated with the ERGS.

Figure 3-7 MISO curtailment flowgate-hours

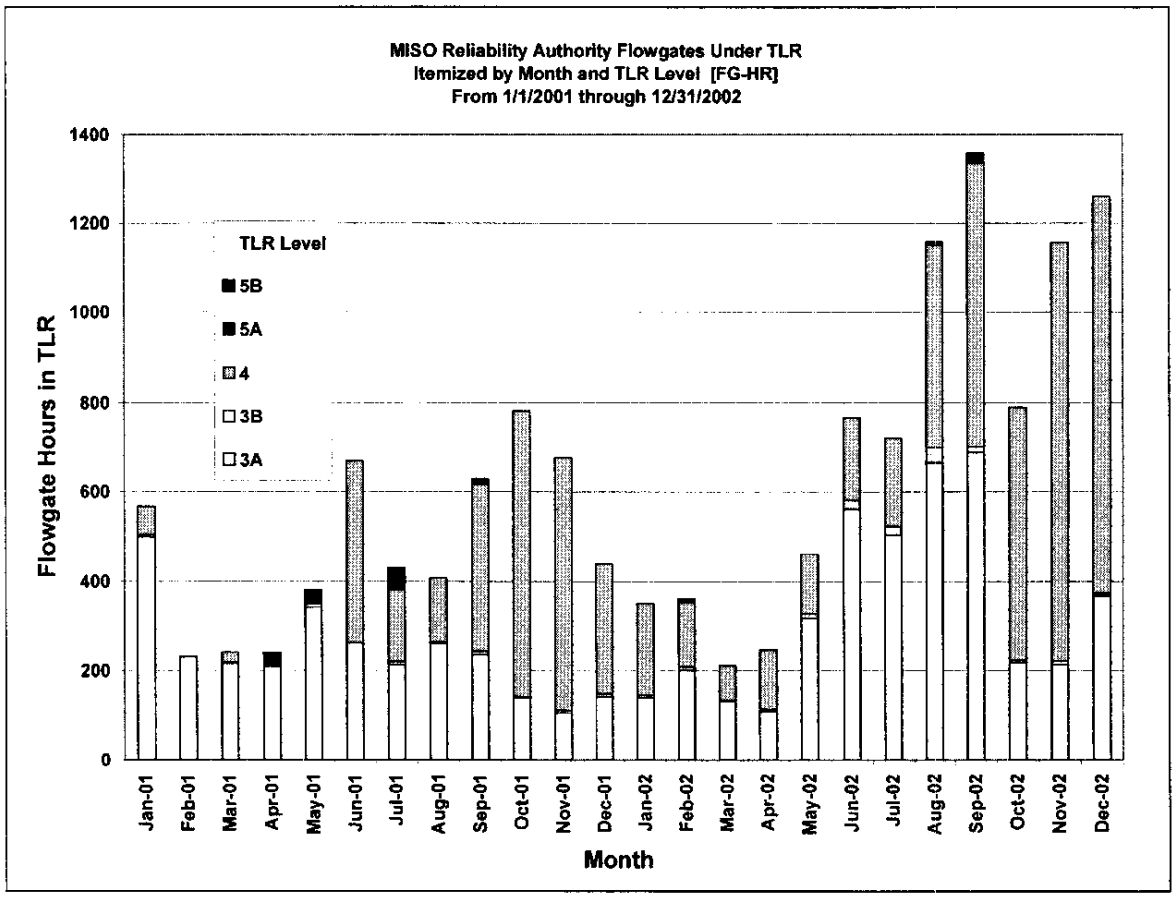


Table 3-5 Selected ATC Zone 5 improvements

Planned Additions	Projected In-Service Date	Need Category
Install 2 - 26 MVAR capacitor banks at Sussex 138 kV	2002	Reliability
Reconductor Mukwonago - Whitewater 138 kV line	2003	Condition, reliability, service limitation, new generation
Uprate Pleasant Prairie - Arcadian 345 kV line	2004	Service limitation, reliability
Rebuild Port Washington - Range Line double circuit 138 kV line	2004	New generation
Construct a new Lannon Junction sub at intersection of Granville-Arcadian 345 kV, Forest Junction - Arcadian 345 kV, Sussex -	2005	Reliability and Germantown generation stability

Planned Additions	Projected In-Service Date	Need Category
Tamarack 138 kV and Sussex -Germantown 138 kV lines; install 345/138 kV, 500 MVA transformer		
Construct a Waukesha - Duplainville - Sussex 138 kV line	2005	T-D interconnection
Rebuild Port Washington - Saukville double circuit 138 kV line	2005	New generation at Port Wash.
Rebuild Port Washington- Saukville single circuit 138 kV line	2005	New generation at Port Washington
Install 138 kV capacitor banks at Summit, Tichigan, Bluemound, and Moorland	2007	Reliability

Planned capacity retirements and nuclear relicensing

In its CPCN application, WEPCO indicated that no existing baseload capacity would be retired in the near future. However, retirement of OCPP units 5 and 6 has been made a condition of the WEPCO-US EPA Consent Decree released in May 2003. Commission staff recommended considering retirement of a generating unit at 60 years and this assumption was incorporated into the EGEAS modeling. Any forced retirements would most likely increase the need for additional generating capacity. Chapter 4 EGEAS base runs assume that OCPP units 5 and 6 are retired in 2012.

No retirement of any nuclear units was factored into staff's analyses. All expansion plans assumed successful relicensing for Units 1 and 2 at the Point Beach Nuclear Power Plant. Any forced retirements would most likely increase the need for additional generating capacity.

Projected Growth, Electric Demand, and Energy

This section discusses past and future projections of growth in energy use and peak demand. A review of previous forecasts for energy requirements indicates the levels of growth predicted have been reached for both energy use and peak demand but usually later than originally predicted. The projections for future growth appear reasonable and are based on a growing economy. If the recent economic slowdown were to continue, the need for additional generation may not be forthcoming or simply delayed. Past history indicates predicting growth accurately beyond a period of five years is very difficult.

Historic growth in energy use

Energy use has continued to grow over the last 30 years, although at a rate less than originally anticipated in the mid-1970's. The growth has been steady and linear. The Environmental Impact Report developed for Pleasant Prairie Units 1 and 2 in 1976 provided projected annual energy requirements up to 1989. These values are shown in Figure 3-9.

The total sales by WEPCO were predicted to reach 30,000 MWh in 1987. Growth in energy use has been steady, yet total sales did not reach the 30,000 MWh level until 1999.[35] Growth in 2001 and 2002 occurred in the residential and commercial sectors while the industrial sales decreased, resulting in no load growth in

[35] FERC Form 1 Page 301 Line 14

2001 and 2002. Energy use or total sales by WEPCO have continued to increase approximately 2.7 percent per year since 1992 as shown in Figure 3-10.

Figure 3-9 WEPCO projected energy demand since 1976

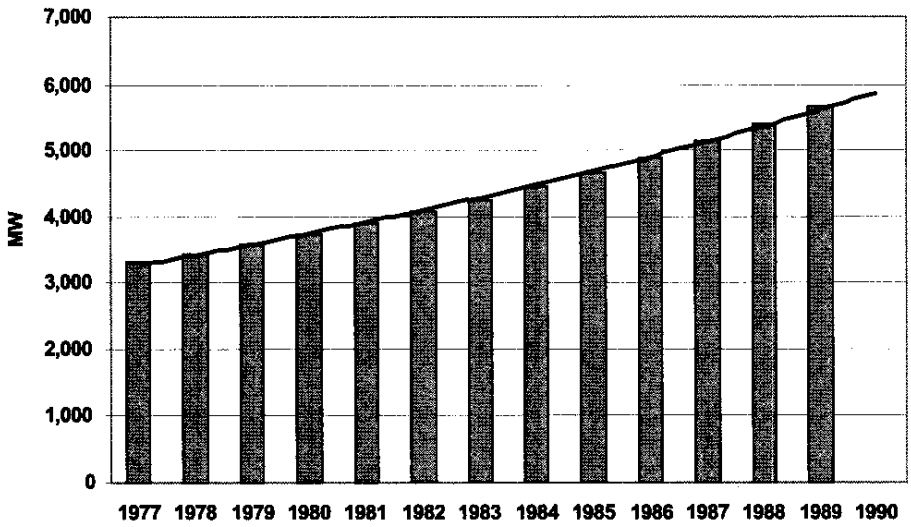
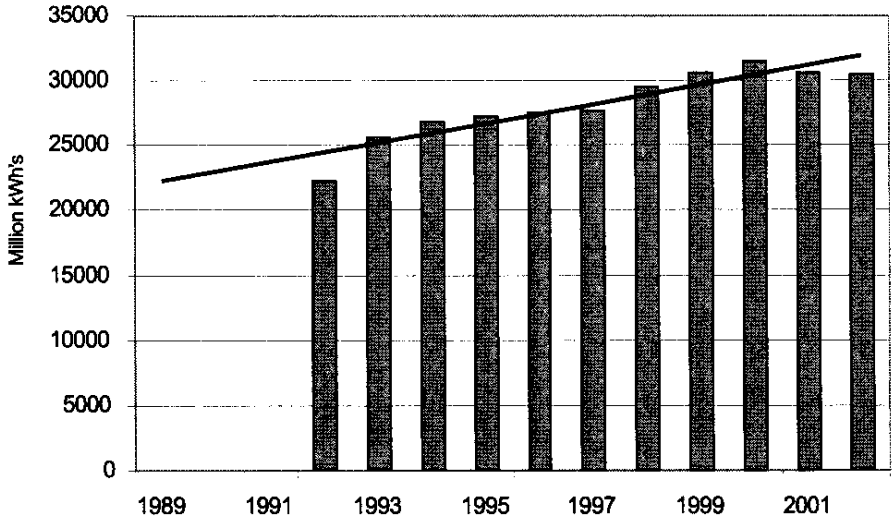


Figure 3-10 WEPCO total sales



WEPCO's annual growth in energy use has been slightly greater than the state's energy use measured in total sales. Figure 3-11 provides an indication that over the past 30 years, growth in total sales for Wisconsin electric utilities has averaged about two percent per year.

Figure 3-11 Sales from Wisconsin electric utility power generation: 1970-2001

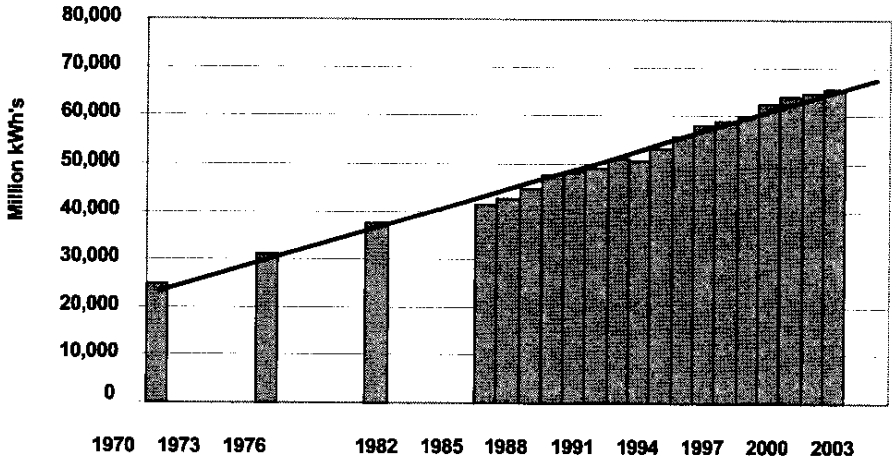
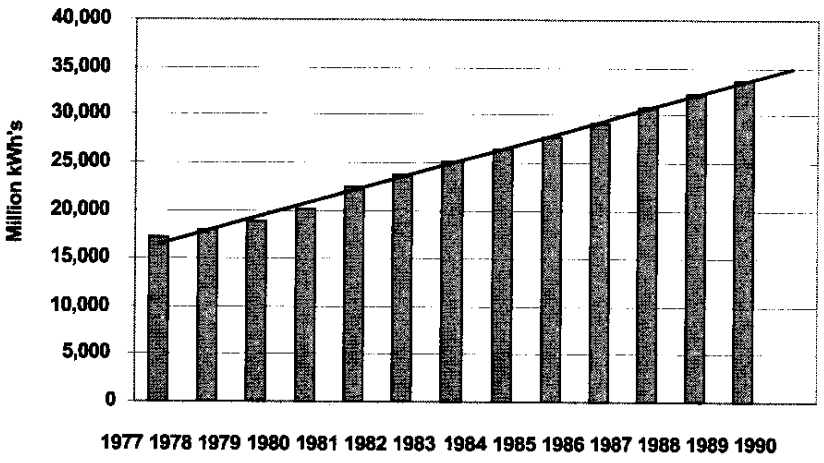


Figure 3-12 WEPCO projected demand in 1976



Historic growth in peak demand

The 1976 projected peak demand is shown in Figure 3-12.

The peak demand predicted was estimated to reach 5,500 MW by 1989. This peak was not reached until 2000[36] but the peak demand has steadily increased. Since 1997, the normalized native system, excluding peak load of mines, has continued to increase approximately 2.5 percent per year as shown in Figure 3-13.

Figure 3-13 Normalized native system excluding mines peak

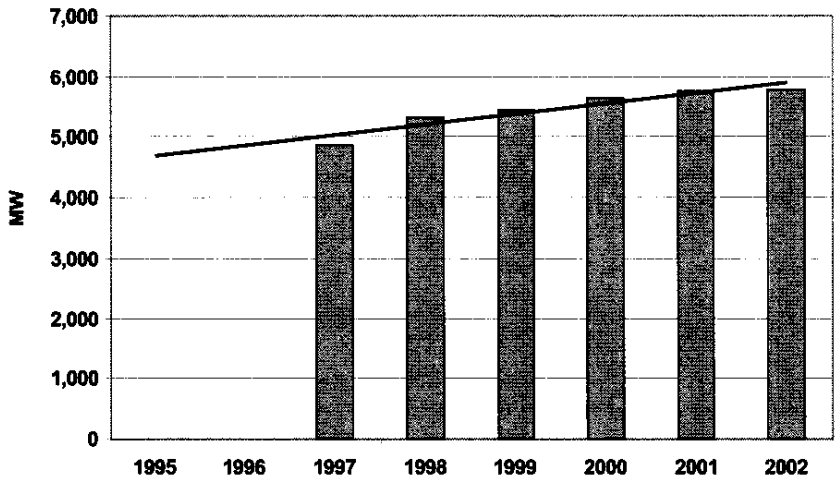


Table 3-6 Summary of peak and energy forecasts: WEPCO and MAIN Region

Year	Peak Demand (MW)		Energy Use (GWh)	
	WEPCO	EIA MAIN Growth Rates	WEPCO	EIA MAIN Growth Rates
2002	5,778	5,778	30,877	30,877
2005	6,276	6,223	33,379	33,254
2010	7,258	6,971	37,920	37,250
2015	8,166	7,665	42,024	40,958
2020	9,175	8,321	46,345	44,464
2025	10,295	8,925	48,974	47,689
2030	11,280	9,515	52,735	50,845
Growth Per Year				
2002-2005	2.8%	2.5%	2.6%	2.5%
2005-2010	3.0%	2.3%	2.6%	2.3%
2010-2015	2.4%	1.9%	2.1%	1.9%
2015-2020	2.4%	1.7%	2.0%	1.7%
2020-2025	2.3%	1.4%	1.1%	1.4%
2025-2030	1.8%	1.3%	1.5%	1.3%

[36] Response to DR-067

Projected growth in energy use and peak demand

Table 3-6 shows both the growth in electric demand and energy use forecasted by WEPCO through 2030 and the lower growth rates used by the Energy Information Administration (EIA) in its estimates of energy growth rates for the Mid-America Interconnected Network (MAIN) through 2020 as applied to WEPCO.

In this docket Commission staff required WEPCO to provide an updated electric demand and energy forecast from the forecast it used for the Port Washington CPCN case (docket 05-CE-117). The company generally lowered its growth estimates for peak and energy relative to the forecast provided for the Port Washington case. However, WEPCO's forecasted growth rates from 2002 through 2011 in this case are very close to those it used for the Port Washington case. Commission staff made a more detailed analysis of WEPCO's updated forecast, analyzing the residential, commercial and industrial sectors. Staff's analysis indicates that WEPCO's updated electric demand and energy forecast is reasonable although it may have a slight upward bias.

Just as in the Port Washington case, Commission staff applied the forecasted growth rates to WEPCO estimated by the EIA for the MAIN region for 2002 to 2020. Commission staff used also the EIA MAIN forecasted increase for 2019 to 2020 for the period 2020 through 2030. The EIA forecast is for energy use only. Commission staff assumed that the growth rate in peak demand would be the same as the growth rate in energy during this period. The difference between the two forecasts is an increase in peak demand of 500 MW in the WEPCO forecast by the year 2015. Under the EIA MAIN forecast, WEPCO would not need the capacity represented by the third coal plant until much later.

Figure 3-14 WEPCO peak load compared to generation supply with and without the Port Washington and ERGS units, and assuming no Oak Creek unit reqirements

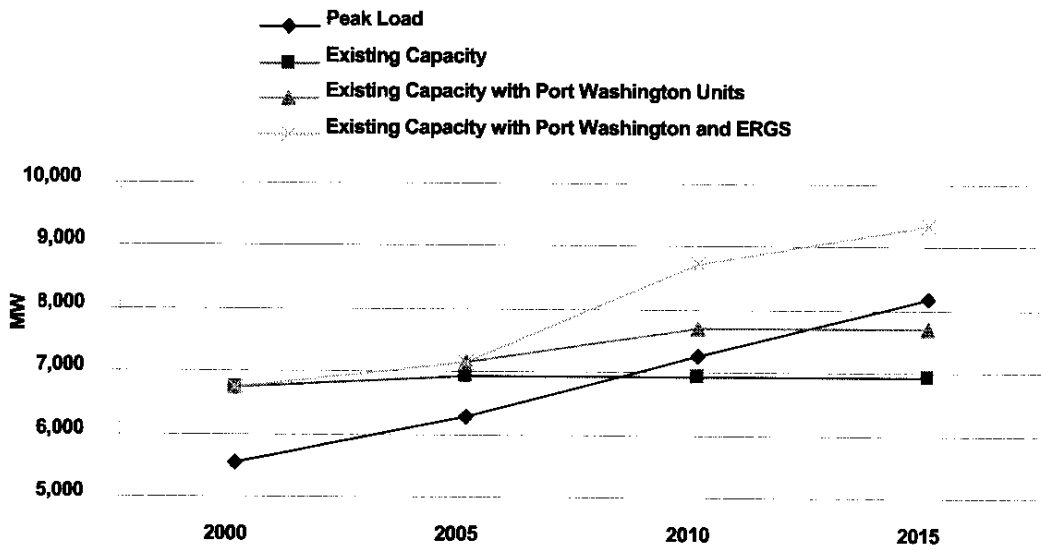
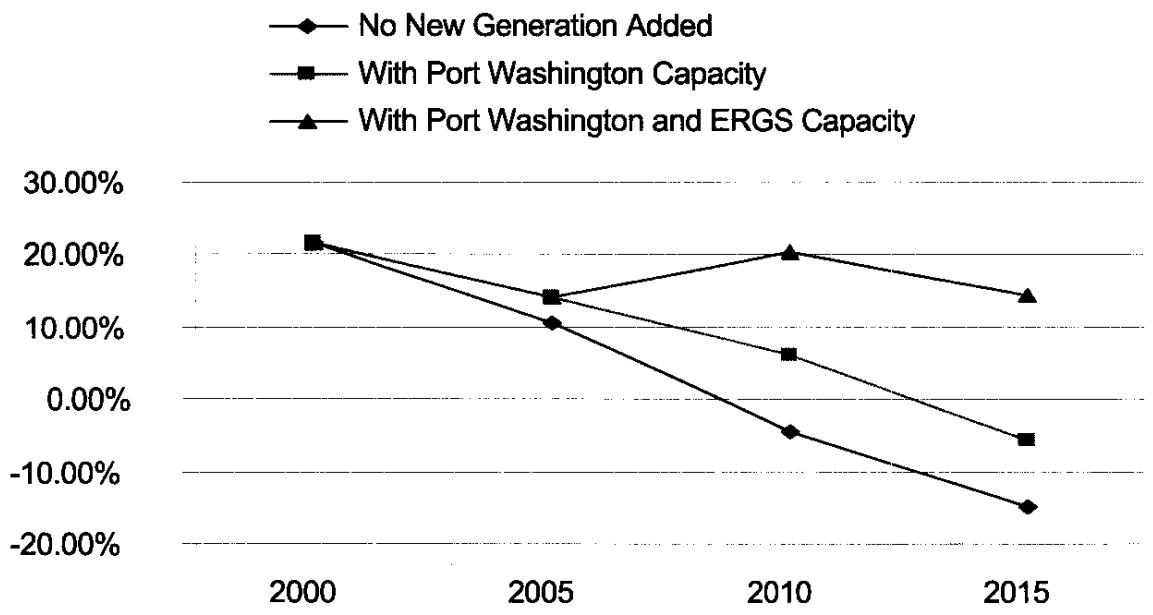


Figure 3-14 displays the WEPCO peak load demand forecast compared to the electric supply resources available to the utility if there is no expansion in existing generating capacity, if the 1,090 MW of Port Washington capacity is added to WEPCO's existing system, and if both the Port Washington and 1,800 MW of ERGS capacity is added to the existing system using the implementation schedule as set forth by the utility. Figure 3-14 demonstrates that without some type of significant capacity addition or IPP capacity after 2007, WEPCO would not be able to meet its expected peak load obligation. Data in Figure 3-14 assume that WEPCO continues to purchase as part of its existing capacity about 1,200 MWs from merchant power plants and other suppliers during the 2005 to 2015 time frame.

An alternative way to depict the information in Figure 3-14 is to examine the expected planning reserve margin for WEPCO if the capacity represented by the Port Washington and ERGS units is added to the existing system. Figure 3-15 portrays expected planning reserve margins with or without the Port Washington and ERGS units. Presently, the PSC requires the state's utilities to maintain an 18 percent planning reserve margin. (See Order Point 9, page 22, Advance Plan 8 Final Order, November 20, 1997). Figure 3-15 highlights the fact that without substantial capacity additions, WEPCO would not be able to maintain an adequate level of reliability, as the planning reserve margin quickly drops below 10 percent. Data in Figure 3-15 assume that WEPCO continues to purchase as part of its existing capacity about 1,200 MWs from merchant power plants and other suppliers during the 2005 to 2015 time frame.

Figure 3-15 Expected WEPCO planning reserve margins 2005 to 2015



Effects on the Wholesale Market

Present state of the WUMS wholesale market

Under Wis. Stat. § 196.491(3)(d)7, the Commission may issue a CPCN for a proposed facility only if it "will not have a material adverse impact on competition in the relevant wholesale electric service market." Such a determination requires an analysis of market power, which is the ability of a firm to charge prices for its product above what a competitive market would allow.

Presently, the relevant wholesale electric service market, from an anti-trust perspective, is the geographic region of WUMS (the Wisconsin and Upper Michigan system). This region is considered to be an electric "island" in which a large electric generating firm could obtain leverage over the prices paid for electricity because of transmission constraints and congestion.

This fact was documented for the Commission in an independent market power study conducted in 2000 for the Commission by Tabors, Caramanis and Associates of Cambridge, Massachusetts.[37] The WUMS wholesale electricity market is highly concentrated.[38] When a market becomes so limited, utilities or other players with a large market share or concentration can obtain leverage over the prices being paid in that market. In essence, a large electric generating firm in a narrow competitive energy market can influence prices to its advantage and everyone else's detriment. In economics, such leverage is referred to as horizontal market power and is policed by federal and state anti-trust law.

Potential effects of Elm Road Generating Station on the WUMS wholesale market

Since WEPCO turned over operational control of its transmission system to ATC in the year 2000, this analysis focuses only on horizontal market power issues associated with the construction and operation of the Elm Road coal facilities. Vertical market power issues associated with the combined operation of proposed coal plant facilities and the transmission system do not need review, given the existence of the Midwest Independent System Operator and its control over the ATC transmission system.

This same issue was reviewed by the Commission in the 2002 Port Washington CPCN docket. In that proceeding, the Commission determined that it was unlikely that there would be any adverse impacts on competition. This is because 1,090 MW of capacity and energy from the Port Washington generating units would be provided to WEPCO via a Facility Lease, at rates that the PSC regulates through its review of the lease's economic terms and conditions. Essentially, PSC economic regulation prevents any material adverse impact on competition in WUMS. The market power study conducted by Tabors, Caramanis and Associates of Boston confirmed that fixed price contracts such as the proposed Facility Lease can mitigate market power. In addition, the Federal Energy Regulatory Commission (FERC) only allows WEPCO to sell in WUMS at cost-based rates.

[37] See, Horizontal Market Power in Wisconsin Electricity Markets, A Report to the Public Service Commission of Wisconsin, November 14, 2000.
[38] Ibid.

In the Port Washington CPCN case, despite these observations, several parties suggested that approval of the Port Washington generating facilities could have a material adverse impact on competition by preventing the development of a competitive wholesale generation sector and hindering further electric industry restructuring in Wisconsin. The Commission did not agree with that position because WEPCO planned to continue contracting for power with IPPs, obtaining up to 1,000 MW of capacity from these providers. Relative to that amount the Port Washington facilities in total were also about the same size, constituting 1,090 MW of capacity. Furthermore, a stand-alone generation company such as WE Power LLC could more easily be divested by WEC than generating assets that are held within WEPCO as rate base assets, should a future legislature or Commission require splitting the generating plant assets away from utilities.

For these reasons, the Commission found that approval of the PWGS project would not prevent the development of a competitive wholesale generation sector nor hinder further electric industry restructuring in Wisconsin. In the present proceeding the Commission will have to examine this market power issue again. Since the regulated price feature of the facility leases has not changed, a similar result could occur. However, given the magnitude of the ERGS at around 1,800 MW, the continued fruition of a long-term competitive power market in Wisconsin, especially WUMS, could be dependent on the Commission requiring WEPCO to continue purchasing 1,000 MW or more of capacity from IPPs, as long as such purchases were cost effective and not an entitlement Additionally, the Commission could postpone the decision on the 600 MW IGCC unit and require WEPCO to solicit competitive bids from IPPs for that capacity at the appropriate time.

Chapter Summary

1) WEPCO has increased its reliance on power purchases and merchant power plant capacity. This trend has limits, translating into the potential need for new baseload and intermediate generating capacity in Wisconsin. Merchant plants have been a promising development, but many independent power producers have been experiencing financial difficulties.

2) Current WEPCO baseload units are being used extensively; the same is true for similar plants in Wisconsin. Baseload unit maintenance scheduling is increasingly more complex, requiring high cost natural gas-fired peaking plants to be used more often even during the winter months and maintenance outage seasons. Such increased usage of peaking plants raises their capacity factors, a sign of increased need for new baseload and intermediate generating capacity for WEPCO and Wisconsin.

3) Present transmission constraints do not allow WEPCO to obtain necessary capacity from Illinois where excess low cost capacity may exist, translating into a potential need for new capacity located in Wisconsin.

4) Prior Advance Plans which established optimal generation expansion plans suggested the need for new baseload power plants in the period after 2006.

5) WEPCO's demand and energy forecast for the next ten years is not unreasonable. Based on prior experience, it may be on the high side however. For this reason, using a lower growth rate demand and energy forecast as provided by the U.S. Department of Energy's Energy Information Administration (EIA) provides a useful sensitivity. Such a sensitivity reduces peak demand by about 500 MW or by about one baseload power plant during the important 2005-2015 time period.

4

Chapter 4 – Alternatives to the Proposed Project

There are several courses of action regarding the proposed project. The range of possibilities varies from taking no action, approving the entire project or portions of the project, or selecting some other alternative. This chapter explores these alternatives.

No Action

Taking no action on this application by denying the entire application (all three units) would result in no change in the number of power plants in the state.[39] WEPCO, and other electricity providers, would have the same sources of electricity available as they have currently. As power purchase agreements expire, with no new generation of its own to utilize, WEPCO would have to negotiate new power purchase agreements. Market rates for those purchases could vary from what they are now.

Taking no action on this application by not making a final PSC decision within the statutorily-mandated timeline would result in a CPCN automatically granted, for the project as proposed, to the applicants under Wis. Stat. § 196.491 (3)(g). The applicants would then have the option of constructing one or more of the three coal-fired units at any of the proposed sites. Without formal PSC approval, however, project financing might not be available. The entire project would still be subject to all DNR permitting requirements for construction and operation of the facilities.

Commission Energy Priorities

Wis. Stat. § 196.025 states "To the extent cost-effective, technically feasible and environmentally sound, the Commission shall implement the priorities under s. 1.12(4) in making all energy-related decisions." Wis. Stat. § 1.12(4) establishes the following priorities:

> (4) PRIORITIES. In meeting energy demands, the policy of the state is that, to the extent cost-effective and technically feasible, options be considered based on the following priorities, in the order listed:
>
> (a) Energy conservation and efficiency.

[39] This statement applies to the 2003-2011 time frame, the construction period for ERGS. It does not factor in the recent WEPCO-EPA agreement which would retire OOCP units 5 and 6.

(b) Noncombustible renewable resources.
(c) Combustible renewable energy resources.
(d) Nonrenewable combustible energy resources in the order listed:
1. Natural gas.
2. Oil or coal with a sulfur content of less than 1 percent.
3. All other carbon-based fuels.

The following sections in this chapter address these priorities, in the order listed above.

Load Reduction (Energy Efficiency) as an Alternative

Types of energy efficiency

Energy efficiency includes conservation, load management, and fuel switching. Energy conservation reduces the use of electric energy. Load management shifts energy use away from periods when demands are highest. Fuel switching replaces the use of electricity with the use of another fuel, such as natural gas. Load management shifts energy use away from periods when demands are highest.

The applicant states that the proposed generating facility is needed because the demand for electricity, including 18 percent reserves, will exceed available supply by 2,479 MW in 2011. Power outages would occur when demand for electricity exceeds supply. To correct such a situation, one can increase the supply or decrease the demand.

The generating facility proposed consists of two baseload SCPC coal units and one baseload IGCC coal unit. Fuel switching and general energy conservation contribute to addressing base loads, while load management is generally used to help meet peak loads.

Using energy efficiency to meet system electric needs can have both economic and environmental advantages over using supply resources such as power plants

Results of energy efficiency

Economic

The most significant economic advantage is that, if cost-effective, energy efficiency can reduce customers' electric bills. If the demand for electricity is reduced, less fuel needs to be bought and transported, and fewer power plants or power lines need to be built. This reduction in electric bills helps make Wisconsin businesses more competitive. By reducing the amount of money spent on energy in Wisconsin, energy efficiency can also improve the state's economy in general. This is because most of every energy dollar spent on coal, natural gas, and uranium, the fuels used by power plants to generate electricity, leaves Wisconsin and our economy.

Environmental

From an environmental perspective, energy efficiency is the best option for meeting energy needs. Conservation and some forms of fuel switching reduce air pollution, water use, coals and uranium mining, disposal of radioactive waste, production of greenhouse gases, and the depletion of non-renewable resources. All three forms of energy efficiency reduce the need for power plants and transmission lines, thereby reducing the negative impacts of these facilities. These impacts can include the use of valuable land, destruction of natural habitats, and aesthetic impacts.

There are some potential negative impacts associated with energy efficiency measures. An example of a negative impact from conservation is the need to dispose of spent fluorescent light bulbs. Switching fuels will still have impacts associated with the use of the alternate fuel. Load management, if not properly designed, can lead to discomfort or the inefficient disruption of industrial production. However, the negative effects of energy efficiency measures are negligible compared to the building and operation of power plants and power lines.

Regulation of energy efficiency

Traditionally, the Commission has relied upon electric and natural gas utilities to promote energy efficiency. Utility energy efficiency programs have largely been cost-effective and successful. It is estimated that from 1991 through 2001, Wisconsin utility programs reduced annual electric usage by about 4,300,000 MWh. Based on typical load factors of energy efficiency measures, these energy savings resulted in about 500 MW of peak demand reduction.

However, the regulatory approach to the promotion of energy efficiency has changed. New legislation passed in the fall of 1999 is having a significant impact on how energy efficiency services are delivered. Beginning in 2001, public utilities have less responsibility for delivering energy efficiency services. A substantial amount of utility ratepayers dollars that in the past funded utility-sponsored energy efficiency programs and services are now being transferred to the Department of Administration (DOA). In addition to this existing funding, new fees for energy efficiency are being collected from utilities. The DOA is responsible for the promotion of energy efficiency through administrators that were awarded contracts through competitive bids.

In addition to the DOA funding of energy efficiency discussed above, the utilities retained funds to be used for utility-administered, energy efficiency-related customer service conservation activities. Also, the utilities may provide, with Commission approval, energy efficiency services in addition to those provided by the DOA. Because the Commission approved retention of some energy efficiency funds, and can approve funds for additional energy efficiency services, the Commission continues to have some authority over utility energy efficiency services and accomplishments. The Commission also ensures that utility dollars are transferred over to the DOA, but has no other authority over DOA actions.

If the Commission finds, under Wis. Stat. §1.12(4) and 196.025, that energy efficiency or conservation can substitute cost-effectively for the proposed generating facility, the Commission's decision must ensure that the energy efficiency savings is implemented. For the Commission to choose energy efficiency over the proposed generating station, the Commission must find:

1. That enough energy efficiency exists to substitute for all or part of the energy demand that would be served by the proposed generating facility (if only part, then something else must provide the rest).
2. That energy efficiency would be cost-effective compared to the alternative facilities for which it would be substituting.
3. That the energy efficiency option is environmentally sound.

Applicant's analysis of energy efficiency as an alternative

The applicant states that it has constructed a portfolio of resources, including energy efficiency measures, to meet future needs. In order to include energy efficiency in its portfolio of resources, the applicant conducted an energy efficiency analysis to estimate the potential savings from energy efficiency programs.

The applicant's analysis first identified energy efficiency measures that can be used in its service territory. The applicant identified and collected technical data on about 100 residential measures. Using this technical data, technical potential was estimated. Technical potential is the load reduction that results when the most efficient measures are adopted by the entire eligible population.

A benefit-cost ratio was then calculated to estimate the economic potential. Economic potential is the load reduction that results when the most efficient measures are adopted when it is economical to do so from society's overall perspective. Measures found to be cost-effective were placed into a set of programs. The programs are sets of related measures that are bundled together and implemented by a utility or another party. When placing measures into the programs, the applicant assumed the measure could be implemented at an 85 percent penetration. This 85 percent market penetration is the applicant's estimate of market potential, or what can reasonably be assumed to be implemented by customers in response to utility, governmental, and marketplace products and services.

Market potential identified

The applicant's analysis identified about 340 MW of technically feasible energy efficiency by 2015. Of this 340 MW, the applicant identified a market potential of about 240 MW over the 2003-2015 timeframe. The applicant estimates that all but 10 MW of the 240 MW of market potential is already included in its forecast. This means that the applicant believes there is only 10 MW of additional energy efficiency that is available to substitute for a portion of the need for the proposed generating facility.

Additional analysis

The above discussion is based on the analysis the applicant provided in its CPCN applications in support of both the Port Washington Generating Station and ERGS. However, in the direct testimony of Karl McDermott and Val Jensen, the applicant submitted a new energy efficiency analysis. The applicant states that this new analysis was completed in response to issues raised in the Port Washington hearing regarding its energy efficiency analysis. The applicant further states that the new energy efficiency analysis in support of ERGS confirms the analysis previously provided by the applicant, although the achievable potential identified is not identical. The applicant's new analysis identifies an energy efficiency potential of between 57 and 146 MW in 2011 that is not already included in the applicant's forecast.

Staff's critique of WEPCO's analysis

PSC staff identified several shortcomings in the applicant's analysis provided in WEPCO's CPCN application. These shortcomings likely result in the applicants underestimating energy efficiency potential. First, the scope of the analysis was limited to the residential sector. In docket 6630-UR-109, the Commission determined that it is no longer appropriate for WEPCO to provide ratepayer-funded energy efficiency services to its Large Commercial and Industrial (C&I) customers, because its participation in the Large C&I energy efficiency market, using ratepayer dollars, would hinder the provision of energy efficiency services by non-utility entities. For this reason, the applicant did not include commercial and industrial customers in its analysis. The applicant also did not include Small C&I customers in its analysis. The applicant assumed the savings potential from these customers is small because sales to Small C&I customers are less than a third of residential sales.

In addition to not including C&I measures in its energy efficiency analysis, the applicant also included few fuel switching and load management measures. The few load management and fuel switching measures looked at by the applicant were rejected because the applicant deemed the measure not mature or not appropriate for Wisconsin. Although load management measures cannot address baseload needs, fuel switching measures can.

Another shortcoming of the applicant's analysis is that the level of energy efficiency savings already included in the forecast cannot be identified. The applicant states that because WEPCO's past energy efficiency efforts are reflected in the historical customer usage data used to develop the forecast for the proposed generating facility, it is reasonable to conclude that the forecast includes similar results. It is likely that some energy efficiency is included in the forecast. However, it is not possible to verify the applicant's contention that almost all of the 240 MW of market potential it identified is already in the forecast.

As a result of these shortcomings, it is likely that the Analysis provided by WEPCO in its CPCN application underestimates the availability of additional cost-effective energy efficiency. Commission staff has not completed its review of the new analysis provided by the applicant in its direct testimony.

Staff's analysis of energy efficiency potential

Commission staff also conducted an energy efficiency analysis. Staff's analysis compares the energy efficiency potential identified in the Commission-approved Statewide Technical and Economic Potential (STEP) Study, adjusted for market potential, to the level of energy efficiency estimated to be included in the forecast supporting the proposed generating facility. Because the proposed generating facility is a baseload plant, staff looked at the potential for both additional energy and demand savings. Commission staff's analysis estimates energy efficiency potential in the years 2007, 2009, and 2011, the proposed in-service dates of the ERGS units.

STEP Study

The STEP Study was a collaborative effort of the state utilities, interveners, and PSC staff that calculated the economic potential of energy efficiency over 20 years. This study was completed in 1994, and updated in 1995.

In the STEP Study "economic potential" was defined as the electric load reduction that results when the most efficient measures are adopted by the entire eligible population. The STEP Study provides an estimate of economic potential for both energy and demand. This was done for the 20-year period of 1994 through 2013. Conservation, load management, and fuel switching measures were all considered in developing the technical and economic potential estimates. The updated STEP Study identified a 20-year economic potential of 35 percent for energy and 29 percent for demand. STEP assumes that this potential will be achieved evenly over the 20-year period.

Market potential identified

The STEP Study reported demand and energy savings by the end of 20 years. Because it is not always cost-effective to replace existing equipment before the end of its useful life, replacement with more efficient technology was assumed to occur in a straight line during the 20 years. However, some technologies in the STEP report have useful lives less than 20 years. Given the uncertainty of the estimate of economic potential in 2007, 2009, and 2011, staff developed a scenario that assumed the full economic potential could be achieved in 15 years.

The STEP Study did not estimate market potential. Market potential is that portion of economic potential that is achievable knowing that some eligible customers will not install energy efficiency measures even when it is economic to do so. In order to compare results of the STEP Study to the level of energy efficiency included in the applicants' forecast, an adjustment for market potential must be made. There have been limited studies of market potential and the studies have been inconclusive. Given the uncertainty of market potential adjustments, Commission staff's analysis includes two scenarios, assuming market potential levels of 50 percent and 85 percent.

Commission staff's most aggressive scenario, which assumes the economic potential is achieved in 20 years and a market potential of 85 percent, identified more than an additional 600 MW of cost-effective savings by 2011, with more than 400 MW available by 2009 and about 200 MW available by 2007. A more conservative scenario, which assumes the economic potential being achieved in 15 years but only a market potential of 50 percent, identified 80 to 90 MW of additional cost-effective energy efficiency potential in 2009 and 2011. No additional cost-effective energy efficiency potential was identified in 2007 in this more conservative scenario.

Commission staff's analysis identified an additional potential of 3,650 GWh in 2007; 5,000 GWh in 2009; and 6,500 GWh in 2011 under its most aggressive scenario. Commission staff's more conservative scenario identified an additional potential of 2,050 Gwh in 2007; 3,000 Gwh in 2009; and 3,100 Gwh in 2011.

Shortcomings of Commission staff's analysis

Commission staff's analysis also has several shortcomings. Similar to the deficiencies in the applicant's analysis, these shortcomings likely underestimate the energy efficiency potential. First, staff used Advance Plan 8 (AP-8) estimates of naturally-occurring impacts in its estimate of the amount of energy efficiency already included in the applicant's forecast. Naturally-occurring impacts are those energy efficiency savings that occur without utility intervention in the energy efficiency market. The forecasting method used by the applicant in support of the proposed generation facility does not allow for the identification of naturally-occurring impacts. Although AP-8 provides the best estimate of naturally-occurring impacts available, it may no longer accurately reflect the naturally-occurring impacts in the applicant's forecast.

Second, the STEP Study was completed in 1994 and last updated in 1995. The energy efficiency market has changed considerably since the STEP Study was completed. Additional technologies are available, the cost of many technologies has decreased, and laws governing appliances and building shell efficiency have improved the market. Also, the avoided energy and demand costs upon which the STEP study was based are outdated. While it would have been better to rely on an updated study that reflects the existing energy efficiency market and today's avoided costs, one is not available.

In addition to being outdated, the STEP Study did not adequately address industrial energy efficiency potential. This significant weakness was stated in the study:

> "This analysis does not include some savings potential available in the industrial sector. This limitation is due to the complexity of estimating the potential for specific industrial processes and to the limited information in the Wisconsin Demand-Side Options Database regarding technology saturations... this limitation is likely to underestimate savings."[40]

Another weakness of the STEP study is the manner in which it addressed transmission and distribution. Although transmission and distribution losses are reflected in the estimate of savings potential, transmission and distribution avoided costs were not included in the avoided costs used to determine the cost-effectiveness of the energy efficiency measures.

Renewable Resources as an Alternative

In Wisconsin, the noncombustible renewable resources in use for electric generation are wind, solar and hydro. Combustible renewable resources include fuel cells fueled by hydrogen that is produced by a renewable resource and biomass energy derived from wood or plant residue, biological waste, crops grown for use as a resource, or landfill gas. The main renewable energy resources for Wisconsin electric generation appear to be wind power and biomass fuels, including waste-to-energy. At this time, solar power appears too costly to install on a utility scale and there is very little additional hydroelectric power potential available in Wisconsin.

Advantages of renewable resources include:

- Low or no fuel cost (except for some biomass).
- Short lead-times for planning and construction.
- Relatively small, modular plant sizes.
- Reduced environmental effects compared to fossil fuels.
- Non-depletable resource base.
- Potentially more job intensive.
- Favorable public opinion.
- Distributed generation potential.

General disadvantages include:

[40] Page E-3, Recalculation of Statewide Technical and Economic Potential

- Uneven geographic distribution.
- Intermittent nature of some resources.
- Lack of maturity or commercial availability of some technologies.
- Public concern for land use, biodiversity, birds, and aesthetics.
- Environmental issues with some types of biomass fuel supply.
- Relatively high capital cost for some technologies.

Wind

Design issues

Wind energy is converted to electricity when wind passes by blades designed like those of an airplane propeller mounted on a rotating shaft. As the wind moves the blades, the rotation of the shaft turns a generator which produces electricity. Three factors affect wind machine power: the length and design of the blades, the density of the air, and wind velocity. The power available to a wind turbine is directly proportional to air density, directly propoertional to area swept by the blades, and proportional to the cube of the wind velocity. [41] Blades are shaped and positioned to take advantage of different wind velocities so that, depending on design, one wind machine may produce power in a different range of wind velocities than another. Cold air is denser, which means it has more force, or ability to turn the blades. A wind machine in Wisconsin's cold, dense winter air can produce up to 20 percent more than the same machine with the same wind speed in hot summer air. Because output has an exponential relationship to the wind velocitry, the speed of the wind is critical for the cost-effective operation of wind machines. The higher the elevation at which a wind turbine is mounted, the more wind it will encounter. As the height of towers on which wind turbines are installed increases from the 65 meters that is typical today to the 80- and 100-meter towers of the newest machines, the average annual wind speed, and therefore, capacity factors will also increase.

Table 4-1 shows potential capacity and electrical generation based on the land area exhibiting each class of wind speed and assuming 12 MW per square mile.[42] Wind power imports from neighboring states with superior wind regimes are also not included because transmission constraints limit the availability of that power.

Table 4-1 Land-based Wind Power Potential in Wisconsin[43]

Class	Area (sq. miles)	Capacity (MW)	Capacity Factor	Estimated Output
Class 4 & 5	170	2,040	32.4	5,790,010 MWh
Class 3	3,330	39,960	20.0	70,009,920 MWh
Total Wind	3,500	42,000		75,799,930 MWh

[41] $P=\frac{1}{2}DAV^3$ (P=power produced; D=air density; A=swept area of the turbine blades; and V=the velocity of the wind in miles per hour).
[42] Based on data in Table 4-1, a 1,157 MW class 4 & 5 wind farm comprising 96 square miles would equal the output of one 500 MW coal plant with a 75 percent capacity factor.
[43] Windy land area from An Assessment of Windy Land Area and Wind Energy Potential in Contiguous United States, Battelle Pacific Northwest Laboratory, 1991.

Offshore Wind

Some of the areas with the best potential for new wind energy development are over large bodies of water such as Lake Michigan. In the past two years, the US Army Corps of Engineers (ACOE) has received permit applications for over 3,000 MW of wind capacity off the east coast of Massachusetts. A study done for the Long Island Power Authority in April of 2002 showed between 2,250 and 5,200 MW of wind-generated power available within six miles of Long Island's south shore. In northern Europe, 12 offshore wind projects with a total capacity of over 300 MW are in operation. According to a report by German consultant Klaus-Peter Lehman, some 70 offshore wind projects are now under development worldwide.

It is likely that within the time frame of the ERGS proposal, at least some of the wind resource in Lake Michigan would be developed. One developer has submitted an application to the ACOE for a project in Lake Michigan east of Chicago. Industry sources indicate that other developers are actively investigating sites elsewhere in the Great Lakes. Data gathered along the shoreline and from mid-lake buoys indicates that there may be significant potential wind capacity in Lake Michigan off the east coast of Wisconsin.

Development of offshore wind is also made more practical by larger turbines designed with offshore application in mind. Two examples are the General Electric 3.6 MW turbine on a 75-meter tower and the Vestas V90 on a 100-meter tower.

Staff's analysis of cost and potential

PSC staff used EGEAS modeling to compare alternatives to the proposed coal plants. EGEAS assumptions for wind include capital costs, operating and maintainance (O&M) costs, capacity costs, life of the federal product tax credit (PTC), and credit to reserve margin.

Overnight construction costs or capital costs for land-based wind power projects (in 2001 $) are assumed to be $1,029 per kW and O&M costs are estimated at $26 per kW-year. The cost of offshore wind is estimated to be 40 to 50 percent higher than land-based projects, or $1,500 per MW with an annual de-escalation rate of 4 percent with a variable O&M cost of $10 per MWh. These offshore O&M costs are based on industry experience in northern Europe. Winter ice conditions would tend to increase O&M costs for Lake Michigan; however, Lake Michigan has the advantage of fresh water and less turbulent winds than those in the North Sea. The capacity factor for offshore wind was set at 35 percent assuming an average wind speed of approximately 16 mph at 100 meters two miles offshore

The federal Production Tax Credit (PTC) for wind generation is an important factor when considering the relative cost of wind generation. The PTC, which has been renewed several times since going into effect on January 1, 1994, provides a tax credit of 1.5 cents per kWh plus an inflation adjustment for the first ten years of production from a qualifying wind power facility. The inflation adder is periodically adjusted by the IRS, so that in 2003 it is 1.8 cents per kWh. Current law applies only to wind and certain biomass facilities that come on line before December 31, 2003. However, there is reason to believe that the credit will be extended. Seven legislative proposals have been introduced in the U.S. Congress calling for extension of the credit for a period of anywhere from three years to indefinitely. Given the substantial, bipartisan support for extending the PTC, there is no reason to conclude that it will not be extended into the future.

Another important assumption in the Commission staff EGEAS runs is the 20 percent credit to reserve margin. This means that for every 100 MW of wind power generated, only 20 MW would be credited

toward WEPCO's reserve margin. This is conservative in light of the Mid-Continent Area Power Pool (MAPP's) wind accreditation reporting for 2000 through 2001, indicating that five wind farms in Minnesota had accredited capacities ranging from 21 to 29 percent. On the other hand, WEPCO erroneously assumed no credit to reserve in its EGEAS runs.

Potential environmental and social effects

The environmental effects of wind energy are mostly positive, but there are some potentially negative impacts also. One of the major benefits of this technology is that it does not create air pollution. Power plants that burn coal, for example, emit sulfur dioxide (SO_2), nitrogen oxides (NO_X), carbon dioxide (CO_2), particulates, and heavy metals into the atmosphere. Gas-fired power plants emit NO_X, particulates and CO_2. Emissions from power plants contribute to acid rain which has been shown to damage lakes, streams, and forests. Power plant emissions also contribute to ozone formation which can affect human health and emissions of CO_2 have been linked to global warming.

Because wind-generated electricity does not use water, potential negative impacts such as thermal pollution of water bodies or water losses in surface and groundwater hydrologic systems are avoided. Wind energy also avoids impacts related to water use such as depletion of ground water supply and impacts to the supply and flow of surface waters. Wind energy does not create substantial solid waste (ash, etc.), so transportation, treatment, and storage of wastes are also avoided.

The risk of avian mortality is one of the major environmental concerns associated with wind energy. Bird collisions with turbine blades and towers have been reported in this country and in Europe. This issue is somewhat controversial and is the subject of increasing study. Impacts to birds and bats can be reduced with careful siting of facilities. Other issues often associated with wind energy include concerns about land use impacts, noise, aesthetics, and negative impacts to property values. Noise problems associated with wind turbine facilities are currently being studied in northeastern Wisconsin. Potential effects on property values are difficult to isolate. Market prices for rural and residential property normally change over time, subject to a variety of variables. Factors affecting property values include the general condition of the local and national economy, taxes, the reputation of the school system, and the availability and condition of infrastructure (i.e. roads, police and fire protection). It is impossible, at this time, to predict the impact to property values from the presence of wind turbines.

From a social and economic standpoint, wind power has several advantages. Wind energy generally requires a larger workforce than typical combustion turbine technologies, but smaller than typical coal-based facilities. Because wind power requires no fuel, the cost of wind generated electricity would not be affected by volatility in fuel prices.

As a stand-alone alternative, it is not likely that enough wind generation capacity is available to replace the entire 1,830 MW of the proposed ERGS facilities. However, wind power could be a significant component of an integrated resource alternative that could substitute for all or a portion of the ERGS. Wind power also has a higher ranking as a renewable resource than any carbon-based combustible fuel under the state's energy priorities law, Wis. Stat.§1.12(4). State law also requires the Commission to implement these priorities when making all energy-related decisions.

Biomass

Design and cost

Biomass energy is the energy derived from plant materials or residue and biological waste. Combustible gases from landfills or anaerobic digestion of waste material is referred to as biogas.

Solid biomass can be burned like coal to produce steam. It can also be gasified and burned like natural gas. Biomass can include waste wood from construction or demolition projects or from wood product manufacturing. It can also include crops or other plantings, such as switchgrass or willows. Waste wood is the most available source of biomass in Wisconsin today. Waste wood is currently burned in several generating plants in Wisconsin, including a few utility-owned plants, to produce steam for both electric energy and industrial processes. Table 4-2 shows the biomass fuel availability, in Wisconsin, based on an Oak Ridge National Laboratory study, Biomass Feedstock Availability in the United States: 1999 State Level Analysis.

Table 4-2 Annual dry tons per year (8,500 BTU/lb) available at $50 per ton delivered.

Biomass Source	Dry Tons (8,500 Btu/lb)	Capacity	Estimated Output
Forest residue	1,138,400		
Mill wastes	192,000		
Agricultural residue	5,179,618		
Energy crops	6,114,270		
Urban wastes	639,110		
Total Biomass	**13,263,398**	**3,028 MW**	**22,547,000 MWh**

At an 85 percent capacity factor, 3028 MW would yield 22,547,000 MWh of energy per year.

Several technologies that utilize solid biomass fuels are in use today. There are power plants that burn chipped wood alone and others that co-fire wood products with fossil fuels. Two additional technologies are at the pilot-plant stage. The first involves harvesting and burning the whole above-ground portion of trees. The second is the gasification of woody or herbaceous biomass.

Biogas is a form of biomass consisting of methane and other combustible gases that can be used in a conventional engine or gas turbine to turn an electric generator. Biogas can be generated from on-farm anaerobic digestion (AD), landfill gas collection, and wastewater treatment plants. Electric generation using on-farm digesters is the fastest growing use of biogas in Wisconsin. The primary application of AD is on dairy operations with 500 or more milk cows, but there is also potential at poultry and hog confinement facilities, as well as smaller dairies. In Table 4-3 the number of dairy animals in the state is used to estimate potential. This number may overestimate the amount of potential dairy AD, but it also could be low because it does not included poultry, hog, or food processing facilities. Landfill gas and wastewater treatment potentials shown in Table 4-3 are from AP7 ***Technical Support Document D21.***

Potential environmental and social effects

Air emissions from biomass combustion are generally less than those from coal or natural gas. Like coal or natural gas combustion, biomass combustion produces CO_2, an important greenhouse gas. Growing

additional vegetation or crops to replace the burned plant material can recapture the CO_2 and avoid increasing the overall amount of CO_2 in the air. Biomass can also emit lower amounts of NO_x, produce less ash than coal, and release significantly less toxic material such as mercury.

Table 4-3 Biogas potential in Wisconsin

Biogas Source	Capacity	Estimated Output
Wastewater Treatment Plants	6.65 MW	52,000 MWh
Landfill Gas	27.0 MW	227,000 MWh
On-farm Anaerobic Digesters	250.0 MW*	1,994,100 MWh**

* Based on number of dairy animals in Wisconsin.
**Assuming a capacity factor just over 92 percent.

A closed methane digestion system on a farm or landfill would reduce the amount of methane lost to the atmosphere (methane is a "greenhouse gas"). In addition, the farm operators could still utilize the source manure for soil fertility, and the landfill operators could still operate the overall landfill as planned. Combustion of the methane as biogas on site at either the farm or the landfill would release emissions similar to those released by natural gas-fired combustion turbines or combined-cycle facilities but at a smaller scale.

Fuel supply can potentially have an impact on the environment. In AP 7, the Commission determined that potential fuel supplies for environmentally sound biomass-fired power plants should be used in the following priority order:[44]

1. Wood industry residues—e.g., lumber mill residues and sawdust, furniture manufacturing wastes, pallets, etc.
2. Urban, forest, or agricultural residues—residues resulting from logging cropping, or city tree trimming. Enough logging or cropping residue must be left on the ground to ensure stable soil conditions and appropriate plant nutrient cycling.
3. Woody or herbaceous energy crops—grown sustainably on cropland or in plantations and dedicated for conversion to electricity. Crops showing the most promise in Wisconsin include hybrid poplars, willows, and switch grass.
4. Natural woodlands—harvesting trees for fuel. This option is by far the least preferable and most complicated environmentally.

The environmental effects of obtaining these fuels vary. All would require truck or rail transportation. Storage emissions and other effects might be a concern. At this time, however, it is early enough in the development of biomass technologies in Wisconsin to investigate storage options and sustainable plantations using landscape-level ecological planning. While biomass technologies continue to progress, on-going research (adaptive resource management) can investigate questions about potential environmental impacts.

From a socioeconomic perspective, money paid for local renewable resources to produce electricity for the state could remain in the state and potentially benefit residents, instead of being paid to out-of-state entities for natural gas or other fossil fuels. This would be especially true for biomass-fuels and biogas generation if fuel crops and other fuel sources were grown on Wisconsin farmland.

[44] PSC docket 05-EP-7, Order dated December 22, 1995, page 21.

Cost assumptions for the biomass alternatives used in the EGEAS modeling are discussed later in this chapter.

Solar power

Design and cost

Photovoltaic (PV) cells convert sunlight directly into electricity. PV panels, consisting of multiple PV cells can be used in small groups on rooftops or as part of a substantial system for producing large amounts of electrical power. The amount of energy produced by a photovoltaic system depends upon the amount of sunlight available. The intensity of sunlight varies by season of the year, time of day, and the degree of cloudiness.

Currently, PV generated power is less expensive than conventional power technologies where the load is small or the area is too difficult to serve by electric utilities. The cost of producing electricity with photovoltaic systems is 30 to 40 cents per kWh; however, recent breakthroughs may reduce the cost of producing electricity with photovoltaic systems to 10 to 12 cents per kilowatt hour (kWh) or lower. This compares to 2.6 cents per kWh for existing coal plants and approximately 6 cents per kWh for natural gas generated power.

While further advances in solar technology are likely, some technologies are available today. As a result of private and government research, photovoltaic systems are becoming more efficient and affordable. Utilities also fund research in these same areas through membership in Electric Power Research Institute (EPRI). With continued improvement, it is likely that photovoltaic technologies will become increasingly cost competitive with conventional generation sources.

The cost of PV systems has been steadily falling as system components decrease in price and efficiency improvements are made in the manufacturing process. PV could be a cost-effective part of an integrated alternative to the second plant in the applicants' proposal.

Potential environmental and social effects

Compared to traditional methods of electric generation, photovoltaic systems have few environmental concerns. They include less hardware than most other electric generation technologies, and generally include no more toxic components than other technologies. The primary environmental impacts of large ground arrays are visual and can be solved by designing the arrays to blend with their surroundings. Since solar power does not involve combustion of fuels, it does not create air or water emissions and would not result in significant water losses or thermal impacts to surface water bodies. Banks of solar panels would replace or shade whatever vegetation occurred at their installation site, but sites without vegetation, such as roof tops, are also available.

Fuel cells and hydrogen

Design and cost

A fuel cell is an electrochemical device that generates electricity by combining hydrogen from a hydrogen-rich fuel (methane, methanol, propane, or biomass) with oxygen from the air to produce electricity, heat, and

water. All fuel cells consist of an anode, a cathode and an electrolyte; much like a battery, except that the reactant fuel is continuously fed to the cell. Electrochemical oxidation and reduction reactions take place at the electrodes to produce electrical current. Each individual fuel cell produces less than one volt of potential, so cells must be stacked to obtain the desired voltage.

Typically, fuel cell capacities range from 2 kilowatt (kW) to 2 MW, and fuel cells have electrical efficiencies that range from 45 to 65 percent. With heat recovery, the efficiency can be as high as 85 percent. Four types of fuel cells are receiving the most attention today. They are the phosphoric acid fuel cell, molten carbonate fuel cell, solid oxide fuel cell, and proton exchange membrane fuel cell.

Hydrogen, the required fuel source for fuel cells, can be produced from water using electrolysis, with the necessary electricity generated using renewable energy. The National Aeronautic and Space Administration is currently working on a "regenerative fuel cell" that would be a closed-loop form of power generation. In the regenerative fuel cell, water is separated into hydrogen and oxygen by a solar-powered electrolyser and fed into the fuel cell to produce electricity and water. The water is then re-circulated to the electrolyser to complete the cycle. However, because this method is relatively expensive, most current fuel cell systems use some form of hydrocarbon fuel as their hydrogen source.

Some source compounds will have fewer and smaller amounts of by-products. The following is a list of hydrogen sources ranked in order of increasing by-products:

- Water
- Methane
- Propane and natural gas
- Gasoline
- Fuel oil
- Gasified coal

Even though they might depend on fossil fuels, fuel cells, because of higher efficiencies and lower fuel oxidation temperatures, emit less carbon dioxide (CO_2) and nitrogen oxides (NO_x) per kilowatt hour (kWh) of power generated than gas turbines or internal combustion engines. The overall air emissions are lower for fuel cells, but the difference is not significant for sulfur dioxide (SO_2) or particulates. If fuel re-forming is done on site, heat produced from the fuel cell process powers the reformer. If the re-forming is done off site, the resultant pollutants would be produced off site, and there would be additional pollutants from transporting the hydrogen to the fuel cell site. Unlike gas-fired combustion turbines and combined-cycle units, noise and vibrations associated with fuel cells are practically non-existent because the fuel cell itself has no moving parts.

As fuel cells decrease in price as a result of large R&D commitments on the part of both government and industry they could become a cost-competitive part of an integrated alternative to a second or third ERGS unit.

Applicant's analysis of renewables as an alternative

WEPCO provided cost comparisons and other parameters for renewable energy sources such as biomass, solar photovoltaic, and wind energy. WEPCO used the Electric Generation Expansion Analysis System (EGEAS) model to analyze additional alternatives to the ERGS. EGEAS is a modular production-costing, generation-expansion software tool that is used to find least-cost generation system plans by comparing all combinations of multiple generation options to meet forecasted system load. EGEAS inputs include forecasted energy and demand, the characteristics of existing and possible new generation units, fuel price forecasts, known or expected energy purchase or sales, desired reserve margin, and the forecasted cost of emission allowances.

WEPCO has signed a Memorandum of Understanding with the American Wind Energy Association, Citizens Utility Board (CUB), Customers First! Coalition, Midwest Renewable Energy Association, RENEW Wisconsin, Sixteenth Street Community Health Center, and Wisconsin Energy Conservation Corporation for a ten-year collaborative process with the stated objective of achieving, by the end of 2011, a target of five percent of all electric energy delivered to WEPCO customers coming from renewable resources. WEPCO has also proposed committing $6 million annually to accomplish this goal. In testimony for the Port Washington phase of PTF, the company stated that its commitment to renewable energy development is conditional upon approval of the entire PTF project, including the ERGS facilities.

Staff's analysis of renewables potential

Commission staff also used EGEAS modeling to compare alternatives to the proposed coal plants. The EGEAS runs incorporate the federal Production Tax Credit (PTC) for wind generation. The PTC, which has been renewed several times since going into effect on January 1, 1994, provides for a tax credit of 1.5 cents per kWh plus an inflation adjustment for the first ten years of production from a qualifying wind power facility. The inflation adder is periodically adjusted by the IRS, so that in 2003 it is 1.8 cents per kWh. Current law applies only to wind and certain biomass facilities that come on line before December 31, 2003. However, there is reason to believe that the credit will be extended. Seven legislative proposals have been introduced in the U.S. Congress calling for extension of the credit for a period of anywhere from three years to indefinitely. Given the overwhelming, bipartisan support for extending the PTC, there is no reason to conclude that it will not be extended into the future.

Another important assumption in the EGEAS runs is the 20 percent credit to reserve margin. This means that for every 100 MW of wind power generated, only 20 MW would be credited toward WEPCO's reserve margin. This is somewhat conservative in light of the Mid-Continent Area Power Pool (MAPP's) wind accreditation reporting for 2000 through 2001, indicating that five wind farms in Minnesota had accredited capacities ranging from 21 to 29 percent.

Natural Gas-Fired Combined-Cycle and/or Simple-Cycle as an Alternative

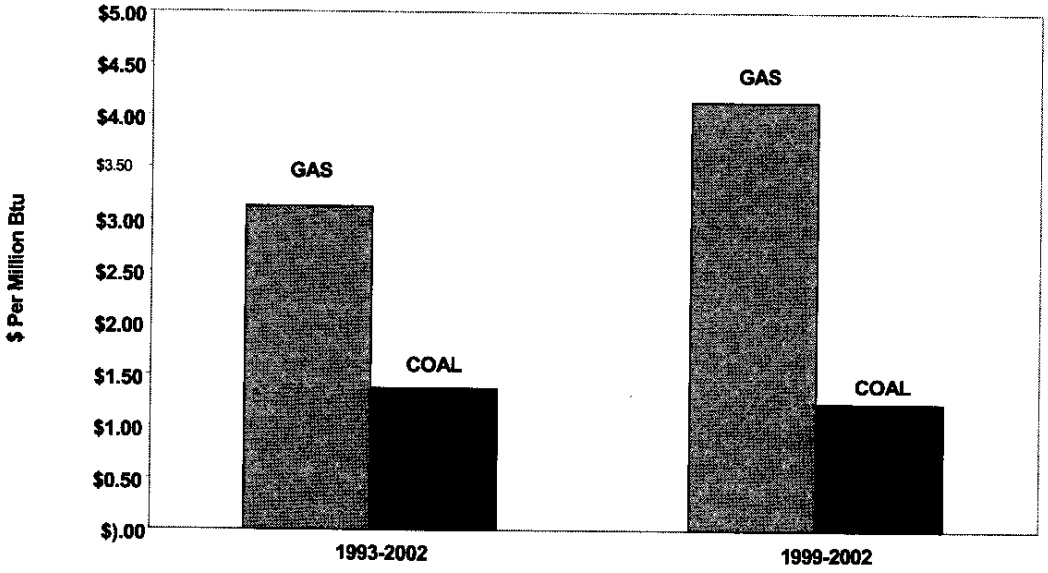
Fuel cost comparisons

An analysis of whether natural gas-fired generation should be built instead of coal generation should include, among other analyses, a comparison of natural gas prices and coal prices. Natural gas is a high-energy-content, premium fuel. These desirable features are offset, however, by the high cost of natural gas on a Btu-adjusted basis, and also by the extreme volatility of natural gas prices.

The average real cost of natural gas sold to electric generators over the past 10 years (1993-2002) has been $3.13 per million Btu (2002 dollars).[45] In contrast, the average real cost of coal over the same period has been $1.37 per million Btu. Natural gas costs have, on average, been 128 percent higher than coal costs over this period. If more recent data are examined, the difference in cost is even more dramatic. Over the past three years (2000-2002) the average real cost of gas was $4.14 per million Btu, whereas the real price of coal averaged $1.23 per million Btu over this period. Thus, in recent times, natural gas prices were 237 percent higher than coal prices. These cost comparisons are shown in Figure 4-1.

Making accurate predictions of future natural gas prices is difficult due to the extreme volatility of the data series. The standard deviation[46] of the annual natural gas price changes over the past 10 years is 24 percent. This contrasts with the standard deviation of annual changes in coal prices of only 2 percent.

Figure 4-1 Average cost of fuels used for electric generation over various time periods



[45] Price data is from the US Energy Information Administration. Prices were converted to constant dollars via use of the GDP price deflator.
[46] The standard deviation is a statistical measure of the dispersion of a data series.

The wide dispersion of natural gas prices in turn leads to very wide statistical prediction intervals for the price of natural gas over time. This can be demonstrated via the following random-walk model[47] of real natural gas prices:

$$\log \text{Gas Price}_{t+1} = \log \text{Gas Price}_t + \varepsilon_{t+1}$$

where

log = natural logarithm
Gas Price_t = real gas price in time period t
Gas Price_t+1 = real gas price in time period t+1
ε_t+1 = log-normally distributed random disturbance in time period t+1

Statistical forecasts can be generated from this model. For example, if this model reasonably represents the behavior of real natural gas prices, then one could be 90 percent sure that the 2003 average annual real gas price forecast would range between $2.48 to $4.91 per million Btu. This range is quite large.

The width of the prediction interval increases as the forecast period moves further into the future. For example, the 90 percent prediction interval for the year 2007 is $1.93 to $6.32 per million Btu. The 90 percent prediction interval for the year 2012 is $1.18 to $10.32 per million Btu.

This analysis indicates that real natural gas prices are essentially unpredictable for planning purposes. The real cost of natural gas for generation over the next five years might be below $3.20 per million Btu, but it also could just as easily be above $5.50 per million Btu. There is a smaller chance that it might decline to below $2.00 per million Btu, but there is also a small chance that it could increase to above $8.00 per million Btu. These types of prediction intervals do not provide much useful guidance as to the likely cost of natural gas over the long term.

Statistical forecasts of real coal prices have much tighter prediction intervals. For example, the 90 percent confidence forecast interval for real coal prices for the year 2012 is $0.58 to $2.55 per million Btu. This contrasts with the real natural gas price forecast interval of $1.18 to $10.32 per million Btu for the same time period. The contrast in predictability for natural gas prices versus coal prices is shown in Figure 4-2.

The volatility of the natural gas data makes it very difficult to draw firm quantitative conclusions about future natural gas prices. One can, however, draw important qualitative conclusions from this analysis. Those conclusions are:

- It is reasonable to assume as a base case that natural gas will continue to be significantly more expensive than coal over the generation planning horizon.
- The risk of incurring very high fuel prices is much greater for natural gas than it is for coal.

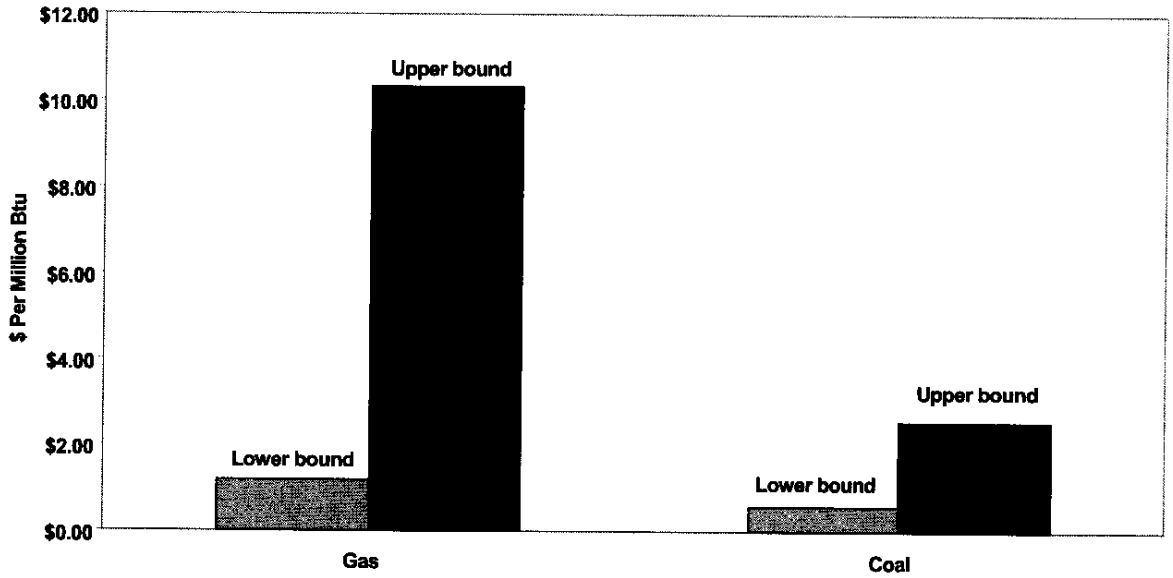
Staff's analysis of natural gas potential

Commission staff included the potential for some generic natural gas-fired combustion turbines in its EGEAS modeling runs and it also modeled and analyzed a proposal for a natural gas-fired combined-cycle plant that was filed at the PSC by Calpine Corporation as an alternative proposal to the ERGS. This

[47] The random-walk model assumes that the best estimate of today's price is yesterday's price.

proposal is described in more detail and compared with the proposed ERGS facilities in the following sections.

Figure 4-2 **Statistical prediction intervals (90 percent confidence) for fuels used for electric generation for the year 2012**



Alternative Proposals from Independent Power Producers

Applicant's treatment of IPP alternatives

As an alternative to all or part of the ERGS, WEPCO could rely on electric generation from an independent power producer (IPP) not affiliated with the utility or any of its affiliates. Such an alternative would require an IPP to construct a wholesale merchant power plant or sell electricity from a plant that is already operating but which has not contracted for all of its electrical output.

In its cost analysis filed in the CPCN application, WEPCO modeled purchases from generic or hypothetical power plants. WEPCO did not solicit power plant proposals or bids from IPPs that would directly compete with the ERGS coal facilities. This means that the costs under the proposed facility lease have not faced market discipline per se and are proxy costs that WEPCO believes are reasonable based on the company's insight of the marketplace.

In some instances, such an approach can be reasonable, especially if a formal bidding-type process to gather such market information would be expensive, untimely, or resource intensive. On the other hand, the use of competitive forces does foster cost discipline that ultimately benefits ratepayers. The fact that WEPCO did not issue an RFP for the capacity of ERGS may be an important issue at the hearing. In addition, the evaluation process itself may be an issue at hearing.

Calpine's proposal

On its own volition and as an alternative to the ERGS project, Calpine Corporation (Calpine) submitted a proposal to the PSC on February 19, 2003 that would develop a nominal 523 MW combined-cycle natural-gas-fired power plant in the town of Fond Du Lac, Fond du Lac County, with similar additional 500 MW units located elsewhere in the state. Calpine's February 2003 proposal which includes the full output of the Fond du Lac Energy project would be in lieu of the coal plants proposed for ERGS. On May 5, 2003 the Commission issued its Order approving Calpine's CPCN application for the Fond du Lac Energy project (docket 9343-CE-100). In addition, on June 20, 2003 Calpine updated its February 2003 proposal by including 260 MW of combined-cycle natural gas-fired capacity from Calpine's recent purchase of the Fox Energy Center located in the town of Kaukauna. Construction on that project has not commenced. However, in November 2002 the Commission issued an Order approving the Fox Energy Center CPCN application (docket 05-CE-115). The Fox Energy Center is rated at 510 MW with 250 MW of that capacity already under contract to Wisconsin Public Service Corporation. As for energy and capacity pricing, Calpine did not materially change terms in its June 20, 2003 proposal update, although it did allow for shorter contracting periods.

The Calpine proposal submitted to the PSC contains a sample power purchase agreement (PPA) with relevant economic and engineering terms and conditions. Such terms and conditions, due to their trade secret nature, have been filed confidentially at the PSC and are available only from Calpine after entering into an appropriate trade secret protection legal framework. Calpine believes its Fond du Lac Energy project and Fox Energy Center are superior in cost, fuel efficiency, and emissions to the ERGS coal plant facilities. Calpine believes it could begin construction on the projects as early as late 2003 with commercial operation in summer 2006. Calpine has indicated that later commercial operation dates are also available.

Staff's analysis of Calpine's proposal

The environmental effects of building and operating the Calpine Fond du Lac Energy Center were fully analyzed and described in a final EIS prepared by Commission staff for Calpine's original CPCN application. Two sites on the southeast side of Fond du Lac were proposed for the facility, one along River Road directly adjacent to Alliant's South Fond du Lac peaking generation plant and the other, about one-half mile east along Hickory Road directly across from a new Charter Steel industrial plant. The executive summary from the final EIS for the Calpine Fond du Lac Energy Center is attached as Appendix A-1.

The environmental effects of building and operating the Fox Energy Center were fully analyzed and described in a final EIS prepared by PSC and DNR staff. The executive summary from the final EIS for the Fox Energy Center is attached as Appendix A-2.

In this final EIS for the ERGS project, Commission staff has performed some initial EGEAS analysis of Calpine's proposal to provide 523 MW of combined-cycle capacity to WEPCO from the Fond du Lac Energy Project and 260 MW of combined-cycle capacity to WEPCO from the Fox Energy Center. That cost analysis is contained and explained more fully in the EGEAS modeling section of Chapter 4 below.

Lastly, as part of any project approval, the Commission will have to determine whether the process used by WEPCO for evaluation and selection of proposals to meet its electric needs has produced a cost effective,

timely, and likely project for WEPCO ratepayers, with respect to all quantitative and qualitative considerations. Given the substantial cost and dollar magnitudes involved and the relatively few projects to choose from, this is an extremely important topic for the Commission to consider, especially because of the significant potential effects on the southeastern Wisconsin economy if too many coal units are approved or there are major cost overruns. The consequences of these errors are described later in this chapter.

EGEAS Sensitivities (Integrated Resource Alternative)

Both the company and Commission staff used the professionally-accepted EGEAS (Electric Generation Expansion Analysis System) model to compare alternatives to the ERGS facilities. EGEAS is a modular production-costing, generation-expansion software tool that is used to find least-cost generation system expansion plans by comparing all combinations of multiple generation options to meet forecasted system load. EGEAS inputs include forecasted energy and demand, the economic and engineering characteristics of existing and possible new generation units, fuel price forecasts, known or expected energy purchases or sales, desired reserve margin, and the forecasted cost of emission allowances.

Commission staff addressed the following scenarios when performing its EGEAS analyses: 1) Base Case; 2) DSM-EIA Load Growth; 3) High Gas Prices; 4) Low Gas Prices; 5) High Coal Prices; 6) Low Coal Prices; 7) Coal Capital Costs plus 10 percent (this scenario addresses the potential for cost overruns as described earlier in Chapter 2); 8) CO_2 Monetization; 9) Monetization of SO_2, Hg, and NO_x Emissions; 10) Capacity of the SCPC of 615 MW; and 11) Retirement of all Coal at 60 years. For each of these scenarios, Commission staff performed an EGEAS run assuming three different outcomes:

- Optimal operation (EGEAS picks the best combination of WEPCO generating options)[48]
- Optimal operation with a Calpine 523 MW combined-cycle unit by 2007
- Two SCPC units (2008 and 2009); no IGCC unit

These scenarios are denoted Optimal (w/o Calpine), Calpine, and ERGS-no IGCC in Table 4-4 below. Lastly, each of the scenarios was modeled assuming the continued existence of the current wind tax credit (escalated for inflation over time). In these runs, wind development potential was limited to that placed into the EGEAS model or "hard-wired" by WEPCO presumably to reflect its potential commitment to the renewable resource under its complete Power the Future plan. (WEPCO recently submitted an RFP for 200 MW of wind generation which the company includes in its model by 2005. The company then adds another 50 MW of wind in 2011. The company also adds more wind in later years, totaling 410 MW of additional wind by 2030.) As a sensitivity, an EGEAS analysis was conducted by placing no limit on wind development potential as discussed later.

Commission staff based its capital cost parameters on the Commission's decision in the Port Washington case (docket 05-CE-117). These assumptions were 12.7 percent return on equity, 6.0 percent cost of long-term debt, and a capital structure of 53 percent equity and 47 percent long-term debt. These financing assumptions are less costly than those sought by WEPCO, namely a 12.90 percent return on equity using 58 percent common equity in the capital structure.

[48] This distinction is necessary relative to the next one because WEPCO does not have the Calpine proposal to evaluate, as PSC staff did.

Commission staff's Base Case assumes the following inputs:

- updated forecast for peak demand and energy use provided by WEPCO
- base coal and gas prices as forecasted by WEPCO beginning at $1.38 MMBtu for coal and $6.57 MMBtu for natural gas in 2003. In 2007, these fuel prices are $1.52 MMBtu and $4.67 MMBtu respectively in the WEPCO base fuel price forecast.
- the approved Port Washington facilities (two 545 MW combined-cycle units with one installed in 2005 and the other in 2007 or 2008)
- retirement of Presque Isle units 1-4 and Oak Creek 5 and 6 at the end of 2012.
- retirement of other coal plants at age 60
- relicensing of Point Beach Nuclear Power Plant Units 1 and 2
- Wind Tax Credit at $18 per MWh for 2002 (and escalated for inflation)

The wind units have a capacity factor of 30.0 percent. Commission staff assumed that these wind units have a 20 percent credit to reserve margin, which means for every 100 MW only 20 MW are counted towards the utility's reserve margin.

As an alternative to WEPCO's higher forecast of demand and energy, Commission staff applied its estimated impact of DSM programs through 2011 and then applied EIA growth factors to the peak and energy forecasted at 2011 for the period through 2031 (see Chapter 3, Table 3-6 "Projected Growth in Energy Use and Peak Demand). Commission staff believes that WEPCO's revised forecast is not unreasonable but perhaps slightly optimistic. Therefore, it is important to identify the impact on the economics of the ERGS proposal assuming a lower forecast for peak and energy.

Commission staff used WEPCO's high and low forecasts for coal and gas for its price sensitivity runs. Commission staff also used a 10 percent cost overrun on new coal units as a sensitivity to reflect WEPCO's new pricing proposal made available in its May 2003 direct testimony. Finally, a Calpine proposal for 523 MW filed with the PSCW in February 2003 (and updated in June 2003) was modeled as a potential substitute for ERGS coal units. In June 2003, Calpine also submitted a proposal for 260 MW of combined-cycle capacity from its recently acquired Fox Energy Center which received a CPCN in November 2002. A sensitivity analysis of that proposal is also examined below.

Commision staff incorporated the retirement of Presque Isle units 1-4 and Oak Ceek 5 and 6 at the end of 2012 to reflect the tentative agreement WEPCO has with the US Environmental Protection Agency (US EPA) which is the result of a settlement for WEPCO's violation of Clean Air Act standards. Commission staff also has a sensitivity where all coal plants are assumed to be retired at age 60.

Commission staff moved the installation of the first SCPC unit from 2007 to 2008 for the ERGS without IGCC proposal since the lease calls for the first unit to come on-line in May 2008.

EGEAS results - with 410 MW of wind by 2030

Table 4-4 shows that, for the DSM-EIA Load Growth and the High Gas Prices scenarios, the EGEAS run with Calpine's 523 MW combined-cycle unit forced to be taken in either 2006 or 2007 is not least cost when

compared with the EGEAS run with WEPCO-only generation incorporated. For the remaining cases shown in Table 4-4, the EGEAS model with the 523 MW Calpine Fond du Lac unit is immaterially different from the EGEAS run with WEPCO-only generation. However, in all of the scenarios in Table 4-4, the EGEAS run that includes the 523 MW Calpine unit is materially more economic than the ERGS without IGCC proposal from WEPCO. In the base run for instance, the expansion plan with the 523 MW Calpine Fond du Lac project is $95.6 million lower cost on a present value basis than ERGS without IGCC.

As is shown in Appendix A, Summary of EGEAS Expansion Plans, the presence of Calpine's 523 MW unit pushes the first coal plant out to at least 2011, except for the CO_2 monetization scenario where the Calpine and Optimal runs without Calpine push coal out to 2025. For the EGEAS runs with WEPCO-only generation, coal is pushed back to 2009, except for the DSM-EIA Load Growth scenario where the first unit is pushed out to 2012, the Coal Capital Costs plus 10 percent scenario where the first coal unit is selected in 2011 and the CO_2 monetization scenario.

Table 4-4 Cost comparisons of EGEAS modeling results with wind limited to 410 MW

	EGEAS Model Results NPV ($000,000)			Differences from Optimal		
Scenario	Optimal w/o Calpine	Calpine	ERGS - no IGCC	Optimal w/o Calpine	Calpine	ERGS - no IGCC
Staff Base Case	19,073.7	19,080.7	19,176.3	0.0	7.0	102.6
DSM- EIA Load Growth	16,914.8	16,979.9	17,144.2	0.0	65.1	229.4
High Gas Prices	19,233.0	19,261.8	19,334.9	0.0	28.8	101.9
Low Gas Prices	18,690.1	18,686.8	18,821.1	0.0	-3.3	131.0
High Coal Prices	19,353.3	19,354.4	19,458.5	0.0	1.1	105.2
Low Coal Prices	18,823.0	18,836.7	18,921.9	0.0	13.7	98.9
Coal Cap. Costs + 10%	19,485.6	19,475.0	19,625.2	0.0	-10.6	139.6
Staff Base Case with CO_2 Monetization	27,009.9	27,017.2	27,356.6	0.0	7.3	346.7
Hg, SO_2 and NO_X monitization	19,506.3	19,504.4	19,610.3	0.0	-1.9	104.0
Coal Capacity at 615 MW	19,106.2	19,106.6	19,261.4	0.0	0.4	155.2
Retire Coal at 60 Years	18,722.8	18,736.3	18,825.2	0.0	13.5	102.4

Note: Optimal without Calpine is equivalent to WEPCO-only generation. This distinction is necessary, related to the Calpine run because WEPCO does not have the Calpine proposal to evaluate, as PSC staff did.

Figures 4-3, 4-4, and 4-5 depict the Base Case expansion plans for the period 2004 to 2014 under the Optimal without Calpine, Calpine, and ERGS w/o IGCC approaches. For reference sake, the Optimal w/o Calpine expansion plan in Figure 4-3 is $7 million less expensive on a present value basis than the expansion plan with Calpine proposals in Figure 4-4. As indicated, this difference is statistically immaterial. On the other hand, the Calpine expansion plan in Figure 4-4 is $95.6 million less expensive than the WEPCO proposed expansion plan w/o the IGCC unit which is depicted in Figure 4-5. Examination of the following figures shows that coal plants are generally part of a least cost EGEAS expansion plan for WEPCO. However, the optimal timing appears to be for the period 2009 and 2011, which is about two to three years later than the operational date sought by WEPCO in its CPCN application.

Figure 4-3 Optimal expansion plan without any Calpine units

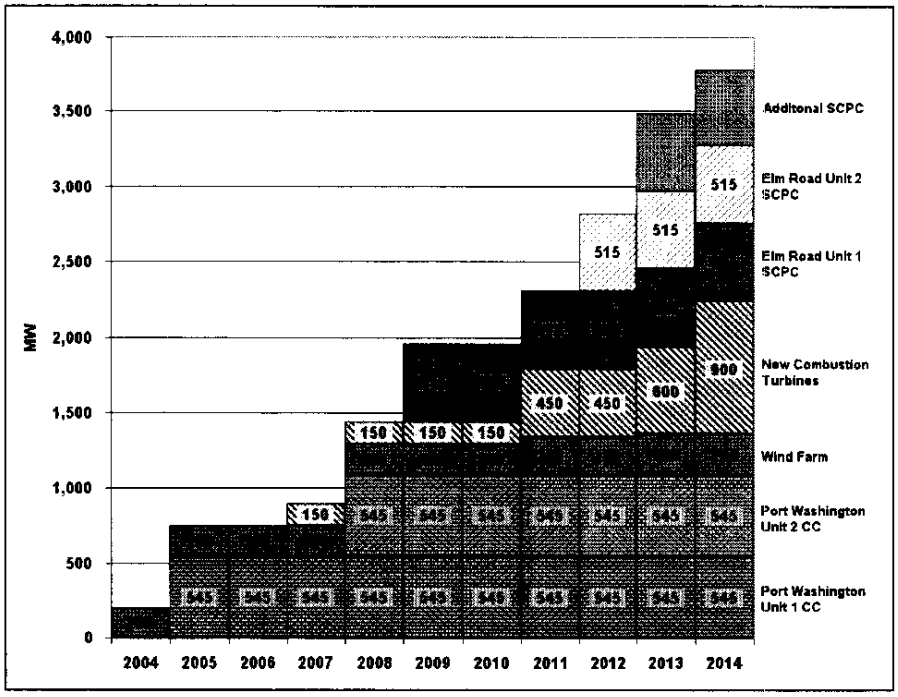


Figure 4-4 Expansion plan with Calpine proposal

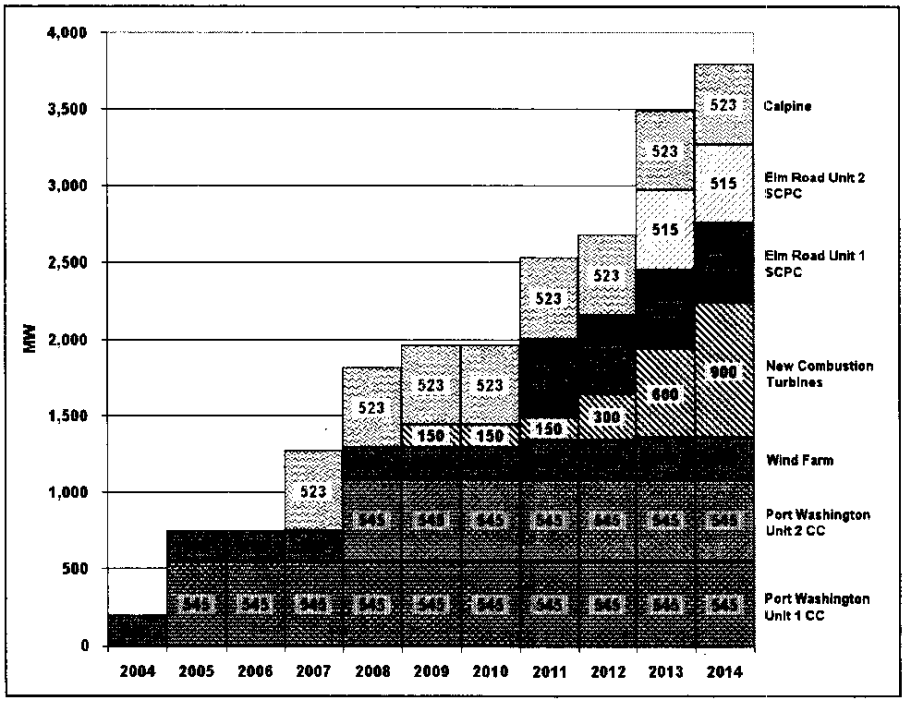
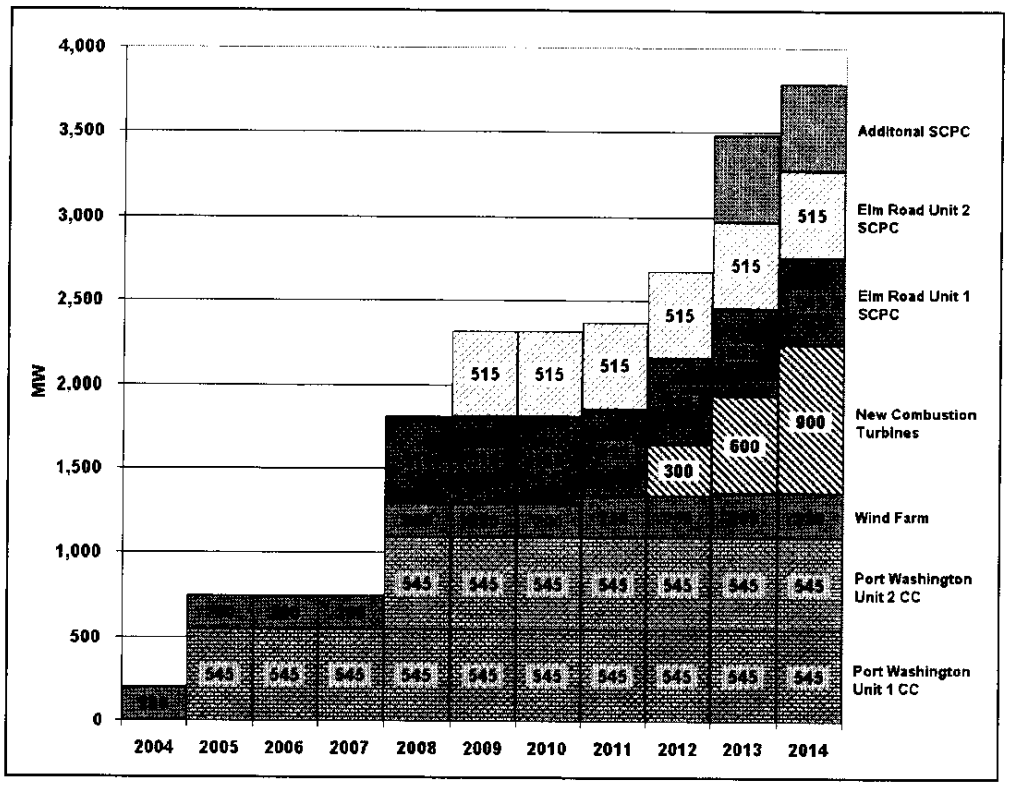


Figure 4-5 Expansion plan for WEPCO's ERGS without IGCC



EGEAS Results- with No Limit on Wind

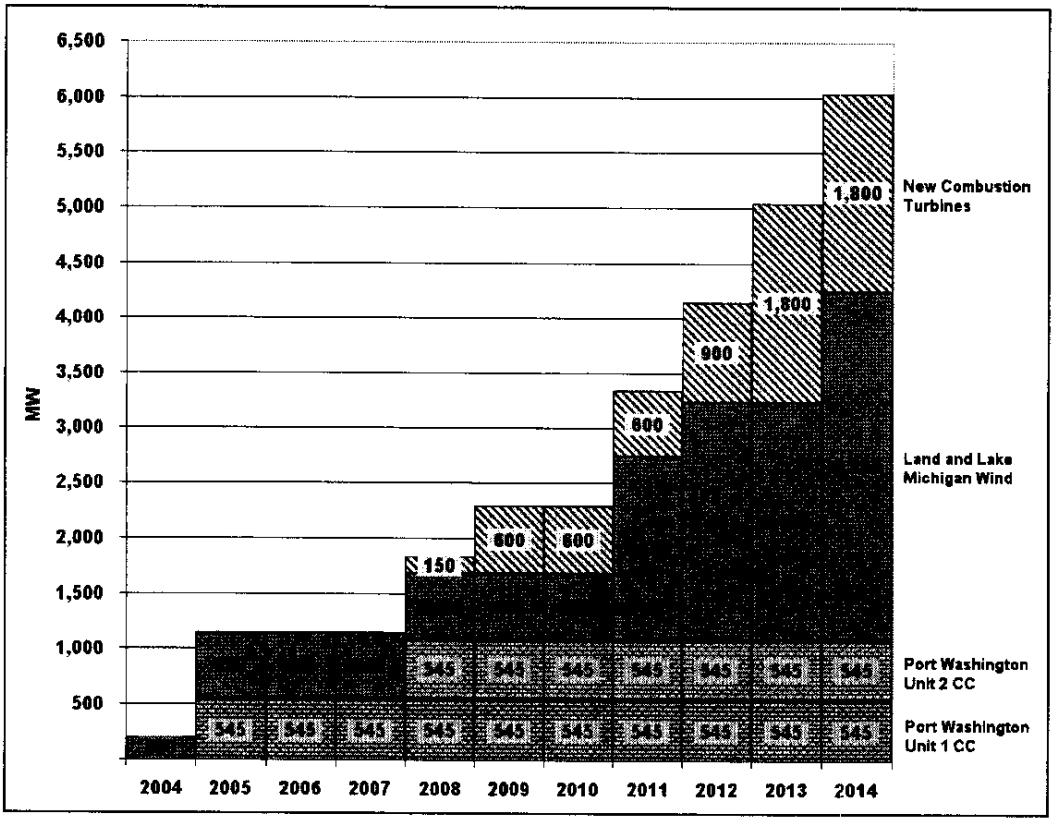
Commission staff also ran scenarios in EGEAS where wind was allowed to be picked freely by the EGEAS model. The results are shown in Table 4-5. Commission staff used two sources of wind—the first was based on the bids that WEPCO received from its RFP (request for proposal) and the second was wind assumed to come from offshore in Lake Michigan. For the Lake Michigan wind, a 35 percent capacity factor was assumed (as compared to the 30 percent assumed by the company for its wind units). Both sources of wind were assumed to make a 20 percent contribution to the capacity reserve.

Commission staff looked at two scenarios—one with the wind tax credit continuing through the foreseeable future and the other with no wind tax credit. In both cases, the Calpine proposal was significantly less expensive than the ERGS w/o IGCC proposal. For the continuing wind tax credit scenario, the Optimal run was, however, less expensive than the Calpine run since the presence of an additional 523 MW of combined-cycle reduces the amount of wind and wind production tax credit (PTC) that the EGEAS model can select. In the "no limit wind" run, the EGEAS model selects up to 2,500 MW of Lake Michigan wind by 2014. This is in addition to 400 MW of new land-based wind placed into service in 2005. In neither the Optimal nor Calpine runs is any coal picked for the wind tax credit continuation scenario. Figure 4-6 displays the 2004 to 2014 expansion plan when there is no limit on wind generation development.

Table 4-5 EGEAS model results under unlimited wind scenario

	EGEAS Model Results NPV ($000,000)			Differences from Optimal		
No Limit on Wind Scenario	Optimal w/o Calpine	Calpine	ERGS - no IGCC	Optimal w/o Calpine	Calpine	ERGS - no IGCC
No limit on Wind with the Wind Tax Credit	14,794.8	14,945.9	15,547.1	0.0	151.1	752.3
No limit on Wind; No wind Tax Credit	18,020.8	17,899.7	18,128.6	0.0	-121.1	107.8

Figure 4-6 Expansion plan with no limit on wind development and with continuing PTC



There are two concerns Commission staff has with the unlimited wind capacity and the continuing wind tax credit scenario. First, EGEAS picks so much wind capacity that baseload units have drastically reduced capacity factors in later years. Second, Commission staff does not believe that the federal government would be willing to pay $18 per MWh (2002$) for the volume of wind of 11,000 MW by 2023 selected by EGEAS under this scenario.

For the no wind tax credit scenario, the Calpine run is the most economic. For the Calpine run, the first coal unit is pushed out to 2011, whereas the Optimal without Calpine run picks its first coal unit in 2009. The Calpine proposal is significantly less expensive than the ERGS w/o IGCC proposal. With no wind tax credit, no new wind is picked by EGEAS until 2017.

Other EGEAS Analyses

Commission staff also analyzed a June 2003 proposal from Calpine for 260 MW of combined-cycle capacity from its Fox Energy Center using Commission staff's Base Case assumptions. The Fox Energy proposal using only 260 MW in 2007 was more expensive than the Calpine Fond du Lac proposal using 523 MW by $12.4 million. (See Appendix A, Summary of EGEAS Expansion Plans) Commission staff did not run the EGEAS model with capacity available from both Calpine projects simultaneously due to limited time, but may explore that possibility in time for the technical hearing.

Commission staff made an EGEAS run with the IGCC unit included in the model for the Base Case scenario. The ERGS proposal with the IGCC was more expensive than the ERGS proposal without the IGCC by $247.1 million.

Commission staff made an EGEAS run assuming no coal nor biomass, and wind limited to that hardwired by WEPCO. The cost of that plan was less economic than the Optimal plan by $1,937.8 million. When Commission staff allowed EGEAS to pick up to 1,500 MW of biomass, the resulting expansion plan was more expensive than the Optimal plan by $1,405 million. These latter sensitivities indicate that a mixture of properly timed gas- and coal-fired units would result in the lowest overall cost expansion plan for WEPCO.

EGEAS summary

10. The IGCC unit, which is the third unit in the ERGS proposal, is not cost-effective.
11. The proposed timing of the SCPC units in 2007 and 2009, as WEPCO has proposed, is not least cost. This scenario is generally more than $100 million more expensive on a present value basis. Timing appears to be about two to three years premature.
12. The Calpine 523 MW CC proposal in Fond du Lac using natural gas is lower cost than the ERGS - w/o IGCC proposal. However, the Calpine proposal would not need to be put in-service until 2007. Selecting the Calpine proposal does not mean that coal plants would not be needed. Several scenarios suggest that a coal plant would not be needed until 2011, if not later, if the Calpine proposal is selected.
13. CO_2 monetization, as well as other emissions monetization scenarios, favors picking the Calpine proposal versus ERGS w/o IGCC.
14. If the coal plants were to have cost overruns of 10 percent, then the Optimal expansion plan does not select a coal plant until 2011.
15. Should lower demand and energy growth occur due to increased energy efficiency efforts and lower overall use of electricity than depicted by WEPCO in its base demand and energy forecast, then the earliest a new coal facility would be needed is 2012.
16. ERGS w/o IGCC could be made competitive with the Calpine Fond du Lac proposal by the Commission choosing an overall finanacing plan that would cost ratepayers between $50 million and $100 million less on a present value basis.

17. Substantial Lake Michigan wind development exceeding 2,500 MW by 2014 and 11,000 MW by 2023 would be effective in meeting demand and energy growth for WEPCO, but it would require a substantial federal transfer via a permanent wind tax creit of $18 MWh. If the federal government were to not renew the wind tax credit presently set to expire in 2004, then no new wind would be selected by EGEAS until 2017.
18. An expansion plan over the next 30 years relying exclusively on natural gas would cost ratepayers $1.9 billion more than a balanced plan using optimally timed gas- and coal-fired electric generation, as well as some wind generation development.

There are important caveats in interpreting and understanding the above comments. First, Commission staff has used a strict materiality threshold of $10 million in interpreting the EGEAS model results. This means that Commission staff believes that expansion plan total costs that differ by more than $10 million are considered significant. Due to modeling complexity, the number and type of input assumptions, as well as the long-term nature of the EGEAS expansion plans, different parties may want to use other materiality thresholds. For instance, the Commission used a materiality threshold of $50 million during the Port Washington CPCN case. Using a $50 million materiality threshold still results in selecting Calpine proposal over the ERGS w/o IGCC proposal.

Another important caveat is that the Commission can choose a financing package other than the one proposed by WEPCO for ERGS and modeled here. The Commission could fashion a financing package for ERGS that would lower present value costs to ratepayers. For instance, in Chapter 3, rate-based financing rather than the lease approach could be used to lower ratepayer costs. Alternatively the Commission could still use a leasing approach but with different financial parameters.

It should also be noted that the above quantitative results only focus on parameters that can be directly modeled in EGEAS. The following sections adjust the EGEAS results for the ratepayer impact associated with mitigation payments under the WEPCO-city of Oak Creek agreement as well as the different transmission system upgrade costs associated with the various generation expansion plans.

Lastly, these results focus on quantitative effects. The Commission will need to consider the qualitative environmental and economic risks associated with the use of different fuels as discussed throughout this final EIS.

Effect on EGEAS results due to the potential for adverse credit quality effects on WEPCO's capital structure arising from the Facility Lease or a Purchase Power Agreement

When a long-term facility lease or purchase power agreement is signed, credit rating agencies can downgrade a utility's credit rating due to the debt-like quality of such agreements. This is especially the case if the lease or signed purchase power agreement constitutes a capital lease under Financial Accounting Standard Board (FASB) standards. Essentially, the signing of leases and PPAs with capital lease attributes and the attendant paying of rent or capacity payments looks much like a stream of continuing finance payments usually associated with long-term debt. This can reduce the utility's ability to obtain new financing and can raise borrowing costs as well. Any such increase in borrowing costs due to signed PPAs or leases needs to be factored into any generation cost analysis, including the quantitative EGEAS analysis reported above.

In this final EIS there has been no need to make quantitative adjustments associated with potential harm to the utility's credit rating. First, Calpine has proposed contract lengths in its proposal that make it less likely that a signed PPA for either the Fond du Lac Energy project or Fox Energy Center would constitute a capital lease under FASB standards. For instance, Calpine has not bid its proposals using a 25-year or longer term that would likely trigger capital lease accounting. Second, in the Port Washington construction case (docket 05-CE-117), WEPCO suggested and the Commission accepted the utility's commitment to treat all leases as operating leases for ratemaking purposes, and not as capital leases. Furthermore, WEPCO committed to a hold harmless provision with respect to debt costs if a transfer or assignment broadly defined of the leases or the Port Washington facility to a non-Wisconsin Energy Corporation company causes a national rating agency to downgrade the utility's debt rating or causes the utility to issue new equity to prevent such a downgrade, citing the lease as the reason. The Commission approved such terms in docket 05-AE-109. Similar conditions are expected in this ERGS docket. Finally, the facility lease itself contains a provision not allowing any such transfer or assignment broadly defined to occur for the first seven years after commercial operation of the ERGS. For these reasons, the EGEAS results have not been adjusted since the potential for credit quality degradation has been significantly reduced. Should underlying financing facts change with respect to either the ERGS or the Calpine proposals, a reexamination of this issue would be warranted.

Effect on EGEAS Results due to the WEPCO and city of Oak Creek Agreement

On March 25, 2003 the city of Oak Creek and WEPCO entered into an agreement by which WEPCO would, among several conditions, annually reimburse the city of Oak Creek $2.25 million after the start-up of the second SCPC plant that is part of the ERGS. This has not been modeled in the EGEAS quantitative results above, but the EGEAS results do need to be corrected for the long-term cost effect of the WEPCO-Oak Creek agreement. Specifically, the above EGEAS present value cost effects for the ERGS should be increased by $23.2 million. This $23.2 million is the 30 year present value of a stream of $2.25 million annual mitigation payments using a discount rate of 8.97 percent in an ordinary annuity formula. A 30-year period is used here because that is the facility lease's initial term.

Effect on EGEAS results due to necessary transmission system improvements

A proper cost analysis requires the inclusion of both generation and transmission costs. The EGEAS present value results depicted above only factor in electric generation capacity and energy costs. To these EGEAS generation costs, necessary transmission system improvement costs must be added in order to provide the overall generation and transmission impact to ratepayers.

Elsewhere in this FEIS it was indicated that the transmission system improvement costs associated with ERGS are $266 million. Without the third phase or IGCC component, the corresponding value is $164 million for the 1,230 MW of supercritical pulverized coal capacity. This latter transmission cost is used in the following discussion due to EGEAS modeling results showing that the IGCC phase is non-economic. It is important to note that this $164 million value may be overstated due to the fact that the July 2002 ATC study underlying it included generation projects that are unlikely to be constructed such as the 1,100 MW PG&E Badger Generating Station. Moreover, the July 2002 ATC study did not factor in the retirement of 500 MW of generating capacity associated with Oak Creek units 5 and 6 that now appears likely due to the EPA-WEPCO emissions agreement. How these elements would affect

the $164 million estimate is unclear without a formal study. ATC is presently conducting such an analysis, but official results are not available at the writing of this FEIS. Preliminary discussion between Commission staff and ATC staff suggests the $164 million may be decreased to $80 to $100 million.

As for the Calpine 523 MW Fond du Lac Energy project and the 510 MW Fox Energy Center, the estimated combined transmission cost is $40 million for 1,033 MW of gas-fired capacity. In order to compare this value which is based on 1,033 MWs with the cost of the ERGS project without the IGCC unit which is based on 1,230 MWs of capacity requires some normalization. For this reason, the $40 million for the combined Calpine projects is escalated by the simple ratio of 1,230/1,033 to arrive at a $48 million value for the cost of necessary transmission improvements. This represents a preliminary and simplistic analysis requiring further advanced study.

Nonetheless, the discussion here indicates that the Calpine projects may enjoy between a $30 and $120 million construction cost advantage with respect to necessary transmission improvements. The 2003 present value of such construction amounts if the transmission assets were put in service in 2008 is between $28 million and $111 million using a 13.70 percent return on equity and a 40-year depreciation period. This $28 million to $111 million present value range would correspondingly increase the Calpine projects' advantage in the EGEAS generation results if both a generation and transmission cost perspective were used. Such a value should be used cautiously as the Calpine projects have not had official ATC load flow or "source and sink" transmission impact studies conducted in which the delivery point is the WEPCO system.

Potential adverse economic development effects caused by constructing a generation expansion plan that is improper or too expensive

In this EIS, there is much discussion about the optimal, cost-effective generation expansion plan for WEPCO. In particular, there are results of various EGEAS computer model simulations. The point of the EGEAS simulations is to find the generation expansion plan that accommodates WEPCO's system needs in a cost-effective fashion. Selecting an expansion plan that does not accommodate WEPCO's system needs would have an adverse economic development impact. First, in the situation where insufficient electric power and energy are available due to an improper generation expansion plan, the electric system becomes unreliable. This leads to general business uncertainty, increased operational costs for business, and scheduling and production inflexibility.

Such factors would impose a tremendous economic cost on the economy of southeastern Wisconsin which would most likely take the form of business relocation or expansion outside of the area and consumers having less money to spend. Estimating the actual economic loss from insufficient electric power and energy is problematical, but the loss would likely be substantial in dollar and qualitative terms.

The second potential adverse impact comes from constructing an optimal expansion plan that is too expensive, due to either cost overruns or poor project selection. Estimating the loss to the southeastern Wisconsin economy is somewhat easier in this situation if the extra expense for electricity is viewed akin to a sales tax increase.

A recent study of the impact of tax increases on the Wisconsin economy shows that each $10 million increase in sales taxes has the potential to eliminate around 350 jobs.[49] Elsewhere in this EIS, it is reported that the annual lease payment from WEPCO to WE Power would be $111.25 million for each of the pulverized coal units. This means that a 10 percent construction cost overrun would make the annual lease payment cost about $11 million more than without the overrun. This ten percent overrun estimate is used because in its June 2003 testimony WEPCO has capped the cost overrun potential under the facility lease to no more than ten percent. If viewed as an unnecessary $11 million tax increase, such a 10 percent cost overrun could hurt the southeastern Wisconsin economy by about 385 jobs per year per unit.[50]

Lastly, there would be an impact if more coal units are approved than are actually needed. If WEPCO were to pay WE Power for a coal plant that was constructed but not needed, WEPCO under the facility lease would have to pay an annual rent of $111.25 million. Using the job-loss-to-sales-tax-increase estimate from above would translate into a loss of about 3,900 jobs per year per unit. For this reason, the Commission may want to consider a phased approach to the construction of the ERGS facilities, requiring the second or third units be constructed only after another examination of electric demand needs. In the case of an overbuilding scenario, the job loss impact would diminish slowly through time as electricity demand grew, eventually requiring the excess capacity to be used.

Nuclear Power as an Alternative

Currently, construction of new nuclear power plants is prohibited by Wis. Stat. § 196.493. However, this prohibition will cease once Yucca Mountain, or a similar geologic repository, becomes operational.

In July 2002, the U.S. Senate approved the development of Yucca Mountain as a long-term geologic repository. According to the Office of Civilian Radioactive Waste Management web site, the US Department of Energy (DOE) is "currently in the process of preparing an application to obtain the Nuclear Regulatory Commission license to proceed with construction of the repository." The 2004 budget proposed by DOE anticipates that Yucca Mountain will be operational by 2010.

During the scoping process, members of the public suggested that the Commission examine the possibility of replacing the proposed ERGS coal units with nuclear power plants. Evaluating the option of a nuclear power plants as an alternative to the ERGS proposal, requires the following assumptions:

1. Wis. Stat. § 196.493 remains unchanged.
2. Yucca Mountain begins operation in 2010.
3. The Nuclear Regulatory Commission's (NRC) early site approval process is not precluded by Wis. Stat. § 196.493.
4. WEPCO could complete the early site approval process by 2010.
5. The Westinghouse AP600 nuclear facility is used in EGEAS modeling. The AP600 is similar in size to the proposed ERGS coal units and its design has been approved by the NRC.
6. A new nuclear unit could be constructed and placed in operation within 36 months, once site approval is obtained. This would allow the EGEAS model to choose a new nuclear unit beginning in 2013.

[49] "Raising Taxes in Wisconsin—Measuring the Full Costs," Wisconsin Policy Research Institute Report, Volume 16, Number 1, January 2003. This study shows that 55,514 jobs would be lost from a $1.6 billion sales tax increase, basically a 350 jobs to $10 million ratio.
[50] Calculated as [$21 million / $10 million] times 350 = 735

Commission staff ran four different scenarios in EGEAS where the model could choose new nuclear generation. The four scenarios included two different capital costs,[51] including contingencies, each run with a "monetize CO_2" (which adds a cost for greenhouse gas emissions) and a "no monetization of CO_2" sensitivity.

WEPCO supplied its estimate of reasonable costs associated with the construction of a new nuclear power plant. It estimated a capital cost of $2,116 per kilowatt (kW). This is very close to the number used by DOE and found in the assumptions to Energy Information Administration's (EIA) Energy Outlook 2002, which is $2,144 per kW for an advanced nuclear generating unit. Commission staff used WEPCO's $2,116 per kW as one estimate of overnight costs in its EGEAS modeling.

Based on information available in Public Utilities Fortnightly, a capital cost (without contingencies) for the AP600 would be $1,500 per kW. Using the same percentage for contingencies as found in the assumptions to EIA's Energy Outlook 2002, the overnight cost for the AP600 with contingencies would be $1,815 per kW. This was the other overnight cost utilized by Commission staff in its EGEAS modeling.

If a capital cost of $2,116 per kW is used, the EGEAS model does not pick a nuclear unit to meet new generation needs, regardless of whether CO_2 is monetized or not. If the lower estimate of overnight costs ($1,815 per kW) is used and CO_2 is monetized, the EGEAS model picks one new nuclear unit in 2013 to meet new generation needs. Without CO_2 monetization, no new nuclear units are chosen.

The assumptions used in this analysis of nuclear plants do include significant uncertainties. There is uncertainty associated with which advanced reactor design WEPCO would actually choose. This has an impact on the overnight costs used in the EGEAS model. The fact that no new orders for nuclear plants have been placed in this county since the late 1970s also adds uncertainty in the overnight cost associated with building a new nuclear unit and the length of time from start of construction to the point when the plant is brought on line.

The largest uncertainties lie in the first two assumptions above. The commercial operation date for Yucca Mountain is not certain. For Yucca Mountain to become operational, NRC must approve the construction of the repository. Any delay in the projected 2010 in-service date for Yucca Mountain directly impacts when a new nuclear unit can be allowed to be chosen by the EGEAS model. The continued applicability of Wis. Stat. § 196.493 is also an uncertainty, but because this statute has no sunset date it is reasonable to assume that it will remain in effect, unchanged.

Given this lack of certainty associated with several important assumptions about a nuclear option, it does not appear that new nuclear generation is a viable alternative to the ERGS proposal at this time.

[51] In the Energy Information Administration's Energy Outlook 2002, these costs are referred to as "overnight" costs.

5

Chapter 5 - Fuel Diversity Perspectives

The topic of fuel diversity has been raised frequently in public discussions and meetings related to this project. Fuel diversity is a complex issue and can be viewed in a number of ways. The applicants have stated, in the CPCN application and at several public forums, that maintaining or enhancing the fuel diversity in WEPCO's generation mix is one of the primary reasons they have proposed the ERGS facilities. An examination of the pie charts in Figures 3-1 and 3-4, shows that about 50 percent of WEPCO's generating capacity is presently coal-fired and that about 70 percent of the energy consumed by WEPCO customers is produced by coal-fired generation. From this perspective, the applicants' statements seem to be inconsistent. However, there are many considerations in determining the appropriate mix of generation technologies and fuel sources.

Some of these considerations include: the age and condition of WEPCO's existing generating units; the source and availability of the fuels; fuel prices and the expected stability or volatility of fuel price over time; the overall energy balance and use in Wisconsin; and the environmental effects and safety issues associated with the use of different fuels.

This chapter will discuss some of these issues and perspectives. The chapter does not contain specific conclusions or recommendations with respect to the proposed ERGS project or any of the alternatives to the project. It is included in the EIS to provide information, raise awareness, and generate discussion. Although this chapter is focused on coal power plants versus natural gas-fired facilities, staff recognizes that a similar analysis of an integrated resource alternative which includes renewables, energy efficiency, electric transmission improvements, and possibly other smaller fossil-fueled facilities would also be valuable. Finally, the chapter is organized under the broad topics of reliability, economics, and environmental issues, but issues discussed under one topic often have implications in other areas.

Reliability Issues

Coal sources and availability

There is an estimated 304.6 billion tons of recoverable coal reserves in the United States.[52] The U.S. has about 25 percent of the world's reserves and uses about 25 percent of the worldwide coal used annually. In 2001, the U.S. mined a record 1.12 billion tons of coal, an increase of 60 percent over a 25-year period.

[52] Based on 60 percent recovery rate and US Energy Information Administration coal reserve data.

The current growth trend in coal production began in 1961. From 1986 to 1997, coal production increased by 22 percent, while the number of operating coal mines in the country declined by 59 percent, from 4,424 in 1986 to 1,828 in 1997. Coal prices decreased by 45 percent in real dollar terms over this same time period. Today, roughly equal amounts of Western coal and Appalachian coal are produced with about half as much interior (such as Illinois) coal produced.[53]

Competition from natural gas has slowed the growth of new coal-fired generation capacity but consumption of coal still increased by 28 percent from 1986 through 1997. By 1997, 90 percent of the coal consumed was used to generate electricity. Coal-fired units account for only 5 percent of planned new generation units between 1998 and 2007. But coal-fired net generation capacity is projected to grow because of an anticipated increase in utilization and capacity additions after 2007.

EIA projections between 1997 and 2010, which take into account scheduled generating capacity additions and baseload mix, anticipate nearly a 14 percent increase in annual coal consumption at electricity generators. These projections, and others like them, provide reasonable assurance of long-term coal markets and motivate large companies, especially those with traditional ties to coal, to hold investment positions in coal for the long term.

Natural gas resources, pipeline capacity and storage

Wisconsin has no indigenous supplies of natural gas. Therefore, owners of any natural gas-fired electric generation would have to procure supplies from outside the state. Natural gas is typically purchased from production areas in Louisiana, Oklahoma, and Canada. It is then transported to Wisconsin via interstate pipelines. Some generators connect directly to the interstate pipeline to receive their natural gas. Other generators purchase natural gas from a Wisconsin utility, which means that the gas must also flow through the utility's distribution system to reach the facility. This results in three possible areas for which reliability of natural gas must be assessed: (1) production, (2) interstate transmission, and (3) distribution. Each sector will be addressed separately in this section. The reliability implications associated with the inability of generator operators to store natural gas on-site will also be discussed.

Natural gas production and use: long-term analysis

With respect to production there are two possible reliability issues. First, natural gas must be available in the production region. Second, wells must be in place to make it possible to remove the natural gas from the field. According to the U.S. Energy Information Administration (EIA), technically recoverable reserves of natural gas in the United States in 2001 amounted to 1,614 trillion cubic feet.[54] This is about 82 times the amount of natural gas produced in the U.S. in that year. This is an overly-optimistic perspective of available supplies, however, because the technically recoverable estimate includes, among other items, gas supplies that are not currently economically recoverable. It also includes estimates of natural gas supply volumes that have not yet been discovered.

[53] The US Coal Industry in the 1990's: Low Prices and Record Production by Richard Bonskowski, September 1999.
[54] Energy Information Administration, "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves," 2001 Annual Report.

In contrast, there are only 183 trillion cubic feet of natural gas in proved reserves.[55] This amounts to only about nine times the 2001 annual production level. This is an overly conservative estimate of the amount of natural gas likely to be available in the future.

The U.S. has about 2 to 6 percent of the world's natural gas reserves and uses about 33 percent of the world's production annually. Currently the U.S. imports 16 percent of its natural gas but that is expected to increase as demand increases from 22 trillion cubic feet (TCF) to 35 TCF by 2025.[56]

Historically, market forces have helped the industry to discover and produce much more gas than the experts had originally thought was available. To wit, the American Gas Association reports that its Potential Gas Committee's 1998 estimate of the amount of gas available in the U.S. was approximately 4 percent higher than its 1990 estimate, even though a substantial amount of the gas supply had been consumed over the intervening period.[57] This suggests that even though large volumes of natural gas continue to be consumed, the available resource base may be expanding, not declining as gas prices move higher. Over the long-term, however, existing production areas may not be able to supply the increases in demand. In that case, gas would need to be brought to market from other areas. Examples include importing LNG, off-shore eastern Canada, the Mackenzie Delta, Alaska, and the Rocky Mountains.

The support for the concept of an increasing supply of gas is founded in part on the fact that currently uneconomic gas reserves may become economically attractive even if there is no technological improvement in natural gas production. The amount of economically recoverable gas interacts dynamically with the price of natural gas. This interaction makes it very unlikely that the country would ever "run out of gas." The more likely scenario is that if supplies begin to dwindle without an accompanying reduction in demand, the price of natural gas would rise.

Under those circumstances natural gas production would increase as natural gas supplies that were formerly too expensive to extract would then become economically attractive. At the same time, the higher prices would tend to have a moderating impact on demand. Thus, the price mechanism would simultaneously tend to increase supplies and decrease demand, thereby returning the natural gas market to balance. It is not surprising to find therefore, that with the current high natural gas prices there could be more economically recoverable supplies of gas than there were 10 years ago.[58]

The impacts of market adjustments that bring on the additional supplies are felt by consumers. The resulting equilibrium price that expands the resource base could be significantly higher than it was prior to the adjustment. So the real threat, in terms of reliability of supplies, is not that we will run out of natural gas, but rather that we might run out of inexpensive natural gas.

Holding all else equal, the pace of escalation in natural gas prices would likely be accelerated if natural gas remains the fuel of choice for new electric power plants. By the year 2001, the use of natural gas by electric generators had already approached the level of consumption from the commercial (non-industrial) sector. There appears to have been a major revision to the EIA consumption data between the time the draft EIS

[55] EIA defines proved reserves to be volumes of natural gas that geological and engineering data indicate with reasonable certainty appear to be recoverable from known reservoirs under existing economic and operating conditions.
[56] EnerFax Daily 2/26/03
[57] American Gas Association, *Fueling the Future: Natural Gas and New Technologies for a Cleaner 21st Century*, 2001.
[58] At the time that this section was drafted, spot natural gas prices were in excess of $6.00 per million Btu.

was prepared and the final EIS was written. When the draft EIS was written, the latest data available was the 2001 data that showed that natural gas use by the electric utilities amounted to 14 percent of the total useage. The new data reported for 2002 show that the figure has almost doubled to 27 percent.[59] In addition natural gas usage in the Industrial sector decreased in the last two years and it is not clear if the decrease was due to a softening economy or demand destruction due to higher prices. PSC staff has not yet had an opportunity to investigate the basis for these dramatic changes.

Table 5-1 Natural gas consumption by sector–2001 and 2002 (billion cubic feet per year)

2001 Data		
Sector	**Annual Consumption**	**Percent of Total**
Industrial	8,656	45%
Residential	4,809	25%
Commercial	3,037	16%
Electric utilities	2,686	14%
2002 Data		
Industrial	7,123	34%
Residential	4,915	24%
Commercial	3,147	15%
Electric utilities	5,553	27%

While the EIA data suggests that natural gas use by electric utilities is rapidly increasing, based on the orders placed for new turbines, the pace of adding natural gas-fired electrical generating capacity has slowed considerably in recent times. Figure 5-1 shows the delivered orders for gas turbines reported by General Electric over several years.[60] (The turbines are key components of natural gas-fired generating facilities.) This suggests that any upward pressure on natural gas prices due to new natural gas-fired generators may be less than had been anticipated several years ago.

Another fact that has bearing on the availability of natural gas for power generation projects is the overall demand for natural gas. The demand for natural gas in the U.S. actually peaked in 1973.[61] By 1986 the country was using 25 percent less natural gas than it did 13 years earlier. This is shown in Figure 5-2.

[59] Source: US Energy Information Administration
[60] Source: Jacqueline Doherty, "Turning on the Lights," *Barron's*, February 22, 2003.
[61] Source: US Energy Information Administration.

Figure 5-1 General Electric's gas turbine shipments by year

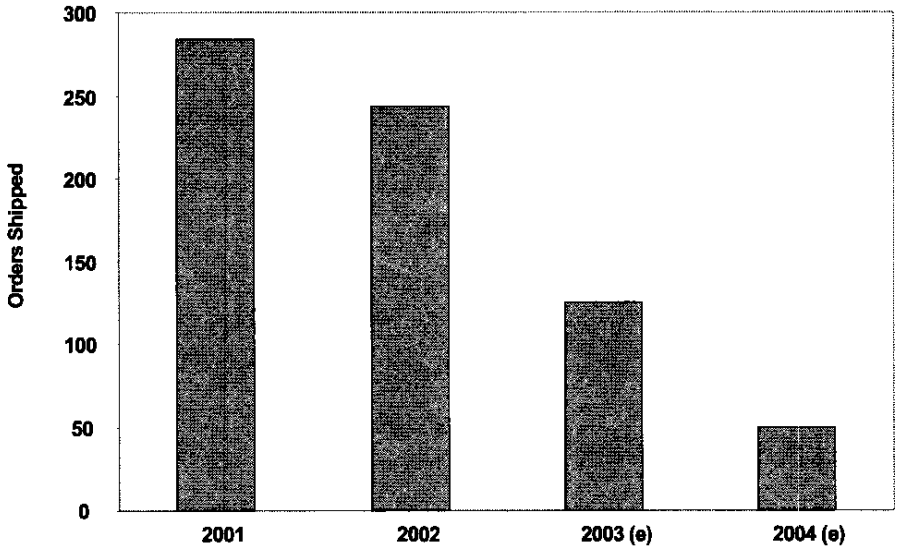
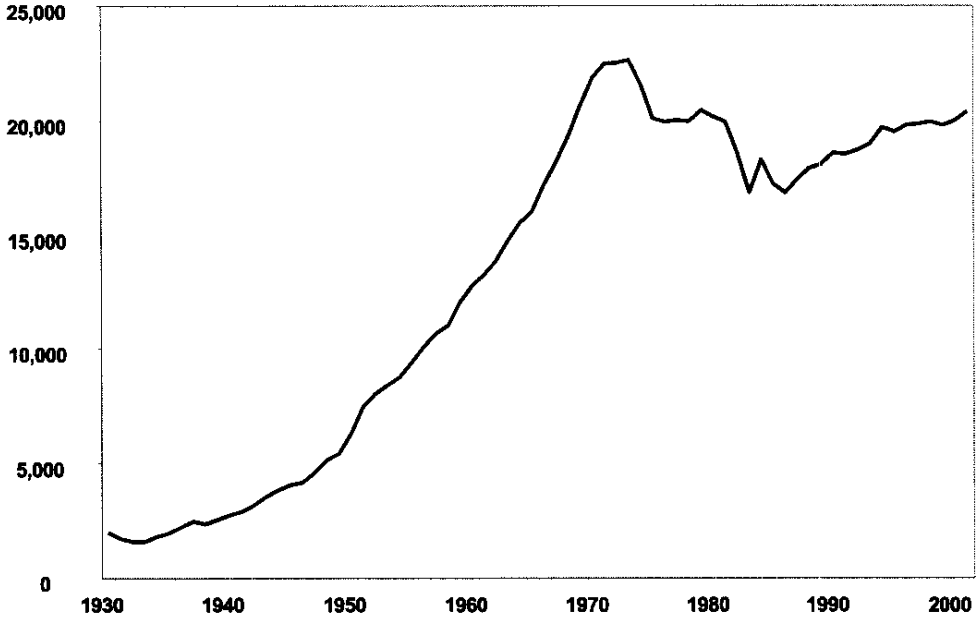


Figure 5-2 Marketed production of natural gas in the U.S. from 1930-2001

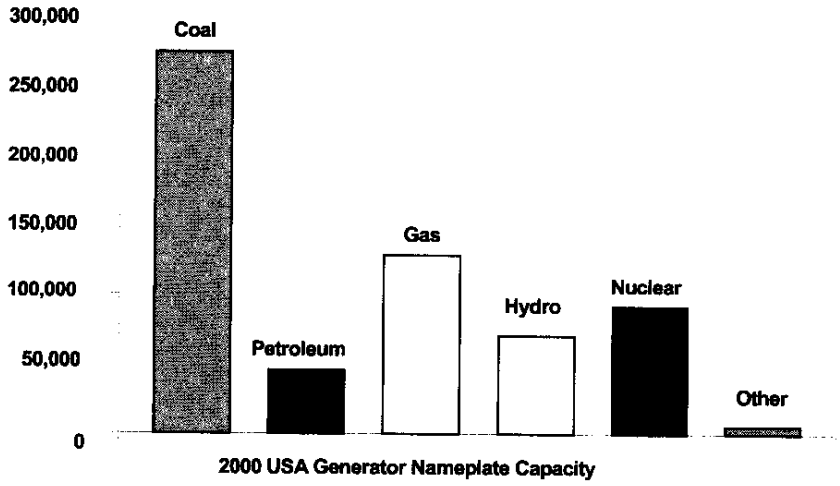


The demand for natural gas reversed its trend in the mid-eighties, although the subsequent growth rate has been slow. Over the past 15 years, natural gas demand has increased by a little more than one percent per year.

With the generally slow growth rate in natural gas demand and the apparent slowing in the pace of natural-gas-fired electrical generation, technological advance and technological innovation could allow for the development of additional supplies to keep pace with the demand for natural gas.[62] In fact, if new ways of drilling for gas are invented, or if news means of finding currently undiscovered gas supplies are developed and implemented, it may be possible to have an expanding resource base at lower prices than those experienced today. Another factor that could increase supplies and decrease prices is the development of natural gas in areas where natural gas production is currently not permitted. This would include Federal lands such as in national parks or in Alaska. Doing so, however, could have substantial environmental impacts that may preclude that option from being allowed.

In 2001 and 2002, over 90,000 MW of generation using natural gas as a primary fuel was installed nationwide. Through 2011, it is estimated that $35 billion in gas infrastructure nationwide will be required.[63] This has resulted in a large shift in the electric generation capabilities as shown in Figures 5-3 and 5-4.

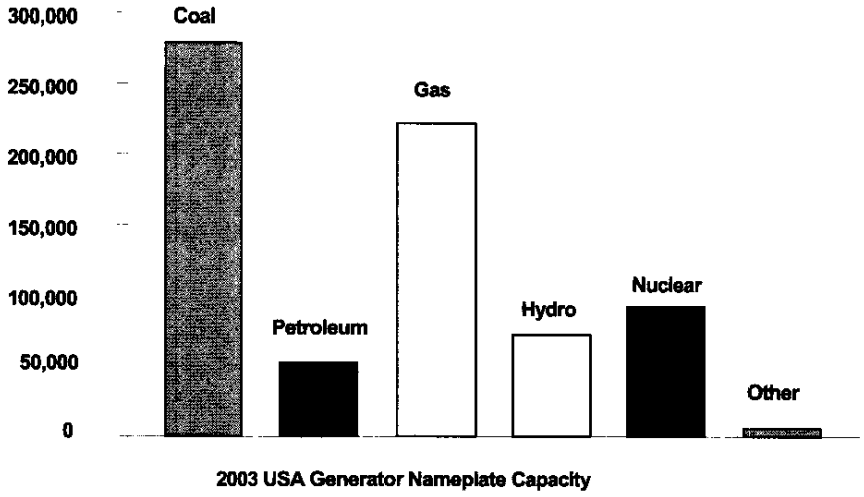
Figure 5-3 U.S. generating capacity in 2000



The addition of 90,000 MW of natural gas capacity in 2001 and 2002 to the existing 130,000 MW will add significantly to the gas consumption used for electric generation. According to EIA, the 1999 demand was 21.4 trillion cubic feet (21,400 billion cubic feet). Gas consumption for electrical generation represented 16 percent or 3,424 billion cubic feet of this total. The EIA estimates for overall demand for natural gas are estimated to increase only 2.3 percent per year.

[62] Technological advance refers to the invention of new technologies. Technological innovation refers to the use of existing technologies that had previously been invented, but that previously had not been used in practice.
[63] PTF Volum 1 Enclosure 1.0, Sec 7.0

Figure 5-4 U.S. generating capacity in 2003



No estimates for the expected capacity factors for this new generation are provided with the EIA data. One could assume that a 70 percent increase in nationwide generation would translate into a 70 percent increase in gas usage for electrical generation. If this is true, total gas consumption nationwide would increase by over 10 percent.

Natural gas production: short-term analysis

The amount of natural gas as a resource base is not, however, the controlling factor as to the availability of natural gas in the short run.[64] There can be a large basin of natural gas that is not developed; i.e., it has no operating drilling rigs to extract the gas. This gas cannot reach consumers. The high prices experienced in recent times appear to be heavily related to a failure of the natural gas producers to expand their operations over time.[65]

The productive capacity of the domestic natural gas industry is often summarized by a term referred to as the rig count, which is simply a count of the number of rigs actively withdrawing natural gas. The rig count has been quite volatile in the past decade and is in part responsible for the volatility of natural prices. For example, Baker Hughes[66] reported that in January 1999 there were 587 drilling rigs in operation in the U.S. This was 41 percent fewer rigs than were in operation a year earlier. Two years later (January 2001), the count had increased by 44 percent over the January 1999 level to 1,118 rigs. As of January 2003, the count has declined to 854 rigs, which amounts to a 24 percent reduction in the count over the past two years.

The short-run capacity to deliver natural gas tends to rise and fall directly with changes in the rig count. It is not so much the absolute level of the rig count that matters most, but rather the rig count relative to the level of demand. When the number of operating rigs is not sufficient to keep up with demand, two things

[64] "Short-run" in this context is a period of no more than 18 months.
[65] Russell Gold and Rebecca Smith, "Effects of Gas Shortage Rip Through Economy," *Wall Street Journal*, February 28, 2003.
[66] The Baker Hughes Rig Count is often used as the standard measure of the rig count in the natural gas industry.

happen: (1) interruptible customers do not receive natural gas; (2) natural gas prices rise; and (3) demand is reduced. So during these situations for the generator using natural gas, supplies might be available at high cost, or under certain conditions might not be available at all.

Natural gas transmission

The preceding discussion suggested that under certain circumstances natural gas might not be available to electric generators. This is almost a certainty if the generator relies on interruptible interstate transmission capacity to ship its natural gas from the production area in the southern U.S. to Wisconsin. Some interruptions may occur even if the generator has a contract for firm transmission, although the frequency of such interruptions would be much lower than that experienced by customers who rely on interruptible transportation.

Interruptible transportation rates for interstate pipelines are set at a fraction of the firm rate. That deep discount in the rate reflects the quality of service obtained. With the exception of very warm winters, interruptible customers can count on the fact that service will be unavailable on one or more days of the year. The pipeline does not expand its capacity when interruptible customers are added to its system. The interruptible customers essentially use any extra space available. On peak winter days there is not likely to be such extra space and the interruptible customers are often forced to stop taking natural gas on those days.

A generator customer that relies on interruptible interstate transmission capacity is by definition not going to be reliable during the coldest winter periods. Such an arrangement is reasonable if the generator is a peaking plant that will be used only during the electric utilities' summer peak periods. If, on the other hand, the plant is expected to be available year-round and the generator relies on interruptible transmission capacity to ship its natural gas to Wisconsin, a potentially difficult situation is very likely to occur. Under these conditions, unless the generator has dual-fuel capability, it will have to cease operation at a time when the electric system is relying on its output.

The Commission faces a potential problem as it relates to merchant power plant providers and knowing how or if these plants will affect overall system reliability. The supply procurement decisions are not always revealed when a merchant plant owner makes a proposal to provide electric capacity. For a merchant plant that is a base load or intermediate load facility, or if the facility is to be available as a peaking unit year-round, the interstate natural gas transmission capacity must be firm if electric reliability is to be maintained. Contracting for interruptible natural gas transmission capacity would be reasonable under these circumstances, only if back-up fuel can be used to power the generator.

That option would be acceptable, however, only if the merchant plant owner maintained adequate supplies of alternative fuel that could be used during periods of natural gas interruptions. During extremely cold weather, interruptions of the natural gas system could last for three days or more. For a dual-fueled 500 MW base load unit, the oil storage capacity would have to be quite large to assure that the plant could continue to operate. Relying on oil service companies to provide back-up fuel when natural gas facilities are interrupted may not be reliable. During periods of cold weather, many industrial customers also must switch to oil as their natural gas service is interrupted. This creates a dramatic increase in the demand for oil in a short time. If the oil service companies do not have the capacity to deliver to all of their customers, a portion of the demand for the generator may go unmet. On-site storage of several days of supplies of alternative fuel reduces the risk of this occurring.

If a merchant plant provider does not reveal the specific arrangements that it has made to meet its natural gas operations, it should be presumed to be of low reliability. Absent a showing that the plant will be available when needed, the Commission could reasonably assume that the plant is interruptible.

Contract provisions between the merchant plant and an electric utility that call for liquidated damages for failure to deliver the needed electricity are not a substitute for physical reliability. While such damage clauses are a necessary complement to such contracts, the only way to obtain the maximum assurance of the plant's reliability is to examine the underlying supply contracts. Payments of millions of dollars of liquidated damages may not compensate the state of Wisconsin for the harm caused by a lack of electrical energy at a critical time.

Even firm interstate pipeline capacity, however, is not a fail-safe alternative. There is always the possibility of *force majeure* type events (examples include war, an Act of God, etc.) that could prevent natural gas from flowing. These situations can affect all fuel types including natural gas, oil, and coal. With natural gas, however, there is an additional concern that may cause reliability concerns. Electric generators that use natural gas as the input fuel generally must receive natural gas at a delivery pressure of about 450 psig or higher. Local distribution utilities can generally maintain reliable service at lower pressures. The first sign of delivery problems on the interstate pipeline system is a drop in delivery pressure. This means that even if capacity arrangements are firm, generators could see problems before the local distribution utilities do when pressure problems occur. Thus an electrical generator with firm interstate pipeline capacity may be less reliable than a local distribution company (LDC) with the same service.

Pressure problems on the pipelines are more than a hypothetical concern. For example, on and around January 23, 2003 ANR Pipeline, the major provider of interstate pipeline capacity to the state, had difficulty maintaining pressure on its system.[67] The specifics of the situation, including the impact on natural-gas-fired power generators, are being investigated at this time.

If a large number of gas-fired generators want to obtain firm capacity on interstate pipelines, the pipelines serving the state may have to expand, or new pipelines may have to be built. The recently-constructed Guardian Pipeline is such an example. It brings an additional 750 million cubic feet per day of capacity to the state, some of which could be used to serve natural-gas-fired electric generators. On the surface, that represents about a 30 percent increase in the net capacity serving Wisconsin.[68]

That figure likely overstates the capacity increase for the state. As customers switch to contracts with Guardian, they temporarily strand capacity on other pipelines. The other pipelines have likely sold this stranded capacity formerly used to serve Wisconsin to customers in other Midwest states. So there is not likely to be a glut of pipeline capacity serving the state. That means that if large-scale natural-gas-fired generators are to be built in Wisconsin, substantial expansion of the interstate pipeline system serving the state may be necessary.

[67] February 6, 2003, letter from David J. Kyto (Wisconsin Public Service Corporation) to Robert Bauer (Public Service Commission).
[68] EIA reported that the net pipeline capacity serving Wisconsin in 2001 was approximately 2,500 million cubic feet/day. See James Tobin, *Natural Gas Transportation—Infrastructure Issues and Operational Trends*, Energy Information Administration, October 2001.

Natural gas distribution

In assessing the reliability of natural-gas-fired electrical generators that take service from a LDC rather than directly from a natural gas transmission pipeline, one must examine operational history of the LDC's distribution system. Like the pipelines, some gas utilities offer firm and interruptible distribution service. The reliability of service during the winter is diminished to some extent when the customer elects interruptible distribution service. The degradation in service quality is not as great, however, on the distribution system as it is on the interstate pipelines. The only LDC in Wisconsin that has interrupted its customers because of distribution constraints in recent years is Wisconsin Gas Company. In fact, distribution-related interruptions on the other utilities have been so rare that some utilities no longer offer interruptible distribution service. (Interruptible customers were essentially receiving firm service at discounted rates.)

There is another reliability issue that needs to be addressed for power generators on an LDC's distribution system. Even firm service is not absolutely guaranteed. For example, if an LDC's major distribution main is accidentally damaged during construction, large customers including electrical generators, would be among the first to be interrupted. The utility would attempt to flow gas to the customers that are at the greatest risk, which on a cold winter day would be residential customers. This type of interruption is rare, but the possibility does exist.

Natural gas reliability as a function of plant operation

Unlike a coal-fired utility that maintains weeks or months of fuel supplies at its site, it is generally not cost-effective for a generator to store natural gas on its site. So while a coal-fired facility is largely unaffected by the derailment of a unit train transporting coal to its facility, an interruption in the flow of natural gas to a gas-fired generator is likely to cause a problem. The situation is less severe if the generator can rely on alternative fuel. Gas-only plants would have no alternative but to cease operations if the flow of natural gas is interrupted.

Natural gas reliability: conclusion

In terms of the supply of the natural gas resource, rather than running out of gas generators are more likely to be faced with pricing problems. Natural gas will generally be available from supply basins if the generator is willing to pay for it. Reliability is more likely to be a concern on the interstate pipeline system if generators purchase interruptible capacity or if pressure problems occur on the pipelines. Reliability can also be impaired on the LDC distribution system, although problems are likely to occur less frequently there than they are on the transmission pipelines.

Solely in terms of reliable fuel supplies, the inability of generator owners to store natural gas on-site means that any interruption in the flow of gas can present major operational problems for the generator. This decreases the overall reliability of natural-gas-fired units relative to plants fired by coal. Whether natural-gas-fired plants are less reliable than coal plants when all relevant factors are considered is beyond the scope of this analysis.

The volatility of natural gas was especially noticeable this winter as winter returned to more normal colder temperatures, gas fired generation increased its share of natural gas needs, Canada was less able to import,

and the US production fell from previous levels. Concern is developing about the adequacy of previous predictions and the availability of gas in the future.[69]

Economic Issues

As discussed earlier in Chapter 3, natural gas prices are extremely volatile. That means that the cost of electricity generated by burning natural gas will also be quite volatile. To the extent that these costs are passed on to consumers via fuel cost adjustments, electricity prices would become more volatile.

Volatility is not desirable for consumers. Volatile energy bills make budgeting more difficult. That affects residential, business, and governmental consumers. The use of natural gas to produce electric power will exacerbate problems currently faced by retail natural gas consumers because electric bills will tend to increase at the same time that natural gas bills increase. Put another way, using natural gas to fire electrical generators provides no diversification from natural gas price spikes. Rather it magnifies the impact of those spikes.

Alternatively, when comparing the capital costs of natural gas generation versus coal-fired generation, the capital construction costs for gas-fired plants are much more consistent, predictable, and significantly lower than those associated with coal-based facilities.

For instance, in the Port Washington CPCN case, the first 545 MW combined-cycle natural gas-fired generating unit is expected to cost $309.6 million in 2001 dollars. This is in contrast to the expected capital cost of $721 million in 2003 dollars for 515 MW from the first SCPC unit. Both units are of nearly equal size in generation output to be used by the utility, but the capital cost of the coal facility is more than double that of the gas-fired project. In addition, in the Port Washington CPCN case, the facility lease has a "hold to" cost feature, meaning that any cost overruns will not be passed on to ratepayers. The fact that a coal facility's capital cost is at least double that of a gas-fired generation facility and that any cost overruns in constructing the coal facilities could be passed on to ratepayers means that choosing a coal facility carries its own significant economic risks that must be weighed against price spikes and supply risks associated with choosing a gas-fired facility. However, in its May 2003 filing, WEPG limited the extent of any cost overruns to 10 percent. This will be a key issue in this case.

The following table displays fuel diversity mix by electric energy generation in the US, Wisconsin and surrounding states.

Table 5-2 Electric power industry generation - percentage of MWH generated by different fuel types in 1999

State	Coal	Nuclear	Gas	Hydro	Other
Illinois	45%	50%	4%	0%	1%
Iowa	85%	9%	1%	2%	3%
Minnesota	62%	27%	2%	2%	7%
Wisconsin	70%	20%	3%	3%	4%
US	51%	20%	16%	9%	4%
WEPCO (2001)	68%	27%	3%	0%	2%

* Source: EIA 1999 State Electricity Profiles and Figure 3-4 of the final EIS.

[69] Effects of Gas Shortage Rip Through Economy: Wall Street Journal, February 28, 2003

This table shows that Wisconsin and WEPCO rely on more coal-fired generation as an electric energy source than the US, Minnesota, and Illinois. Only Iowa uses proportionately more coal-fired electric generation. This table also shows the importance of nuclear generation. That is, Illinois uses less baseload coal-fired generation due to its sizeable use of nuclear power.
On a forward-going basis, given that the coal generation at Port Washington will be retired, if Oak Creek Units 5 and 6 are retired and only the SCPC units at ERGS are constructed, WEPCO's percentage share of electric generation in Table 5-2 may only moderately increase for the period after 2012.

Environmental Issues

Although much of the previous discussion focusing on fuel prices and volatility may appear to favor use of coal, a general environmental comparison of natural gas versus coal generation draws attention to other factors that should be considered in making a choice for future baseload generation capacity. The following discussion focuses on some of the basic environmental differences between these fuel choices.

Coal mining and transport

The use of coal as a fuel supports the coal mining industry, which has grown over the last several decades directly because of the nation's increased need for electricity. According to the U.S. Department of Energy, Energy Information Administration (EIA), in 1949, 84 out of a total of 483.2 million short tons of coal (approximately 17 percent) were purchased by electric utility plants. However in 2001, 948 out of a total of 1060.3 million short tons (approximately 89 percent) of coal were purchased by electric plants, showing an increase in the amount of coal mined and a significant increase in the percentage of coal mined for coal-fired electric power plants.

The coal mining industry is responsible for many severe environmental impacts. By necessity, surface land is disturbed in the process of mining coal. The actual coal mine facility can disturb a footprint of a few acres for underground mining operations or tens of square miles for a surface mining operation. However impacts from coal wastes, road building activities, subsidence, acid mine drainage, groundwater contamination, and other natural resource impacts can also have wide ranging effects, well beyond the boundaries of the surface disturbance of the coal mine.

To grasp the impact coal mining has had on the environment, one can examine the statistics for Pennsylvania, the fourth largest coal-producing state in the U.S. and the source of the coal to be used in the ERGS facilities. Pennsylvania currently has about 2.6 billion cubic yards of coal refuse which is generally unsuitable for plant growth and a potential source of acid mine drainage. According to the Federal Office of Surface Mining, Pennsylvania ranks first in the nation in the total estimated cost (over $15 billion) of environmental cleanup needed for the past mining of coal. In recent years, Pennsylvania spending for mine reclamation has averaged $21 million annually. Despite many regulations written to protect environmental resources from adverse effects associated with new mines, impacts as a result of newer technologies and environmental accidents continue to occur.

In addition to environmental concerns, as a heavy industry, underground coal mining, including longwall mining, has many safety concerns for those individuals engaged in the mining work.[70] Accidents related to electrical work, hydraulics, fire, or flood can occur. There is a need to monitor coal dust production and exposures to arsenic, cadmium, lead, mercury, and other components in the coal. While much progress has been made in reducing respirable dust levels in mines, black lung (also known as coal workers' pneumoconiosis and silicosis) continues to occur among coal miners. Black lung can devastate a miner's quality of life, affect a miner's family, and lead to premature death.

ERGS has proposed the use of Pittsburgh #8 bituminous coal with the Blacksville Mine as a typical coal supply. The Blacksville Mine uses the longwall method, a type of underground, continuous, highly mechanized mining method. Whereas the permanent changes on the landscape are clearly visible from surface mining operations, underground mining also has wide-reaching environmental impacts as well. Surface mining affects many acres by eliminating surface vegetation, permanently and drastically altering soil and subsurface geological structure, and disrupting surface and subsurface hydrologic regimes. Underground mining due to subsidence can have the same set of impacts.

By its very nature, underground coal mining entails a risk of surface subsidence as gravity induces the downward movement of the overlying rock strata to fill the void left where coal has been removed. Longwall mining, by contrast with more traditional methods of underground coal removal, induces deliberate, uneven subsidence of the land surface relatively quickly after mining. This subsidence affects surface water hydrology, altering soil and subsurface structure, and species habitat. Subsidence and fracturing can also induce the acidic water associated with overlying coal seams to enter drinking water wells and streams.

Coal is transported primarily by train. As the utility industry need for coal has increased, the amount of coal transported by train has increased. The EIA reported that the quantity of contract coal shipped by rail to electric utilities rose from 269.6 to 366.2 million short tons from 1988 to 1997, an increase of 36 percent. The average distance contract coal has been shipped by rail rose from 640 miles in 1988 to 793 miles in 1997. The increase of coal trains and train traffic in turn has increased the amount of noise and coal dust blowing off trains. Air pollution has also increased from train operation, especially nitrous oxides, carbon monoxide, and sulfur dioxide. CO2 production is discussed in Chapter 7. If a carbon tax is imposed, the additional cost could be dramatic. A carbon tax is one of the sensitivities discussed in the EGEAS modeling in Chapter 4.

Natural gas extraction and transport

Natural gas is extracted either through "free-flowing wells" because of natural pressure underground or by some type of pumping system. After the natural gas is extracted, it is treated at gas plants to remove impurities such as hydrogen sulfide, helium, carbon dioxide, hydrocarbons, and moisture. Pipelines transport the natural gas from the gas plants to power plants. Construction of major gas transmission pipelines and the numerous distribution laterals can cause substantial environmental effects, depending on the terrain, land use, and land cover.

[70] Information on black lung and mine safety can be found in the web site of the Mine Safety and Health Administration of the U. S. Department of Labor -- http://www.msha.gov/

The extraction of natural gas and the construction of natural gas power plants can destroy natural habitat for animals and plants. Possible land resource impacts include erosion, loss of soil productivity, and landslides. However, natural gas extraction is a much less disruptive installation than a typical coal mine. A field of production wells often can share the landscape with fields of corn and soybeans, though the oil and natural gas extraction process does result in outputs of drilling mud, drill cuttings, and well maintenance products. Disposal of these materials, as well as materials resulting from equipment cleaning, have the potential to create water quality impacts if not carefully managed.

Resource needs and impacts

Water

Coal-burning technologies have major resource needs related to water, land, and solid waste disposal compared to natural gas-fired combined-cycle plants or simple combustion turbines. The following discussion describes some of these needs and the associated impacts.

The two SCPC units of the ERGS project (about 1,230 MW) would require about 1,400 million gallons per day (mgd) of water for purposes of cooling, ash removal, demineralization processes and make-up water. Approximately 1.7 mgd would be "consumed" by various processes or evaporated, thus discharging approximately the same amount of water as was initially withdrawn. Release of this large quantity of heated water into a surface water body can result in major environmental impacts and substantial changes due to thermal pollution. These impacts could vary depending on the ambient water temperature, the physical characteristics of the water body (i.e. flow rate, water depth, etc.), and the time of year.

Alternatively, a similarly-sized natural gas-fired combined-cycle plant (1,180 MW) would require about 7.0 mgd for operation. However, the majority of this water (about 5.0 mgd) would be consumed during plant operation or evaporated from the plant's cooling towers returning less than 2.0 mgd to the river or lake from which it was drawn.

Thus, with respect to the ERGS and an alternative gas-fired generation plant, there is a trade-off between the potential thermal pollution effects and a water consumption concern. (Note: Coal plants can also utilitize cooling tower technologies rather than once-through cooling systems as proposed for the ERGS. In coal plants that have cooling towers, the quantity of water evaporated is much greater than for a natural gas-fired plant.)

Solid waste

The need for ash landfills is always a consideration when proposing to build new coal-generation. The two SCPC units of the ERGS facilities are expected to produce 206, 300 tons of fly ash and 51,600 tons of bottom ash per year. New landfills are very difficult to site and must be maintained to avoid impacts due to surface runoff or leaching. The potential to reburn some amount of landfilled ash and the developing beneficial re-use market for ash and other coal-based generation by-products will help to reduce the need for new landfills and slow the rate at which existing landfills reach capacity.

Solid wastes produced by natural gas-fired facilities are primarily limited to sludge cakes resulting from the pre-treatment of raw surface water for use in the plant.

Land

The amount of land required for a natural gas-combined cycle plant is much less than that needed to accommodate a similarly sized (MW capacity basis) coal-burning generator. The auxiliary facilities, such as rail tracks, coal silos and coal handling equipment, coal piles, and ash landfills result in a much larger "footprint" of disturbed land. In addition, the noise, fugitive dust, and safety issues create a need for a substantial buffer area around the plant facilities. As in the case of the existing OCPP property however, if managed properly, this buffer land can preserve special resources and habitat functions.

Air emissions

The air emissions profile for a coal-fired generator is quite different from that of a natural gas-fired combined-cycle plant. Coal and limestone are the mercury sources for the ERGS facility, which is expected to emit about 300 lbs. of mercury per year. Mercury is not a pollutant emitted by natural gas combustion.

In addition, SO_2 (3-hr and 24-hr) and particulate matter, specifically PM_{10} (24-hr) are emitted in much higher concentrations from coal-fired plants than from natural gas facilities. These higher concentrations occur even though the best available control technologies have been implemented to reduce emissions. The proposed ERGS SCPC units include a flue gas desulfurization system (FGD) and the IGCC plant would have a sulfur recovery unit (SRU) to minimize the amount of sulfur emitted.

CO_2 emissions

In data response 1-SUP-178 dated March 4, 2002 WEPCO indicated to PSC staff that CO_2 emissions from 600 MW of coal would be about 3,500,000 tons per year. A DNR analsyis completed since the issuance of the draft EIS indicates that CO_2 emissions up to 4,450,000 tons per year could occur. This is in contrast to 450,000 tons per year for a 500 MW natural gas-fired combined-cycle plant. Presently, CO2 is not a regulated emission. Due to concerns over climate change, CO2 emissions could come under closer regulation in the future. To the extent such emissions did come under supervision, ratepayers in Wisconsin could be faced with higher compliance costs under an expansion plan utilizing more coal-fired generation than natural gas.

Chapter Summary

In summary, the primary points raised in this chapter are:

- The supply of coal is plentiful.
- Gas use is increasing nationwide with the potential to increase dramatically at the state level, depending on the level of merchant plant development.
- It is unlikely natural gas growth can be sustained without increasing price volatility and more infrastructure improvements such as gas wells, interstate pipelines, intrastate pipelines, and liquid natural gas facilities.
- .Reliability issues with electric generation may increase as the percentage of natural gas generation increases.
- Natural gas prices have been volatile. Increased reliance on generation from natural gas-fired power plants could lead to more volatile electricity prices for consumers.

- In selecting the appropriate electricity supply resources, the Commission must balance the higher marginal energy cost, price spike potential, and supply risks associated with natural gas-fired facilities versus the economic risks of choosing a coal facility in which a coal facility's capital cost is at least double that of a gas-fired generation facility for a similar amount of energy output and that cost overruns in constructing the coal facilities can be passed on in part to ratepayers.
- If a carbon tax is imposed, coal plants could be dramatically affected to the ratepayers' detriment.
- Coal can be stored on-site in large quantities providing a fuel inventory that can last longer than natural gas.
- Coal-burning power plants typically emit higher concentrations of SO_2, Hg, and certain particulates than natural gas-fired facilities with a similar capacity.
- Disposal of solid waste, including ash and other by-products, is an environmental issue for coal facilities, but not natural gas plants.
- The amount of land needed for placement of auxiliary facilities and buffer area is much greater for coal plants than for natural gas-fired generators.
- Coal-based facilities have major cooling water requirements. Although this may not be a consumptive water use, it can result in thermal pollution concerns.
- Natural gas-fired combined-cycle facilities often evaporate a large percentage of the intake water, causing consumptive water use concerns.
- Coal mining is generally more disruptive to the environment than natural gas drilling. Also, health problems associated with underground coal mining, including black lung disease, continue to occur despite federal efforts to improve conditions for miners.

6

Chapter 6 - Overview of Proposed Sites and Technologies

This chapter provides a descriptive overview of the proposed sites for the ERGS facilities and the coal-based technologies proposed by the applicants. It also explains the site selection process and siting criteria used by the applicants to choose the proposed sites that were submitted in their CPCN application.

Site Selection Process

The applicants state that the site selection process started with over 140 potential sites. The number of potential sites was further reduced through a process that evaluated the sites on various social, environmental, and technical/economic parameters that were embodied in 55 screening criteria, which were weighted according to their importance. Social issues captured in the criteria included public attitudes, current and future land use, need for land acquisition, and effects on property owners, and the general public. Examples of environmental issues included in the criteria are air and water quality, presence of wetlands and natural areas, and landfill capacity among others. Technical/economic aspects included in the criteria were availability of cooling water, proximity to railways, highways and transmission lines, physical site conditions, ease of construction, and adequacy of pre-existing conditions.

The primary site selection criteria used by the applicants to select the proposed coal generation locations focused on the criteria related to cooling water, fuel delivery, and electrical transmission. The ability to locate all three proposed units at one site as well as the potential re-use of existing infrastructure were also important considerations in the applicants' final selection of sites. Five possible sites, shown in Table 6-1, were closely compared in making the final selection.

Table 6-1 Site alternatives compared in the applicants' final selection

Site	County	Type	WEPCO – Controlled
North Oak Creek	Milwaukee	Brownfield	Yes
Pleasant Prairie	Kenosha	Brownfield	Yes
Haven	Sheboygan	Greenfield	Yes
Ozaukee	Ozaukee	Greenfield	No
Little Suamico	Oconto	Greenfield	No

The sites in Ozaukee and Oconto Counties were eliminated because of the increased cost and environmental impact to develop greenfield sites and acquire a substantial amount of land. Because of its irregular shape, the applicants state that acquisition of additional land may have been required to build the ERGS facilities on the Haven site and once-through cooling would not have been a viable option because the site is about 0.25 miles from Lake Michigan.

WEPCO's existing Pleasant Prairie Power Plant site would have been large enough to accommodate only the two SCPC units, not the third IGCC plant. Also, because of the site's distance from Lake Michigan, cooling towers would have been required, reducing the efficiency and overall output of the proposed facilities.

In reviewing the North OCPP site, the applicants identified other possible sites near the southern end of the WEPCO-owned property in Racine County that could also accommodate all three coal-based units and share the advantages of once-through cooling, and use of the existing transmission infrastructure and rail lines.

Although the sites would share the use of some of the common existing OCPP infrastructure such as the coal-handling equipment, rail lines and ash landfills, there are several ways in which the sites can be differentiated as alternative sites. These differences include: 1) having building footprints in different municipalities and counties resulting in different entities receiving shared-revenue payments if the ERGS proposal is approved, 2) separate service water discharge locations, and 3) significant differences in the amount of excavation required to build and safely operate the facilities.

A detailed description of the proposed sites and these differences are described below.

Proposed Sites

Two site options (one of which has a variation) have been proposed by the applicants for the ERGS facilities. As described above, all of the sites are on WEPCO-owned property adjacent to the existing OCPP on the shore of Lake Michigan (see Figure 6-1). One of the sites is north of the existing OCPP, while the other alternatives are south of the existing OCPP. The existing plant is shown in the aerial photo in Figure 6-2. The North Site and South Site are located completely on WEPCO-owned property. The South Site-Exp is located mostly on WEPCO property, but extends onto what is currently a federally-owned shooting range. WEPCO has reached an agreement to secure the shooting range property in the event that the South Site-Exp is chosen by the Commission as the approved site for the ERGS facilities. The shooting range would be relocated to an area on the north side of Seven Mile Road east of the railroad corridor.

After the draft EIS was issued, WEPCO and the city of Oak Creek negotiated another site layout plan for use on the North Site. Some information regarding this new site layout was filed in WEPCO's direct testimony. Additional information and maps requested by PSC and DNR staff were provided in mid to late-June. This new site layout, the CUP Option, would also require use of a portion of the shooting range property. A more detailed description of the CUP Option layout and the potential environmental effects related to this layout are found in Chapter 12.

Detailed information about the local environment and potential community impacts related to building the facilities on the North and South Sites is found in Chapters 7 through 12.

Figure 6-1 **Location map showing OCPP property in relation to the city of Oak Creek and northern Racine County**

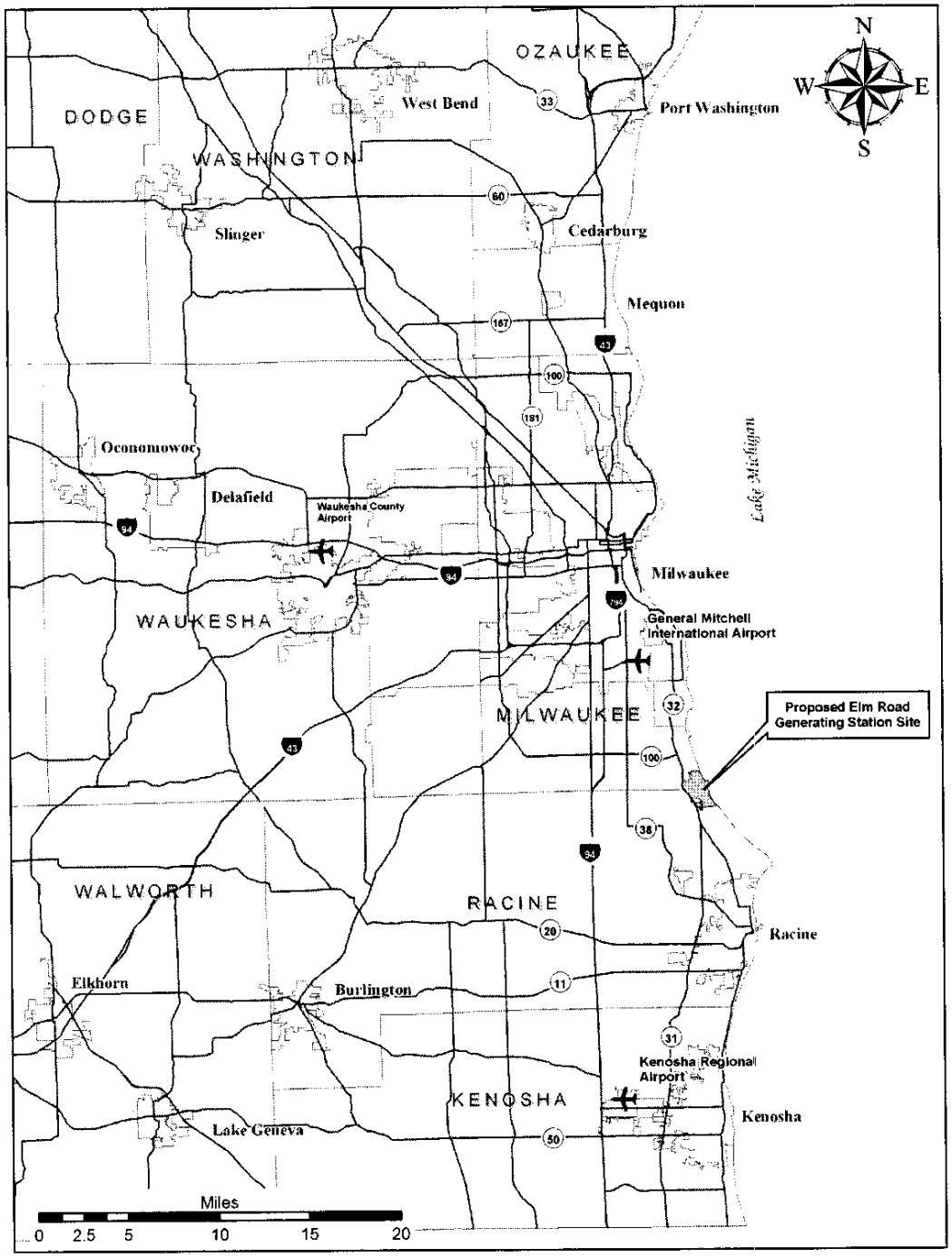
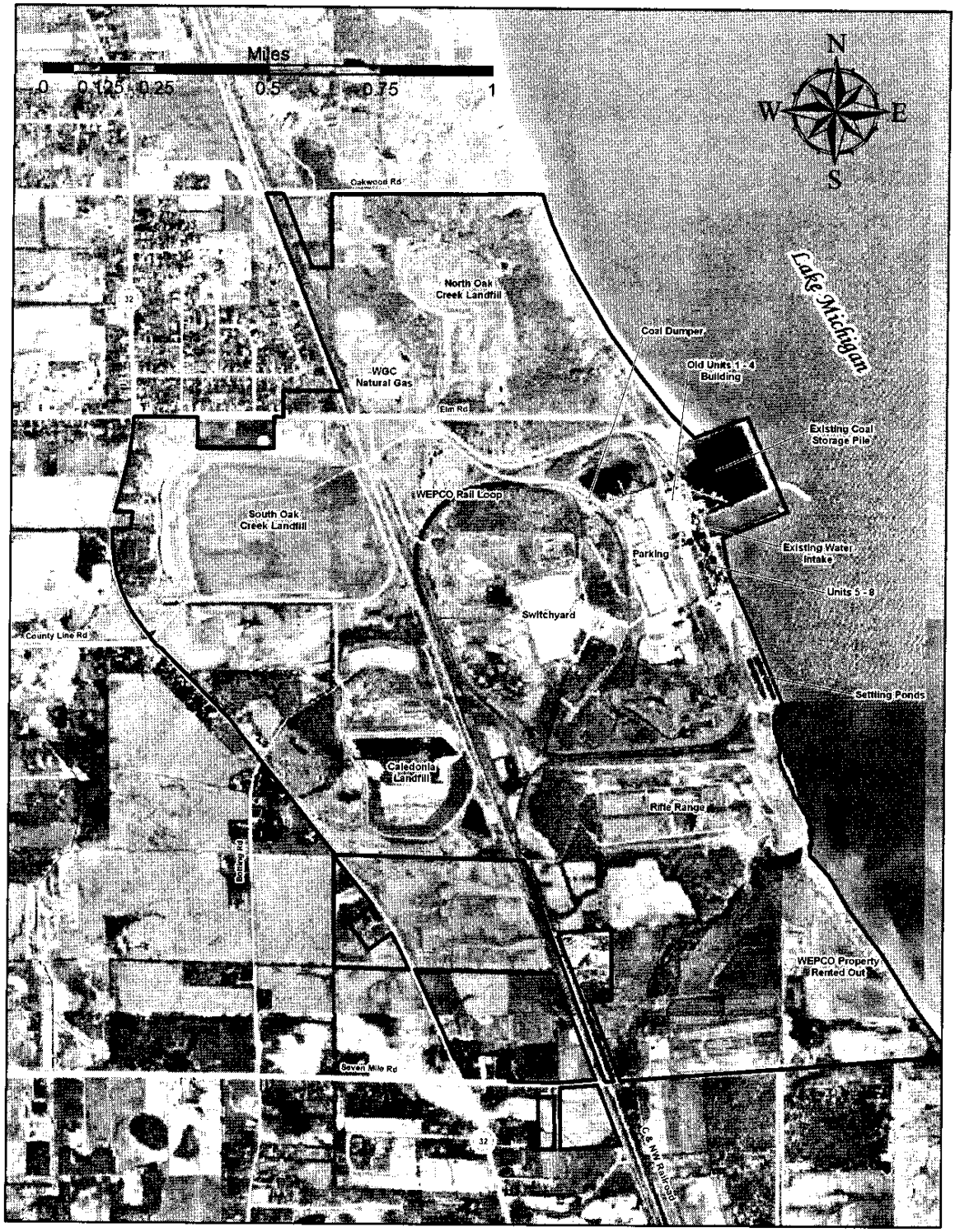


Figure 6-2 Aerial photo of existing OCPP site



North Site

Existing structures and land cover

The North Site is located on WEPCO's property in the city of Oak Creek in Milwaukee County, Wisconsin. This portion of the property is comprised of about 35 acres located along the Lake Michigan shoreline. A 100-foot bluff now parallels the lake shoreline and is present along the entire length of the proposed North Site. The southern half of the North Site currently consists of some previously graded lands and an access road that passes through a large ravine as it runs from the top of the bluff to the existing North OCPP building. The northern portion of the North Site includes a portion of the existing, closed North Oak Creek Ash Landfill. To the east of the bluff, depending on the location along the site, the site is relatively flat for about 100 to 350 feet leading to beach material and the lake. A large coal dock, created by filling in a portion of the lake near the former North OCPP units 1-4, is located southeast of the end of Elm Road. The natural features of the North Site are discussed in more detail in Chapters 8 and 10.

The location of the SCPC units on the North Site would be near the east end of Elm Road and about 0.25 miles north of the building that formerly housed the OCPP units 1-4. The proposed SCPC units would be located in Section 31, Township 5 North, and Range 23 East (T5N-R23E). The location for the IGCC unit is south of the SCPC units in the vicinity of the present North OCPP building. See Figure 6-2.

The existing operating South OCPP units lie south of the proposed IGCC location. This plant contains four coal-fired plants (units 5-8) and one combustion turbine (unit 9) which generate about 1,200 MW total. Unit 9 would be retired before operation of the first SCPC unit. At one time, the OCPP was a nine-unit 1,700 MW power plant, prior to the retirement of the North Oak Creek units. Units 3 and 4 were retired and substantially removed on April 1, 1988, and Units 1 and 2 were retired on December 31, 1989. The building for the former North Oak Creek units still remains because it supports coal handling and other facilities serving the remaining units. It would be demolished, however, to make way for the new plant. The larger features of the South Oak Creek plant are shown in Figure 6-2.

Figure 6-2 also shows an existing substation and switchyard that interconnects the plant to the American Transmission Company (ATC) electric transmission system. An existing rail line and track system for coal delivery connects to interstate railroad tracks running north and south parallel to the lake shore. Inside the upper portion of the train track is a relatively mature beech maple woodland (discussed in detail in Chapter 10) that appears to be the habitat for an endangered plant species as well as a beech forest community.

The coal unloading process currently requires the break-up of trains and creates local traffic congestion south of the site in Racine County. This problem and proposed solutions are discussed in detail in Chapter 11. Coal storage piles are located on the dock area which is a filled area in the lake present just south of the access road and another east of the car dumper near the rail track. Coal handling systems presently run from the dumper along the track to the storage piles and back to the currently operating boilers. A water intake system in Lake Michigan provides water for cooling and other process water for the existing OCPP units. The intake channel currently provides a means to accept delivery of coal, limestone, or other needed raw materials via barges or lake vessels for the existing units. Bottom ash from the boilers is temporarily stored on the coal dock, and fly ash not being utilized for other purposes is currently being landfilled in the only on-site operating landfill. This landfill, the Caledonia Landfill, is located in the southwestern portion of the property. Two closed landfills exist on the northwest end of the property south of Elm Road.

The proposed locations of the ERGS facilities are discussed below and in more detail later in this chapter. A more detailed discussion of the ash handling and landfills can be found in Chapter 9.

Proposed structures and land cover

Generating station equipment would occupy about half of the site, and the balance would be areas that include access roads, storage buildings and open areas for electrical transmission line corridors. Detailed descriptions of the proposed SCPC and IGCC power plants and their auxiliary facilities are found later in this chapter. The proposed layout for the ERGS plant at the North Site is shown in Figure Vol. 2-1.

Conventional SCPC facilities are typically constructed on relatively flat sites. This allows for standardized designs that provide the most cost-effective means to complete engineering and construction work. If the elevation differs across the site, equipment arrangements, duct runs, piping locations and the ability to share common utilities for both SCPC units (such as coal handling, circulating water, and service water) becomes more difficult and the economics of a standardized design are lost. The units need to at the base of the bluff to facilitate open-cycle cooling. Therefore, WEPCO and WE Power have proposed that the bluff be cut back to allow for the installation of these units.

The SCPC units would include air pollution control equipment buildings such as the selective catalytic reduction (SCR) facility, a new baghouse or high efficiency electrostatic precipitators, and wet scrubbers. The footprint for each generating unit would be about 300 feet wide and about 1,200 feet long (perpendicular to the lakeshore), covering about 8.3 acres.

The IGCC unit would be located along the shoreline at the site of the old North OCPP building, and its related buildings would extend westward from there, with most of them placed on the north and east side of the existing rail loop. Both the combined-cycle (CC) facility and air separation unit (ASU) of the IGCC would be at the base of the bluff to facilitate open-cycle cooling with lake water.

Some of the auxiliary facilities for the existing OCPP units would be the same, while others would need to be changed. The substation and switchyard would remain where they are, but a substation expansion is proposed. The existing rail loop would be widened inward to accommodate additional tracks with new dumper equipment, resulting in a loss of some of the mature woodland inside the loop. The coal conveyance facilities would be relocated to accommodate new coal piles in the northwest portion of the property, north of the rail loop. The new coal piles would occupy approximately 55 acres of land with a footprint of approximately 1,425 by 1,650 feet, exclusive of the various conveyors.

The existing coal dock could accommodate barge coal delivery and would be used for barge limestone delivery and storage. The limestone handling and storage system would occupy approximately 13 acres of the existing coal dock and have a footprint of approximately 750 by 750 feet. The current docking facilities may be expanded to handle larger coal barges and ships. A new ship unloading facility, including a breakwall, is proposed for east of the existing dock in the lake. A proposed new expansion of the existing dock would require filling in additional lake area for a distance of about 500 to the north of the existing dock. Some materials handling facilities would be located on the new fill. A new intake structure would be installed approximately 3,500 to 9,000 feet out into the lake with bored tunnels that would contain the pipeline for carrying water to the new ERGS and existing OCPP facilities. No new landfills would be created.

A potential site for a commercially-owned wallboard plant has been set aside south of OCPP units 5-8 and north of and parallel to a federally-owned shooting range which is discussed in more detail in Chapters 9, 11, and 12. The potential for construction of a wallboard plant is discussed in more detail later in this chapter and in Chapters 9 and 10.[71]

South Site

Existing structures and land cover

The proposed South Site is in the northwest quarter of Section 6 in T4N-R23E, in the town of Caledonia in Racine County, Wisconsin. WEPCO owns the land, which is south of the currently operating South OCPP units. The 60-acre portion of the site proposed for the SCPC units is approximately 1,300 feet wide. It lies south of the county line and north of the shooting range property. The site extends, on average, about 2,000 feet west of the Lake Michigan shoreline to a point near the railroad tracks. A 100-foot bluff parallels the lake shoreline along the entire length of the South Site. East of the bluff, the shoreline is relatively flat for about 300 to 350 feet to the lake. There are existing settling ponds south of the operating OCPP power plant units on this part of the property. At the top of the bluff, the land is also fairly level. It supports a few buildings and roads. An area designated as an "isolated natural resource area" (INRA) is at the west end of the proposed IGCC plant location east of the rail loop. The location of and impacts to this and other INRAs are discussed in Chapter 10.

Proposed structures and land cover

Figure Vol. 2-2 shows the South Site layout. Similar to the North Site, the facility would be entirely located on WEPCO-owned property. Again, as at the North Site, construction of the SCPC and IGCC units on the South Site would require extensive earthwork to create a flat site large enough for all the plant equipment that needs to be placed at or close to lake level. The IGCC buildings for the South Site would be aligned east to west and perpendicular to the lakeshore in a relatively tight space, adjacent to the shooting range property line and extending into the INRA. The proposed IGCC facility would be directly south of the SCPC units. The air separation unit, sulfur recovery unit, sulfuric acid storage tanks, and waste water treatment pfacilities would be located within the area of the INRA.

The same road and rail loop construction would be needed for the South Site as for the North Site. The shape and dimensions of the coal storage area would differ slightly from that planned for the North Site, but it would be stored at the same location. The coal conveyor system would be routed differently to deliver coal to each of the new units on the South Site. The wastewater discharge channel would be located near the southeast corner of the SCPC units. The same expansion of the transmission system would be necessary regardless of site. The same ash landfills would be used but the on-site haul roads would be adapted as needed.

The potential site for the commercially-owned wallboard plant would be shifted for the South Site to a northern location along the top of the bluff at a point near the east end of the existing Elm Road and next to the proposed coal piles.

[71] The originally proposed wallboard plant site was at the current site of the South Oak Creek Landfill. This location would have required excavation and reclamation of at least some of the landfill ash. WEPCO has since revised the most likely wallboard plant locations for the three sites so that it would be built closer to the lakeshore rather than near the South Oak Creek Landfill.

South Site - Exp

Existing structures and land cover

The South Site-Exp, also in the northwest quarter of Section 6, T4N-R23E, includes land owned by WEPCO south of the operating South OCPP units plus the land parcel further to the south that is owned by the federal government and is currently used as a shooting range. The WEPCO land available south of units 5-8 is about 60 acres, and most of it would be used for the SCPC units, laid out in the same manner as for the South Site. The shooting range property is about 70 acres in size. If this land could be purchased, it would allow the proposed IGCC facility to be expanded in acreage and sited closer to Lake Michigan.

WEPCO has met with the Department of Military Affairs (DMA) to discuss the shooting range property. According to WEPCO, the DMA has been supportive of a land swap or purchase. WEPCO and the DMA have reached an agreement. Based on discussions at the time of this EIS, WEPCO indicates that it would likely obtain the site in 2004, in time to begin construction of the IGCC facility.

The 100-foot tall bluff along the lake shore continues along the entire length of the South Site and the South Site-Exp. The site is bordered on the east by Lake Michigan and on the west by the bluff. East of the bluff, and on the WEPCO-owned property, the land is relatively flat for about 300 to 350 feet to the lake. Along the shooting range property, and to the south of it, the bluff essentially forms the lakeshore, with some artificial bluff stabilization work in place. A large wooded ravine is located just south of the shooting range on existing WEPCO-owned land. This ravine would not be used as part of the ERGS facilities site.

Proposed structures and land cover

Similar to the South Site, use of the South Site-Exp option would require cutting into and leveling portions of the existing 100-foot tall bluff that parallels the lake shoreline. Figure Vol. 2-3 shows the site layout. While the SCPC units would be located in the same place, the South Site-Exp includes a different location for the IGCC facility, placing it south of the proposed SCPC unit sites, but closer to Lake Michigan and extending onto the shooting range property.

WEPCO prefers this site option to the other South Site arrangement for engineering and construction reasons. Use of this option would allow equipment that requires cooling water to be located closer to Lake Michigan without as much bluff removal. The IGCC equipment could also be expanded to a more accessible size and less tightly arranged. Potential impacts related to utilizing the shooting range propeorty are discussed in Chapters 9, 10, and 11.

The coal piles for both the new bituminous and the currently used subbituminous coals would remain on the north portion of the existing OCPP site. A coal conveyor from the bituminous coal pile on the north portion of the site would be routed to deliver coal to the gasification building. The coal conveyor length would be similar to that needed for the South Site SCPC site layout. The rail loop would also be the same as for the South Site and the North Site. The transmission switchyard and rail loop would be the same as they would be for the South Site or the North Site.

The potential site for a commercially-owned wallboard plant would be at the same place as described and shown for the South Site.

Proposed Coal Technologies

Super critical pulverized coal (SCPC)

Description of the technology and plant components

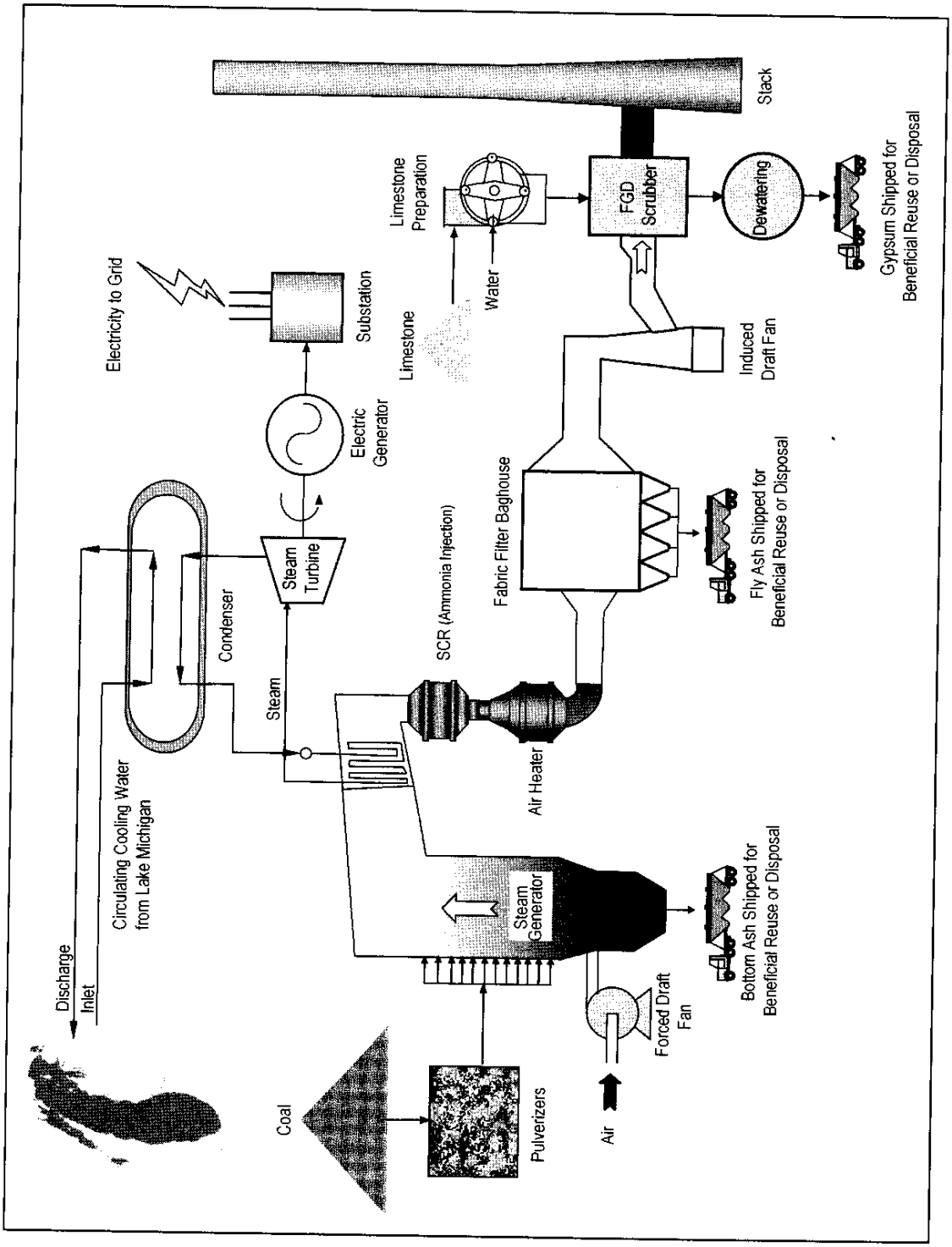
To generate electricity, conventional coal-fired power plants mix pulverized coal with hot air and inject the fine particles into a furnace lined with water-filled tubes. Steam from the boiling water spins a steam turbine generator to produce electricity.

The coal combustion process that the applicants are proposing for two of the 615 MW base load units at the ERGS is more advanced than the conventional process and employs supercritical pulverized coal (SCPC) technology. SCPC technology involves heating water to a temperature and pressure that exceeds its critical point. The critical point of water is above a pressure of about 3,200 pounds per square inch absolute (psia) and 705 degrees Fahrenheit (^{O}F). Above the critical point, distinct liquid and vapor (gas) phases no longer exist and the state of the water is that of a supercritical fluid. Instead of boiling, water is continuously transformed from the liquid phase to a steam as the temperature of the supercritical fluid is increased. In a supercritical steam generator, no steam drum is required to separate steam from liquid.

The higher temperatures and pressures achieved in a supercritical steam generator increase the energy content of the fluid delivered to the turbines. Increasing the energy, or enthalpy, drop across the turbine improves efficiency. The use of cold Lake Michigan water in the condenser of the SCPC units at the ERGS would also increase plant efficiency. The lower condenser temperatures achieved as a result of using colder circulating water would result in lower condensing temperatures and pressures, and hence, energy in the condensed steam. Greater plant efficiency means less fuel burned per unit of electrical output.

Figure 6-3 provides a schematic of the overall SCPC plant process. The site layouts for the North Site, South Site, and South Site-Exp are shown in Figures Vol. 2-1, 2-2, and 2-3. The new site layout for the CUP Option (using the North Site) that was negotiated between WEPCO and the city of Oak creek in May 2003, is shown in Figure Vol. 2-4. The company states that based on preliminary engineering, the steam generator for the SCPC units would be a supercritical pulverized coal, balanced draft-type unit. The generating unit would be designed to operate as a base-loaded facility, but the design would allow for cycling to accommodate load required by the electrical system demand.

Figure 6-3 SCPC plant process



The steam generation process involves pumping feedwater through the economizer to recover heat from the combustion gases exiting the steam generator. The water is then pumped through to the water wall circuits enclosing the furnace. After passing through the lower and upper furnace circuits in sequence, the fluid passes through the convection enclosure circuits to the steam generator's superheater section. The fluid is mixed in cross-tie headers at various locations throughout the path.

The steam then exits the steam generator enroute to the high-pressure turbine. High-energy fluid from the steam generator enters the turbine at approximately 3,500 psig/1,050 ^{o}F. The supercritical fluid initially flows through the high-pressure turbine and then returns to the steam generator for reheating. It then returns to the intermediate-pressure section. After passing through the intermediate-pressure section, the steam enters a cross-over/cross-under pipe, which transports the steam to the low-pressure section. The steam then divides into multiple paths and flows through the low-pressure sections exhausting downward into the condenser.

In the air and combustion process, air from the forced draft fans is heated in the air preheaters, recovering heat energy from the exhaust gases on its way to the stack. This air is distributed to the burner windbox as secondary air. The primary air fans supply a portion of the combustion air. This air is also heated in the air preheaters and then used to transport the fuel to the pulverizers while drying the fuel in the process. A portion of the air from the primary fans is routed around the air heaters and is used as tempering air for the pulverizers. Preheated air and tempering air are mixed at each pulverizer to obtain the desired pulverizer outlet temperature.

The pulverized coal and combustion air mixture flows to the coal nozzles at the various furnace elevations. The hot combustion products rise to the top of the steam generator and pass horizontally through the superheater and reheater in succession. The gases then turn downward, passing in sequence through the primary superheater and economizer. The gases exit the steam generator at this point, and flow to the selective catalytic reduction system, preheater, fabric filter, induced draft fans, flue gas desulfurization system and stack.

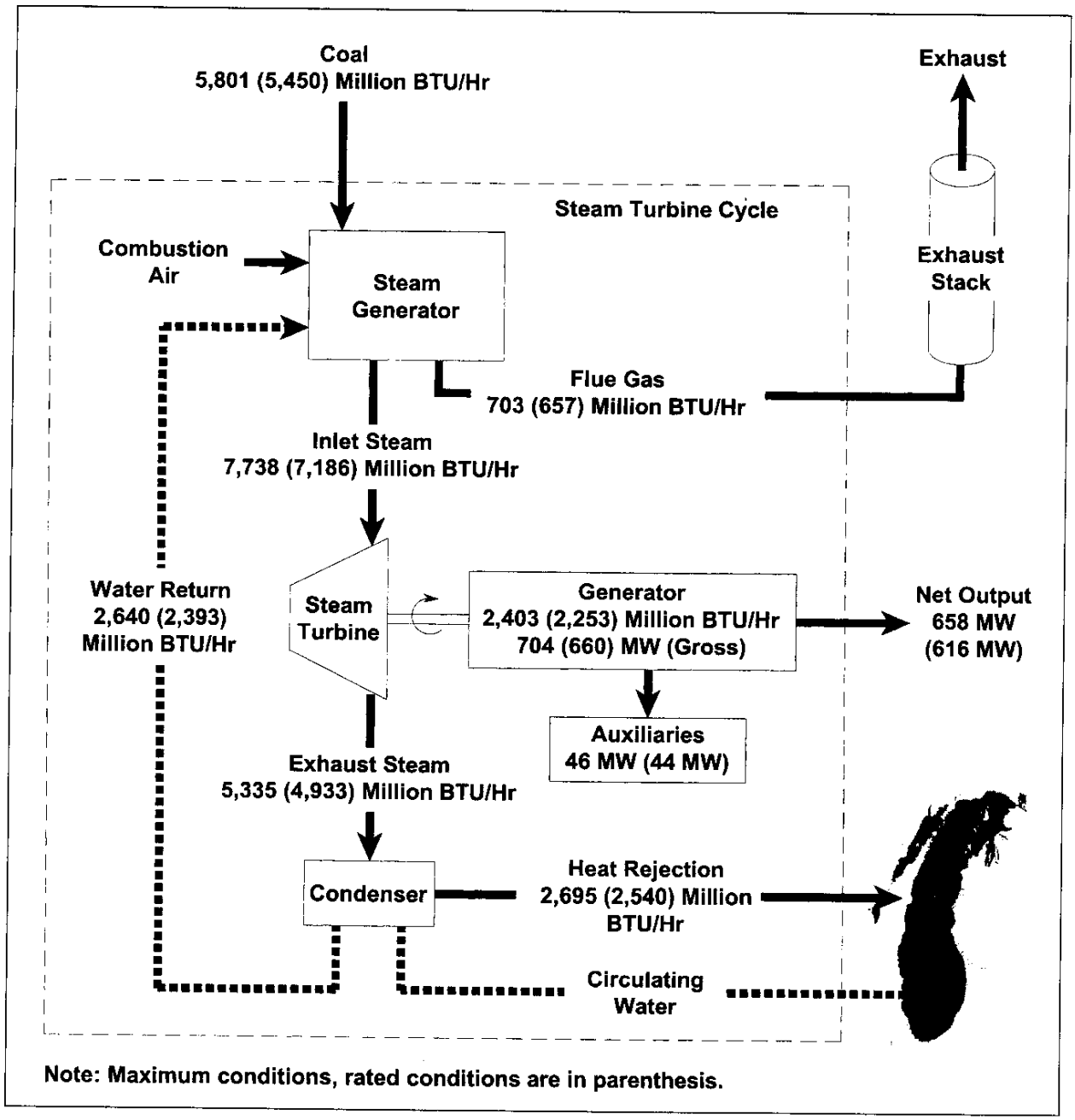
Expected hours of operation, expected outages, and life expectancy

The assumed capacity factor for the SCPC facility is in the range of 85 to 90 percent. The applicants expect the plant to be operated, for the majority of the year, as a base-load facility over a life of 40 to 45 years. The plant is expected to operate 24 hours per day. Each unit would be expected to operate between 7,426 and 7,862 hours per year.

Reductions in annual output for the units are expected to occur from two planned outages each year, forced outages due to unplanned equipment failures, and partial load reductions required due to miscellaneous process limitations. Generally, planned power plant outages would relate to periodic inspections based on a combination of hours run and start-ups.

The rated heat load input is estimated to be 5,450 million British thermal units (mmBtu/hr) as shown in Figure 6-4. This heat input would double for both units. In general, the SCPC units would convert approximately 38 to 39 percent of the heat content into electricity.

Figure 6-4 Heat balance diagram for one SCPC unit



Fuel source and supply

Bituminous coal would be the primary fuel for the SCPC generating units. For planning and air permitting purposes, eastern United States Pittsburgh #8 bituminous coal is the applicants' bituminous coal of choice,

with the Blacksville Mine as a typical operation that can supply this coal. This coal seam is located and predominantly mined in Pennsylvania and West Virginia.

The SCPC units are being designed to burn a washed fuel.[72] Table 6-2 provides the ultimate analysis of the potential coal fuel source and ash content. For marketing coal combustion/conversion products, higher ash content coals are more desirable.

Table 6-2 Typical values for coal and ash for Pittsburgh #8 bituminous coal

Coal Ultimate Analysis	Units	Pittsburgh #8 Washed Bituminous Coal
Carbon	%	72.67
Sulfur	%	2.69
Oxygen	%	4.84
Hydrogen	%	4.89
Nitrogen	%	1.38
Chlorine	%	0.10
Ash	%	7.73
Moisture	%	5.71
Coal Proximate Analysis		
Moisture	%	5.71
Volatile Matter	%	35.73
Fixed Carbon	%	50.84
Ash	%	7.73
Gross (Higher) Heating Value	Btu/lb	13,100.00
Hardgrove Grindability Index		55.00
Coal Ash Analysis		
Silica	%	43.17
Ferric Oxide	%	21.17
Alumina	%	21.95
Titanium Dioxide	%	0.93
Calcium Oxide	%	5.18
Magnesia	%	0.90
Sulfur Trioxide	%	4.28
Potassium Oxide	%	1.45
Sodium Oxide	%	1.06
Phosphorous Pentoxide	%	0.59
Undetermined	%	0.68
Total	%	100.00

Each of the two SCPC generating units is expected to have a maximum coal consumption of 5,640 tons per day, or roughly 1.8 million tons per year. WEPCO stated that it has had discussions with coal suppliers and

[72] DR-032 indicates that coal washing will not occur on-site. It will occur prior to coal delivery.

transportation providers but no final decisions on the initial provider of coal, and associated contract terms and conditions for either the coal or transportation, have been made.

Fuel transportation and storage

The preferred method for coal delivery to the power plant site is by rail. If coal is delivered directly to the site, it would be delivered by unit trains consisting of 130 to 150 rail cars averaging 100 to 120 tons per car.

Delivery from Lake Erie or Chicago coal docks via lake vessels that deliver coal to the ERGS site is also an option. If coal is delivered from Lake Erie or Chicago coal docks, lake vessels about 1,000 feet long, carrying between 15,000 tons to 45,000 tons of coal would be utilized. A proposed new breakwater east of the existing dock and a northward expansion of the existing dock would provide a protected area to facilitate lake delivery of coal. If lake delivery of coal is implemented, it is likely that some rail delivery would still occur due to weather related restrictions that affect Great Lakes shipping in the winter. Without supplemental rail delivery, the coal stockpile at the plant would need to meet a four-month supply, due to possible winter shipping stoppages. Given that there is not sufficient space to accommodate a four-month supply of coal on the existing dock and proposed storage areas, WEPCO has expressed a preference for rail deliveries that could accommodate fuel delivery needs at the facility year round.

The existing Oak Creek coal delivery rail system holds one train with room for another on a railroad siding just outside the plant property. To accommodate the larger number of trains expected if the ERGS is built, another rail spur, a rotary car dumper, and a car positioner (indexer) would be added to the plant's rail system. The new plan for accommodating the ERGS facilities would allow two full and two empty trains on the ERGS-OCPP site.[73] The existing dumper and associated conveyors would be removed.

Figure 6-5 shows a conceptual design of the coal handling process following delivery to the site. Rail car unloading would be done using a rotary car dumper. After completing modifications to the rail loop on the plant property, an entire unit train, consisting of up to 150 cars, could be pulled through the site without breaking the train into smaller segments. The installation of the new car dumper and the car positioner (the indexer) would increase the speed of the unit train unloading process. The applicants estimate that an entire unit train could be unloaded in about six hours.

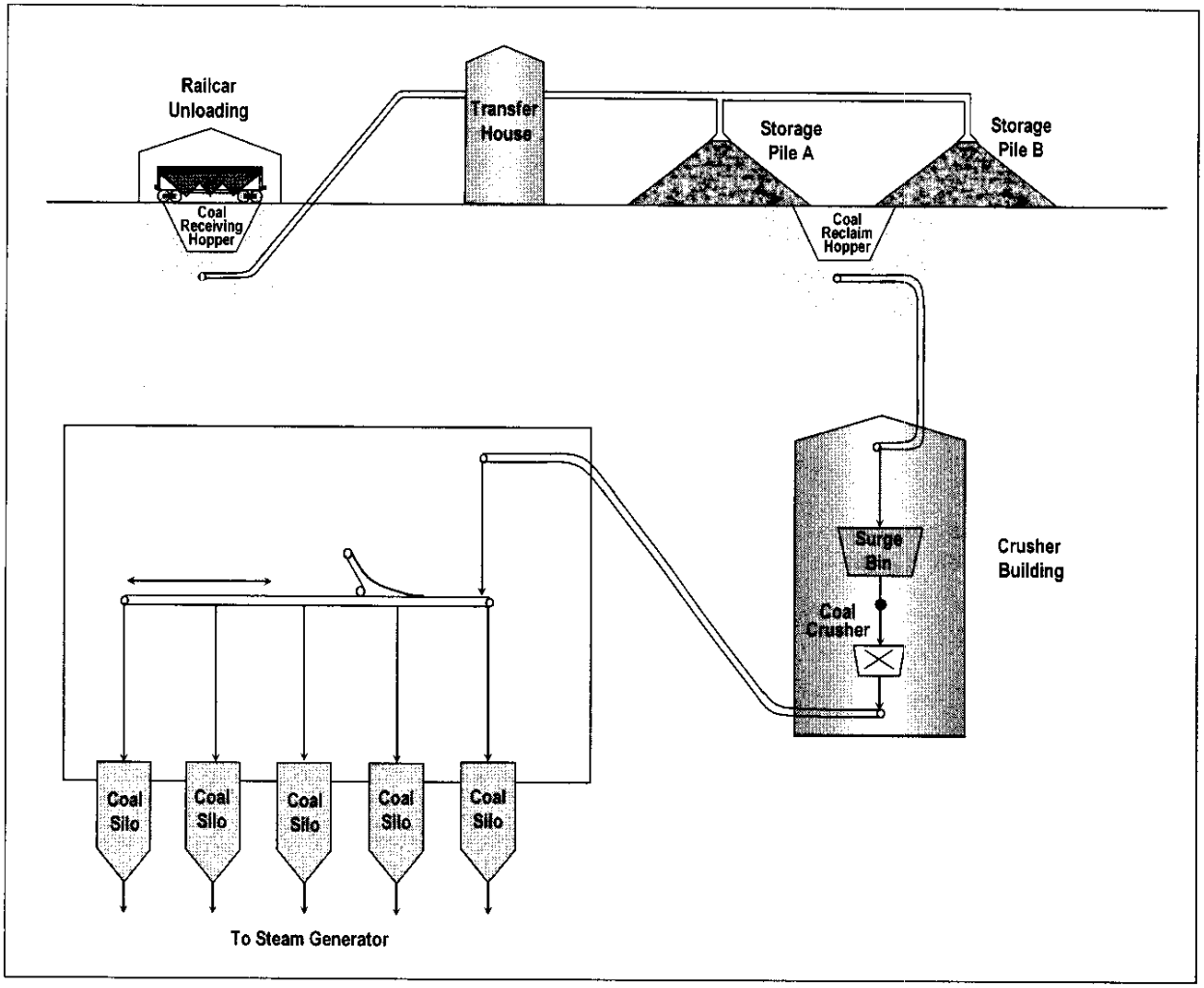
Coal from the dumper would be discharged onto a belt conveyor that would move the coal to a transfer house. All new coal belt conveyor transfer points would include dust suppression or collection systems consisting of fog, water, or baghouse filter; a fire protection system; and exhaust fan ventilation. Coal belt conveyors handling crushed coal would be located inside steel galleries; whereasconveyors handling uncrushed coal would be covered. Galleries would be provided with service water for washdown clean-up, compressed air and welding outlets for conveyor maintenance, lighting, automatic fire protection, and ventilation. Transfer buildings would include the same ancillary features for clean-up as the coal conveyor galleries.

After the transfer house, coal would be conveyed to an inactive coal pile reclaim area or to the coal crushers. There are two types of coal storage: inactive outdoor storage and active indoor storage. The inactive coal storage area would hold coal that is being held in reserve, and would be located north of the existing coal

[73] Response to 1-SUP-145

dumper. Each pile would be stacked out and reclaimed using mobile equipment that interfaces with the stationary systems at the surge pile stackout conveyors and reclaim hoppers. The active coal storage piles would be enclosed in a coal storage shed, storing enough coal for three day's operation. The active storage stockpile would serve as the buffer between the steam generator's continuous demand and the intermittent arrivals of bulk shipments.

Figure 6-5 Coal handling process for the ERGS project



Total on-site storage capacity would be approximately 1.2 million tons of coal. The company notes that all new coal storage areas would be equipped with clay liners, concrete or some other type of suitable barrier to minimize infiltration, a curbed runoff collection system, and a lined pond to detain and treat coal pile runoff.

Coal would be supplied to individual silos located at the site of each generating unit. Coal would be discharged from the storage silos to variable speed gravimetric feeders where the coal feed rate would be regulated by the combustion control system and unit load demand. Coal would then be discharged from the

gravimetric feeder to the pulverizer. The coal would then be transported to the burners using primary air as the conveying media.

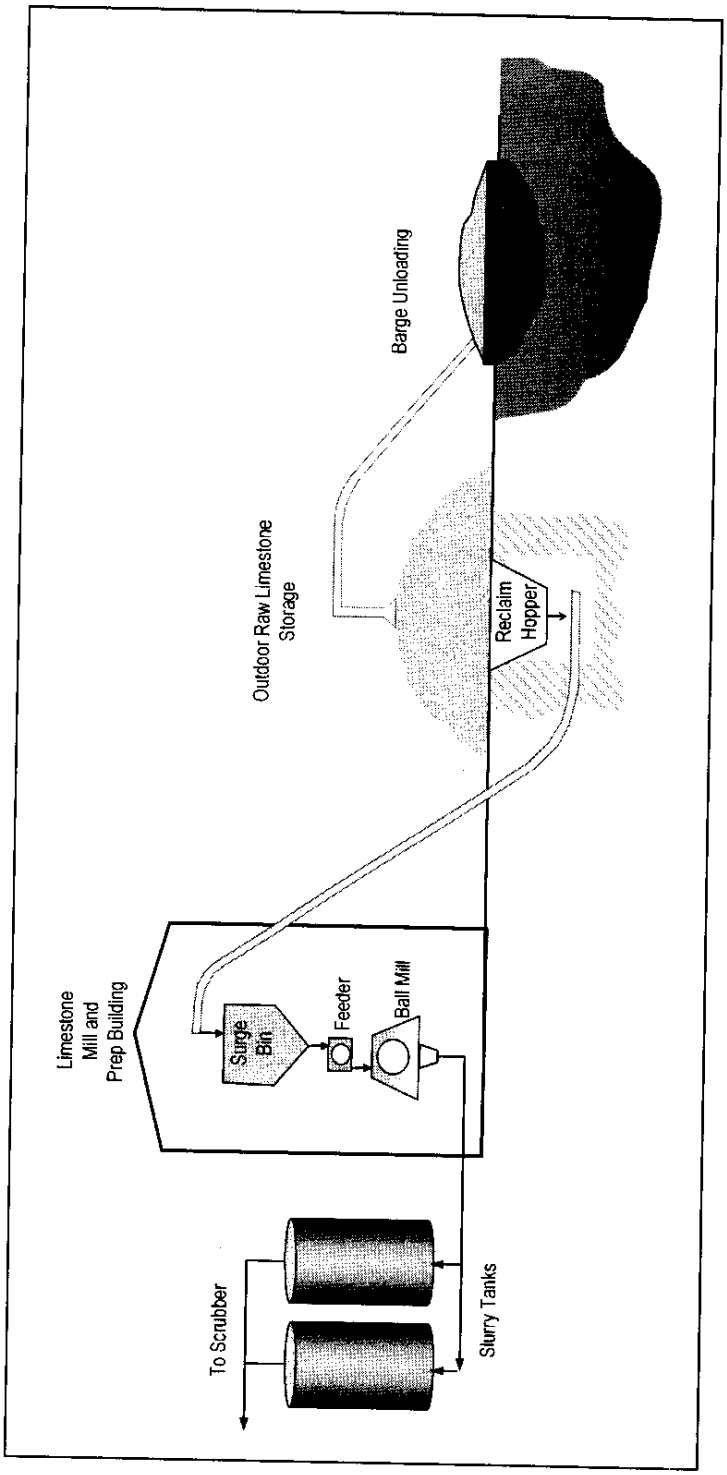
Limestone transport and storage

Limestone would be delivered to the power plant site by rail delivery or barge delivery. If barge delivery is used, a grab bucket type unloading system would convey limestone from the barges to the receiving hopper. If rail delivery is used, limestone would be conveyed from the rail loop to the dock. The limestone receiving hopper would include a dust suppression system to minimize fugitive dust generated from the unloading operation. A belt conveyor and a telescopic chute would be used to convey limestone to an open storage pile. A typical limestone unloading and handling process is shown in Figure 6-6.

Limestone would be stored on an open pile in a segregated area on the existing coal dock. The limestone would then be pushed into a reclaimer hopper and transported by conveyor to the crushers as needed. The company anticipates having a four-month supply of limestone on the storage pile. This would provide a sufficient amount to cover the winter months, should the limestone quarry operations and shipping on the Great Lakes be shut down.

As shown in Figure 6-6, wet ball mills produce a pulverized limestone slurry for use in the Flue Gas Desulfurization (FGD) system. Limestone and water are added at the inlet to the ball mill. The limestone is then ground in the ball mill to produce a slurry that is discharged into the mill slurry tank. Mill recycle pumps convey the limestone water slurry to an assembly of hydroclones and distribution boxes. Based on suspended solids content and size distribution, the slurry is then separated in streams. The hydroclone underflow, which is comprised of oversize limestone particles, is directed back to the mill for further grinding. The hydroclone overflow is routed to reagent storage tanks. Reagent distribution pumps pump limestone slurry from the storage tanks in a recirculation loop to the absorber modules.

Figure 6-6 Limestone unloading and handling process for the ERGS project



Water use, storage and discharge

Table 6-3 shows the estimated water demands for the SCPC plant operation. A water balance diagram is shown in Figure 6-7

Table 6-3 SCPC water demands for one unit at various operating modes

Once-through Cooling Water	Rated Load Operation (gpm)
Condenser	450,000
Service water	10,000 to 13,250
City Water Supply	
Potable water	5 to 10
Steam generator make-up	100 to 200

Potable water would be available from the existing city supply. Water from Lake Michigan would be used at the plant site to supply cooling water to condense the low-pressure turbine exhaust steam at the anticipated flow-through rate for each SCPC unit. This flow-through rate would be 458,000 gallons per minute (gpm), with a 12 degree temperature rise. Because the SCPC plant would operate in a once-through manner, the amount of water withdrawn from the intake structure would be essentially equivalent to the amount of water discharged. The largest water consumption would occur in the FGD system.

A new pump house would be installed in a location that would be southwest of the proposed SCPC units on the North Site. OCPP units 5-8 would utilize the existing south plant pump house that would withdraw water from the planned forebay area that would enclose the western end of the intake channel. Both the forebay and new SCPC pumphouse locations would be connected to the proposed intake tunnel by means of a vertical dropshaft.

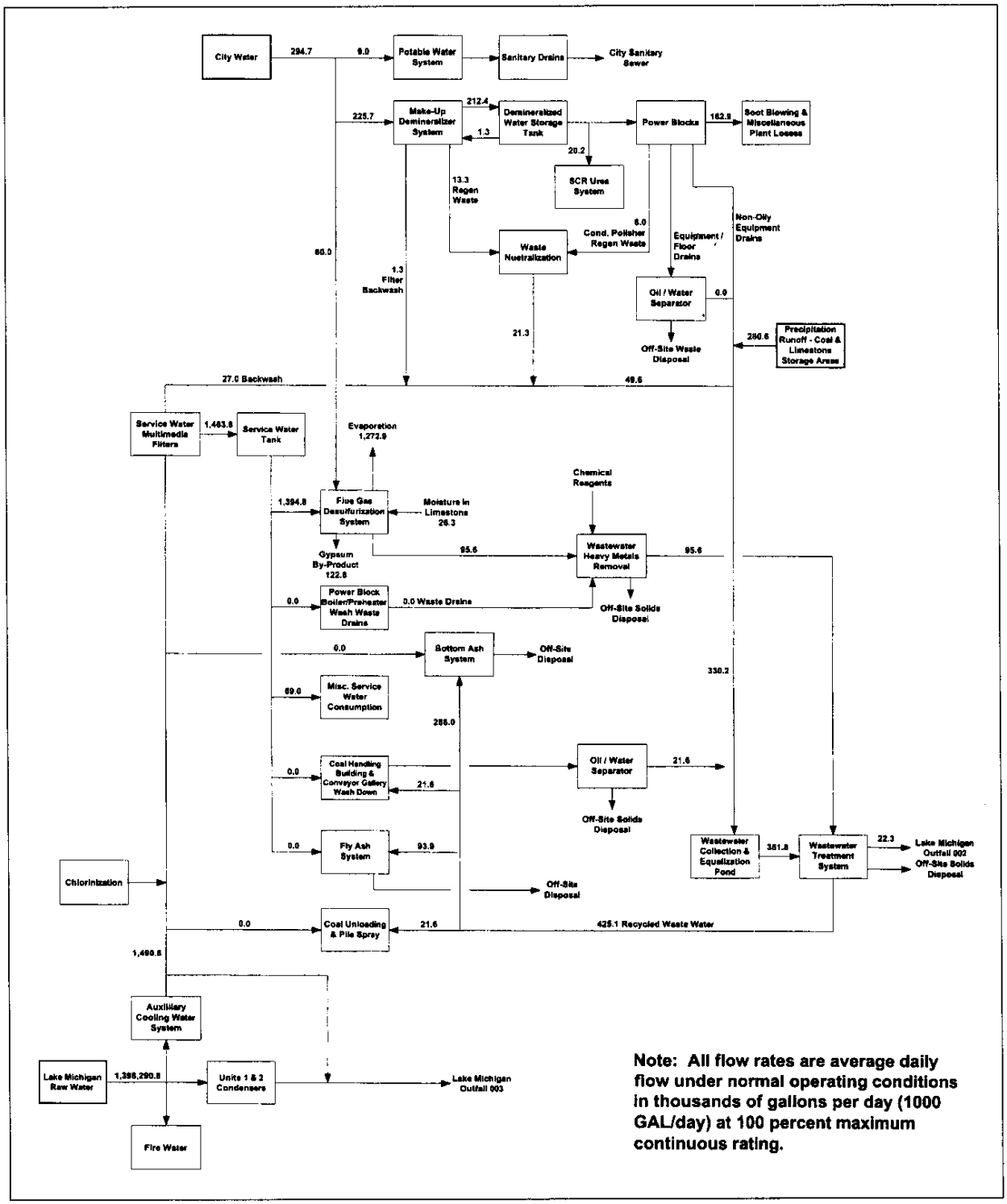
New circulating water pumps would also need to be installed. These new pumps would be designed to have the capacity equal to the highest optimum flow for the seasonal range of lake temperatures, heat rejection at full load, and desired discharge temperature. Cooling water would be piped to the main condensers of both the first and second SCPC units via an underground large diameter piping system. If the North Site is used, discharge water from the condensers for both proposed units would be piped underground to the north side of the new dock extension and then east along the shoreline (see Figure Vol. 2-1). If the facilities are built on the South Site or the South Site-Exp, discharge water would be piped underground to a discharge channel located directly off of the southeast corner of the proposed SCPC units (south of the coal dock). See Figures Vol. 2-2 or 2-3.

Solid waste production, storage, and beneficial use

The primary coal combustion/conversion products produced at a SCPC power plant are fly ash, bottom ash, and synthetic gypsum.

WEPCO has stated that its long-term goal is to utilize 100 percent of the coal combustion products (CCP). The company estimates that the combined total of coal combustion/conversion materials produced by the SCPC units would be:

Figure 6-7 Water balance diagram for the SCPC units (using Pittsburgh #8 bituminous coal)



Note: All flow rates are average daily flow under normal operating conditions in thousands of gallons per day (1000 GAL/day) at 100 percent maximum continuous rating.

Fly Ash	206,300 tons/year
Bottom Ash	51,600 tons/year
Synthetic Gypsum	543,600 tons/year

Due to the company's need to characterize and demonstrate consistency in CCP materials, develop markets and new customers, and establish uses for these materials, WEPCO anticipates reaching full utilization of these products within ten years from the start of commercial operation of the two SCPC units.

Fly ash and bottom ash CCP have several beneficial uses. Fly ash, which accounts for 80 percent of the coal ash produced, is widely used in the production of concrete and concrete products, portland cement, controlled low strength materials, liquid waste stabilization, cold in-place recycling of asphalt, and soil stabilization. Bottom ash, which accounts for the remaining 20 percent of the coal ash, is used primarily as an alternative for sand, gravel, and crushed stone pavement, and parking lot and foundation base materials. Synthetic gypsum uses are described below.

Fly ash

Fly ash is collected in the fabric filter or electrostatic precipitator ash hoppers and the air heater hoppers. The fly ash would be transported from the ash hoppers to a fly ash silo via a pneumatic transport line using low-pressure air from a blower. From the silo, the ash would be unloaded, either wet or dry, into a truck which would transport the ash to its final usage location, i.e. landfill or commercial use.

Bottom ash

Bottom ash from the steam generator is collected and transported from the bottom of the boiler via a submerged scraper (drag chain) conveyor to either a concrete holding pad or a holding bin (hydrobin). The ash would then be loaded from the pad to a truck with a front end loader or directly from the bin to a truck. The truck would then take the ash to its final usage location, i.e. a landfill or an commercial use.

Synthetic gypsum

Gypsum (calcium sulfate) is produced in the wet Flue Gas Desulfurization (FGD) system by the injection of oxygen to mix with calcium sulfite produced in the absorber reaction tank. Currently, there are no FGD systems operating in Wisconsin boilers. The gypsum dewatering system removes water from the slurry leaving the FGD absorber modules. The recirculating reagent in the FGD absorber vessel accumulates dissolved and suspended solids, as byproducts from the SO_2 absorption reaction process. To maintain quality of the reagent, a portion of the reagent needs to be withdrawn and replaced by fresh reagent on a continual basis. This is done by the bleed pumps pulling off spent reagent, and the reagent distribution pumps supplying fresh reagent to the absorber.

Dewatering of the gypsum slurry is accomplished in two stages. The primary dewatering stage utilizes hydroclones which use centrifugal force to concentrate the slurry. Underflow from the hydroclones, which would typically have 35 to 50 percent solids levels, is sent to vacuum filters for secondary dewatering. The vacuum filters would reduce the gypsum filter cake moisture content to 10 percent or less. Either rotary drum or horizontal belt filters could be utilized depending upon the end user's requirements for the gypsum. Overflow from the hydroclones, which would have 3 to 5 percent solids, is returned to the absorbers. A belt conveyor system would transport the gypsum from the vacuum filters located in the dewatering building to an adjacent storage shed. Plans are for the gypsum to be eventually transported to a wall board manufacturing plant if one is built nearby or barged off-site.

Natural gypsum is mined at various locations in the country for production of wallboard (drywall or sheet rock) and other products. Quality synthetic gypsum material produced from the proposed wet scrubbers could also be used for the production of wallboard and other products. The quantity of gypsum produced is directly proportional to the sulfur content of the fuel being burned.

The company would, ideally, like to be in a position to produce a sufficient amount of gypsum for use at a dedicated commercial wallboard plant located either on or near the power plant property. WEPCO is currently investigating the feasibility of having a wallboard manufacturer locate a new facility in close proximity to the plant site. It is possible at a later date that a new wallboard facility could be located at the Oak Creek South Landfill Site or at an area industrial park. This type of plant, combined with outdoor gypsum storage, could require a site of up to 100 acres. If smaller quantities of gypsum are produced, WEPCO notes that the gypsum materials could be transported to an existing wallboard producer to supplement natural gypsum supplies.

Integrated gasification combined-cycle (IGCC)

Description of the technology and plant components

The applicants propose to develop a new 600 MW net nominal baseload Integrated Gasification Combined Cycle (IGCC) electric generating facility for commercial operation starting in 2011. The proposed IGCC process is designed to break down coal into its basic constituents and obtain a synthetic gas (syngas) that would be burned in two combustion turbines. The gas conditioning process enables the separation of any pollutants from the syngas prior to its use as fuel in the CT's. Waste heat is also utilized to produce steam for steam turbine use. The proposed IGCC system consists of:

- Two or three oxygen-blown, coal gasifiers
- An air separation unit (ASU)
- A gas conditioning system for removing sulfur compounds and particulates
- Two CTs with heat recovery steam generators (HRSGs)
- A steam turbine generator (STG)
- Systems for coal handling and preparation equipment

Demolition of the former north plant building would be necessary before the IGCC facility could be constructed at the North Site.

The equipment described by WEPCO in its CPCN application is based on the existing Texaco Gasification Power System process and available combined-cycle power plant technology. It represents one of several IGCC technologies that are currently being developed.

Because technology changes (in both gasification and combustion turbine science) are likely to occur between now and when the IGCC facility is proposed to be in service in 2011, the information described in the application is preliminary. As technologies develop, a more thorough screening process would be implemented to select the appropriate technology and vendor for use on this project.

A two-train gasifier system (with potential addition of a spare) is proposed. A schematic for the IGCC process is shown in Figure 6-8.

The overall "footprint" of the entire facility would cover about 25 to 30 acres. The approximate size of each major components is:

- Air separation unit – 500 x 650 feet
- Combined cycle power plant – 300 x 400 feet
- Gasification facility – 550 x 550 feet
- Acid gas recovery unit – 275 x 300 feet
- Sulfur recovery unit – 275 x 275 feet
- Water treatment building – 60 x 120 feet
- Waste water treatment building – 60 x 120 feet
- Coal slurry/preparation facility – 120 x 160 fee

The site layouts are as shown in Figures Vol. 2-1, 2-2, and 2-3.

Gasification plant

The Texaco coal gasification technology uses a single-stage, downward-firing, entrained-flow coal reactor fed with a coal/water slurry (60 to 70 percent solids) and 95 percent pure oxygen. The coal reacts with steam and oxygen at a temperature in excess of 2,600^{0}F to produce raw synthesis gas and molten slag.

The main sub-systems of the gasification plant include: gasifier, ASU, low temperature gas cooling (LTGC), acid gas removal (AGR), and SRU. The following sections describe each sub-system.

Gasifier

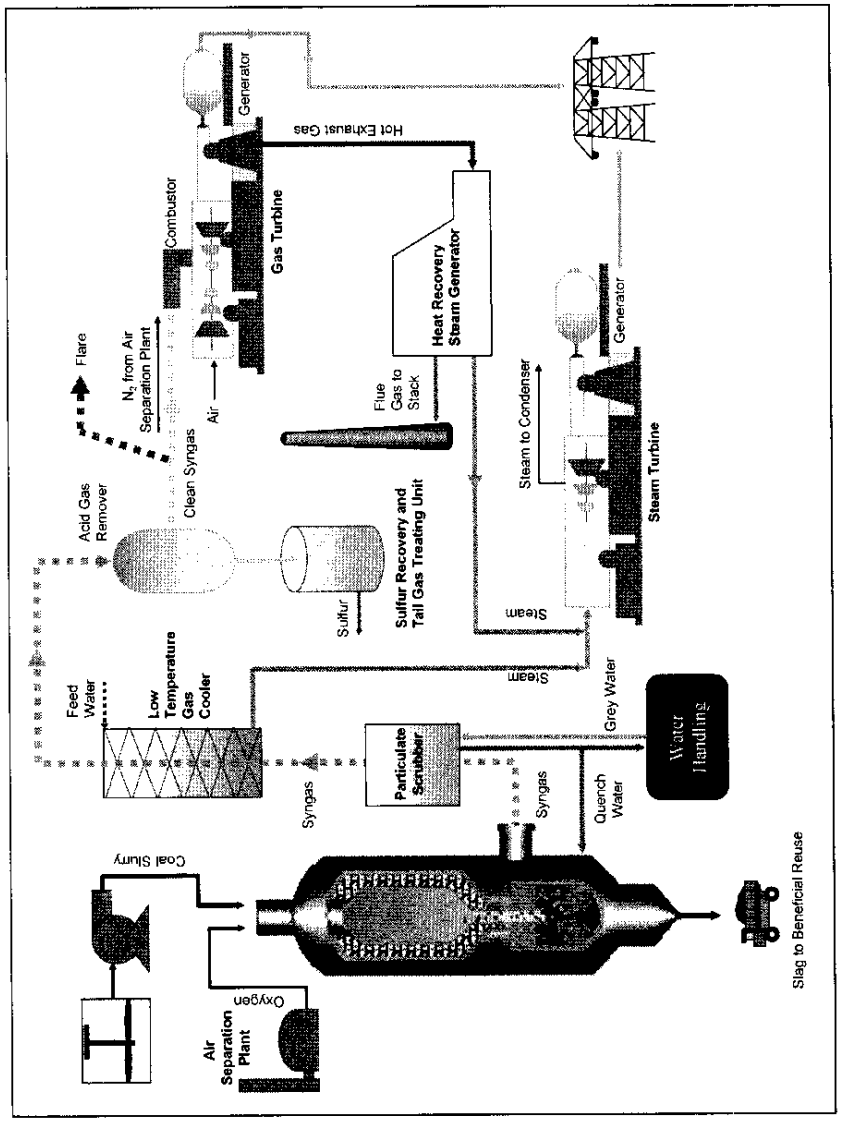
In the gasifier, the slurry is mixed with oxygen in a specially designed feed injector. The oxygen-limited atmosphere inside the gasifier vessel generates syngas. Syngas consists primarily of hydrogen and carbon monoxide (CO) with lesser amounts of carbon dioxide (CO_2), H_2S, methane, argon, nitrogen, and water vapor. Traces of carbonyl sulfide and ammonia also are formed. Inorganic mineral matter, which was present in the coal and the unconverted carbon in the gasifier, form a liquid melt called slag.

Hot syngas and slag flow downward into the gasifier quench chamber via a dip tube. The syngas and slag are intimately mixed with and cooled by quench water at the bottom of the dip tube. The raw syngas leaves the gasifier quench chamber and enters a syngas-scrubbing step to remove entrained particulates. The carbon-rich particulate material is recycled back to the gasifier.

Acid gas removal (AGR) plant and flare

The cool syngas then passes through the AGR plant where over 98 percent of the sulfur containing compounds are removed. This is accomplished by absorbing the H_2S in a circulating solvent stream. This "rich" solvent then flows to a second column where heat is used to remove the H_2S from the solvent. The H_2S free or "lean" solvent is then returned to the absorber where more H_2S is removed.

Figure 6-8 IGCC plant process



Air separation plant

The ASU supplies high-pressure, high purity oxygen for gasification and nitrogen to dilute the fuel fed to the CTs. The ASU operates at cryogenic temperatures and will produce 95 percent pure oxygen. It also will be designed for full nitrogen recovery. Nitrogen also is used for inert gas purging. Oxygen also will be supplied to the sulfur recovery plant to increase efficiency.

Low temperature gas cooling

The particulate-free clean syngas from the particulate scrubber is routed to the LTGC section. The syngas is cooled and heat is recovered by generating steam. Most of the water in the syngas is condensed and extracted prior to reaching the AGR section.

The sulfur compounds released in the stripper are then processed in the SRU using a multi-step catalytic process to produce an elemental sulfur by-product. SO_2 that is not converted to elemental sulfur is routed to the Tail Gas Treating Unit (TGU) for conversion to H_2S and recycled to the SRU. After leaving the AGR section, the clean syngas is sent to the CTs.

In the event that syngas quality is not adequate for use in the CTs, it would be ignited in a stack approximately 200 feet tall. The maximum height of the flare has been estimated at 80 feet.[74] During a normal startup the height of the flare is expected to be 56 feet. It is expected that the length of time that syngas would be flared is four hours during normal startups.

Sulfur recovery unit (SRU)

In the sulfur recovery plant, the sulfur-containing gases from the AGR system are converted to elemental sulfur or sulfuric acid. Either by-product would be suitable for sale to other industries for various process uses. The conversion of H_2S to sulfur involves a multi-step catalytic process in which the reaction of H_2S and SO_2 form water and sulfur.

The sulfur is removed in the TGU prior to venting the CO_2 to the atmosphere. In the TGU, hydrogen is reacted with the SO_2 to convert it back to H_2S. The H_2S is then absorbed in a very selective solvent and the other gases are vented. The absorbed hydrogen sulfide is removed from the solvent in a stripping column and recycled to the SRU.

If elemental sulfur is produced, a storage tank would be provided to hold molten sulfur until it could be transferred to railcars for shipment off-site. If sulfuric acid were produced, an aboveground storage tank would be constructed to temporarily hold the acid until it could be transported off site by specially designed rail cars or trucks for commercial use.

Combustion turbine

The facility would employ industrial frame, advanced technology CTs. Each CT would be housed in an enclosure that provides thermal insulation, acoustical attenuation, and fire extinguishing media containment. The enclosure would allow access for routine inspections and maintenance. Each CT would be furnished with all accessories and auxiliary systems required for start-up and generating capability for combined-cycle operation. Each CT would incorporate an air inlet system with specially designed equipment and ducting to modify the quality of air under various temperatures, humidity, and contamination situations in order to make it more suitable for use. The self-cleaning inlet air filter would utilize high efficiency media filters. The inlet air ducts also would have noise attenuation features.

Either a recirculating hydrogen gas stream cooled by gas-to-water heat exchangers or water-to-air heat exchangers would cool the turbine generators. A hydrogen storage system would be provided to maintain the hydrogen pressure in the generators, if cooled by hydrogen. The hydrogen system would consist of standard pressurized hydrogen storage cylinders connected to a generator manifold supplied with the generator. A CO_2 system would be provided to purge the hydrogen from the generators. The CO_2 system would consist of standard pressurized CO_2 cylinders connected to a manifold supplied with the generator.

[74] Response to 1-DR-019

Heat recovery steam generator

One important feature of a combined-cycle plant is the use of hot exhaust gas from the CT to produce steam which in turn, is expanded in a steam turbine to drive an electric generator and produce electricity. The HRSG is the key piece of equipment necessary for steam production. The HRSG units are designed to fully integrate with the combined-cycle plant and include required inlet/outlet ductwork, structural supports, piping and accessories. The HRSGs would be multiple-pressure reheat type steam generators. The various pressure sections would consist of economizer, evaporator and superheater sections. The HRSGs also would be equipped with a reheater to further improve cycle efficiency. Supplemental duct-firing also may be installed. One tank would be provided for each HRSG to receive blowdown and water/steam releases. This blowdown, in conjunction with the chemical feed system, would control the steam drum water chemistry. A nitrogen blanketing system (consisting of N_2 cylinders) would be used during long-term shutdowns to protect the internal surfaces of the HRSGs.

Steam turbine generator

The STG would be a multiple admission, reheat, condensing turbine with an electric generator. The HP portion of the STG receives high-pressure superheated steam from the HRSG and then exhausts steam into the reheat section of the HRSG. Reheated steam from the HRSG is supplied to the intermediate pressure (IP) turbine, and the IP turbine exhausts into the LP turbine. The LP turbine also receives low-pressure superheated steam from the HRSG and exhausts steam into the condenser. Steam also would be produced in the gasification process and then supplied to the STG. An auxiliary steam system also would be provided.

Emissions control equipment

Additional information regarding emission control technologies and equipment can be found in Chapter 7.

NO_x control

Nitrogen, supplied by the ASU, is added to the combustors in each CT to reduce NOx emissions. The added nitrogen gas reduces the combustion temperature to minimize NOx emissions to about 15 ppm (0.06 lb/mmBtu). Additional post-combustion devices are not proposed.

Particulate control

Particulate removal to a level of about 0.011 lb/mmBtu occurs by a combination of good combustion practices and the syngas production process. Post-combustion equipment would not be required.

SO_2 control

IGCC facilities do not require any post-combustion SO_2 controls. Sulfur removal occurs in the AGR plant as part of the syngas production process. Approximately 98 percent of the sulfur is removed in the syngas conversion process.

Hazardous air pollutants (HAPs) control

HAPs, including mercury, would be controlled in the gasification process. Information from currently operating IGCC facilities suggests that at least 50 percent of the mercury is removed in this gasification process.

Expected hours of operation, expected outages, and life expectancy

The assumed capacity factor for the IGCC facility is in the range of 75 to 80 percent. The applicants expect the plant to be operated, for the majority of the year, as a base-load facility over a life of 40 years. The plant is expected to operate 24 hours per day at full capacity when available.

Reductions in annual output for the units are expected to occur from two planned outages each year, forced outages due to unplanned equipment failures, and partial load reductions required due to miscellaneous process limitations. Generally, planned power plant outages would relate to periodic inspections based on a combination of hours run and start-ups.

The rated heat load input is estimated to be 5,035 million British thermal units (mmBtu/hr) as shown in Figure 6-9. The IGCC unit efficiency would be 37 percent, which currently is slightly less than a SCPC unit under the same conditions.

Since the IGCC technology is relatively new, there are several issues with the proposed IGCC unit at Elm Road that should be considered from a reliability standpoint.

- Equipment malfunctions continue to hinder its effectiveness.
- More adaptations for a colder climate are needed for the IGCC compared to other units. A large amount of electrical heat tracing for the gasifier would be required to accommodate colder climates.
- The technology and process have been proven to work, but reliability is compromised due to many mechanical failures.
- A long startup (up to four days) for the Air Separation Unit is required.
- There are concerns about scaling up the plant. The Elm Road IGCC facility would be twice the size of other existing units and would be the largest in the USA.

Fuel sources and supply

Bituminous coal would be the primary fuel for the IGCC generating unit. For planning and air permitting purposes, eastern U. S. Pittsburgh #8 bituminous coal, is the company's bituminous alternative of choice, with the Blacksville Mine as a typical operation that can supply this coal. This coal seam is located and predominantly mined in Pennsylvania and West Virginia.

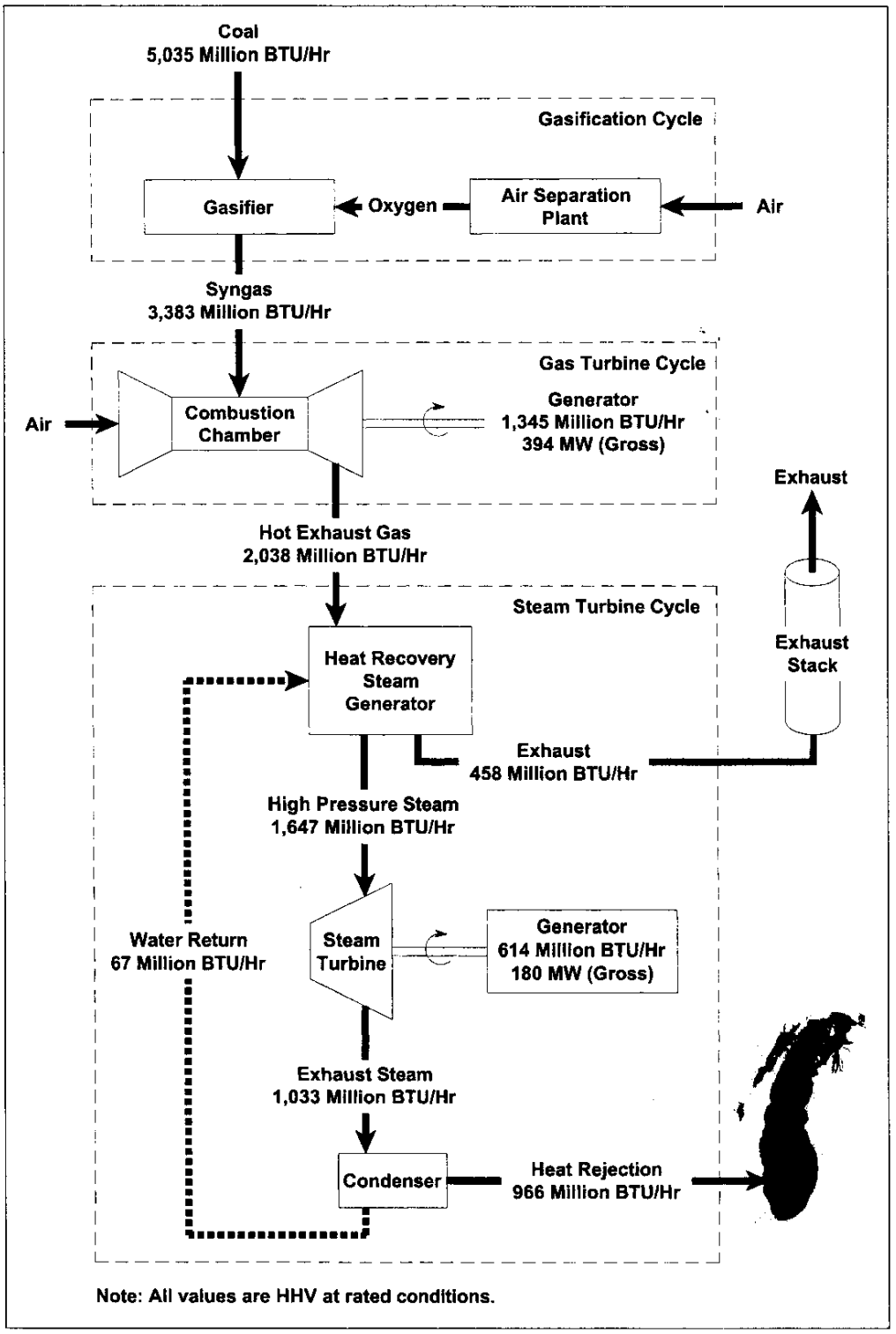
Table 6-2 in the SCPC section outlines the potential coal fuel sources and ash content. Note: IGCC facilities elsewhere have utilized other fuel sources such as petroleum coke.

The IGCC generating unit would be expected to have a maximum coal consumption of 5,540 tons per day, or roughly 1.6 million tons per year.

Water use and storage

The proposed IGCC unit would require water for coal gasification, cooling the compressors used in the ASU and for steam condensing. At this time, the plan for the cooling water supply would be a pumping station and pipeline drawing water from the common intake structure.

Figure 6-9 IGCC heat balance for one unit



Construction of a new cooling water intake structure would be expected to occur during construction of the first SCPC unit. This new intake would support the IGCC facility and would be a shared facility with the SCPC units and existing units 5-8. Cooling water use for the IGCC facility would be expected to be similar to that of a conventional steam electric power plant as shown in Figure 6-10. Compared to a conventional plant that uses nearly all its cooling water for steam condensing, the IGCC would require about one-third that amount for steam condensing. However, the air separation unit used to produce pure oxygen fed to the gasifier would require a considerable cooling water supply and, when combined with steam condensing requirements, the amount of water used for once-through cooling at an IGCC facility is comparable to a conventional steam electric plant.

Additional information about cooling water intake structure plans is discussed in Chapter 7.

A service water system would supply various systems including cooling of auxiliary plant equipment (primarily various tube and shell heat exchangers), fire protection systems, and provide water to the gasification process.

Water treatment and discharge

Wastewater from the slag handling process would need to be handled in a new wastewater treatment facility. Process wastewaters would be routed to either a wastewater facility that also handles the existing coal units or a new facility designed to process only the IGCC related wastewater.

Solid waste generation and use

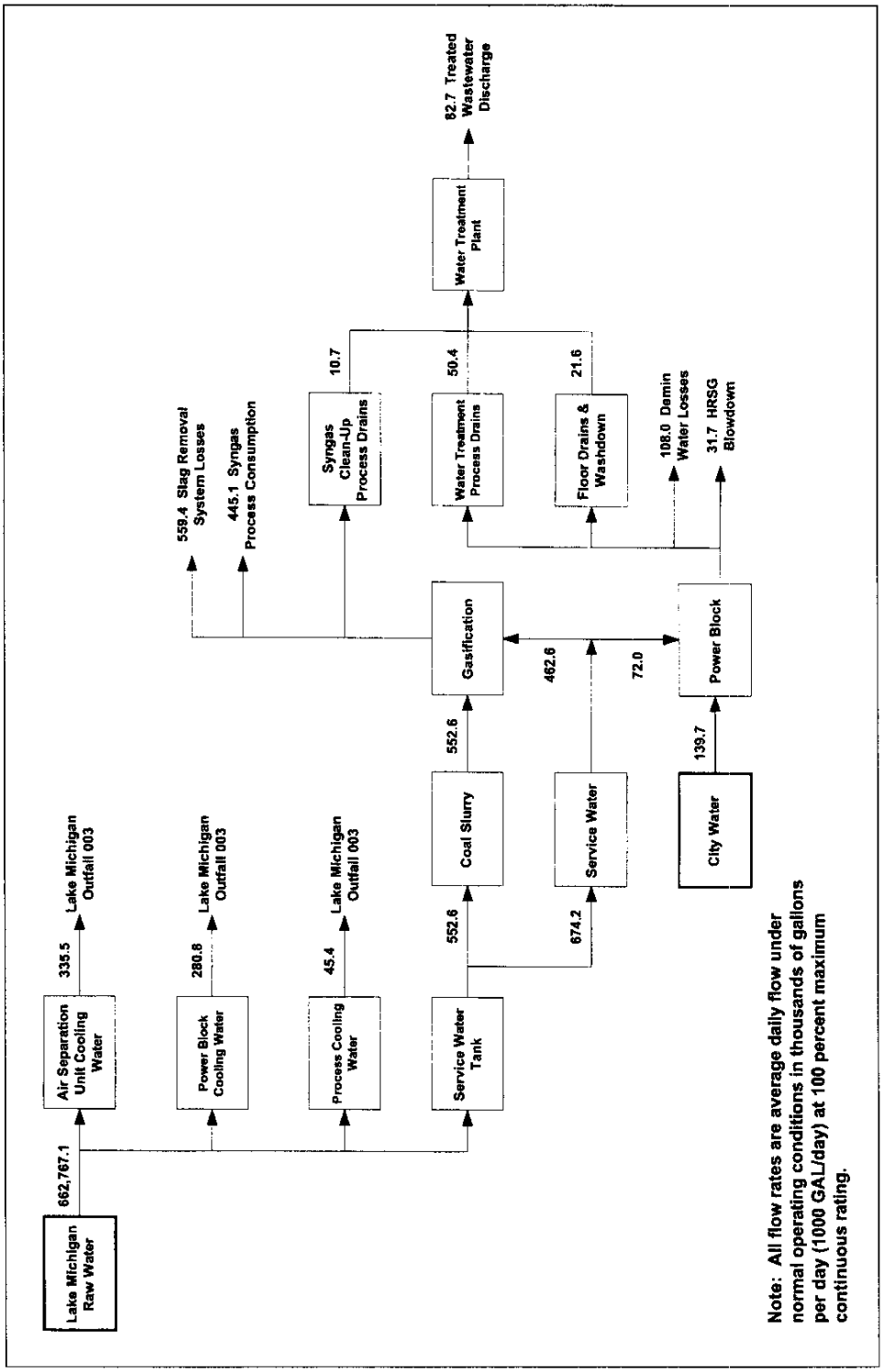
IGCC units would produce both sulfur and slag. It is expected that there would be a beneficial use market for these by-products, therefore little landfill use is expected.

Sulfur

One of the primary raw syngas clean-up steps involves the removal of acid gas and the production of either elemental sulfur or sulfuric acid. Removal of 98 percent of the sulfur (present as hydrogen sulfide (H_2S)) can be achieved using existing technology. Both form of sulfur can be beneficially used and the form of sulfur produced would depend on market conditions.

Elemental sulfur and sulfuric acid production are directly related to the sulfur content of the coal. For the bituminous coal, the quantity of elemental sulfur generated annually is estimated to be about 33,200 tons/year and the quantity of sulfuric acid is approximately 109,200 tons/year. Based on preliminary discussions with potential vendors that may be able to sell either material, the market for sulfuric acid is currently much better than it is for elemental sulfur. In fact, WEPCO purchased over 425,000 gallons of sulfuric acid for use at its own generating facilities in 2000. Sulfuric acid produced from the AGR process could be used by existing and proposed WEPCO facilities. Elemental sulfur likely would require rail transportation to Florida for subsidized use in the fertilizer industry. If a 12,000 Btu/pound bituminous coal with a 3.2 percent sulfur content were utilized, sulfuric acid would be produced at 2,600 gallons/hour.

Figure 6-10 Water balance for the IGCC plant



Trucks holding 3,000 gallons of sulfuric acid would result in peak shipments to commercial users of 30 truckloads per day on a Monday through Friday basis. Rail cars hold a capacity of 10,000 to 11,000 gallons depending on the car and could be considered for longer distance shipments. Estimated quantities of elemental sulfur and sulfuric acid are very conservative as these values are based on a 3.2 percent coal sulfur content. Material quantities would change in proportion with the sulfur content of the coal or other fuel used. In other words, a one percent sulfur content in the fuel would produce one-third as much elemental sulfur or sulfuric acid compared to a three percent sulfur coal.

Slag

The syngas process results in the formation of slag at the bottom of the gasifier. Liquid slag from the combustion section is solidified and fractured by contact with water. Slag produced would require some processing, but it could be expected to be of similar quality to bottom ash or a glass aggregate type product that can be beneficially used.

The coarse fraction of the slag would be removed from the quench section through a water-filled lock hopper system. The slag would be collected and stored in a retention pile that would be a commercial by-product. Slag produced in the IGCC process is a vitrified glass-like product. This material has a wide variety of beneficial uses including in the production of roof shingles, as a blasting grit, as a chip seal material for roads and parking lots or use as an alternative sand, gravel or crushed stone for pavements, parking lots or foundation bases. About 100,000 tons per year of slag would be expected from the proposed IGCC facility

Landfill use

Based on past experience, WEPCO expects to grow utilization of these new by-products from zero percent to full utilization within 10 years on a straight-line basis from the start of commercial operation of these new power plant units.

If necessary, landfill space would be available at the Caledonia site and other WEPCO-owned landfills. Only minimal amounts of the slag would be expected to be landfilled, as markets are developed for this new mineral resource.

Realizing that there could be an initial need for landfill space and that WEPCO would need to demonstrate 10 to 15 years of existing landfill capacity, the existing landfill capacity was reviewed and found to be sufficient for these additional materials assuming a straight line utilization growth rate from 0 to 100 percent over 10 years (see Chapter 8). Therefore, additional landfill space is not expected to be needed for the new coal-based units proposed.

Hazardous Chemicals Management

A number of chemicals would be used and stored on-site during construction and operation of the ERGS facilities. The quantity, type and size of storage vessel, and containment plans for each of these chemicals are described below.

Diesel fuel

During construction

Diesel fuel and gasoline for operating a number of construction vehicles including dump trucks and excavation equipment would be temporarily stored on-site during construction, in tanks within above-ground containment units consisting of dikes capable of containing at least 110 percent of the storage tanks' capacity. The applicants have not specified the exact amount of diesel fuel that would be present on the site during soil excavation and stockpiling activities and construction of the SCPC and IGCC units. It has stated that potential bidders have suggested differing approaches to keep the high number of construction vehicles fueled. Options under consideration include a mobile fuel truck that would come to the site daily to fuel and lube the vehicles, a tanker trailer holding between (4,000 and 8,000 gallons) inside a secondary containment on a sled that is pulled around the site to staging locations, or the use of a fixed tank inside a secondary containment to act as a back-up to the mobile fuel truck. All trucks would carry spill kits.

A diesel storage location has not been identified but it would likely be located above the rim of the excavation pit away from Lake Michigan. Possible staging locations for refueling include at the point of excavation and backfilling as well as along the haul roads. Staging locations would move as the excavation and backfilling develop.

The construction superintendent would be responsible for reporting spills and overseeing the cleanup and disposal of any affected soil and spill clean-up materials. Minor spills of fuel or other chemicals would be cleaned with absorbent pads or other manufactured absorbent products. Larger-quantity spills would not be expected to exceed the capacity of a 55-gallon drum, and would be removed from within the containment area using a vacuum tank truck or by being pumped into a suitable container. Soil or absorbent materials that have come in contact with fuel or chemicals would be immediately removed, stored, and disposed of in accordance with state regulations. All construction equipment would be expected to be kept in good working condition so that transmission, hydraulic, or brake fluid leaks do not occur. The chemical storage areas would include hose stations, spill kits, safety showers, eye wash stations, and first aid kits.

Other chemicals

Other chemicals expected to be on-site during construction and operation include various cleaning agents. They are listed in Tables 6-4 through 6-6.

Table 6-4 Typical chemicals stored during SCPC unit construction

Product	Nominal Quantity	Storage Method
Chemicals used in cleaning of piping		
Trisodium and disodium phosphate	2,500 lbs.	Delivered by contractor at time of service and stored in temporary tanks on-site
EDTA	40 gals.	
OSI-1 Inhibitor	10 gals.	
Sodium Nitrite	4,000 lbs.	
Pen-7 Surfactant	10 gals.	
Anti-foam agent	10 gals.	
Turbine cleaning		
Various Detergents		

Table 6-5 Typical chemicals stored during IGCC construction and operation

Product	Nominal quantity	Storage method
Methanol	10,000 gals.	Storage tanks
Monoethanol amine	3,000 gals.	Storage tanks
Oxygen	3 bottles	Steel pressure cylinders
Helium	3 bottles	Steel pressure cylinders
Hydrogen	20 bottles	Steel pressure cylinders
Lube oils	30,000 bottles	Lube oil tanks
Ammonium hydroxide (20%)	5,000 bottles	Storage tanks
Caustic soda	5,000 gals.	Storage tanks

Table 6-6 Typical chemicals stored during construction and operation of the IGCC combustion turbine and heat-recovery steam generator

Product	Nominal quantity	Storage method
Diesel fuel (start-up and emergency)	500,000 gals.	Storage tanks
Sulfuric acid (by-product)	200,000 gals.	
Sulfuric Acid (demineralizer)	5,000 gals.	
Sodium hydroxide (demineralizer)	5,000 gals.	
Oxygen	20 bottles	Steel pressure cylinders
Hydrogen (generator cooling)	20 bottles	
CO2 (hydrogen purging)	20 bottles	
Propane	10 bottles	
Acetylene	10 bottles	
Di-and trisodium phosphate (HRSG feedwater pH and scale control)	10 to 50 lbs. of each	Stored on pallets in granular form
Hydrazine or carbohydrazide (feedwater oxygen scavenger)	100 gallons	Drum storage
Step-up transformer insulation oil	15,000 to 20,000 gals.	Transformer vessel
Auxiliary transformer insulation oil	2,500 to 5,000 gals.	
Lube oils	15,000 gals.	Lube oil tanks (steel)
Hydraulic oil (steam turbine)	500 gals.	Oil tanks (steel)

Sodium hydroxide and sulfuric acid (H_2SO_4) would also be stored on-site. These two chemicals are used in the water treatment process to produce demineralized water.

Electric Transmission

Interconnection on the plant site

The new generation for the ERGS project would have generator step-up unit transformers adjacent to the buildings housing the generators. The generators would produce power at approximately 20 kV. This power is raised to 345 kV to connect to the transmission network.

As originally proposed in the project application, the interconnection would consist of three circuits. Each circuit would be approximately 4,000 feet in length. For the North Site, the line route from the generators to the substation would travel southwest over the coal handling area, then south to the new expanded 345 kV substation. For the South Site (see Figure Vol. 2-1), the transmission interconnection lines from the SCPC units would head west northwest across the proposed rail loop track toward the expanded substation which would be located inside of the loop. The interconnection from the IGCC unit would proceed west along the south side of the rail tracks and then turn north, crossing several sets of railroad tracks to reach the substation (See Figure Vol. 2-2). The on-site transmission interconnection would be similar for the South Site-Exp, except that the connection from the IGCC unit would run in a more north-south direction, crossing the railroad tracks several times (see Figure Vol. 2-3).

In its Conditional Use Permit agreement with the city of Oak Creek, WEPCO has proposed to split the existing 345/138 kV substation into two portions and relocated them outside of the new proposed rail loop. A diagram showing this arrangement is shown as Figure Vol. 2-4 and described in Chapter 12.

Substation changes on the plant site

For all site options proposed in the original CPCN application, the existing 345 kV substation would be expanded to the west with dimensions of approximately 500 feet by 500 feet. This equates to approximately a 40 percent increase in overall size. The modified substation and switchyard are shown in Figure Vol. 2-1. For the CUP Option, which was negotiated by WEPCO and the city of Oak Creek after the draft EIS was issued, a different location and layout for the substation changes has been proposed. The electrical duties and performance of the substation equipment would not change. The proposed substation location and layout related to the CUP Option and its potential environmental impacts are described in Chapter 12.

Possible system-wide transmission impacts

The high voltage and extra high voltage transmission system additions for the ERGS are summarized in the Generation Interconnection Study Report, Final Summary Report for IC012 Revision 1, July 17, 2002.

Transmission lines and substations support a power plant's ability to deliver power to customer's load requirements. There are three basic requirements the transmission system provides:

> Thermal Requirements – this defines the system capacity to not overheat and damage equipment or violate safety code clearances
> System Stability – this defines the ability of the generator and other regional generators to stay synchronized with each other and not trip off line due to faults, power surges, etc.
> Short-Circuit – this determines the ability of the equipment to remove faults from the system quickly and not damage equipment while maintaining the system integrity

For the purposes of the Generation Interconnection study, the ERGS project was proposed to be installed in three increments of 650 MW each. (In actuality, the two SCPC units would be 615 MW each and the IGCC capacity would be 600 MW.) The following tables and figures detail the items, purpose, and general location.

Tables 6-7, 6-8 and 6-9 below describe the transmission system improvements and costs that are associated with each of the generating units proposed for the ERGS project. Maps showing the transmission construction required for each generation increment are found in Volume 2. They are Figures Vol. 2-5, 2-6, and 2-7.

Stability issues

One of the key issues for southern Wisconsin and northern Illinois power plants is to remain stable during different system load periods and with different generation levels at the many sites in the region. The ATC "Generation Interconnection Study Report, Stability Study for IC012 Phase 2 - July15, 2002" details some of the alternatives to meeting the stability requirements when the second phase of the project (the second SCPC unit) comes on line. Three plans were studied.

At the initial time of the report's issuance in 2002, the Pleasant Prairie to Zion to Libertyville 345 kV lines were deemed the best plan to meet all the needs. This solution had about 13 miles of line from Pleasant Prairie to Zion and about 17 miles of line to be rerouted west of Zion to tap the Libertyville 345 kV line. One of the alternatives was Plan D, which had a new Big Bend 345 kV substation on the Arcadian to Oak Creek 345 kV line, and a new Big Bend to Paddock 345 kV line which would be about 56 miles in length. The changes would include rebuilding some of the 138 kV lines connecting the Mukwonago, Whitewater, Janesville, Lakehead, Sunrise, Rock River and Paddock substations.

ATC issued a 10-Year Assessment Update February 2003. The update indicates the conceptual plan for a number of 345 kV lines in southern Wisconsin connecting to Illinois and Iowa. The Big Bend to Paddock 345 kV line is illustrated as one of several 345 kV lines that could meet future needs. The line is not being proposed at this time.

A third set of IC012 (Elm Road) interconnection studies are being conducted during the summer of 2003. The following generating units which were ahead of the first two ERGS units in the MISO generation list queue have been removed:

- #GIC001 (Midwest Power – Germantown) - 1194 MW, on the Arcadian – Zion 345 kV line
- #GIC003 (Badger Gen – Kenosha) – 375 MW on the Arcadian – Pleasant Prairie 345 kV line
- Reduction with 3 of 4 proposed units in northern Illinois resulting in the generation dropping from 2146 MW to 825 MW

Removal of these facilities will affect the incremental amount of transmission in the region required to interconnect the new generation and will change the thermal capabilities of the transmission system to move the power to the designated load area.

The new study is assessing the region of southern Wisconsin and northern Illinois through 2011. ATC is conducting the restudy. ATC completed a stability restudy of the second unit on June 13, 2003. The first report of this restudy which covers the first two SCPC units is expected to be complete in mid-July. The preliminary results clearly indicate that no, new long 345 kV line is required to provide reasonable stability responses for the first two 650 MW SCPC units. (One of the original study solutions for adequate stability was a 345 kV from Pleasant Prairie to Libertyville via Zion.)

The expected results of the restudy, as of June, are summarized below. The detail projects are described in Table 6-10. Some stability performance issues still need to be determined for Phases I and II. The solution possibilities beyond the other transmission lines:

- Another 345 kV breaker line position at Elm Road
- Series breakers at two Pleasant Prairie 345 kV lines
- And either a power system stabilizer on Oak Creek Generator #9 or a restriction on it's operation

The original study had the cost assessed as follows;

Phase I	$117,711,544
Phase II	$ 46,338,542
Total	$164,050,086

The incomplete restudy has the follow estimate:

Phase I	$ 16,639,391	plus move the 345 kV and 138 kV substations
Phase II	$ 64,320,789	
Total	$ 80,960,180	plus move the 345 and 138 kV substations

It has not been estimated when the transmission studies for all three phases will be completed. Another uncertainty factor is the potential retirement of Oak Creek Units 5 and 6 which total 550 MW. That could have a significant influence on the transmission requirements for the third ERGS unit, the IGCC.

Table 6-7 Estimated costs for Phase 1 Improvements - original study

Item No.	Project	Projected Cost ($2007)
System Reinforcements for System Stability (Required)		
1.	Expand Oak Creek 345 kV Switchyard into 10 position breaker and a half design[a, b]	17,647,133
2.	Construct Oak Creek – Brookdale 345 kV Line a. Construct new line from Oak Creek – Brookdale 345 kV line b. Convert/Reconductor non-operative 230 kV line segment from C&NW RR to St. Martins c. Convert/Reconductor 5 miles of Bluemound-St. Martins 138 kV line (KK5066) from St. Martin Substation to Brookdale site	17,277,670
3.	Construct Brookdale 345/138 kV Substation with 1,500 MVA 345/137 kV transformer	14,813,630
4.	Construct Brookdale – Granville 345 kV Line a. Convert/Reconductor 5.6 miles of Bluemound St. Martins 148 kV line (KK5066) from Brookdale to Bluemound Substation b. Rebuild western lower line from Bluemound to Carmen site and install 7-mile 345 kV line segment c. Convert Carmen to Granville (3 miles) segment of Tamarack Granville 138 kV line (KK3444) to 345 kV	18,196,380
5.	Install line breaker and termination equipment at Granville 345 kV substation	1,112,000
6.	Convert Oak Creek to Bluemound 230 kV line (K873) to 345 kV	18,983,330
7.	Construct Bluemound 345 kV Substation with 1,500 MVA 345/138 kV Transformer	4,933,164

Item No.	Project	Projected Cost ($2007)
System Reinforcements for System Stability (Required)		
8.	Install two series line brakers at Pleasant Prairie Substation[c]	2,126,684
Subtotal		**95,089,991**
System Reinforcements for Short Circuit (Required)		
9.	Replace at Bluemound Substation seven 138 kV overdutied circuit breakers having an interrupting rating of 42 kA with breakers having a interrupting rateing of 63 kA	2,435,391
Subtotal		**2,435,301**
Total		**97,525,382**
System Reinforcements for Thermal (Optional)		
10.	Install two breakers and termination equipment at Oak Creek Switchyard 138 kV [d]	1,643,377
11.	Construct Oak Creek-St. Martins circuit #2 (Refer 4a) [d]	3,276,000
12.	Relay modification St. Martins Substation [d]	114,000
13.	Construct Butler to Carmen line segment to form Butler-Tamarack Line (Refer 4c) [d]	332,300
14.	Butler Substation (add one line breaker and ancillary equipment) [d]	523,170
15.	Install Bluemound-Butler Line (KK5051) on new 345 kV structures (Refer 4b) [d]	582,220
16.	Reconductor Oak Creek-Ramsey 138 kV	138,000
17.	Reconductor underground segment Harbor-Ramsey 138 kV line	11,535,000
18.	Reconductor Oak Creek-Allenton 138 kV	2,034,000
19.	Reconductor Harbor-Norwich-43rd Street 138 kV [e]	----------
Total		**20,178,067**
Grand Total		**117,703,449**

Notes:

a. Includes transfer of unit #7 from 230 kV to 345 kV bus.

b. Transmission breakers for unit connections are required for stability purposes in Phase 3. These breakers are not required for stability purposes in this phase and have not been included. However, the additional breakers may be included in Phase 1 pending development of connection standards presently under review.

c. Alternate solution is construction of 345 kV ring bus at Bain Substation ($4,481,132).

d. System reinforcements needed to maintain the integrity and thermal capability of transmission system due to facilities converted to 345 kV operation for stability purposes.

e. Included in Lakeside retirement project.

Table 6-8 Estimated costs for Phase 2 improvements - original study

Item No.	Project	Projected Cost ($2007)
System Reinforcements for System Stability (Required)		
1.	Install two breakers and termination equipment at Oak Creek 345 kV Switchyard to accommodate second 650 MW unit [a, b]	4,211,858
2.	Install 345 kV breaker and termination equipment at Pleasant Prairie Substation	1,063,342
3.	Construct Pleasant Prairie-Libertyville 345 kV line (~ 23 miles). [d]	40,000,000
4.	Install 345 kV breaker and terimation equipment-Libertyville Substation (Exelon/CECo)	1,063,342
Subtotal		**46,338,542**
System Reinforcements for Short Circuit (Required)		
	Replacement of overdutied circuit breakers	0
Subtotal		**0**
Total		**46,338,542**
System Reinforcements for Thermal (Optional)		
	No items to be entered [e]	0
Total		**0**
Grand Total		**46,338,542**

Notes:

a. Includes addition of the second 650 MW generating unit.

b. Transmission breakers for unit connections are required for stability purposes in Phase 3. These breakers are not required for stability purposes in this phase and have not been included. However, the additional breakers may be included in Phase 2 pending development of connection standards presently under review.

c. Short Circuit Study for Phase 2 did not identify any overdutied circuit breakers.

d. An alternative line being considered is a Big Bend-Paddock 345 kV Line ($61,544,474):
- Construct initial 3-position 345 kV ring-bus at Big Bend Switching Station site ($4,481,132).
- Install circuit breaker #4 at Paddock 345 kV ring-bus and termination equipment ($1,063,342).
- Construct 56 mile Big Bend-Paddock 345 kV line by rebuilding existing 138 kV ROW with double circuit structures to accommodate existing 138 kV circuits and new 345 kV circuit ($56,000,000).

e. The reinforcements identified in the thermal study for Phase 2 are already required in Phase 1 for stability purposes (Refer to Table 6-4.).

Table 6-9 Estimated costs for Phase 3 improvements - original study

Item No.	Project	Projected Cost ($2007)
System Reinforcements for System Stability (Required)		
1.	Expand Oak Creek 345 kV Switchyard breaker and a half design to 16 positions.[a]	21,880,544
2.	Install three breakers and termination equipment at Oak Creek 138 kV Switchyard.[b]	6,848,088
3.	Convert Oak Creek-Bluemound 230 kV line (K862) to 345 kV and reroute line into Arcadian Substation.	28,171,000
4.	Expand Bluemound 345 kV Substation into 7-position ring-bus with 2,500 MVA, 345/138 kV transformers.	17,194,478
5.	Install two 345 kV circuit breakers and termination equipment at Arcadian Substation.	5,568,096
6.	Convert Oak Creek-Racine 138 kV line to 345 kV to create second Oak Creek-Racine 345 circuit.	7,036,000
7.	Install 345 kV circuit breaker and termination equipment at Racine Substation.	1,112,000
Subtotal		**87,810,206**
System Reinforcements for Short Circuit (Required)		
8.	Replace a total of 22-138 kV overdutied circuit breakers at Harbor, Everett, and Haymarket Substations having an interrupting rating of 50 kA with breakers of 63 kA. [d]	7,654,086
Subtotal		**7,654,086**
Total		**95,464,292**
System Reinforcements for Thermal (Optional)		
9.	Install two 500 MVA 345/138 kV transformers at Arcadian Substation	55,700,370
Total		**55,700,370**
Grand Total		**151,164,662**

Notes:

a.. Includes the transfer of unit 8 from the 280 kV to the 345 kV bus. Includes seven transmission breakers for unit connection plus one line connection required for stability purposes.

b. Includes the transfer of units 6 and 9 from the 230 kV to the 138 kV bus.

c. Includes re-route of Brookdale-Granville into Bluemound Substation.

d. Except for the one project listed here all reinforcements identified in the thermal study for Phase 3 are already identified and required for stability purposes for Phase 3.

Table 6-10 Estimated costs for restudied improvements associated with the ERGS project

Item No.	Restudy Projects	Projected Cost ($ 2007)
	Not detailed by type or requirement	
RI.1	Replace and relocate Oak Creek 345 kV 5 position ring bus with new Elm Road 4 section, 8 position, conventional breaker-and-half	Not completed
RI.2	Replace and relocate Oak Creek 138 kV 9 section, 12 position, inverted breaker-and-half, with new Elm Road 8 section, 13 position, inverted breaker-and-half	Not completed
RI.3	Reconductor Oak Creek – Ramsey6 138 kV (0.8 mile)	135,000
RI.4	Reconductor Oak Creek - Allenton 138 kV (5.4 miles)	2,034,00
RI.5	Reconductor underground segment Harbor – Ramsey5 138 kV (5.7 miles)	11,535,000
RI.6	Replace at Bluemound substation 7 – 138 kV overdutied circuit breakers having an interrupting rating of 42 kA with breakers with an interrupting rating of 63 kA	2,435,391
	Subtotal Phase I	**16,139,391** w/o RI.1 & RI.2
RII.1	Install bus section with three breakers and termination equipment at Elm Road 345 kV for second 650 MW unit and one 345 kV line	4,211,858
RII.2	Add line position (2 circuit breakers) to Oak Creek 138 kV inverted breaker-and-half bus design	1,643,337
RII.3	Construct Oak Creek – Brookdale 345 kV line (25.1 miles)	17,277,670
RII.4	Construct Brookdale – Granville 345 kV line (16.6 miles)	18,196,380
RII.5	Build Brookdale 345 & 138 kV substation including 3 position 345 kV ring bus with single 500 MVA 345/138 kV step down transformer and initial 2 section, 8 position 138 kV radial bus	14,813,630
RII.6	Install 345 kV line breakers and termination equipment at Granville substation	1,113,000
RII.7	Construct Oak Creek – St. Martins 138 kV line (17.3 miles)	3,276,000
RII.8	Construct Butler – Carmen 138 kV line segment to form Butler – Tamarack (1.6 miles)	443,400
RII.9	Install Bluemound – Butler line (KK5051) on new 345 kV structures (5.4 miles)(Reference RI.4)	582,220
RII.10	Add line breakers and ancillary equipment at Butler substation	523,170
RII.11	Add two - series line breakers at Pleasant Prairie substation	2,126,684
RII.12	Relay modifications at St. Martins substation	114,000
	Subtotal Restudy Phase II - Preliminary	**64,321,349**
	Total for Phase I and II (w/o R1.1 & RI.2)	**80,460,740**

7

Chapter 7 - Air Emissions

This chapter has three primary components and they are described under the following subtitles:

- Common Pollutants of Coal-burning Power Plants
- Relevant Air Pollution Regulation in Wisconsin
- ERGS Air Quality Analyses

The first section is a general description of the pollutants produced by coal-fired power plants and an explanation of the general health and environmental concerns related to these pollutants. The next section explains the DNR permitting process and other regulatory details. The last section discusses existing air quality in the region, the projected emissions of the proposed generating units, and the emission control technologies likely to be required by the air construction permit issued by the DNR. This last section is supported by a series of tables, both in the chapter and additional tables in Appendix D, that show how the calculated emissions (assuming that the best available control technologies have been implemented), in combination with the ambient air pollutant concentrations, compare to the National Ambient Air Quality standards (NAAQS) and the Prevention of Significant Deterioration (PSD) increments.

In the draft EIS these tables contained data showing the results of air modeling conducted by the applicants. The draft EIS indicated that the DNR would conduct its own air modeling analyses to verify these results and determine whether the proposed project was permittable. However, due to continuing revisions to the proposed project design, layout, and air emission parameters (as described in the next section of this chapter), the DNR was not able to complete its analyses for the final EIS. The tables included in this final EIS contain updated information, data, and results submitted by the applicants. The DNR must still conduct its own air quality modeling analysis in order to determine if the project is permittable, and if so, under what circumstances and conditions. This analysis is fundamental the DNR's air permitting process.

Finally, several short summary points are found at the conclusion of the chapter, to highlight some of the key areas of information in the chapter.

Project changes and resulting delays in DNR's analyses

The potential air quality impacts of the project design and layout need to be determined through DNR modeling analyses. The draft EIS used WEPCO's data and modeling results from its permit applications for the three proposed sites because the DNR had not had time to complete its modeling on the three proposed

sites. The expectation was that DNR modeling results would be used in the final EIS to verify potential air quality impacts.

The DNR's air modeling analysis has not been completed. Changes to the original permit application were made by WEPCO in April and June of 2003. Changes in the height of the exhaust stacks for the two SCPC units if located on the South Site or the South Site-Exp option were made as a result of FAA concerns. (See Chapter 11 regarding the Racine airport.) The stack height changes were submitted by WEPCO to the DNR just before the release of the draft EIS in April. DNR has verified that the stack height changes in conjunction with reduced sulfur dioxide hourly emission rates proposed by WEPCO would not result in exceedances of the ambient air quality standards or air increments for all pollutants.

On June 2, 2003; June 27, 2003; and July 11, 2003, WEPCO submitted "supplemental information to DNR regarding the air pollution control permit application" related to operational refinements for the original ERGS North Site proposal, as well as changes to the original North Site facility layout that were recently negotiated with the city of Oak Creek for the CUP. The refinements[75] required the DNR to redo its analyses for the original North Site proposal. In early July, the applicants indicated that these refinements should also be applied to the South Site alternatives.

The changes related to WEPCO's recently designed CUP Option require a separate new set of air modeling analyses. Thus, the DNR is now reviewing four air pollution control permit applications instead of the three originally related to the CPCN filing. Information related to the CUP Option was not submitted to the PSC as an amendment to the CPCN application. Air emission information pertaining to the North Site CUP Option is discussed in detail in Chapter 12.

The DNR intends to provide testimony related to the completed analysis of at least one of the siting/operating scenarios at the time of the project hearings in late summer 2003. WEPCO has prioritized the order in which the applications should be processed, beginning with the the original North Site alternative with operational refinements, the CUP Option for the North Site, and finally the South Site and South Site-Exp. The DNR is expected to conduct a separate hearing on the applications for the air pollution control permits once the air permit applications are deemed complete and the DNR has completed its air quality analysis and preliminary determination on these applications. However, the DNR still awaits complete air permit applications from WEPCO.

Common Pollutants of Coal-burning Power Plants

The combustion of fossil fuels by coal-burning power plants can create harmful impacts to the environment and to human health. Some of the toxic chemicals that are emitted from power plants include a variety of metals, organic compounds, acid gases, sulfur, nitrogen, carbon dioxide, and particulate matter. The quantity and type of emissions from coal combustion greatly depends on the rank and composition of the fuel, handling of the fuel, the type and size of the boiler, firing conditions, types of emission control technologies, and the level of equipment maintenance.

[75] These refinements are described later in this chapter in the section "Expected Emissions & Proposed Best Available Control Technology."

Currently, power plants account for 73 percent of Wisconsin's sulfur dioxide (SO_2) emissions and nationally, 27 percent of the nitrogen oxide (NO_x) emissions. Once released into the air, some of these chemicals react in the atmosphere and can form particulates, increase ozone levels, reduce visibility (smog), and acidify surface waters. They are a major contributor of greenhouse gases and can also cause significant health problems especially for the elderly, individuals with heart and lung disease, and children.

State and federal regulation imposes limits on many of the emitted pollutants. The EPA's National Ambient Air Quality Standards (NAAQS) regulate the emissions of six "criteria" pollutants: carbon monoxide (CO), nitrogen dioxide (NO_2), ozone (O_3), lead (Pb), particulates (PM_{10} and $PM_{2.5}$), and sulfur dioxide (SO_2). State air permits also regulate the emissions of these and other classes of pollutants. Regardless of whether the facility meets existing standards, there is often a question of whether sensitive individuals are adequately protected. In general, when air pollution levels increase, sensitive individuals may experience adverse respiratory symptoms. The problem is complicated because some of the harmful pollutants emitted by coal-burning power plants such as NO_x are also emitted in a larger percentage by motor vehicles and some of the pollutants travel long distances from their source.

Regulations related to air emissions are discussed in the next section of this chapter. Pollution controls are also discussed in Chapter 6 under "Proposed Coal Technologies."

Particulates

Particulate matter (PM) is a complex mixture of very tiny solid or liquid particles, composed of chemicals, soot, and dust. Their chemical and physical composition varies widely because particulates originate from a variety of sources. PM can arise both from direct emissions and from atmospheric reactions of gaseous pollutants.

Coarse particles (10 to 2.5 micrometers in diameter) are generated by processes that stir up dust such as material handling, vehicles traveling on unpaved roads, and crushing and grinding operations. Coarse particles typically have limited spatial impact, tending to settle rapidly in the downwind area near the emission point.

Very fine particles (less than 2.5 micrometers in diameter) result from fuel combustion (motor vehicles, power plants, and industrial processes), residential fireplaces, and wood stoves. They can also be formed by reactions in the atmosphere of emitted organic gases, NO_x, sulfur oxides (SO_x), and ammonia. Power plants and motor vehicles are the primary sources of NO_x emissions that oxidize in the atmosphere and form PM. The primary source of SO_2 emissions are power plants and other coal-burning facilities which react in the atmosphere to form sulfate particles. These very fine particles can remain suspended in the air for long periods of time and travel 10 to 100 miles before deposition occurs.

Both sizes of particles can penetrate the sensitive respiratory tract and cause serious health problems. EPA has estimated that airborne particles cause over 15,000 premature deaths in the United States per year. Scientists have correlated exposure to airborne particles with increased hospitalizations for asthma attacks, worsening of lung disease, and heart damage. Recent studies have suggested a link between PM and lung cancer. Exposure to coarse particles is primarily associated with aggravation of respiratory conditions such as asthma. Fine particles are most closely associated with decreased lung function, increased hospital

admissions and emergency room visits, increased respiratory symptoms and disease, and premature death. Sensitive groups that appear to be at greatest risk to PM effects include the elderly (>65 years), individuals with cardiopulmonary disease such as asthma or congestive heart disease, and children.

The EPA "1996 Air Quality Criteria for Particulate Matter" concluded that there was adequate evidence of fine particles playing an important role in observed PM mortality effects. Studies conducted since 1996 have confirmed and expanded earlier findings. Though exact values vary from study to study, all consistently conclude that an increase in as little as 25 $\mu g/m^3$ of PM causes a 1.75 to 8.5 percent increase in nonaccidental death. This holds true for both long-term and short-term exposures, coarse and fine PM, and in different cities. Despite these widely accepted morbidity studies, current research is just beginning to understand the toxicological mechanisms by which ambient PM affects the biological system.

The sulfate component of PM has been implicated in the corrosion of metals, damaging and staining of stone buildings and monuments, soiling of structures and motor vehicles, and harmful impacts to vegetation and the environment.

PM has the potential to cause haze and affect local and regional visibility. Haze is caused when sunlight encounters tiny pollution particles in the air. As the amount of PM increases, more light is scattered and absorbed, which reduces the clarity and color of what is seen. Periods of poor visibility normally occur in conjunction with elevated levels of PM and ozone.

The EPA has set standards for particulate matter with a diameter of 10 micrometers or less (PM_{10}). All of Wisconsin meets the current PM_{10} standard. In 1997, the EPA adopted a new annual arithmetic mean and 24-hour average standard for fine PM with diameters of 2.5 microns or less ($PM_{2.5}$). This was in response to studies which show greater health concerns surrounding low concentrations of fine PM because it has the potential to penetrate deeper into lungs. Implementation of the $PM_{2.5}$ standard was challenged in court, but was upheld by the Supreme Court in 2001. The EPA plans to establish non-attainment areas (areas that do not meet the $PM_{2.5}$ standard) and then take steps to reduce its emissions.

Wisconsin's $PM_{2.5}$ monitoring network has been operating statewide since 1999. Air pollution monitoring sites are discussed later in this chapter under "Ambient Air Quality in the Region." Based on the monitoring results from the years 2000 - 2002, the Wisconsin DNR plans to submit a State Implementation Plan (SIP) for $PM_{2.5}$ at the end of 2005. EPA designations of non-attainment counties are anticipated in 2007. Monitoring results from the last three years indicate that no county currently exceeds either the annual arithmetic mean or the 24-hr average $PM_{2.5}$ NAAQS. The annual arithmetic mean (averaged over three years) for the Milwaukee County area has ranged from 12 to 13.5 $\mu g/m^3$, below the standard of 15$\mu g/m^3$. Individual monitors have recorded higher concentrations. The potential increase of PM by the ERGS may result in Milwaukee area counties that are not in attainment for $PM_{2.5}$. Alternatively, current approved programs (lower vehicle emission levels, low-sulfur diesel and gasoline use, reduction of NO_x emissions) are anticipated to lower the ambient concentrations of PM in the near future.

NO_x

NO_x is the generic term for a group of highly reactive gases, all of which contain nitrogen and oxygen in varying amounts. The primary sources of NO_x emissions are motor vehicles (40 percent) and electric utilities (40 percent). The primary NO_x emission from the combustion of coal is nitric oxide (NO), with only a few

NO_x is one of the main ingredients in the formation of ground-level ozone (see ozone section). One form of NO_x, nitrous oxide (N_2O), is a greenhouse gas and contributes to global warming (see greenhouse gas section). Nitrogen oxides can also form small nitrate particles that are associated with serious health impacts like heart attacks. Additionally, the nitrate particles can form nitric acids in the atmosphere which contributes to acid rain, and can provide too much nitrogen and over-fertilizing the ecosystem.

High levels of NO_2 may be fatal to humans, while lower levels affect the delicate structure of lung tissue. Humans exposed to high concentrations suffer lung irritation and potential lung damage. Long-term lower levels of exposures can destroy lung tissue, leading to emphysema. Concentrations of NO_x as low as 0.1 ppm, can cause lung irritation and measurable decreases in lung function in asthmatics. Children, the elderly and people with lung diseases, such as asthma, emphysema or bronchitis are sensitive to NO_x.

Since 1970, EPA has tracked NO_x emissions. To help reduce acid rain, EPA devised a two-phased strategy to cut NO_x emissions from coal-fired power plants. In Phase I of the strategy (1996-1999), NO_x emissions were reduced by over 400,000 tons per year by installing burner and air supply equipment that stage delivery of oxygen to burning coal in utility power plants. The goal of the second phase is to reduce emissions by over 2 million tons per year beginning in the year 2000. NO_x emissions increased 9 percent between 1982 and 2001 and decreased 3 percent between 1992 and 2001. Concentrations of nitrogen dioxide (NO_2) in the air decreased 13 percent between 1982 and 1992 and by 11 percent between 1992 and 2001.

SO_2

Sulfur is a component of both coal and oil. Gaseous sulfur oxides are emitted when the sulfur is oxidized during the combustion process. On average, about 95 percent of the sulfur present in bituminous coal would be emitted as gaseous sulfur oxides, primarily SO_2. The amount of SO_2 released into the atmosphere through the exhaust stack would depend on the sulfur content of the coal. Nationwide, the sulfur content of coal normally ranges between 0.7 and 2 percent by weight. However, much of the coal mined in the eastern U.S. has a much higher sulfur content. The SO_2 emissions from Wisconsin coal-burning power plants currently accounts for 73 percent of all sulfur oxide emissions in the state. These SO_2 emissions and sulfate particles are often transported long distances and deposited far from the point of origin.

Sulfur dioxide causes a wide variety of health and environmental impacts because of the way it reacts with other substances in the air. SO_2 irritates the respiratory system and can cause pronounced health problems. Sulfate particulates are a primary factor in the production of hazy atmospheric conditions. Acid rain is caused by SO_2 and NO_x reacting with other substances in the air (see Acid Rain section). Corrosion and damage to metals and masonry may also result from increased sulfur dioxide emissions.

Severe health affects are associated with increased sulfur dioxide emissions. Peak levels of SO_2 in the air can cause breathing difficulty for people with asthma. Long-term exposure to high levels of SO_2 gas and particles may cause respiratory illness and aggravate existing heart disease. Sulfate particles are associated with increased respiratory symptoms, respiratory disease, and premature death. Exposure to high concentrations of sulfur dioxide for short periods of time can constrict the bronchi and increase mucous flow, making breathing difficult. Children, the elderly, those with chronic lung disease, and asthmatics are especially susceptible to these effects.

Acid rain

Acid rain has been studied in Wisconsin since the early 1980s. The combustion of fossil fuels is the major cause of acid rain. Rain uncontaminated by any pollutants has a pH of 5.0 to 6.0. Rain with a pH less than 5.0 is considered "acid rain." The primary cause of acid rain is the emissions of SO_2 and NO_x, which enter the atmosphere and combine with moisture, returning to earth in the form of acidic rain, snow, or fog. Acidic deposition also may occur in a dry form when acidic compounds attach to particulates and return to earth. These acids can overwhelm the neutralizing capacity of some soils and lake waters.

Research has determined that acid rain is linked to declines observed in the health of many forests in the U.S. However, there has been no identified major decline in Wisconsin forests due to acid rain. Bodies of water affected by acid rain lose some of their biodiversity as more acid-sensitive species of plant and animal life die off or experience a decrease in reproductive success. Approximately 2 percent of Wisconsin's lakes are acidic and an additional 10 percent are "extremely" sensitive to acid rain. Acid deposition also has been connected to elevated mercury concentrations in fish and fish-eating wildlife. This in turn endangers the health of people, especially infants and children who may eat fish from affected lakes.

In 1986, Wisconsin passed one of the first and strongest state acid rain control laws in the nation. Wisconsin's major electric utility companies were required by 1993 to reduce their SO_2 emissions by 50 percent from 1980 emission levels. In 1990, overall annual SO_2 emissions from electric utility companies had fallen 46 percent. In 1990, the Clean Air Act Amendments were enacted, requiring electric utility companies nationwide to reduce their collective SO_2 emissions by the year 2000 to 10 million tons per year below 1980 emission levels (or 40 percent). Utility SO_2 emissions will be capped at 8.9 million tons per year in the year 2000 and thereafter.

Results of these and additional regulations have reduced the average pH levels of the state's rain. In 1990, the annual average pH ranged from 4.59 in southeastern Wisconsin to 5.06 in northwestern Wisconsin. In the early 1980s, pH levels ranged from 4.4 to 4.8. For the last several years, the streams and lakes in the northeastern and upper Midwestern parts of the U.S. have shown decreased sulfate concentrations and increased pH levels, indicating a consistent improvement. In the upper Midwest, the number of acidified lakes has gone from 3 percent to less than 1 percent.

Greenhouse gases

Greenhouse gases (GHGs) are trace gases in the atmosphere that trap heat and help keep our planet warm enough for life to survive here. The three major human-influenced greenhouse gases are carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O). Since the beginning of the industrial revolution, atmospheric concentrations of CO_2 have increased by about 30 percent, CH_4 concentrations have more than doubled, and N_2O concentrations have risen by about 15 percent. Scientists believe that these increases in greenhouse gas concentrations have contributed to the warming of the planet by about one degree Fahrenheit over the past 100 years, and continued increases are expected to cause further warming and climate change in the future.

The combustion of fossil fuels to produce energy is the major source of greenhouse gas emissions in Wisconsin and the US, accounting for 80 to 90 percent of emissions. Electric utilities and transportation are each responsible for about one-third of total greenhouse gas emissions.

Increasing amounts of CO_2 and other greenhouse gases in the atmosphere are likely to have significant impacts on the environment and human health everywhere around the planet. Some of the potential impacts of global warming on Wisconsin include:

- Wisconsin's weather is expected to be warmer and dryer with increased frequency of heat waves, droughts, floods, and severe weather events. Winters will likely be milder with less snow and decreased ice cover on lakes.
- Water levels are expected to decrease on the Great Lakes and inland lakes and streams. Lake Michigan water levels could drop by several feet. Lower water levels will decrease the amount and quality of water available. Wetlands will be especially vulnerable to changing water levels.
- Water temperatures are expected to increase. This will lead to more weeds and algae in lakes and lower water quality in general. Warmer waters will favor warm water fish species and populations of cold water species (such as trout) could decrease significantly.
- Ecosystem and forest composition is likely to change as species adapted to warmer and dryer conditions prevail while other species disappear. Wildlife and plants are expected to move their ranges northward as the temperature warms. Endangered species may disappear if they cannot adapt.
- Increased frequency of droughts and floods will affect crop productivity. Crops adapted to dryer and warmer conditions may replace current crops. A potential increase in insect pests could require more pesticide use. Heavy rains may increase runoff of soil, pesticides and fertilizer, increasing water pollution. Heat waves will stress livestock.
- Increased frequency of heat waves will cause more heat stress and mortality in people. With milder winters, increased incidence of insect-borne diseases (e.g., West Nile virus, malaria) and increased incidence of water-borne diseases (e.g., cholera, cryptosporidium) are expected. Warmer air temperatures could exacerbate air quality problems, especially ozone and smog episodes in eastern Wisconsin.
- Warmer and dryer conditions will likely increase forest fire frequency and severity.
- Lack of snow cover will decrease opportunities for snowmobiling and skiing. Lack of ice cover on lakes will decrease opportunities for ice fishing, ice skating, ice boating. Lower water levels on lakes and streams could affect water sports.
- Lower water levels on the Great Lakes may affect shipping. Low water in ports could decrease shipping volume and increase the number of ships traveling on the lakes. More dredging will likely be needed to keep ports and channels navigable. Increased dredging will be expensive and may increase water pollution.

Volatile Organic Compounds and Ozone

Volatile Organic Compounds (VOCs) include a very wide range of individual substances, such as hydrocarbons (for example benzene and toluene), halocarbons, and oxygenates. Breathing zone exposure to specific concentrations of VOCs can be toxic and cause significant health impacts. Currently there are no

state or federal ambient air quality VOC regulations. However, the release of VOCs from the elevated plume of a power plant poses only minor inhalation risks.

VOC emissions are a concern because they are a major precursor to ground-level Ozone (O3), a principal component of smog. Ozone is created when cars, power plants, large factories, and other sources emit volatile organic compounds (VOCs) and NOx which interact with sunlight. Ozone levels rise most frequently during the summer months.

In general, as ground-level ozone concentrations increase, more and more people experience health effects and the effects become more serious. Exposure to ozone can trigger health problems such as chest pain, coughing and lung damage, and aggravate conditions like asthma, bronchitis, heart disease, and emphysema. Ozone irritates the respiratory system. Exposure to ozone may reduce the ability of the immune system to fight off bacterial infections. Those most likely to be affected by ozone exposure include active children and adults, people with asthma, and people that are unusually sensitive to ozone. Frequent exposure can cause permanent lung damage.

Ozone can also damage crops, trees, rubber, fabrics, and other materials. Ozone impairs the ability of plants to produce and store food. This reduces the yield and weakens the plants' ability to survive disease, insect attacks, and extreme weather like drought or wind. Ozone can have long-term effects on forests and ecosystems.

Ozone is regulated under the EPA's National Ambient Air Quality Standards (NAAQS). Counties that do not meet the ozone standard are designated as either, marginal, moderate, serious, severe, or extreme "non-attainment" areas. Six Wisconsin counties (Kenosha, Milwaukee, Ozaukee, Racine, Washington, and Waukesha) are designated as being in severe non-attainment of the national one-hour ozone standard. Door County is designated as a marginal rural transport non-attainment. Based on air quality monitoring data, the DNR has requested that the EPA change the status of Door County to attainment.

In addition to the one-hour ozone standard, in 1997 the EPA adopted an eight-hour ozone standard. Monitoring data has indicated that ten Wisconsin counties may be non-attainment for the eight-hour ozone standard. They include, in addition to the six one-hour ozone non-attainment counties, Door, Kewaunee, Manitowoc, and Sheboygan. U.S. Environmental Protection Agency (EPA) will make final eight-hour non-attainment designations by April 15, 2004.

States are required to use specific control measures to achieve compliance with the NAAQS including the development and adoption of a State Implementation Plan (SIP). The SIP identifies the measures a state is taking to control emissions of regulated pollutants and how these measures will meet the standards by specified deadlines. The EPA required Wisconsin to submit a SIP that would result in a 15 percent reduction of ozone-forming VOCs from a 1990 base level of emissions. And, starting in 1996, the state was required to achieve an additional 3 percent annual reduction in VOCs in the severe non-attainment counties. Wisconsin must demonstrate to the EPA that the targeted reduction in emissions was achieved in 1996 and every third year thereafter until the area reaches attainment or until the required attainment date in 2007. Using various emission-controls and programs, Wisconsin has met all rate-of-progress requirements and emission-reduction milestones.

Stationary air pollution sources are regulated through the Wisconsin's air permit program. Existing stationary sources in non-attainment areas are required to install equipment with emission controls. The facilities that must install control equipment are determined based on the amount of pollution emitted by the facility, the severity of the pollution problem in the non-attainment area, and the industrial category of the facility. The emission limits are referred to as reasonably available control technology (RACT).

Hazardous Air Pollutants (HAPs)

Hazardous air pollutants (HAPs), also known as toxic air pollutants or air toxics, are those air pollutants that may cause cancer or other serious health effects or adverse environmental and ecological effects.[76] The EPA is required to control 188 hazardous air pollutants. At sufficient concentrations and duration, health effects related to HAPS can include damage to the immune system as well as neurological, reproductive, developmental, respiratory, and other types of problems. In addition to exposure from breathing air toxics, risks also are associated with the deposition of toxic pollutants onto soils or surface waters, where they are taken up by plants and ingested by animals and eventually magnified up through the food chain. Like humans, animals may experience health problems if exposed to sufficient quantities of air toxics over time.

Health risks from HAPs can result from a variety of types of exposure:

- Breathing contaminated air.
- Ingesting contaminated food products, such as fish from contaminated waters; meat, milk or eggs from animals that fed on contaminated plants; and fruits and vegetables grown in contaminated soil on which air toxics have been deposited.
- Ingesting water contaminated by toxic air pollutants.
- Ingesting contaminated soil. Young children are especially vulnerable because they often ingest soil from their hands or from objects they place in their mouths.
- Touching (skin contact) contaminated soil, dust or water (for example, during recreational use of contaminated water bodies).

Once toxic air pollutants enter the body, some accumulate in body tissues. Through a phenomenon called "biomagnification," predators typically accumulate ever greater pollutant concentrations than their contaminated prey. As a result, people and other animals at the "top" of the food chain that eat contaminated fish or meat are exposed to concentrations that are much higher than the concentrations in the water, air, or soil.

Hazardous air pollutants emitted from coal-fired utility boilers and IGCCs may be classified in four broad categories:

a. Inorganic, solid phase HAPs, such as arsenic
b. Inorganic, acid gas HAPs, such as hydrochloric acid
c. Organic HAPs, such as formaldehyde
d. Mercury

[76]From EPA website -- http://www.epa.gov/ttn/atw/allabout.htmnl

Inorganic, solid HAPs occur as trace substances in coal. These substances are emitted by power plants in solid form, and are generally effectively controlled by modern, high-efficiency particulate matter control devices such as fabric filter baghouse. Inorganic, acid-gas HAPs include primarily hydrochloric acid and hydrofluoric acid, form from trace substances in the coal. Flue gas desulfurization (FGD) systems that reduce flue gas temperatures may condense and improve the control of these substances. In addition, these acids are generally highly water soluble and are effectively controlled in wet FGD systems. Regardless of the emission control technology used, power plant HAP emissions are best controlled through good combustion practices.

Mercury chemistry and its control is complex. It is discussed separately below.

Regulation pertaining to HAPs is discussed in the section, "Relevant Air Pollution Regulation in Wisconsin." There is a requirement in the Clean Air Act that the EPA significantly reduce the routine daily emissions of air toxics. In the 1990 Clean Air Act Amendments, Congress directed the EPA (1) to use a technology-based and performance-based approach to reduce significantly the emissions of air toxics from major sources of air pollution and (2) to use a risk-based approach to address any remaining, or residual, risks. As a technology-based approach, the EPA has developed standards for controlling the routine emissions of air toxics from each major type of facility within an industry group (or "source category"). These standards are known as "maximum achievable control technology" (MACT) standards. MACTs are based on emissions levels that are already being achieved by the better-controlled and lower-emitting sources in an industry. Eight years after each MACT standard is issued, the EPA must assess the remaining health risks from the various source categories. If necessary, it may implement additional standards that address any significant remaining risk. Appropriate MACTs are discussed later in this chapter.

Mercury

Mercury (Hg) is an air toxic of great concern. Currently, 341 Wisconsin lakes and river stretches carry fish consumption advisories for mercury (Hg).

Hg is a naturally-occurring element that is found in soil, wood, and petroleum. Because Hg is an element, human activities such as the combustion of fossil fuels do not create Hg. Rather, these activities transfer Hg from the limestone or fossil fuels into the air. Airborne Hg falls back to earth in precipitation, ending up in lakes. Once entering the water, it can bioaccumulate in fish and animal tissue in its most toxic form, methylmercury. Bacteria in lake sediment convert Hg into a form easily absorbed by fish and other organisms, including people who eat these fish. Studies have shown that Hg accumulation in fish-consuming wildlife may lead to reproductive problems. Human consumption of fish that contain Hg can damage the nervous system, especially in children and fetuses.

Because fishing is a strong tradition in Wisconsin, there are also important economic consequences associated with potential reductions in recreation and tourism activities.

The DNR estimates that Wisconsin sources of Hg contribute as much as 50 percent of the Hg entering Wisconsin lakes. The rest comes from sources in other states and countries, and some comes from mercury-contaminated sediments already in the lake and river bottoms. An illustration of Hg sources in Wisconsin in

1990 and 1995 is shown in Table 7-1. Wisconsin sources emitted about 6,580 pounds (about 3.29 tons) of Hg to the atmosphere in 1995, with about half of those emissions coming from energy production. The 1999 mercury emissions from the existing Oak Creek Units 5 through 8 totaled about 233.2 pounds or about 0.12 tons. This accounting was based on plant-reported fuel use and mercury tests.[77]

Table 7-1 Estimated mercury air emissions in Wisconsin in 1990 and 1995*

Activity	1990	1995
Energy Production		
Coal (total)	(2,361)	(2,508)
Coal (electric utility)	1,967	2,088
Coal (industrial and residential)	394	420
Petroleum sector	580	509
Wood	13	10
Natural gas	0.24	0.3
Refuse and tire-derived fuel	17	21
Gasoline and diesel - mobile	223	231
Subtotal	3,188	3,268
Purposeful Use of Mercury		
Latex paint volatilization	500	10
Municipal solid waste combustion	1,041	176
On-site household waste incineration	666	270
Medical waste combustion	363	601
Sewage sludge incineration	166	166
Fluorescent lamp breakage	107	107
Chlor-alkali production	1,072	1,114
Volatilization during solid waste collection and processing	258	258
Miscellaneous	128	127
Subtotal	4,774	3,168
Emissions Incidental to Other Activities		
Pulp and paper manufacturing	4	4
Soil roasting	12	12
Lime production	92	128
Subtotal	108	144
Grand Total - All Hg Sources	8,069	6,580

*Source: Bureau of Air Management, Wisconsin Department of Natural Resources.

Hg emissions from coal combustion can be controlled through pre-combustion controls, such as fuel cleaning, or through post-combustion controls. Post-combustion controls include particulate control systems such as electrostatic precipitators (ESPs) or fabric filter baghouses (FF), fluegas desulfurization (FGD) systems, and the injection of sorbents such as activated carbon. Table 7-2 summarizes the EPA's current knowledge on the control of mercury emissions from coal-fired utility boilers.

[77] From DNR website at http://www.dnr.state.wi.us/org/aw/air/reg/mercury/util99hg.htm

Table 7-2 Average mercury emission reductions for various control devices

Boiler Type	Control Device	Control Efficiency (percent)	
		Bituminous Coal	Subbituminous Coal
Pulverized coal	Cold Side ESP	46%	16%
Pulverized coal	Hot Side ESP	12%	13%
Pulverized coal	FF Baghouse	83%	72%
Pulverized coal	Dry FGD Scrubber and FF Baghouse	98%	25%
Fluidized bed boiler	FF Baghouse	90%	No Test

During combustion, Hg in the coal and limestone is volatilized and may remain in a volatile or gaseous state throughout the boiler and pollution control systems. As long as the Hg remains in a volatile state, it cannot be collected by particulate control devices. Typical flue gas temperatures for conventional coal-fired boilers in Wisconsin are approximately 300° F for cold-side electrostatic precipitators (ESPs), and approximately 700° F for hot-side ESPs. The use of FGD systems significantly reduces flue gas temperatures, providing the opportunity to condense and collect the Hg compounds[78].

The EPA estimates that the current air pollution control devices installed on utility coal-fired units capture an average of 43 percent of the Hg in the coals combusted in the United States. Based on the current state of knowledge, the average emission control efficiency in Wisconsin may be less than this national average because most of Wisconsin's power plants burn sub-bituminous coals, which do not require sulfur removal.[79]

Conversely, coal combustion controlled by fabric filter baghouses (the technology proposed for the ERGS SCPC units) achieves 83 to 98 percent reduction in Hg. Therefore, the use of this technology could represent a 70 to 90-plus percent reduction in the current mercury emission rates from coal combustion in Wisconsin. Furthermore, the EPA states that dry FGD systems are already equipped to control emissions of SO_2 and PM. The modification of these units by the use of appropriate sorbents for the capture of Hg and other air toxics is considered to be a solvable retrofit. In other words, the controls proposed for the ERGS SCPC units also have an improved potential for mercury control through sorbent injection.

There is no current efficiency information on activated carbon sorbent injection systems. Use of injected activated carbon is on a "pilot project" scale with results of a full-scale utility boiler test to come. It is expected to be able to help remove 50 to over 95 percent of the Hg. It would also add to the solid waste production. Increased carbon in fly ash is a contaminant that affects durability and strength of potential ash utilization products. Carbon and mercury in fly ash is discussed again in Chapter 9 on Solid Waste.

In May 2000, the DNR received a petition to adopt rules requiring reductions in Hg emissions to the air. The petition was signed by a number of legislators, environmental organizations, conservation groups, and sports clubs. In its December Board meeting, the Natural Resources Board instructed the DNR to begin drafting rules to reduce mercury emissions in Wisconsin. The Board instructed DNR staff to prepare proposed rules for the March 2001 Board meeting that protect public health and the environment but are cost effective, reasonable, and do not interfere with the utilities' ability to supply the state's energy needs.

[78] A fluegas FGD system is proposed to be installed on the two SCPC units.
[79] Bituminous coal is WEPCO's fuel of choice for all three units of the ERGS project.

In a separate regulatory initiative, the EPA announced on December 14, 2000, that it would require reductions of Hg emissions from coal-fired power plants. The agency planned to propose regulations by 2003 and issue final rules by 2004. Under the Clean Air Act, the EPA had been required to study toxic air pollution from power plants in order to determine if additional regulations were necessary to protect public health. The EPA reported its study to Congress in February 1998. After completion of the study, the EPA was required to determine whether to proceed with the development of regulations. In the December 2000 announcement, the EPA affirmed its decision that Hg emissions from power plants should be regulated.

Although neither the DNR nor the EPA have draft rules in place, previous DNR and legislative initiatives in Wisconsin envisioned a flexible, cap-and-trade Hg control program similar to the federal Acid Rain Program, and set reduction targets at 50 to 90 percent for utility systems emitting greater than 100 pounds per year of mercury. Other sources emitting greater than 10 pounds per year would be affected by a mass emission cap. The petition to the DNR sought a 90 percent reduction in Hg emissions from utility and government-owned boilers, municipal waste incinerators, and medical incinerators, among other potential sources, by 2010. Regulations of Hg emissions, as well as emissions of other pollutants are discussed in the next section of this chapter.

Relevant Air Pollution Regulation in Wisconsin

The EPA has approved Wisconsin's Air Permitting and review authority under the Clean Air Act.

WEPCO originally submitted a Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR) permit application for the Elm Road Generating Station (ERGS) to the DNR under Wis. Admin. Code chs. NR 405, NR 406, and NR 408, and the Code of Federal Regulations, 40 CFR S. 52.21. The applications request permits for the North Site, the South Site, and the South Site-Exp. On June 2, 2003, WEPCO submitted additional air permit information describing the need to permit the CUP Option it negotiated with the city of Oak Creek. On June 27, 2003, WEPCO requested that the DNR review this fourth permit application.

This section of the EIS describes the numerous aspects of air pollution regulation as they relate to the ERGS project.

Expected schedule for air permitting

WEPCO proposes to begin construction on its ERGS project in 2003. The in-service dates for the first and second SCPC units would be 2007 and 2009. WEPCO proposes that the IGCC would be put in service in 2011.

The initial air permit required for a project like this is a "construction permit." A construction permit allows a company to build, initially operate, and test the source. Unless a longer term is provided in the permit a construction permit normall exprires after months and can be extended 18 months. Prior to the expiration of the construction permit, the company must file a complete application for an operation permit, so that it may continue to operate the source under the operation permit "application shield." The source may not operate after the construction permit expires unless there is a complete and timely operation permit application on file.

The the time of preparation of this final EIS, the DNR had not yet declared the construction permit applications complete.

WEPCO has requested that it be given 90 months by the DNR to complete the construction of the entire project. If this time is specified in the permit, WEPCO would be required to submit information for reevaluating BACT to the DNR at least 18 months prior to the commencement of construction of any emission units on which construction had not begun within eighteen months from the date of the issuance of the final permit.

National Ambient Air Quality Standards

The federal Clean Air Act requires the EPA to establish National Ambient Air Quality Standards (NAAQS) for air pollutants that could adversely impact human health or welfare. Primary standards have been established to protect public health, while the secondary standards have been established to protect public welfare and the environment. NAAQS have been established for the following pollutants, collectively referred to as "criteria pollutants."

- Sulfur dioxide (SO_2)
- Nitrogen oxides (NO_x)
- Carbon monoxide (CO)
- Particulate matter less than 10 microns in diameter (PM_{10})
- Ozone—volatile organic compounds (VOC) must be considered
- Lead

EPA describes an area as "non-attainment" if the ambient air quality standard for one or more criteria pollutants is not met. (See a general discussion on "non-attainment areas" earlier in this chapter.)

The Clean Air Act Amendments of 1972 resulted in a national permitting program for all areas of the country in 1977. Areas in which the existing air quality meets the NAAQS are subject to the rules of the Prevention of Significant Deterioration Program. Areas in which the existing air quality does not meet the NAAQS are subject to non-attainment area New Source Review (NSR) requirements. The analysis as to whether or not an area meets the NAAQS is done on a pollutant-by-pollutant basis.

The state of Wisconsin regulates air pollutant emissions under Wis. Admin. Code Chapters 400-499 and has adopted the EPA primary and secondary standards. All counties in Wisconsin are classified either as "attainment" (their ambient air has less of that pollutant than the standard allows) or "non-attainment" (their ambient air has more of that pollutant than the standard allows). In addition, Wisconsin has a secondary or welfare-based standard for particulate matter (PM).

The area of the state that would include the ERGS is presently classified as severe non-attainment for ozone. The area is presently classified as attainment for all other criteria pollutants. The proposed project is classified as a major modification to the existing OCPP major stationary source for Prevention of Significant Deterioration (PSD) and New Source Review (NSR) regulatory purposes. Therefore, a PSD permit application is required for all pollutants emitted by the ERGS above the PSD significant emission levels and

a non-attainment area NSR permit is required for the volatile organic compounds emission to help control ground-level ozone development.

Non-attainment new source review requirements

Because the area of the project is non-attainment for ozone, a non-attainment area NSR permit is required for VOC emissions, which are precursors of ground level ozone formation. See Table 7-9 for expected ERGS VOC emissions.

In addition, the non-attainment area NSR regulations under Wis. Admin. Code ch. NR 408 require the application of the lowest achievable emission rate (LAER) control technology to all VOC emissions sources. The NR 408 regulations also require that WEPCO obtain VOC emissions offsets for the potential VOC emissions from this project. WEPCO needs to obtain offsets at a rate of 1.3 to 1 for the emission increases from this project.

Prevention of significant deterioration

In addition to the NAAQS, the PSD program under 40 CFR Part 52 and Wis. Admin. Code ch. NR 405 has established maximum allowable ambient air "increments." These increments were established at approximately 20 to 40 percent of the primary or secondary standard, and were intended to limit the deterioration of air quality in a "PSD region." Once an application for a PSD source in a given county is deemed complete, the PSD baseline is established by the DNR in the area in which the source is located. If the PSD baseline has been established for a pollutant by another source, all new projects, including minor sources, are required to limit their maximum ambient air impacts to levels at or below the PSD increments. The PSD program objectives are:

1. To ensure that economic growth will occur in harmony with the preservation of existing clean air resources.
2. To protect the public health and welfare from any adverse effect that might occur even at air pollution levels better than the NAAQS.
3. To preserve, protect, and enhance the air quality in areas of special natural recreational, scenic, or historical value, such as national parks and wilderness areas.

Proposals submitted after the PSD baselines have been set are modeled along with existing and permitted facilities. The combined modeling determines how close their combined emissions would come to using up all the capacity of the area to receive pollutants. This capacity would be limited by the air quality standards and additional emissions would be allowed only in "incremental" increases toward that capacity limit. The standard measurement is called the "PSD increment." The total impact at any point, from all sources that have been constructed or modified after the baseline date, including the proposal, must not exceed the incremental level. If a proposed project exceeds the increment, it cannot be permitted unless it is modified to reduce the proposed emissions, or unless a reduction in emissions elsewhere leaves some additional increment that can be utilized.

The provisions of the PSD program apply to major new sources and major modifications of existing "major sources" constructed in areas where existing ambient air quality meets the NAAQS. Major sources are those

sources that have the potential to emit more than 100 tons per year (tpy) of any one of the criteria pollutants listed in one of 28 specific pre-designated categories, or 250 tons per year of criteria pollutants in all other source categories.

The major elements of a PSD review include:

- Control Technology Review (Wis. Admin. Code § NR 405.08)
- Air Quality Analysis (Wis. Admin. Code § NR 405.11)
- Source Impact Analysis (Wis. Admin. Code § NR 405.09)
- Additional Impacts Analysis (Wis. Admin. Code § NR 405.13)

Control technology review

One of the requirements of the PSD program is that the Best Available Control Technology (BACT) be installed for all pollutants regulated under the Act that would be emitted in significant amounts from new major sources or modifications of existing major sources. The PSD requirements require the application of BACT to each source of emissions subject to PSD review. The BACT is determined based on what controls have recently been permitted or are in operation at similar facilities. All new major stationary sources must apply BACT for each regulated air contaminant that they will have the potential to emit in significant amounts. The determination of BACT is discussed later in this chapter.

Top-down approach to BACT

Any control technology (BACT) review must include an evaluation of environmental, energy, technical, and economic impacts. Currently, the EPA is recommending a "top-down" approach in conducting a BACT analysis. The first step in the top-down BACT approach is to determine the most stringent control available for a similar source or source category. If it is shown that the level of control is technically or economically infeasible for the source in question, then the next level of control is determined and similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any substantial or unique energy, environmental, or economic impact.

The energy impact analysis estimates the direct energy impacts of the control alternatives in units of energy consumption. If possible, the energy requirements for each control option are assessed in terms of total annual energy consumption. The net environmental impact associated with a control alternative is considered through the use of computer driven air dispersion modeling analyses. The economic impact of a control option is assessed in terms of cost effectiveness.[80]

Once the energy, environmental, and economic impacts are assessed, the level of control achieved through the use of the technology being evaluated is determined to be BACT.

New Source Performance Standards

Section 111 of the Clean Air Act establishes a regulatory scheme for controlling emissions of criteria air pollutants from identified source categories. Any construction or reconstruction of a source for which a New Source Performance Standard (NSPS) has been set is subject to that standard if construction or

[80] The economic impacts are reviewed on a cost per ton controlled basis, as directed by the EPA's Office of Air Quality Planning and Standards (OAQPS) Cost Control Manual, Fifth Edition.

reconstruction occurs on or after the date the standard was proposed by the EPA. The requirements of 40 CFR 60 are the NSPSs for new or modified units. Either they set the base, or the minimum control requirements for BACT set the base of emission control if they are more stringent.

Any affected emission unit that is subject to a specific NSPS requires the following (under 40 CFR Part 60, Subpart A, and Wis. Admin. Code ch. NR 440):

- Notification and recordkeeping
- Performance tests
- Compliance with standards and maintenance requirements
- Monitoring

In addition, there are more detailed requirements for specific technologies. These are as follows.

SCPC boilers

The SCPC boilers would be subject to Subpart Da of the NSPS requirements because they are electric utility steam generating units with heat inputs greater than 250 MMBtu/hr. The applicable Subpart Da emission limitations are summarized in Table 7-3.

Table 7-3 NSPS emission limits for SCPC boilers

Pollutant	NSPS limit	Reduction Requirements	Averaging period
PM	0.03 lb/mmBtu*	99 percent	-
Visible emissions	20 percent opacity	-	-
SO_2	-	-	-
Coal	1.2 lb/MMBtu	90 percent **	30-day rolling average
Distillate oil	0.20 lb/MMBtu	0 percent	-
NO_x	1.6 lb/MW-hr	-	30-day rolling average

* The particulate emission standard under Ch. NR 440.20 does not include condensable particulate matter.
** The NSPS limit varies depending upon fuel sulfur content, with a 90 percent reduction and 1.2 lb/MMBtu limitation or a 70 percent reduction when emissions are below 0.60 lb/mmBtu.

SCPC auxiliary boiler

The SCPC auxiliary boiler would be subject to Subpart Db of the NSPS requirements, because this boiler would fire diesel oil. It would be subject to the emission limits and continuous emissions monitoring requirements under Wis. Admin. Code § NR 440.205 for NO_x, PM, and SO_2. However, the sulfur percentage of the diesel would not exceed 0.05 percent by weight, less than the 0.5 weight percent threshold for "very low sulfur oil" under 40 CFR 60.41. Affected sources combusting only very low sulfur oil are not subject to federal percent reduction requirements and not required to conduct performance testing or install and operate continuous monitors for SO_2 if fuel receipts are maintained.

SO_2 and PM standards for opacity would be applicable. Any gases emitted from each stack when the units are diesel-fired would not be allowed opacity greater than 20 percent (six-minute average). The exception is one six-minute period per hour with opacity not exceeding 27 percent. The opacity standard would not

apply during periods of startup, shutdown, or malfunction, but a continuous opacity monitor would be installed for when diesel is burned in the boiler.

Because this boiler would be designed as a low heat release rate boiler (a maximum heat release rate of less than 70,000 Btu/hr-ft3), the maximum allowable NO_x emission would be 0.10 lb/MMBtu, regardless of whether the diesel or natural gas is burned. Compliance with the NO_x emission limit is to be determined on a 30-day rolling average basis and applies at all times, including startup, shutdown, and malfunctioning.

IGCC stationary natural gas combustion turbine

As specified, Subpart GG of the NSPS requirements applies to any stationary gas turbine with a heat input at peak load greater than or equal to 10.7 gigajoules/hour (10.1 MMBtu/hour) and which begins construction, reconstruction, or modification after October 3, 1977. Each of the two proposed ICGG stationary gas turbines would be rated at a peak load heat input of approximately 2,139 MMBtu/hour when combusting syngas, so they would qualify. Subpart GG constains NO_x and SO_2 emission standards and associated monitoring, record keeping, and reporting requirements. However, the BACT requirements of PSD are more stringenet than the NO_x and SO_2 emissions standards contained in Subpart GG, so BACT would be more stringent than these NSPS.

IGCC auxiliary boiler

The IGCC auxiliary boiler would be subject to NSPS under Subpart Dc and NR 440.207 because it would have a heat rate between 10 and 100 MMBtu/hr. It would be subject to emission limits and opacity standards for PM and SO_2 when burning diesel. The allowable SO_2 emission limit would be 0.5 lb/MMBtu. With the diesel at less than 0.05 percent sulfur by weight, the estimated SO_2 emission rate would be 0.056 lb/MMBtu, which is significantly below the allowable SO_2 limit. Compliance with the limitation might be determined based on a certification from the fuel supplier and monitoring.

In terms of opacity standards, any gases emitted from the stack when diesel was fired would not be allowed opacity greater than 20 percent (six-minute average). The exception would be one six-minute period per hour with opacity not exceeding 27 percent. The opacity standard would not apply during periods of startup, shutdown, or malfunction, and a continuous opacity monitor would not be required.

Coal handling and storage

The coal handling and storage operations would subject to Subpart Y and NR 440.42. For these operations, NR 440.42 would prohibit visible emissions of 20 percent opacity or greater from any coal processing and conveying equipment, coal storage system (except open storage), or coal transfer and loading systems.

Limestone handling and storage

The limestone materials handling and storage operations, with the exception of the open storage piles and railcar or truck dumping operations, would be subject to Subpart 000 and NR 440.688. These limitations are summarized in Table 7-4 below. The acronyms "gr/acf" and "gr/dscf" indicated "grains per actual cubic feet" and "grains per dry standard cubic feet," respectively.

Table 7-4 ERGS operations related to limestone handling and storage, and emission limits required under NSPS

Operation	NSPS Emission Limits
Limestone silos and receiving hoppers	0.022 gr/acf; 7 percent opacity
Limestone dryer/mill building vents and exhaust	No visible emissions; 0 percent opacity
Limestone dryers/mills	0.022 gr/dscf; 7 percent opacity
Limestone crusher/conveyor transfers	0.022 gr/dscf; 7 percent opacity
Limestone conveyors, transfer points, and enclosures	10 percent opacity

Air quality analysis

The PSD program requires an air quality analysis for each regulated pollutant that a proposed major source would emit at levels greater than the significant emissions level. The purpose of the air quality analysis is to demonstrate, through the use of air quality dispersion models and background ambient data, that allowable emission increases from the proposed source, combined with emissions from other sources will not cause or contribute to violations of any Wisconsin Ambient Air Quality Standards or NAAQS, or any applicable maximum allowable increases over the baseline concentration in any area including PSD increments.

As discussed in the beginning of this chapter, the DNR is currently engaged in its modeling analysis. The air quality analysis information in the draft EIS was based on the air pollution control permit application information provided by WEPCO in the fall of 2002. As discussed in the first part of this chater, the air quality analysis information in the final EIS is based on the air pollution control permit application information provided by WEPCO on April 26, 2003; June 2, 2003; and June 27, 2003. It considers the following:

- Refinements proposed by WEPCO to the DNR in June 2 and June 11 submittals for the North Site. The refinements are discussed later under "ERGS Air Quality Analyses."
- The South Site and South Site Exp information provided by WEPCO for the DEIS, but modeled using the revised stack heights for the SCPC units required as an adjustment for the Racine airport, discussed in Chapter 11. WEPCO submitted this revision in its April 16, 2003 submittal to the DNR. DNR modeling for this revision at the South sites has been completed and is shown later in this chapter under "ERGS Air Quality Analyses." Because WEPCO did not request that the "refinements" applied to the North Site be applied to the South sites until early July, the data in the final EIS does not reflect use of these refinements.

The CUP Option for the North Site is, as discussed in the beginning of this chapter, discussed in Chapter 12.

Source impact analysis

All owners and operators of new major stationary sources must demonstrate that allowable emission increases from the proposed major source, in conjunction with all other applicable emissions increases, would not cause or contribute to air pollution in violation of the NAAQS and PSD increment. The NAAQS compliance demonstration would be performed by adding the measured existing background ambient air levels to the modeled impacts from the proposed project and all other explicitly modeled sources in the NAAQS source inventory. The total modeled impact is compared to the NAAQS. This comparison can be found later in this chapter under "ERGS Air Quality Analyses."

The PSD increment compliance demonstration would be performed by modeling actual emission changes that have occurred since the baseline date. The total ambient air quality concentration change would then be compared to the applicable PSD increment.

Additional impacts analysis

All applications for operation permits must provide an analysis of the potential impairment to (1) visibility, (2) soils, and (3) vegetation that would occur as a result of both the major source and the general commercial, residential, industrial, or other growth associated with the major source. Preliminary DNR conclusions are discussed later in this chapter under "EGS Air Qulaity Analyses."

Federal Acid Rain Program

Title IV of the 1990 Clean Air Act Amendments established the federal Acid Rain Program, which sets as its primary goal the reduction of acid deposition through reductions in emissions of SO_2 and NO_x, the primary causes of acid rain. The Acid Rain Program established a system to reduce the total U.S. annual SO_2 emissions by 50 percent from 1980 levels. This reduction is equal to an annual reduction of 10 million tons per year. To achieve this goal at the lowest cost to society, the program employs a market-based approach for controlling air pollution. In addition, the program encourages energy efficiency and pollution prevention.

The Acid Rain Program affects existing utility generators with an output capacity of greater than 25 megawatts and all new utility units. During Phase II of the program, which began in 2000, the Act sets a permanent annual ceiling (or cap) of 8.95 million "allowances" (one allowance is equal to one ton of SO_2 emissions) as the total annual allowance allocation to utilities. This cap firmly restricts emissions and ensures that environmental benefits will be achieved and maintained, even when new facilities are constructed.

The SCPC boilers and the IGCC turbines would be subject to the provisions of the federal Acid Rain Program requirements in 40 CFR Parts 72 to 76, so an acid rain permit application has been submitted. The units would need to employ monitoring consistent with 40 Part 75 at the time that each SCPC boiler and IGCC unit begins initial operation.

Hazardous air pollutants

The EPA lists two main types of stationary sources that generate routine emissions of hazardous air pollutants (HAPs or air toxics):

"Major" sources are defined as sources that emit 10 tons per year of any of the listed toxic air pollutants, or 25 tons per year of a mixture of air toxics. These sources may release air toxics from equipment leaks, when materials are transferred from one location to another, or during discharge through emission stacks or vents.

"Area" sources consist of smaller-size facilities that release lesser quantities of toxic pollutants into the air. Area sources are defined as sources that emit less than 10 tons per year of a single air toxic, or less than 25 tons per year of a combination of air toxics listed in Section 112(b)(1) of the Clean Air Act Amendments. Though emissions from individual area sources are often relatively small, collectively their emissions can be of concern - particularly where large numbers of sources are located in heavily populated areas.

The ERGS case is being treated as a major source for HAPs, which are analyzed later in this chapter in the section called, "ERGS Air Quality Analyses."

Case-by-case MACT

The EPA's regulation of hazardous air pollutants (HAPs) has, since 1996, involved a case-by-case maximum achievable control technology (MACT) as set out in 40 CFR Part 63 Subpart B. Those regulations require case-by-case determinations of MACT for each "major source" of HAPs constructed or reconstructed after an effective date which are listed by EPA and have yet to have a MACT standard promulgated. Electric utility steam generating units had been exempted from the case-by-case provisions because they were not yet added to the source category list. On December 14, 2000, the EPA added coal- and oil-fired power plants to the Section 112(c) list of HAP sources, making coal- or oil-fired electric utility steam generating units that are constructed or reconstructed after December 14, 2000 subject to the case-by-case provisions until the EPA promulgates a nationally applicable MACT standard to address them. The EPA expects to promulgate a final standard in 2004. Thus, a case-by-case MACT determination for the ERGS SCPC units would need to be completed.

IGCC units are not included in a source category yet. However, simple-cycle combustion turbines are listed as a source category under Section 112(c). Based on a broad interpretation of EPA's interpretive rule, dated May 25, 2000, the HAP emissions associated with the IGCC CTs need to be considered when determining major source thresholds.

There are two basic MACT concepts in the case-by-case technology determination:

1. The MACT emission limitation or requirements recommended by the applicant shall not be less stringent than the emission control which is now achieved in practice by the best controlled similar source.
2. Based upon available information, the MACT emission limitation and control technology shall achieve the maximum degree of HAP emissions reduction that can be achieved by utilizing those control technologies that can be identified from the available information, taking into consideration the costs of achieving such emission reduction and any non-air quality health and environmental impacts and energy requirements associated with the emission reduction.

General HAP requirements

Since the proposed SCPC and IGCC units would each be subject to a regulation contained in 40 CFR Part 63, they would also have general notification, record keeping, and monitoring requirements under 40 CFR Part 63, Subpart A.

Prevention of accidental releases

The CAA amendments of 1990 include language that requires chemical accident prevention provisions at affected facilities. Affected facilities are those stationary sources that store, use or handle any of 140 listed hazardous substances in amounts greater than the listed threshold quantities. Section 112(r) of 40 CFR Part 58, "Prevention of Accidental Releases," establishes the requirements for owners and operators of stationary sources that produce, process, handle or store any of the regulated chemicals. The purpose of this requirement is to prevent and mitigate accidental releases of these substances by preparing a detailed risk

assessment and implementing a number of safety procedures through the preparation of a Risk Management Plan.

WEPCO has stated its intention to do an analysis after the plant design is finalized to determine if it would store any of the listed chemicals or substances in quantities near or above the threshold levels. It has also stated its intention to comply with the general duty clause of the CAA, Section 112(r)(1).

Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) rule (40 CFR Part 64) establishes criteria for monitoring certain existing air pollution control devices to provide reasonable assurance of compliance with emission limits and standards. As specified in 40 CFR § 64.2(a), the CAM rule applies, on a pollutant-specific basis, to each emission unit at a major source if it:

- Is subject to an emission limitation or standard for the pollutant.
- Uses a control device to achieve compliance with the limit or standard.
- Has the potential for uncontrolled emissions of the pollutant equal to or greater than the major source threshold for that pollutant (in this case, 100 tpy of any criteria pollutant, 10 tpy of any individual HAP, or 25 tpy of any combination of HAPs).

However, 40 CFR 64.2(b)(1)(iii) specifies an exemption from the CAM rule for emission units (on a pollutant-specific basis) that are subject to Acid Rain Program requirements. It remains to be seen whether the CAM rule would apply to the SCPC units. WEPCO has indicated that it believes that the CAM rule would not apply to the IGCC unit because, while NO_x and SO_2 qualify the two natural gas turbines, those turbines are subject to Acid Rain Program requirements for those two pollutants. The DNR is in the process of verifying this point.

Mercury

Although neither the DNR nor the EPA have rules in place, previous DNR and legislative initiatives in Wisconsin envisioned a flexible, cap-and-trade mercury control program similar to the federal Acid Rain Program, with reduction targets at 90 percent. Point sources with actual mercury emissions of more than ten pounds per year would need to comply. Until such rules are made law, mercury still qualifies under the case-by-case MACT requirement for the SCPC units.

State requirements (Wisconsin)

Opacity

According to Wis. Admin. Code ch. NR 431, the opacity from the SCPC units and the IGCC unit shall not be greater than 20 percent except during cleaning periods for combustion equipment. During those cleaning periods, emissions are allowed to exceed 20 percent but may not exceed 80 percent for five minutes in any one hour.

Control of nitrogen compound emissions

As specified in Wis. Admin. Code § NR 428.04, NO_x requirements and performance standards for new or modified sources apply to emission units located in Kenosha, Milwaukee, Ozaukee, Racine, Washington, or Waukesha County that are constructed or that undergo a major modification after February 1, 2001.

The proposed SCPC boilers would qualify because they would have a maximum design heat input of more than 250 MMBtu per hour. The performance standard is 0.15 pounds per MMBtu heat input on a 30-day rolling average. Additionally, NR 428 contains both general and specific notification, monitoring, and record keeping requirements.

The IGCC unit would be subject to an emission limit of 15 ppm at 15 percent O_2 on a 30-day rolling average, in accordance with Wis. Admin. Code § NR 428.04(g)(3).

PM

The SCPC and IGCC units are subject to Wis. Admin. Code § NR 415.06 and have an allowable emission rate of 0.1 lb/MMBtu, for fuel burning sources that have a heat input of greater than 250 mmBtu/hr and emit PM.

HAPs

The state of Wisconsin regulates the emissions of hazardous air pollutants under Wis. Stat. ch. NR 445. NR 445 exempts fuels that meet the definition of a "Virgin Fossil Fuel." Virgin fossil fuels are defined as any solid, refined liquid or refined gas fossil fuels with Btu contents greater than 7,000 Btu/lb that are not blended with reprocessed or recycled fuels. Natural gas, liquid petroleum gas, fuel oil, distillate fuel oil, gasoline, and diesel fuel are Group 1 virgin fossil fuels. Coal and residual fuel oil would be Group 2 virgin fossil fuels.

Ammonia might be emitted as a result of ammonia "slip" from the SCR system for NO_x emission control. Ammonia is a regulated HAP under NR 445, Table 1.

The primary fuel for the ERGS generation boilers would be a blend of 95 percent washed bituminous coal and 5 percent coal ash (on a weight basis). A variety of fuel ashes have been analyzed. The analyses demonstrate that the fuel ash meets the definition of lignite coal as found in Wis. Admin. Code § NR400.02 (22e).

Wisconsin's climate change action plan

The DNR, in cooperation with other agencies and organizations, completed the Wisconsin Greenhouse Gas Emission Reduction Cost Study in 1998. The study states that Wisconsin's greenhouse gas emissions can be reduced by 21 million tons in 2010 by switching coal-fired power plants to natural gas. This change would double the state's consumption of natural gas. The study results estimate the cost for switching electric utility coal-fired power plants to natural gas would be about $460 million. However, this cost does not include the cost of expanding and extending natural gas pipelines and the associated environmental impacts or the potential increase in natural gas prices that this increased use of natural gas could cause.

The study suggests that energy efficiency savings may balance the cost of fuel switching. However, natural gas prices have increased dramatically since this study was completed. In order to realize the energy efficiency gains suggested in the study, a more rigorous and concerted effort on the part of the state regulatory agencies and the regulated community as a whole would be required. To that end the Wisconsin Climate Change Action Plan envisions specific "actions to implement energy efficiency measures." These actions call for the Wisconsin state government to:

- Lead by example.
- Vigorously promote voluntary, private sector-led initiatives to adopt energy efficiency measures.
- Provide financial incentives for adopting energy efficiency measures.
- Revise or update existing building codes to support energy efficient improvements.
- Perform "actions to promote a shift to a higher proportion of cleaner energy sources." These actions are to include having the state government:
    - Lead by example.
    - Vigorously promote voluntary, private sector-led initiatives to move toward cleaner energy sources and technologies.
    - Provide financial incentives to increase renewable energy use.
    - Participate actively in research and development projects designed to reduce emissions per unit of energy generated.

Currently, there are no regulatory requirements for individual projects such as the proposed ERGS to reduce or eliminate CO_2 emissions. At any rate, requirements to reduce emissions from this facility may be counterproductive if those requirements restrict this facility's utilization, since this project would be more efficient than the existing coal-fired generation equipment that it would displace. In that sense, limiting the deployment of new, modern power plants such as the ERGS may not be the best means to ultimately reducing greenhouse gas emissions.

ERGS Air Quality Analyses

Ambient Air Quality in the Region

Regional climate

Several factors control the climate of the Great Lakes region. The most important of these are:

- Latitude
- Continental location
- Large-scale circulation patterns
- The lakes themselves

The Great Lakes are large enough to have significant impacts on local weather.

Temperature

Overall, the region can be described as having warm summers and cold winters. For the period 1971-2000, average daily summer temperatures range from daytime highs of 81°F to nighttime lows of 63°F. Average

daily winter temperatures range from daytime highs of 28° F to nighttime lows of 13° F. The average annual temperature is 48° F.

The average summer temperature is 70° F, and the average maximum summer temperature is 79° F. In winter, the average temperature is 24° F, and the average minimum temperature is 17° F. Yearly, daily maximum temperatures will exceed 90° F an average of nine times, while daily minimum temperatures will be below 32° F an average of 133 times. Record temperatures since 1942 range from 103° F (August 1, 1988 and July 13, 1995) to -26° F (January 17, 1982 and February 3, 1996).

Precipitation

Average historical precipitation data for the period from 1971 to 2000 are presented in Table 7-5. Total annual precipitation averages 34.8 inches, while historic extremes from 1927 to the present, range from a maximum of 44.4 inches in 2000 to a minimum of 19.1 inches in 1963. Annual snowfall averages 52.6 inches with an all-time high of 93.3 inches in 1959 -1960.

Table 7-5 Temperature and precipitation data for Oak Creek

Month	Temperature (°F)			Precipitation (inches)			
				Rainfall		Snowfall	
	Maximum	Minimum	Mean	Mean	High	Mean	High
January	28.0	13.4	20.7	1.85	4.38	15.3	39.0
February	32.5	18.3	25.4	1.65	3.94	11.3	42.0
March	42.6	27.3	34.9	2.59	6.93	7.4	30.3
April	53.9	36.4	45.2	3.78	7.31	2.6	15.8
May	66.0	46.2	56.1	3.06	9.68	0.1	3.2
June	76.3	56.3	66.3	3.56	9.98	0.0	0.0
July	81.1	62.9	72.0	3.58	7.66	0.0	0.0
August	79.1	62.1	70.6	4.03	9.05	0.0	0.0
September	71.9	54.1	63.0	3.30	9.87	0.0	0.0
October	60.2	42.6	51.4	2.49	7.03	0.4	6.3
November	45.7	31.0	38.4	2.70	7.11	3.7	16.1
December	33.1	19.4	26.2	2.22	5.42	11.8	49.5

Wind

Based on the *Wind Atlas of Wisconsin, 1996* (Wisconsin Geological and Natural History Survey Bulletin 94), the overall average wind speed from the nearest National Weather Service Station (Milwaukee) is 11.4 mph. The predominant wind directions are westerly, varying from west-northwesterly in the winter to southwesterly in the summer. However, due to the effect of Lake Michigan, the prevailing winds during the late spring (April, May, and into early June) is from the north-northeast.

Ambient Air Quality Standards for Oak Creek

NAAQS and PSD

Standards for ambient air quality in Wisconsin are codified under Wis. Admin. Code ch. NR 404. WEPCO submitted air pollution control permit applications for all three proposed power plant site options plus the CUP Option (an new site design and layout for the North Site). The ambient air quality standards for the ERGS are summarized for the North and South Site alternatives in Tables 7-6 and 7-7.

Milwaukee is a PSD county, and the baselines have already been established for particulate matter less than ten micrometers in diameter (((PM_{10}), sulfur dioxide (SO_2), and nitrogen oxides (NO_x). When the DNR Bureau of Air Management deems the applicant's PSD applications complete, the project would be expected to set the baselines for all three pollutants for Racine County. Therefore, the concentrations of the air pollutants from the proposed project are subject to the corresponding PSD increment limits. The PSD increment levels are summarized in Tables 7-6 and 7-7 also.

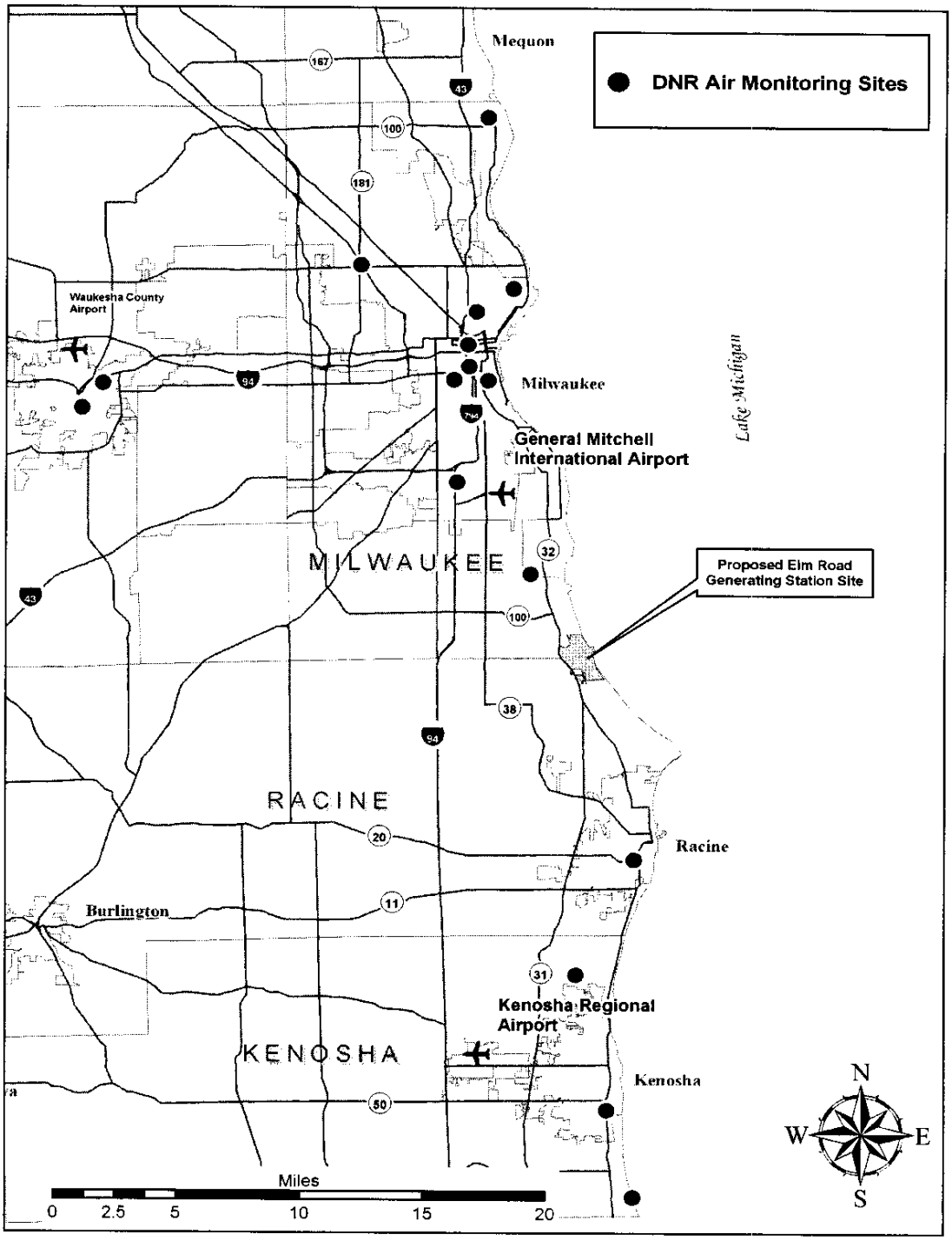
Existing air quality

Attainment or non-attainment areas are classified based on ambient air quality data collected at monitoring sites around the state. Monitoring sites for air pollutants in the Milwaukee and Racine County area are shown in Figure 7-1. Table 7-6 shows more precisely the monitoring locations as well as the pollutants monitored at each site.

Table 7-6 Milwaukee area criteria air pollutant monitoring stations

County	City	Site Address	DNR Site ID	Monitored Pollutant
Kenosha	Kenosha	Barbershop Quartet Scy 7944 Sheridan Rd.	550590002	O_3
Kenosha	Pleasant Prairie	Chiwaukee Prairie 11838 First Court	550590019	O_3, $PM_{2.5}$
Kenosha	Kenosha	UW Parkside 900 Wood Rd.	550590022	O_3,
Milwaukee	Milwaukee	Health Center 1337 S. 16th St.	550790010	$PM_{2.5}$, O_3
Milwaukee	Milwaukee	DNR Headquarters 2300 N M.L. King Jr. Dr.	550790026	CO, O_3, SO_2, $PM_{2.5}$, NO_2
Milwaukee	Milwaukee	Virginia Fire Station 100 W. Virginia St.	550790043	$PM_{2.5}$
Milwaukee	Milwaukee	Fed. Aviation Adm. 4942 S. 16th St.	550790059	$PM_{2.5}$, PM_{10}
Milwaukee	Milwaukee	Milwaukee Fire Dept. 711 W. Wells St.	550790099	$PM_{2.5}$
Milwaukee	Milwaukee	7528 W Appleton Ave.	550790044	CO, O_3
Milwaukee	Milwaukee	UW-Milwaukee North Campus 2114 E. Kenwood Blvd	550790041	O_3
Milwaukee	Milwaukee	Great Lakes Water Inst. 600 E. Greenfield	550790064	PM_{10}
Milwaukee	Bayside	601 E. Ellsworth Lane	550790085	O_3
Milwaukee	S. Milwaukee	Blakewood School 3501 Blakewood Ave	550791025	O_3
Racine	Racine	1519 Washington Ave.	551010017	O_3
Waukesha	Waukesha	1310 Cleveland Ave.	551330027	$PM_{2.5}$, PM_{10}
Waukesha	Waukesha	Carroll College, 225 N. Grand Ave.	551330017	O_3

Figure 7-1 Air pollutant monitoring stations in the area of the proposed ERGS facilities



Milwaukee and Racine Counties are classified as attainment for all pollutants except ozone. Both counties are classified as moderate non-attainment for ozone. This criteria pollutant's background concentrations for Milwaukee and Racine Counties are summarized in Tables 7-7 and 7-8.[81]

Table 7-7 Criteria air pollutant background concentrations, PSD increments, and NAAQS for Milwaukee County and the North Site

Parameter	Averaging Period	Milwaukee County		NAAQS (micrograms/ m^3)
		Background Concentration (micrograms/m^3)	PSD Increment Level (microgram/m^3)	
Total suspended particulate (TSP)	24-hour	76	NA	150
PM_{10}	Annual	27	17	50
PM_{10}	24-hour	58	30	150
SO_2	Annual	9.3	20	80
SO_2	24-hour	7.8	91	365
SO_2	3-hour	208.1	512	1,300
CO	8-hour	3,274.2	NA	10,000
CO	1-hour	4,319.6	NA	40,000
NO_x	Annual	31	25	100
Pb	Calendar quarter	NA	NA	1.5

Table 7-8 Criteria air pollutant background concentrations, PSD increments, and NAAQS for Racine County and the South Sites

Parameter	Averaging Period	Racine County		NAAQS (micrograms/ m^3)
		Background Concentration (micrograms/m^3)	PSD Increment Level (microgram/m^3)	
Total suspended particulate (TSP)	24-hour	76	NA	150
PM_{10}	Annual	27	17	50
PM_{10}	24-hour	58	30	150
SO_2	Annual	9.3	20	80
SO_2	24-hour	57.8	91	365
SO_2	3-hour	208.1	512	1,300
CO	8-hour	3,274.2	NA	10,000
CO	1-hour	4,319.6	NA	40,000
NO_x	Annual	31	25	100
Pb	Calendar quarter	NA	NA	1.5

The background concentrations of ozone, the PSD increment levels, and the NAAQS for the CUP Option are discussed in Chapter 12. The values would be similar to the values for the North Site in Table 7-7.

[81] The information in these tables is based on information submitted June 2, 2003 by WEPCO for its air permit application. The data is slightly different that the data provided in the draft EIS. The data is subject to further change pending DNR's review and analysis.

Expected annual project emissions for the ERGS

Pollution emission sources

The sources of air pollutant emissions from the proposed ERGS are included in WEPCO's PSD construction permit application and additional information submitted to the DNR. The sources vary slightly among sites.

North Site

The emission sources included in the original North Site permit application were:

- Two 615 MW supercritical pulverized coal (SCPC) electric generating units
- One 600 MW integrated gasification combined cycle (IGCC) unit
- Two auxiliary boilers
- Two emergency diesel generators
- One diesel fire pump
- Fuel storage tanks
- Coal handling and other material handling equipment - this item would include urea silos, a baghouse on the active coal shed, and material transport to and from barges and storage and handling facilities, among other things.

The refinements in the plant design at the North Site based on WEPCO's June 2, 2003 submittal to the DNR include:

- The use of washed coal instead of unwashed coal. This revises the detailed fugitive emission calculations for all fugitive and point sources
- No urea silo point sources
- No wallboard plant
- No baghouse on the active coal shed. The shed itself is proposed BACT
- Three fire pump diesels instead of one
- Use of 0.003 percent sulfur fuel oil instead of 0.05 percent sulfur fuel oil
- Revised emission estimates for the auxiliary boiler
- Increase in size of the emergency diesel generators
- No barge delivery of coal, and no material transfer point (S51) from barge
- New gypsum transfer tower from landfill to barge
- New vacuum exhaust on fly ash building #1 and #2
- New dust collectors for gypsum, fly ash, and coal
- All road emissions were updated for revised locations. New ash haul routes for the original North Site and the CUP Option were identified in WEPCO's June 2, 2003 and June 27, 2003 submittals and are described in Chapter 12 under "pollution emission sources."

South Sites

The emission sources included in the original South Site and South Site-Exp permit applications were:

- Two 615 MW supercritical pulverized coal (SCPC) electric generating units
- One 600 MW integrated gasification combined cycle (IGCC) unit
- Two auxiliary boilers
- Two emergency diesel generators
- One diesel fire pump
- Fuel storage tanks
- Coal handling and other material handling equipment -- this item would include urea silos, a baghouse on the active coal shed, and material transport to and from barges and storage and handling facilities, among other things

In its June 27, 2003 submittal WEPCO indicated that the emission sources and BACT limits should remain the same as the original proposal but be applied to the shorter SCPC stacks and other changes already proposed in its April 16, 2003 submittal. On July 2, 2003 it submitted additional information seeking the same BACT limits for the South Sites as for the North Site. However, the applicant has not provided appropriate emission summary tables and BACT limits to the DNR to reflect these changes. Thus, the information provided here is based on the original air permit application and additional information provided on April 16, 2003.

Expected project emissions and PSD thresholds

As discussed above in the regulations section of this chapter, if the emission of any pollutant from the ERGS is at a level that is greater than the PSD significance level, the ERGS qualifies as a major pollutant source and is subject to PSD review for that pollutant. The North Site's and South sites' estimated emissions are tabulated in Tables 7-8 and 7-10. Comparisons with the PSD significance levels are tabulated in Tables 7-9 and 7-11.

As discussed above and at the beginning of this chapter, presumably to handle review time constraints and submittals late in the review period, WEPCO has requested that the North Site and the South sites be treated differently in the air permitting and this EIS. Conclusions common to both sites are identified at the end of this section.

North Site emissions

The estimated North Site emission levels take into account the refinements delineated above. The stack heights would be 675 feet high for the SCPC units and 275 feet for the IGCC unit. The CUP variation would take the refinements into account but also take into account the siting accommodations and consolidation of SCPC stack heights that WEPCO proposed to make for the city of Oak Creek. (The CUP analyses can be found in Chapter 12.) Potential emissions are estimated based on the worst-case operating scenarios, taking into account control equipment and federally enforceable conditions expected to be in the power plant's permit.

Table 7-9 summarizes the potential annual emissions to the air expected from various components of the proposed ERGS and the total facility at the North Site in tons per year (tpy), once all three phases of power plant development are operational.[82]

Table 7-9 Estimated annual emissions of the project in tons per year

Pollutant	Two SCPC Units	IGCC Unit	SCPC & IGCC Auxiliary Boilers	Diesel Equipment	Material Handling Point Sources	Fugitive Dust Sources	Storage Tanks	Facility Total
CO	6,496	564	23.1	23.1				7,106
NO_x	3,811	1,396	20.0	27.2				5,245
PM	974	199	5.4	1.12	120	359.1		1,659
PM_{10}	974	199	5.4	1.12	120	171.7		1,471
SO_2	8,662	1,117	0.59	0.03				9,780
VOC	189	79	2.1	0.65			0.0025	273
Hg	0.12	0.03	0.0003	0.0				0.15
Be	0.02	0.03	0.003	0.0				0.05
Fluorides (as HF)	48	0.50	0	0.0				49
Sulfuric Acid Mist	541	26	0.12	0.0001				567
Pb	0.40	0.50	0.0008	0.0				0.90

Ammonia is also a pollutant regulated under NR 445. It is discussed along with other expected toxic pollutant emissions later in this chapter. The estimate of potential SCPC boiler ammonia emissions is based on a proposed SCR emission rate of 5 ppm dry volume (ppmdv).

Table 7-10 illustrates WEPCO's estimates of project emission increases compared to their respective PSD significance levels.[83] If the emission of any pollutant increase is at a level that is greater than the PSD significance level, the project is subject to PSD for that pollutant. If any of the emission increases are greater than the PSD significance level, the project qualifies as a major pollutant source.

Table 7-10 Net change in emissions from the ERGS at the North Site in tons per year compared to PSD significance levels

Pollutant	Net Emissions Change (tpy)	PSD Significance Level (tpy)	PSD Review Required? (Yes/No)
CO	7,106	100	Yes
NO_x	5,245	40	Yes
PM	1,659	25	Yes
PM_{10}	1,471	15	Yes

[82] Estimates for the North Site are from WEPCO air permit application materials, including its June 2 and 27, 2003 submittals. Values are subject to change with completion of DNR review and analyses.
[83] Based on WEPCO's permit application information submitted in the original PSD application plus later submittals, including the submittal of June 2, 2003 and June 27, 2003. Values are subject to change with completion of DNR review and analysis.

Pollutant	Net Emissions Change (tpy)	PSD Significance Level (tpy)	PSD Review Required? (Yes/No)
SO_2	9,780	40	Yes
VOC	273	25 for New Source Review	Yes
Pb	0.90	0.6	Yes
Hg	0.15	0.1	Yes
Be	0.05	0.0004	Yes
F (as HF)	49	3	Yes
Sulfuric acid mist	567	7	Yes

South Site emissions

The estimated South Site emissions levels, shown in Table 7-11, take into account the April 16 submittal that lowered the SCPC stack heights to 470 feet and some reductions in expected SO_2 emissions. WEPCO had been notified by the FAA that the 675 foot stacks for the SCPC units on the South Site and the South Site-Exp constituted a hazard to air navigation as applied to the John H. Batten Airport in Racine County. WEPCO was informed that the stack height at its originally-proposed location would have to be lowered so as not to exceed 474 feet in order to receive a determination of no hazard.

Again, potential emissions are estimated based on the worst-case operating scenarios submitted by WEPCO, taking into account control equipment and federally enforceable conditions expected to be in the power plant permit. No updated data has been received from WEPCO, with respect to the auxiliary boiler, fire pumps, emergency generators, or the revised coal emission rates from washed coal.

Table 7-11 Estimated annual emission of the project a the South sites in tons per year

Pollutant	Two SCPC Units	IGCC Unit	SCPC and IGCC Auxiliary boilers	Diesel Equipment	Material Handling Point Sources	Fugitive Dust Sources	Storage Tanks	Facility Total
CO	6,496	564	15.6	18.0				7,094
NO_x	3,811	1,396	20.8	17.6				5,245
PM	974	199	3.5	0.9	160	377		1,714
PM_{10}	974	199	3.5	0.9	160	175		1,513
SO_2	8,662	1,117	5.4	0.4				9,785
VOC	189	79	2.1	0.7			0.0025	271
Hg	0.12	0.03	0.0003	0.0				0.15
Fluorides (as HF)	48	0.50	0	0.0				49
Sulfuric Acid mist	541	26	0.1	0.0				567
Pb	0.40	0.50	0.0008	0.0				0.90
Ammonia	175.2	-	-	0.0				175

As mentioned previously, ammonia is also a pollutant regulated under NR 445. It is discussed along with other expected toxic pollutant emissions later in this chapter. The estimate of potential SCPC boiler ammonia emissions is based on a proposed SCR emission rate of 5 ppm dry volume (ppmdv).

Table 7-12 illustrates WEPCO's estimates of project emission increases compared to their respective PSD significance levels.[84] If the emission of any pollutant increase is at a level that is greater than the PSD significance level, the project is subject to PSD for that pollutant. If any of the emission increases are greater than the PSD significance level, the project qualifies as a major pollutant source.

Table 7-12 Net change in emissions from the ERGS at the South sites in tons per year, compared to PSD significance levels

Pollutant	Net Emissions Change (tpy)	PSD Significance Level (tpy)	PSD Review Required? (Yes/No)
CO	7,094	100	Yes
NO_x	5,245	40	Yes
PM	1,714	25	Yes
PM_{10}	1,513	15	Yes
SO_2	9,785	40	Yes
VOC	271	25 for New Source Review	Yes
Pb	0.90	0.6	Yes
Hg	0.15	0.1	Yes
Be	0.05	0.0004	Yes
F (as HF)	49	3	Yes
Sulfuric acid mist	567	7	Yes

Conclusions

- Pollutants subject to PSD review -- regardless of the changes submitted by WEPCO in April and June, 2003, all of the pollutants listed in Tables 7-10 and 7-12 are subject to PSD review.
- Facility subject to PSD review -- based on the values in Tables 7-9 and 7-11, the proposed facility is classified as a major source under both the operation permits program in Wis. Adm. Code ch. NR 407, and the New Source Review programs under Wis. Adm. Code chs. NR 405 and NR 408. Because the facility belongs to one of the 28 pre-designated categories and would have potential to emit at least one criteria pollutant in excess of 100 tpy, it is subject to PSD review.
- Pollutants subject to control technology review -- the tables also show that CO, PM, PM_{10}, SO_2, sulfuric acid mist, NO_x, Pb, Hg, Be, and HF would all be emitted in quantities in excess of the PSD significant levels under Wis. Admin. Code § NR 405.02(27)(a), Table A. As a result, these pollutants are subject to the control technology review requirements of Wis. Admin. Code § NR 405.08.

[84] Based on WEPCO's permit application information submitted in the original PSD application plus later submittals, including the submittals of April 16 and June 27, 2003.

- VOCs subject to LAER -- the tables show that VOC emissions would be subject to non-attainment New Source Review under Wis. Admin. Code ch. NR 408, and also would be subject to the lowest achievable emission rate (LAER) control technology. NR 408 requires WEPCO to obtain VOC emissions offsets for the potential VOC emissions from this project at a rate of 1.3 to1.

Proposed BACT

As discussed earlier, control technology analyses are an important part of the PSD review. WEPCO used the top-down approach to determine BACT. The DNR is currently reviewing the air permit application and will provide an update on its review at the CPCN Hearing Proceedings.

North Site

The proposed BACT controls for each potential emissions source at the North Site are summarized in Tables 1 through 11 in Appendix D. The tables also include WEPCO's proposed emission limits for each pollutant from each source covered by the BACT requirements. The tables in Appendix D indicate the best control technology for each pollutant that WEPCO determined it could propose for each emission source that is part of the ERGS. The emissions sources are listed above, under "Pollution emission sources," with the June 2003 refinements for the North Site.

The data in Appendix D is based on WEPCO's air permit application information and additional information submitted on April 16, June 2, and June 27, 2003 and does not reflect DNR analysis, which is still in progress. The tables are subject to change pending DNR's further review and analyses.

A summary of the proposed BACT for the ERGS pollution emission sources at the North Site is contained in Table 7-13. This table summarizes the BACT recommendations shown in Tables D-1 through D-11. Tables D-1 through D-11 include not only recommendations of control technologies specific to the pollutant but also proposed emission limits for each pollutant using that technology. Pollution sources include not only boilers and diesel engines but also materials storage and handling facilities.

Table 7-13 Summary of control technologies proposed to reduce emissions from ERGS pollutant emission sources, with reference to Appendix D

Pollutant emission source	Proposed control technologies	Reference to Appendix D
SCPC boilers	Low NO_x burners, good combustion practices, fabric filter baghouse, FGD, wet electrostatic precipitator (ESP), SCR	D-1
SCPC auxiliary boiler	Low NO_x burners, good combustion practices, use of natural gas, use of fuel oil with <0.003% sulfur	D-2
IGCC auxiliary boiler	Low NO_x burners, good combustion practices, use of natural gas, use of fuel oil with <0.003% sulfur	D-3
Diesel generators	New diesel engine design, fuel oil with <0.003% sulfur, good combustion practices	D-4

Pollutant emission source	Proposed control technologies	Reference to Appendix D
Diesel fire pumps	New diesel engine design, fuel oil with <0.003% sulfur, good combustion practices	D-5
IGCC combined cycle plant	Good combustion practices, diluent injection, use of syngas, IGCC process and gas clean-up	D-6
Inactive coal storage piles	Wet suppression, compaction, covered piles and conveyors, telescoping chute	D-7
Gypsum handling system	Wet suppression, covered piles and conveyors, telescoping chute, vent filters	D-8
Limestone handling system	Enclosed barge unloading clamshell, telescoping chute, baghouse	D-9
Coal material handling point sources	Baghouse	D-10
Ash material handling point sources	Vent filters	D-11
Ash material hauling to landfill	Paved roads, new technology vacuum street sweeping for mitigation twice daily or whenever visible emissions from the haul	No reference

Fuel oil with less than 0.003 percent sulfur is called "ultra-low" sulfur fuel, as opposed to "low" sulfur fuel at 0.05 percent sulfur.

South sites

WEPCO's proposed BACT and emission limits for the South Site and South Site-Exp remain the same as those discussed in the draft EIS.[85] Limits would change, especially for the increased size of the diesel generators and the additional diesel fire pumps. Appendix D, Tables D-12 through D-23, show WEPCO's proposed BACT for the emission sources at the South Sites, including the urea handling systems. The differences in the BACT for the South Sites are summarized in Table 7-14.

[85]WEPCO submitted additional information to the DNR on July 2, 2003 seeking the same BACT limits for the South Sites as for the North Site. Based on review of this additional information, the DNR determined that WEPCO's air permit applications for the South Sites are still not complete. Thus, the information in the final EIS is based on WEPCO submittal for its original application in December 2002 and supplemental material on April 16, 2003. The DNR is currently reviewing this information and will provide an update on its review at the CPCN hearing proceedings.

Table 7-14 Differences in BACT between the South Sites and the North Site

Pollutant emission source	Control technology at South Sites as different from that for the North Site	Reference to Appendix D
Auxiliary boilers	Use of fuel oil <0.05 % sulfur	D-13, D-14 vs. D-2, D-3
Diesel generators	Use of fuel oil <0.05 % sulfur, generators not as large	D-15 vs. D-4
Diesel fire pumps	Use of fuel oil <0.05 % sulfur, only one pump	D-16 vs. D-5
Urea handling system	Vent filters (North Site - no urea handling)	D-21
Fly ash handling point sources - storage building*	Baghouse (North Site - no fly ash storage building)	D23 vs. D-11

* The fly ash storage building baghouse has already been permitted as a separate project.

Air quality impacts - construction phase

In addition to long-term air quality impacts, short-term temporary air quality impacts of the project construction must also be addressed. Air emissions from the project's construction phase would result primarily from:

- the use of construction equipment needed to clear, excavate, contour, and grade land
- construction of the structures
- associated fuel combustion emissions from trucks and other equipment

Fugitive particulate matter emissions would be expected from the site preparation activities and from the use of mobile equipment and vehicles. The DNR's air pollution permit would establish general fugitive dust control requirements. For example, despite the massive amount so excavation necessary for any site option, the applicant must take precautions to prevent fugitive dust emissions during excavation. Fugitive dust concerns are addressed in Chapter 11.

Total suspended particulates (TSP) would constitute the major portion of the air emissions during the construction phase. Most of the TSP would be fugitive dust emissions from grading activities and from excavation, hauling, loading, and dumping. Emissions of SO_2, NO_x, and CO would result from construction equipment exhaust.

Wis. Admin. Code ch. NR 415 contains provisions for the control of fugitive dust. The air permit would require the applicants to minimize fugitive dust emissions during construction. Potential dust resulting from construction activities and track traffic would be controlled by following standard practices during construction, such as watering of exposed surfaces, reduced speed limits on the site, and limiting construction activities during high wind conditions.

Emissions generated during the construction phase generally would be expected to be limited to the site area. Except for the duration and amount of emissions (due to the large amount of excavation necessary for each siting option,) the emissions themselves would not be expected to be different from those related to construction of numerous other types of businesses, like office buildings, and commercial property. If the applicable dust control requirements are adhered to, the DNR would expect no significant impacts to local

air quality from the ERGS project construction. Potential impacts on the site neighbors are discussed in Chapter 11.

Air quality impacts - plant operation

An air modeling analysis was submited by WEPCO for the proposed operation of the ERGS. The DNR is currently performing its modeling analyses, based on changes in the air permit application and the additional information submitted by WEPCO on June 2 and 27, 2003. All of WEPCO's air permit applications include the continued operation of Oak Creek Units 5 and 6.

To assess pollutant-specific impacts, the maximum predicted impact for each air pollutant is added to the respective background ambient air concentration to determine worst-case concentrations. These worst case concentrations are then compared to NAAQS. The air modeling data submitted by WEPCO is summarized in Tables 7-14, 7-15, and 7-16 for the North Site, South Site, and South Site-Exp, respectively. More details, on impact distances and directions, are found in the tables in Appendix D.

Air modeling is being conducted at the DNR to determine the maximum predicted impact relative to the NAAQS and also to the allowable PSD increments. The resulting DNR Air Pollution Control permit would establish the PSD baseline for the area. Comparisons to the PSD increments are shown in Tables 7-15, 7-16, and 7-17 also, with more details in Appendix D. These tables include cumulative impacts and cumulative percentages of increment consumed.

Table 7-15 Air quality and PSD increment modeling results for the ERGS at the North Site

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	TSP 24- hour	Pb Calendar quarter	SO_2 3 – hour	SO_2 24 - hour	SO_2 Annual	NO_2 Annual
Background concentration (ug/m3)	58	27	76	NA	208.10	57.80	9.30	31.00
Background plus ERGS concentration(ug/m3)	123.99	34.98	148.26	0.00157	857.88	223.11	15.01	61.35
NAAQS standard (ug/m3)	150	50	150	1.5	1,300	365	80	100
Percent (%) of NAAQS	**82.7%**	**69.9%**	**98.8%**	**-**	**65.9%**	**61.1%**	**18.8%**	**61.35%**
PSD Class II Increment Concentration (ug/m3)	30	17	-	-	512	91	20	25
Maximum ERGS Only Concentration (ug/m3)	27.45	5.03	-	-	239.09	76.86	4.30	1.14
Percent (%) of Class II Increment	**91.5%**	**29.6%**	**-**	**-**	**46.7%**	**84.5%**	**21.5%**	**5.0%**

Table 7-15 shows that the modeled concentrations from the proposed ERGS and other NAAQS sources are below the level of pollution allowed for the region, although the concentration of TSP would approach 100 percent of the standard. Most of the expected PSD increment would be consumed by the ERGS for 24-hour PM_{10} and 24-hour SO_2 concentrations.

The project would also consume over half of the remaining annual PM_{10} and 3-hour SO_2 PSD increment. Other pollutant concentrations would consume less of the increment.

Table 7-16 shows similar trends for the ERGS if it is located at the South Site.

Table 7-16 Air quality and PSD increment modeling results for the ERGS at the South Site *

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	TSP 24- hour	Pb Calendar quarter	SO_2 3 - hour	SO_2 24 - hour	SO_2 Annual	NO_2 Annual
Background Concentration (ug/m3)	58	27	76	NA	208.10	57.80	9.30	31.00
Background plus ERGS concentration(ug/m3)	119.96	35.06	149.71	0.0030	9938.21	236.28	22.10	59.52
NAAQS Standard (ug/m3)	150	50	150	1.5	1,300	365	80	100
Percent (%) of NAAQS	**79.9%**	**77.0%**	**99.8%**	**-**	**72.2%**	**64.7%**	**27.6%**	**59.52%**
PSD Class II Increment Concentration (ug/m3)	30	17	-	-	512	91	20	25
Maximum Elm Road Project Only Concentration (ug/m3)	29.61	5.67	-	-	185.20	85.21	6.09	2.72
Percent (%) of Class II Increment	**98.7%**	**33.4%**	**-**	**-**	**36.2%**	**93.6%**	**30.5%**	**10.9%**

*Assumptions: SCPC units stack heights at 470 feet; SCPC units short-term SO_2 emission rate at 1,650 lbs/hr

Table 7-16 shows that the modeled concentrations from the proposed ERGS and other NAAQS sources are below standard level of pollution allowed for the region, although the 24-hour concentration of TSP and 3-hour concentration of SO_2 would come very close to 100 percent of the standard. Most of the PSD increment would be consumed by the ERGS for 24-hour PM_{10} and 24-hour SO_2 concentrations. The project would consume over half of the 3-hour SO_2 increment. Other pollutant concentrations would consume less of their increments.

Table 7-17 shows similar trends for the ERGS if it is located at the South Site-Exp.

Table 7-17 Air quality modeling results for the ERGS at the South Site-Exp*

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	TSP 24- hour	Pb Calendar Quarter	SO_2 3 - hour	SO_2 24 - hour	SO_2 Annual	NO_2 Annual
Background Concentration (ug/m3)	58	27	76	NA	208.10	57.80	9.30	31.00
Background plus ERGS concentration(ug/m3)	119.97	34.98	149.77	0.0030	940.10	238.78	22.23	59.47
NAAQS Standard (ug/m3)	150	50	150	1.5	1,300	365	80	100

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	TSP 24- hour	Pb Calendar Quarter	SO_2 3 - hour	SO_2 24 - hour	SO_2 Annual	NO_2 Annual
Percent (%) of NAAQS	**79.9%**	**69.9%**	**99.8%**	**-**	**72.3%**	**65.4%**	**27.8%**	**59.47%**
PSD Class II Increment Concentration (ug/m3)	30	17	-	-	512	91	20	25
Maximum Elm Road Project Only Concentration (ug/m3)	29.73	5.66	-	-	276.76	89.92	2.91	2.91
Percent (%) of Class II Increment	**99.1%**	**33.3%**	**-**	**-**	**54.1%**	**98.8%**	**14.6%**	**11.6%**

*Assumptions: SCPC units stack heights at 470 feet; SCPC unit short-term SO_2 emission rate at 1,650 lbs/hr

Table 7-17 shows that the modeled concentrations from the proposed ERGS and other NAAQS sources are below the standard level of pollution allowed for the region, although the 24-hour concentration of TSP and 3-hour concentration of SO_2 would approach 100 percent of the standard. Most of the PSD increment would be consumed by the ERGS for 24-hour PM_{10} and 24-hour SO_2 concentrations. Over half of the 3-hour SO_2 increment would be consumed. Other pollutant concentrations would consume less of the increments.

Based on WEPCO's air quality modeling analyses, the ERGS would appear to qualify for a DNR permit. However, the WEPCO permit applications remain to be completed, and the subsequent DNR analyses remain to be finished before a preliminary permit judgment can be made. DNR analyses would also examine the cumulative impacts of each unit at each site so that the effects of adding each unit can be seen. The cumulative modeling results are expected to be available in the DNR's analyses and review of WEPCO's permit applications.[86]

If the preliminary determination is that the project qualifies for a permit, then the final determination would be made after the requirements of Wis. Admin. Code ch. NR 150, the DNR WEPA rule, are satisfied. If the project cannot be permitted, the project will not be built.

Additional impacts

The following section summarizes results of the additional impacts analyses performed for the DNR under the PSD program by WEPCO. These results remain to be confirmed by the DNR analyses.

Visibility impact

PM, NO_x, and SO_2 emissions from this power plant have the potential to impact local and regional visibility. NO_x and SO_2 emissions react in the atmosphere to form sulfate and nitrate compounds. These compounds condense as very fine particulate matter and can cause visibility impairment.

[86] WEPCO submitted additional information to the DNR on July 2, 2003 seeking the same BACT limits for the South sites as for the North Site. Based on review of this information, the DNR determined that WEPCO's air permit applications for the South Sites are still not complete. The information in the final EIS is based on WEPCO's submittal for its original application in December 2002 and supplemental material on April 16, 2003. The DNR is currently reviewing this information and will provide an update on its review at the CPCN hearing proceedings.

However, nitrate and sulfate deposition rates are air pollution issues for regional or long range transport. The potential emissions of these pollutants from this power plant would be a small fraction of the annual statewide emissions as discussed below. As a result, this power plant is not expected to cause any perceptible visibility impacts to the region. In addition, a Level I screening analysis indicates that the maximum visual impacts to the nearest Class I wilderness areas, the Rainbow Lake and Seney Wilderness areas in northwest Wisconsin, would be less than the screening criteria and thus constitute no significant visual impact.

Particulate matter

Both the SCPC and IGCC units would be subject to Wis. Admin. Code § NR 415.06 and have an allowable PM emission rate of 0.1 lb/MMBtu, for fuel burning sources that have a heat input of greater than 250 MMBtu/hr and emit PM. The maximum particulate emissions from the SCPC units would be 0.018 lb/mmBtu, and the maximum emissions from the IGCC CTs would be 0.011 lb/MMBtu (based on the air permit application's maximum of 23.0 lb/hour and 2,139 MMBtu/hr on syngas). Therefore, the SCPC units and the IGCC would be in compliance with this standard.

Opacity

It appears that the two SCPC units and the IGCC unit would meet this requirement under Wis. Admin. Code ch. NR 431.

Impacts to soils and vegetation

Impacts to soil would result from deposition and incorporation of pollutants into the soil so that soil characteristics are changed and the soil or plant life are affected. Impacts to vegetation could also be more direct, resulting from deposition of pollutants onto the plants themselves or absorption of soil pollutants by the plant roots.

The primary pollutants in this case would be NOx, CO, SO_2, and PM. In addition, this power plant would be a source of hazardous air pollutants, including ammonia, mercury, and other trace elements that occur in coal and limestone. The emissions and potential concentrations of hazardous air pollutants from the project are discussed below in more detail.

Emissions from the ERGS units could cause increases in nitrate (NO_3) and sulfate (SO_4) ion deposition to soils and vegetation in the area. However, as discussed above with respect to visibility impairment, nitrate and sulfate deposition rates are regional or long range transport air pollution issues. NO_x and SO_2 emissions are normally transported tens to hundreds of miles before deposition occurs. As a result, the proposed project is not expected to affect area nitrate or sulfate deposition rates significantly.

The national ambient air quality standards include public health and welfare standards intended to protect soils and vegetation from significant air pollution impacts. The ERGS units are being modeled, and to the extent that they demonstrate compliance with the NAAQS and PSD increment requirements, significant deposition impacts would not be expected. If the plant operated at 100 percent capacity and all of its emissions were deposited uniformly in an area surrounding it within a radius of 200 miles, the nitrate and sulfate deposition rates would represent a small percentage increase in nitrate and sulfate deposition. Actual impacts are expected to be very small.

Acid deposition emissions

SO_2 emissions

The potential SO_2 emissions from this power plant, based on the worst-case fuel and the operation of the plant at its maximum capacity for 8,760 hours per year, are shown in Table 7-9 as 9,785 tons per year. For facilities of this type, normal operation is typically 75 to 90 percent of this maximum capacity. For comparison, the total Wisconsin utility emissions and total Wisconsin annual emissions can be summarized as follows:

ERGS	9,785 tpy
Wisconsin major utilities combined	211,522 tpy
Total Wisconsin emissions	303,049 tpy

The total Wisconsin SO_2 emission of 303,049 tons is down 56 percent from the 1980 level of 686,399 tons. As illustrated, the potential annual SO_2 emissions would be less than one-half of one percent of the annual actual emissions from all Wisconsin utilities combined. The expected ERGS emissions would, however, represent new SO_2 emitted into the Wisconsin atmosphere.

NO_x emissions

The total potential NO_x emissions expected from this power plant amount to about 5,245 tons per year, as shown in Table 7-10, again based on the worst case scenario. Normal plant operations would emit less. For comparison, the total Wisconsin utility emissions and total Wisconsin annual emissions can be summarized as follows:

ERGS	5,245 tpy
Wisconsin major utilities combined	116,538 tpy
Total Wisconsin emissions	193,795 tpy

Again, the potential annual NO, emissions from this power plant are less than half of one percent of the annual actual emissions from all Wisconsin utilities combined. However, the expected ERGS emissions would represent new NO_x emitted into the Wisconsin atmosphere.

Federal Acid Rain Program

The ERGS would be an affected new unit under the federal Acid Rain Program in 40 CFR Part 72 - 76. In order to operate, the ERGS would be required to buy allowances from another power plant that has reduced its emissions below the allowances allocated. Even though the ERGS would be a modification of an existing major stationary source, the total U.S. emissions are capped, so that the ERGS cannot add new SO_2 emissions beyond the cap.

Greenhouse gas emissions

The primary greenhouse gas from the ERGS units would be CO_2. Small amounts of N_20 and methane would also be emitted. Methane and N_2O emissions are converted to equivalent CO_2 emissions using global warming potentials.[87]

[87] Nitrous oxide absorbs about 296 times as much heat as CO_2, and methane absorbs about 23 times as much heat as CO_2 (Intergovernmental Panel on Climate Change, Third Assessment Report, 2001). Estimated annual ERGS N_2O emissions are about 46,000 tons of CO_2-equivalent per

ERGS greenhouse gas emissions were calculated only for the two SCPC units. No emission factors or information was available to calculate greenhouse gas emissions from the proposed IGCC unit. Because of the nature of the IGCC process, it would be expected to emit much less CO_2 than the SCPC units.

The maximum potential CO_2-equivalent greenhouse gas emissions from the two SCPC units would be 10.6 million tons per year. This estimate is based on the use of bituminous coal and the operation of the SCPC units at maximum capacity for 8,760 hours per year.

For facilities of this type, normal operation is typically 75 to 90 percent of this maximum potential capacity. Expected average greenhouse gas emissions were calculated using the expected hours of operation of the two SCPC units (7,426 to 7862 hours per year) and the expected rated heat input of 5,450 million Btu per hour. Under normal operating conditions, average annual greenhouse gas emissions from the two SCPC units are expected to fall somewhere between 8.4 and 8.9 million tons of CO_2-equivalent per year.

For comparison, Wisconsin electric utility emissions, transportation emissions, and total greenhouse gas emissions for 2000[88] are:

ERGS maximum potential emissions	10.6 million tpy
ERGS expected average emissions	8.4 to 8.9 million tpy
Wisconsin electric utilities	47,261,390 tpy
Wisconsin highway and non-highway transportation	34,060,742 tpy
Total Wisconsin GHG emissions	141,762,500 tpy

From these data, it can be seen that the expected average annual greenhouse gas emissions from the proposed ERGS would be about 18 percent of 2000 annual emissions from all Wisconsin electric utilities combined and about six percent of total statewide greenhouse gas emissions in 2000. The ERGS project would thus significantly increase Wisconsin's greenhouse gas emissions.

Hazardous air pollutants

The primary fuel for the ERGS generation boilers would be a blend of 95 percent washed bituminous coal and 5 percent coal ash (on a weight basis). A variety of fuel ashes have been analyzed. The analyses demonstrate that the fuel ash meets the definition of lignite coal as found in Wis. Admin. Code § NR 400.02 (22e). For this reason, the fuel ash is exempt from review under the hazardous air pollutant rule, Wis. Admin. Code ch. NR 445.

The emissions of HAPs from the combustion of natural gas and fuel oil are also exempt from NR 445 requirements because these fuels are considered virgin fossil fuel.

However, as discussed near the beginning of this chapter, and as confirmed by Table 7-18 below, the HAPs from the ERGS sources are subject to MACT.

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year and estimated methane emissions are about 2,600 tons of CO_2-equivalent per year. These estimates were made using USEPA emission factors from the State Greenhouse Gas Emission Inventory Tool.

[88] The year 2000 greenhouse gas emission estimates for Wisconsin are unpublished estimates done by DNR in 2003. They were done using the USEPA State Greenhouse Gas Emission Inventory Tool and USDOE EIA fuel combustion data for 2000. The state total emissions do not include carbon sinks.

HAPs emissions estimates

Tables in Appendix D summarize the HAPs emissions, including emissions of mercury, expected by WEPCO from the main ERGS emission sources.

- SCPC boilers, burning bituminous coal
- SCPC auxiliary boiler, burning either natural gas or fuel oil (ultra-low sulfur fuel oil at the North Site or low-sulfur fuel oil at the South sites).[89] WEPCO has elected to limit firing natural gas to 1,500 hours per year and fuel oil to 500 hours per year.
- IGCC unit, gasifying bituminous coal and burning the syngas produced. The associated equipment that would produce sulfuric acid as a by-product of the IGCC operation is anticipated to emit the criteria pollutant emissions of nitrogen oxides, sulfur dioxide and sulfuric acid mist.
- IGCC auxiliary boiler, burning either natural gas or fuel oil (ultra-low sulfur fuel oil at the North Site or low-sulfur fuel oil at the South sites).[90] WEPCO has elected to limit firing natural gas to 1,500 hours per year and fuel oil to 500 hours per year.
- Diesel engine/electric generator sets, burning fuel oil (ultra-low sulfur fuel oil at the North Site or low-sulfur fuel oil at the South sites)[91]
- Fire pump(s),[92] burning fuel oil (ultra-low sulfur fuel oil at the North Site or low-sulfur fuel oil at the South Sites)[93]

The emissions levels in Appendix D and Table 7-18 are based on WEPCO's calculations in its air permit application and additional information submitted on June 2, 2003 and June 27, 2003. This data is subject to change pending DNR's further review and analysis.

Table 7-18 provides a summary of the estimated potential emissions of hazardous air pollutants from major emissions sources in the ERGS. It does not include fugitive coal dust and other dust, which should be low if appropriate controls are implemented.

Table 7-18 Hazardous air pollutant emissions from the major components of the ERGS in tons per year

Hazardous Air Pollutant	SCPC Unit 1	SCPC Unit 2	IGCC	SCPC Auxiliary Boiler	Diesel Generator	Fire Pump(s)	IGCC Auxiliary Boiler
Antimony	0.091	0.091	0.021	Negligible	Negligible	Negligible	Negligible
Arsenic	0.164	0.164	0.490	0.0000	0.00003	0.00001	0.0001
Beryllium	0.009	0.009	0.025	0.000	0.00000	0.00000	0.0001
Cadmium	0.030	0.030	0.018	0.0000	0.00001	0.00000	0.0000

[89] In WEPCO's June 27, 2003 submittal for its air pollution control permit application, it requested new BACT for sources at the North Site and CUP option but not for the South Site or South Site Exp.

[90] In WEPCO's June 27, 2003 submittal in support of its air pollution control permit applications, it requested new BACT for sources at the North Site and CUP option but not for the South Site or South Site Exp.

[91] In WEPCO's June 27, 2003 submittal in support of its air pollution control permit applications, it requested new BACT for sources at the North Site and CUP option but not for the South Site or South Site Exp.

[92] According to WEPCO's June 2 and June 27, 2003 submittals in support of its air pollution control permit applications, there would be one fire pump at the South sites or three at the North Site or CUP).

[93] In WEPCO's June 27, 2003 submittal for its air pollution control permit applications, it requested new BACT for sources at the North Site and CUP option but not for the South Site or South Site Exp.

Hazardous Air Pollutant	SCPC Unit 1	SCPC Unit 2	IGCC	SCPC Auxiliary Boiler	Diesel Generator	Fire Pump(s)	IGCC Auxiliary Boiler
Chromium	0.239	0.239	0.310	0.001	0.00004	0.00001	0.0002
Cobalt	0.038	0.038	0.119	0.002	0.00023	0.00008	0.0008
Lead	0.202	0.202	0.501	0.001	0.00006	0.00002	0.0002
Manganese	0.332	0.332	0.585	0.001	0.00010	0.00004	0.0004
Mercury	0.062	0.062	0.029	0.000	0.00000	0.00000	0.0001
Nickel	0.226	0.226	0.334	0.044	0.00504	0.00182	0.0178
Selenium	1.328	1.328	0.254	0.000	0.00001	0.00001	0.0001
Hydrogen Chloride	69.360	69.360	2.946	0.145	0.01683	0.00608	0.0587
Hydrogen Fluoride	23.930	23.930	0.520	0.007	0.00078	0.00028	0.0027
Formaldehyde	0.130	0.130	2.886	0.015	0.00056	0.00303	0.0060
Organic HAPs	0.002	0.002	0.261	0.018	0.00100	0.00145	0.0073
Total HAPs	96.1	96.1	9.30	0.23	0.0060	0.0045	0.094

Table 7-17 shows that the total potential emissions of Section 112 HAPs from the ERGS are estimated at just over 200 tpy. The provisions in 40 CFR Sec 63.41 define constructing a major source to mean installing at any developed site a new process or production unit, which in and of itself, emits or has the potential to emit 10 tons per year of any individual HAP or 25 tons per year of any combination of any HAPs. Thus, the proposed ERGS project is subject to case-by-case MACT requirements for HAPs.

The case of mercury

Hg emissions from the ERGS would occur as a result of trace amounts of this element coming from the coal and limestone. Of all the inorganic HAPs on the federal HAPs list, Hg is generally present in limestone and coal at the lowest levels, but its toxicity is of widespread concern. As shown in Table 7-8 and 7-10, total ERGS Hg emissions would be over 300 lbs/yr. Based on these tables, Hg emissions are also subject to the PSD program under Wis. Admin.Code ch. NR 405. WEPCO would be required to implement MACT for Hg.

Case-by-case MACT

Table 7-19 summarizes the case-by-case MACT proposed by WEPCO. The HAPs are aggregated into different types depending on their chemistry: inorganic solid HAPs, inorganic acid HAPs, organic HAPs, and mercury.

Table 7-19 Case-by-case MACT proposed for ERGS HAPs emission sources

Type of pollutants	Proposed MACT				
	SCPC boilers	IGCC unit	Diesel engine	Fire pump	Aux. boilers
Inorganic Solid HAPs	Complying with the PM emission limit	Syngas cleanup operation and good combustion practices for the CT	Use of fuel oil and complying with the PM BACT limits	Use of fuel oil and complying with the PM BACT limits	Use of natural gas and fuel oil and complying with the PM BACT limits
Inorganic Acid HAPs	Complying with and	Syngas cleanup operation and	Use of fuel oil	Use of fuel oil	Use of natural gas and fuel oil

Type of pollutants	Proposed MACT				
	SCPC boilers	IGCC unit	Diesel engine	Fire pump	Aux. boilers
	meeting the SO_2 emission limit	good combustion practices for the CT			
Organic HAPs	Complying with and meeting the VOC emission limit	IGCC process and good combustion practices for the CT	Complying with and meeting the VOC emission limit	Complying with and meeting the VOC emission limit	Complying with and meeting the VOC emission limit
Mercury	Multi-pollution controls	Use of carbon bed filter or filters containing other similar material in the syngas, or a removal of 90% achieved without carbon filtration, or other requirements for effective control of mercury as promulgated by the EPA	Use of fuel oil and complying with or meeting PM emission limit	Use of fuel oil and complying with or meeting PM emission limit	Use of natural gas and fuel oil and complying with meeting PM emission limit

The case of ammonia

Ammonia emissions are expected from the use of SCR at the SCPC boilers. Ammonia is regulated under Table 1 of Wis. Admin. Code ch. NR 445. For ammonia, compliance with an acceptable ambient air concentration established by rule is required.

The proposed ammonia emission limit from the SCPC units is 5 ppm, which is equivalent to 20 lb/hour from each SCPC stack. The threshold value for ammonia from stacks in excess of 25 feet, according to Table 1 of Wis. Admin. Code ch. NR 445 is 6.28 lb/hr. Since the SCPC boilers may emit ammonia in excess of the table value, NR 445 requires that dispersion modeling be performed to demonstrate that the maximum ambient concentrations of ammonia do not exceed 2.4 percent of the threshold limit value (TLV) established by the American Conference of Governmental and Industrial Hygienists (ACGIH).

The ACGIH, 2001 standards list a TLV of 25 ppm for ammonia. This is equal to 17,678 ug/m^3. Ten percent (1 hour value) of this TLV would be 1,767 ug/m^3, and 2.4 percent (24 hour value) of the TLV would be 424 ug/m^3.

WEPCO's modeling shows that the maximum hourly-modeled impact would be 4.37 ug/m^3, that the 24-hour modeled impact would be 0.36 ug/m^3, and that the annual impact would be 0.013 ug/m^3. This WEPCO information in the air permit application is subject to change depending on the DNR's review and analysis. Based on these modeling results, ERGS would meet the ambient air standards required under NR 445 for ammonia.

Chapter Summary

- Each component of the plant that has the potential for producing emissions has been analyzed to determine the Best Available Control Technology for that component based on its fuel and operating characteristics. (All of WEPCO's air permit applications include the continued operation of Units 5 and 6. In general, low NO_x burners, selective catalytic converters, low sulfur fuel, wet flue gas desulfurization, and good combustion practices are the expected emission control technologies for reducing NO_x, SO_2, CO, PM and PM_{10}. Fabric filter baghouses and flue gas desulfurization are the expected control technologies for reduction of lead, mercury, beryllium, and fluorides.
- Using WEPCO's modeling analysis, concentrations of particulate matter, especially total suspended particulates (TSP 24-hour), PM_{10} (24-hour), and SO_2 (both 3-hour and 24-hour) would increase substantially due to operation of the ERGS. Several of these pollutant concentrations are approaching 100 percent of the NAAQS for the region.
- PM_{10} (24-hour) would also consume nearly 100 percent of the PSD increment for that pollutant in the region, meaning that the ERGS would use up nearly all of the available capacity of the area to receive more PM_{10} emissions from another source.
- Under WEPCO's air modeling analysis for the North Site, the total concentrations of all pollutants, except the suspended particulates (TSP) emissions are at approximately 80 percent or less of the NAAQS, indicating that the project may be permittable. However, the concentration of total suspended particulates (TSP 24-hour) emitted from the ERGS would nearly double the background concentration of this pollutant and result in a concentration that is about 99.5 percent of the Wisconsin secondary (welfare-based) standard.
- WEPCO's analysis for the South Sites, based on a stack height of 470 feet for the two SCPC units (but without the BACT refinements used for the North Site) shows that the total concentrations of all pollutants, except the suspended particulates (TSP) emissions are also at approximately 80 percent or less of the NAAQS, indicating that the project may be permittable at either of the South Sites. However, the concentration of total suspended particulates (TSP 24-hour) emitted from the ERGS would nearly double the background concentration of this pollutant at the South Sites and result in a concentration that is about 99.8 percent of the Wisconsin secondary (welfare-based) standard.
- The concentration of total suspended particulates (TSP 24-hour) that could be emitted during the earth-moving phase of construction has not been assessed. Up to 30 or more large excavating machines and several dozen dump trucks could be operating on the construction site up to 12 hours per day for six days per week for nearly one year to excavate and move up to 10,000,000 cubic yards of earth and demolition debris to the proposed soil stockpile sites described and mapped in the CPCN application. Because these vehicles use diesel fuel, it is possible that localized diesel emissions could be very high.

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Chapter 8 - Water Resources

Existing Environment

Lake Michigan (near-shore and offshore)

Physical environment

Lake Michigan is the sixth largest freshwater lake in the world, the third largest of the Laurentian Great Lakes, and the only Great Lake entirely within the borders of the United States. Lake Michigan is 307 miles long, up to 118 miles wide, and up to 925 feet deep. The Lake has a surface area of 22,300 square miles, an average depth of 279 feet, and a volume of 1,180 cubic miles (1.29×10^{15} gallons).[94]

The near shore environment of Lake Michigan, adjacent to the ERGS, varies from a sand beach to quarried stone revetment. The quarried stone revetment begins at the existing coal dock and continues to the southern boundary of the federal rifle range property. North of the existing coal dock, there is a wide sand beach ranging from 60 to 150 feet wide, which helps to protect the toe of the bluff and helps reduce the rate of erosion along the steep clay bluffs.

Littoral process/currents

In coastal systems, beach sediments are transported along the shoreline as a result of waves combining with currents. This transport, known as "littoral drift," results in the creation of sandbars, pocket beaches and embayments cut into a beach. Littoral drift can move hundreds of thousands of cubic meters of sand along a coast each year. This section discusses how the ERGS project would change the littoral drift of sand, and the related changes in shoreline erosion rates.

The littoral drift of Lake Michigan at this location generally transports littoral material from the north to the south.[95] This is primarily controlled by northerly storms that largely occur during the winter months.[96] Structures such as breakwaters, jetties, and dredged navigational channels tend to trap littoral material behind the structure or move the material into deeper areas of the lake where it sinks. This interruption of littoral drift can exacerbate coastal erosion experienced at adjacent properties.

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[94] The Great Lakes: An Environmental Atlas and Resource Book. United States Environmental Protection Agency / Environment Canada ISBN 0-662-23441-3

[95] US Army Corps of Engineers, 1992. USING MORPHOLOGY TO DETERMINE NET LITTORAL DRIFT DIRECTIONS IN COMPLEX COASTAL SYSTEMS. Coastal Engineering Technical Note II-30 (3/92).

[96] W. F. Baird & Associates Ltd., 2002. Coastal Analyses, Sediment Transport & Regional Impacts for the Elm Road Generating Station-Qualitative Assessment. (12/02).

To help understand the coastal processes occurring adjacent to the ERGS, WEPCO submitted a coastal analysis report which suggests that the ERGS project would reduce the transport of sand to the properties located downdrift (south) by an insignificant amount. Further, the analyses in this report conclude that this change in volume of sand transport would have an insignificant effect on shoreline erosion rates.

In order to reach these conclusions, WEPCO's consultant analyzed Lake Michigan water levels and wave conditions, calculated the historical rates of shoreline erosion based on aerial photography, and used numerical models to estimate sand transport along the shoreline. A "littoral cell" was identified as extending from the St. Francis shoreline near Howard Avenue south to the Racine Harbor. Coastal engineers frequently study shoreline processes within distinct "littoral cells," within which there is no sediment transport into or out of the littoral cell.

Shoreline, nearshore, and shoreline protection survey results were provided by WEPCO's consultant. These results were used to evaluate potential erosion rates along the shoreline. The shoreline within the littoral cell of the OCPP, is composed primarily of glacial till and glacial lake deposits, which have 20 to 50 percent sand content and the nearshore lakebed consists primarily of glacial tills with a few areas that are classified as Sandy or Bedrock nearshore lakebed.

The Coastal Study conducted by Baird for WEPCO at the ERGS facility evaluated the historical, current and predicted amount of littoral drift for this littoral cell. The analysis by Baird indicates that this littoral cell has the capacity to carry 170,000 m^3/ year (222,000 yd^3/year) of littoral material past the location of the OCPP site on an average annual basis. However, when Baird analyzed the possible inputs and outputs to the littoral process and evaluated the average annual recession rates of the shoreline, Baird found that even when no littoral barriers were constructed, i.e. pre-1950, the amount of littoral material transported, past where the existing power plant is located, was only approximately 62,000 m^3/year (81,000 yd^3/year). This suggests that even prior to any structural barriers along the shoreline, this littoral cell was starved for transportable material.

Changes related to shoreline modifications since 1952 and the OCPP construction

Since 1950, numerous structures have been placed along the shoreline including a number of large structures that effectively trap littoral material and prevent this material from being transported to the south. The largest of these structures include the Shore Waste Water Treatment Plant, the existing Oak Creek Power Plant and the Racine harbor. A number of additional shoreline modifications such as groins, riprap, bluff grading, and navigational dredging have further entrapped the littoral material bypassing the OCPP site. The impact of these structures and the construction of the existing OCPP facility are evident in the Coastal Analyses Report.

When structures are placed along a shoreline the bathymetry adjacent to the structure is altered over time in response to changes in littoral transport and waves. In comparing the historical bathymetric maps with the new bathymetric surveys conducted by WEPCO it is apparent that the lakebed profile adjacent to the power plant has changed in response to the construction of the existing coal dock. This comparison of historical and new bathymetric maps indicate that the lakebed south of the existing coal dock has experienced a gradual steepening of the lakebed profile, whereas the area north of the existing coal dock appears to have had a gradual accumulation of material resulting in shallower lakebed contours in this area. These changes are

consistent with the current knowledge of coastal processes and the impacts of structures within littoral zones.

In addition, shoreline erosion rates downdrift (south) of the Oak Creek Power Plant appear to have increased since 1950. Analysis of historical aerial photos shows that prior to 1950, very few areas of the shoreline within the littoral cell had shoreline protection structures and the estimated annual shoreline recession rates for the properties located downdrift of where the OCPP was constructed, were on average less than 1.5 feet a year. However, these recession rates change dramatically between 1950 and 1970 when the existing OCPP facility was constructed along with many of the other large structures mentioned in the previous paragraph. These structures have trapped littoral material and prevented most of this material from being transported to downdrift shorelines. Bluff stabilization projects continued from 1970 to the present day and today only 2.4-km (1.5 miles) total out of 9 km (5.6 miles) of shoreline between the OCPP facility and Wind Point is unprotected by groins, jetties, or revetments. Since 1950, these unprotected shorelines have experienced drastic increases of shoreline recession rates of up to six feet per year.

The impact of the existing shoreline structures within this littoral cell is also evident in the estimated 2002 littoral transport rates, provided by Baird, which suggests that only approximately 3,000 m^3/year (3924 yd^3 /yr) is able to bypass the existing ERGS site. Baird also analyzed the grain size of this material to determine if this material was large enough to play a significant role in the stabilization of the downdrift shorelines. The conclusion of Baird's Coastal Analyses suggests that this small amount of littoral material, which is currently bypassing the site, is very fine and would not provide adequate protection to a shoreline south of the existing power plant. Based on this information Baird determined that the construction of the proposed harbor would not cause a significant impact on properties located downdrift (south) of the proposed harbor.

Geology / stratigraphy

The Wisconsin glaciation greatly influenced the geology of southeastern Wisconsin.[97] As ice sheets advanced and retreated in the Great Lakes basin, material was deposited and layers of differing material were formed on the land and within Lake Michigan. These glacial deposits, combined with the more recent deposits from the littoral processes of Lake Michigan and underlying bedrock, form the bed of Lake Michigan. This section describes the various geologic layers that comprise the bed of Lake Michigan.[98]

Overlying the bedrock are layers of lacustrine and glacial deposits. Lacustrine deposits are composed of unconsolidated and cohesionless sands and gravels which have generally been subject to the littoral processes. These deposits vary in thickness depending upon location. Underlying the lacustrine deposits are glacial deposits composed of alternating layers of lacustrine sand, silt, and clay and clay tills which are approximately 45 feet deep. The clay tills are cohesive sediments and have been compressed by the weight of glaciers. As a result, they tend to be stiffer, have lower water content, and greater density than the lacustrine soils.

The stratigraphic units encountered by Montgomery Watson Harza and Associates (MWH), the applicant's consultant, at the Elm Road site reflect a transition in depositional environments between those bedrock

[97] Montgomery Watson Harza, 2002. Geotechnical Data Report- Elm Road Generating Station Cooling Water Intake System prepared for WE Power, LLC. (November 2002).
[98] Southeastern Wisconsin Regional Planning Commission, 2002. Groundwater Resources of Southeastern Wisconsin. Technical Report No. 37. (June 2002).

units typically seen in the subsurface of Milwaukee and those found in the Chicago area. The bedrock beneath the lacustrine and glacial deposits consists of gently inclined sedimentary rock of the Silurian series. These consist primarily of dolomite of the Racine Formation, Waukesha Formation, Brandon Bridge member of the Joliet Formation, and the Kankakee Formation (see Figure 8-1).

Racine formation

The Racine formation is at the surface of the bedrock. At the site, this formation ranged in thickness from approximately 70 feet to over 120 feet thick. The rock is a light to medium gray fossiliferous dolomite.

Waukesha formation

The Waukesha formation underlies the Racine formation; the two units are differentiated by a change in rock texture. The Waukesha formation is less pitted, is light gray to buff in color and has an argillaceous and crystalline texture. The Waukesha formation at the project site ranges in thickness from 13 to 52 feet thick.

Brandon Bridge member

Lying below the Waukesha formation is the Brandon Bridge member. The Brandon Bridge member is composed of three distinct subunits. The upper unit of the Brandon Bridge is a light buff gray finely crystalline dolomite with numerous dark gray and green wavy shale partings and parting clusters. The upper unit average thickness is 43 feet.

The middle unit of the Brandon Bridge is argillaceous and crystalline and is differentiated from the upper unit by the appearance of red shale partings and layers. The middle unit is composed of light green and pink fine crystalline dolomite interbedded with green shale and reddish-brown shaley dolomite. The average thickness of the middle unit is approximately 34 feet.

The lower unit of the Brandon Bridge is marked by the disappearance of reddish-brown shale and shaley dolomite. The unit is thin to medium bedded green shaley dolomite with green shale partings and parting clusters. It is argillaceous to finely crystalline, fresh, medium hard to hard, and medium dense. The lower unit of the Brandon Bridge is the thinnest of the three subunits and averages five feet thick.

Kankakee formation

Underlying the Brandon Bridge member is the Kankakee formation, which is a medium to thick bedded light to medium gray buff, with fine to medium crystalline dolomite. Green and gray shale partings are also found throughout the formation. The thickness of the Kankakee formation is unknown for a portion of the sampling site because it was not fully penetrated as part of the sampling program conducted by MWH. However, two of the sampling cores that did penetrate through this formation found that it was approximately 63 feet to 70 feet thick.

Basal shale formation

The Basal shale formation underlies the Kankakee formation. The unit only appears in significant thickness in one sample, and only the upper 19 feet of the formation was penetrated. The unit is a reddish-gray shaley dolomitic mudstone and is soft to moderately hard, with areas that contain yellow staining.

Bathymetry

WEPCO completed a hydrographic survey in October 2002, which updated the bathymetric data of Lake Michigan within the project boundaries. The updated bathymetric data indicates that the elevation of the

lake bed gradually decreases to the east. The near shore areas generally contain more irregularities on the surface than the offshore areas. However, there were a number of areas further offshore where there are prominent step-like features. (See Figure Vol. 2-9.)

Lakebed characterization

WEPCO contracted with the Great Lakes Water Institute to provide high resolution maps of bathymetry and characterize the substrate or habitat types for siting the water intake structure. The study characterized the substrate of Lake Michigan, offshore from the existing power plant beginning at 20-foot water depths up to 60-foot water depths. The lakebed was then categorized into four categories: 1) cobble or boulders; 2) cobble, gravel and sand; 3) hard clay outcrops; and 4) sandy or silty sand. The maps generated by the Great Lakes WATER Institute show that this area tends to consist of rock area between 20-to 30-foot water that the area of the proposed intake structure to consist of primarily sand. (See Figure Vol. 2-10)

Temperature

Lake Michigan experiences an annual temperature cycle which is influenced by weather conditions and seasonal fluctuations in solar radiation, ambient air temperature and wind speed.[99] Changes in these seasonal fluctuations have drastic impacts on the thermal stratification (the development of distinct layers within the lake based on temperature) of Lake Michigan. Water temperature in Lake Michigan varies from approximately 0°C (32°F) to 18°C (65°F). The annual temperature cycle can generally be broken down into three stages:

Fall turnover

Near the end of August the surface water layers become cool and become more dense than the deeper water layers which are warmer. This leads to the cooler surface water layers sinking via wave and wind action. This progressive sinking leads to a mixing of the cooler surface water with the deeper warmer water layers causing a cooling of the lake. This mixing continues until December when all layers of the lake are mixed to approximately 0°C (32°F) to 18 °C (65°F).

Winter stratification

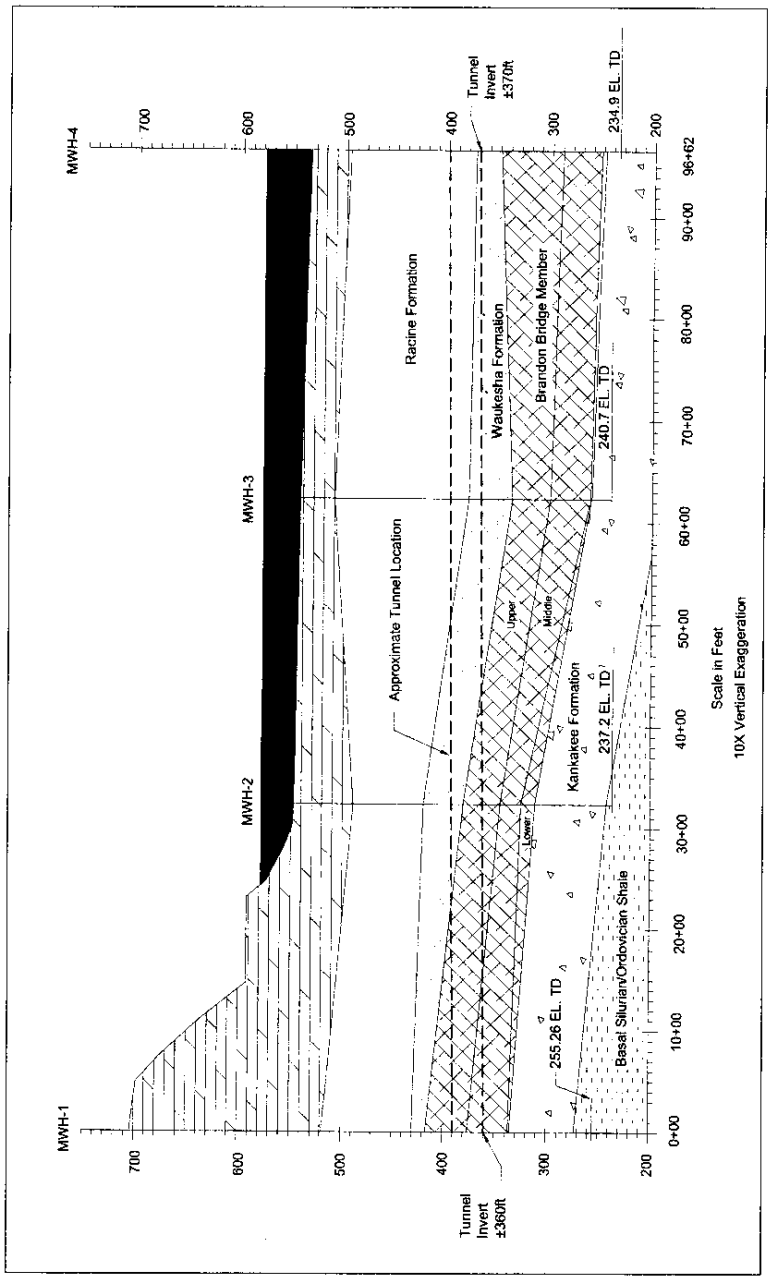
This stage occurs from January until April when the surface water temperatures continue to cool to below 4° C due to wind energy, ambient air temperature, and possibly ice formation. This layer of cooler water then lies over a deep warmer water which remains approximately 4°C.

Spring/summer warming and stratification

In May and June the surface water layers warm to a temperature above 4°C and form a distinct thermal bar (often clearly visible) that expands and starts moving offshore until the entire surface layer of the Lake is warmed to well above 4°C (39°F). As the summer progresses and until August, the surface water layers continue to warm and a thermocline (an area in the lake where water temperature decreases very steeply) is formed. The warmer water floats on top of the cooler denser water, and very little mixing occurs. As the summer progresses the surface layer continue to increase in temperature and the thermocline deepens. This continues until the Fall Turnover stage.

[99] Mortimer, Hiley Center for Great Lakes Studies. 1971. Large-Scale Oscillatory Motions and Seasonal Temperature Changes in Lake Michigan and Lake Ontario. Special Report No. 12 Part I.

Figure 8-1 Stratigraphy of the near shore bedrock of Lake Michigan at the OCPP site



Biological environment

Vertebrates

The Lake Michigan fishery consists of nearly 100 species. The table below lists the species that are commonly found in the near shore waters of Lake Michigan. The fish community in Lake Michigan has undergone considerable changes since the construction of the Welland Canal around Niagara Falls in the

early 1900's. The Welland Canal allowed marine species, notably the alewife and sea lamprey, to invade the upper Great Lakes. The sea lamprey, along with over-fishing, led to dramatic declines in the numbers of native piscivorous fish. This decline allowed the alewife population to explode, which led to significant declines in native fish species, including lake herring, lake whitefish, chubs and yellow perch. Sea lamprey control and fish stocking programs have increased predator fish numbers and stabilized alewife numbers.

An additional benefit of the stocking program has been the development of a popular sport fishery.

Table 8-1 Fish species commonly found in near shore waters of Lake Michigan

Brook trout	Rainbow smelt	Sand shiner	Walleye
Brown trout	Alewife	Fathead minnow	Johnny darter
Lake trout	Gizzard shad	Longnose sucker	Rock bass
Rainbow trout (Steelhead)	Lake chub	White sucker	Trout-perch
Chinook salmon	Emerald shiner	Burbot	Three-spine stickleback
Coho salmon	Spottail shiner	Slimy sculpin	Nine-spine stickleback
Lake whitefish	Longnose dace	Yellow perch	Brook stickleback
Round whitefish	Common carp	Smallmouth bass	Round goby
Bloater chub	Bluntnose minnow	Largemouth bass	

The annual stocking of six species maintains the Wisconsin Lake Michigan trout and salmon fishery. This stocking consists of two native species (lake trout and brook trout) and four introduced species (Chinook and Coho salmon, Brown trout and Steelhead). The five-year average stocking levels for Milwaukee and Racine Counties is listed in the table below.

Stocking locations near the proposed project area include Bender Park, Oak Creek, Green Can Reef and South Milwaukee Reef. Only lake trout would be stocked on the two reefs, while all the species could potentially be stocked at Bender Park. Stocking in the Oak Creek proper could include all of the trout and salmon species except for lake trout.

Table 8-2 Salmonid species and numbers of fish stocked in Milwaukee and Racine Counties

Five-year Average of Salmonid Species Stocked in Milwaukee and Racine Counties (1997– 2001)						
County	Brook Trout	Brown Trout	Chinook Salmon	Coho Salmon	Lake Trout	Steelhead
Milwaukee	18,268	109,397	157,808	32,142	160,014	56,583
Racine	5,370	105,642	146,795	56,747	58,860	95,994
Total	23,638	215,039	304,603	88,889	218,874	152,577

Wisconsin DNR sport fishing surveys estimated fishing effort and harvest in Racine and Milwaukee Counties. Angler hours ranged from 201,774 angler hours in 2000 to a high of 360,474 angler hours in 2001. The average angler hours spent fishing in these two counties on Lake Michigan was 530,157 per year. Harvest estimates were calculated for a variety of salmon and trout species as well as native species. Harvests ranged from zero for several species to 44,013 Coho salmon in 1997. Anglers in Racine harvested an average of 67,562 fish from 1997 to 2001 while Milwaukee area anglers harvested an average of 61,122 fish from 1997 to 2001. The creation of Bender Park has increased access to Lake Michigan for Milwaukee County anglers and has made it easier to access the warm water discharge from the Oak Creek Power Plant.

Anglers concentrate in this area in the spring and fall to catch brown trout. It is also used heavily during the summer to harvest yellow perch.

Table 8-3 Estimates of fishing effort in Racine and Milwaukee Counties

Estimates of Fishing Effort (hours) Calculated by Wisconsin DNR, 1997-2001						
County	1997	1998	1999	2000	2001	Average
Racine	302,364	232,660	260,600	201,774	256,390	**250,757.6**
Milwaukee	283,356	295,991	244,605	212,570	360,474	**279,399.2**
Total	**585,720**	**528,651**	**505,205**	**414,344`**	**616,864**	**530,156.8**

Table 8-4 Estimates of Lake Michigan Fish Harvest in Racine County

Harvest Estimates for Racine County Calculated by Wisconsin DNR, 1997-2001.						
Species	1997	1998	1999	2000	2001	Average
Coho Salmon	44,013	10,170	15,979	19,788	12,047	**20,399.4**
Chinook Salmon	8,619	8,344	17,796	20,137	16,046	**14,188.4**
Rainbow Trout	9,803	9,329	7,619	5,439	11,664	**8,770.8**
Brown Trout	4,739	1,979	3,317	4,475	3,132	**3,528.4**
Brook Trout	2	2	9	7	0	**4.0**
Lake Trout	9,710	16,603	11,526	8,838	8,224	**10,980.2**
Northern Pike	8	6	0	0	16	**6.0**
Smallmouth Bass	0	0	0	0	0	**0.0**
Yellow Perch	7,016	5,201	6,482	2,512	27,213	**9,684.8**
Walleye	0	0	0	0	0	**0.0**
Total	**83,910**	**51,634**	**62,728**	**61,196**	**78,342**	**67,562**

Table 8-5 Estimates of Lake Michigan Fish Harvest in Milwaukee County

Harvest Estimates for Milwaukee County Calculated by Wisconsin DNR, 1997-2001						
Species	1997	1998	1999	2000	2001	Average
Coho Salmon	23,212	10,436	5,717	16,705	8,989	**13,011.8**
Chinook Salmon	10,089	15,278	11,677	9,339	19,578	**13,192.2**
Rainbow Trout	7,114	12,715	5,450	3,392	11,068	**7,947.8**
Brown Trout	11,536	7,550	3,169	9,463	3,921	**7,127.8**
Brook Trout	59	30	0	5	39	**26.6**
Lake Trout	5,069	5,300	1,589	2,248	4,473	**3,735.8**
Northern Pike	164	183	0	0	173	**104.0**
Smallmouth Bass	53	19	30	0	0	**20.4**
Yellow Perch	1,482	4,686	6,330	5,633	61,074	**15,841**
Walleye	353	194	25	0	0	**114.4**
Total	**59,131**	**56,391**	**33,987**	**46,785**	**109,315**	**61,121.8**

Data from commercial yellow perch fishermen as reported to the DNR show an average of 94,671 pounds of yellow perch (*Perca flavescens*) harvested annually from 1992 to 1996 in Lake Michigan locations close to the proposed Elm Road facility. Pounds harvested ranged from 11,420 in 1996 to 137,270 in 1992. Commercial

fishing for yellow perch was closed in the fall of 1996 due to the decline in the yellow perch population and is represented by the decline in the harvest from 137,270 to 11,420 pounds from 1992 to 1996.

Table 8-6 Commercial harvest of yellow perch in locations near the ERGS from 1992-1996

Commercial Harvest (pounds) of yellow perch in Grids 1901, 1902, 2002 and 2102, 1992 – 1996						
	1992	1993	1994	1995	1996	Average
Yellow Perch	137,270	126,681	123,419	74,565	11,420	**94,671**

Estimates of the yellow perch population in southern Lake Michigan were calculated using DNR surveys, assessments and other sources. Yellow perch populations were estimated to be over 20,000,000 fish in Wisconsin waters off Lake Michigan in 1986. Strong year-classes in the mid-1980's created a large population that was fished heavily by both sport and commercial anglers. Poor recruitment in the 1990's was caused by unknown factors which may include poor weather, low abundance of female spawners, reduction in zooplankton abundance and increased vulnerability to predators.

Recent trends show a marked decline in the overall numbers dropping to less than 500,000 in 1998. However, a modest year class in 1998 increased the overall yellow perch population in the late 1990's. Wisconsin DNR SCUBA surveys show increased egg deposition on traditional yellow perch spawning grounds since 1997. Now that the 1998 year-class of yellow perch are fully mature, egg deposition and potential for production of another modest year-class may be good over the next couple of years.

Figure 8-2 Yellow perch population estimate (number) for southern Wisconsin's Lake Michigan waters, 1986-2001

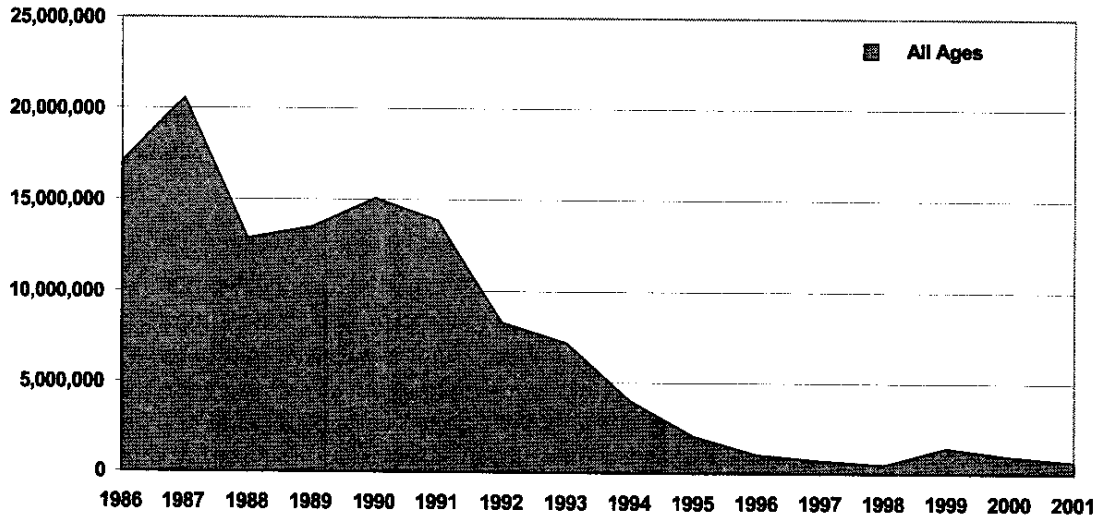


Table 8-7 Yellow perch dive summary conducted by DNR for the years 1997- 2002

Wisconsin DNR Yellow Perch Dive Summary from 1997 to 2002				
Year	Diver bottom time (hrs)	# Egg masses found	Area covered (m2)	# Egg masses per 1000 m2
1997	31:40	9	18,000	0.50
1998	12:48	0	9,200	0.00
1999	-	-	-	-
2000	1:10	8	4,225	1.89
2001	4:30	223	30,600	7.29
2002	8:00	573	49,701	11.53

Reproduction and spawning

While natural reproduction has not been documented, lake trout are known to spawn on both the Green Can and South Milwaukee Reefs. Green Can Reef is located off of St. Francis, while the South Milwaukee Reef is located approximately 3.5 miles off the mouth of Oak Creek (the creek) in 25 to 55 feet of water. Spawning runs of anadromous trout and salmon occur annually on rivers and stream tributaries of Lake Michigan. Chinook salmon, Coho salmon, Brown trout, Brook trout and Rainbow (Steelhead) trout all utilize Oak Creek as a spawning site, although natural reproduction does not occur.

Yellow perch spawning in Lake Michigan occurs on boulder and rubble reefs in the near shore waters. The Green Can Reef is the major yellow perch spawning location in the area but spawning also occurs on similar habitat along the shoreline, such as the South Milwaukee Reef.

Alewife spawn in the near shore waters of Lake Michigan from June to August, with inshore migration beginning in May. The population of alewives has fluctuated widely, from the extreme levels seen in the late 1960's and early 1970's to much lower numbers at present. Despite the drop in population, alewives remain the dominant forage species in the diets of trout and salmon in Lake Michigan. The number of alewives in the near shore waters varies seasonally, with a large inshore movement coinciding with spawning, followed by offshore movement following spawning. In winter, alewives seek the warmest water available and are typically found in deep water. An annual die-off is associated with the spawning migration, either from spawning stress or fluctuations in water temperature.

The table below lists the spawning requirements of a selected number of Lake Michigan fish species. The list includes species resident to the project area, as well as those that may be seasonally or temporally abundant. Habitat for spawning is available for all of the listed species in the general vicinity of the proposed intakes, but this habitat is not necessarily limited to the project area. The availability of spawning habitat outside of the project area should mitigate potential losses due to construction, but all necessary precautions must be taken to minimize disturbance of the existing habitat. Losses due to entrainment and impingement are potentially greater for those species with pelagic eggs or larvae. Data from previous entrainment and impingement studies at the Oak Creek Power Plant support this, with higher densities of alewife larvae entrained during the periods of highest overall abundance (July and August). Entrainment of yellow perch larvae followed a similar trend, with densities highest in late June and early July (WEPCO, 1976; EA Engineering 2003).

Weather and currents, both internal and wind-driven, influence the presence and density of eggs and larvae in the project area. Thus, entrainment and impingement losses could vary depending on temporal and environmental differences. However, the best available means for reducing losses due to entrainment and impingement should be implemented in the final design of the intakes. Finally, additional entrainment and impingement studies should be implemented following completion of the intakes to assess the affects of mitigating technologies.

Table 8-8 Spawning requirements for selected Lake Michigan fish

Species	Habitat	Spawning Period	Temperature	Egg/Larval Characteristics
Lake Trout	Near shore and offshore reefs; boulder/cobble/ honeycomb rock	October-November	37 – 58 F	Semi-buoyant, 5-6mm diameter/demersal
Rainbow Trout	Streams; gravel	January – May, depending on strain	38 – 50 F	Semi-buoyant, 4-5 mm diameter/demersal
Brown Trout	Streams; gravel	September – January	35 – 55 F	Semi-buoyant, 5-7 mm diameter/demersal
Chinook Salmon	Streams; gravel	September – October	37 – 50 F	Demersal, 6-7 mm diameter/demersal
Coho Salmon	Streams; gravel	October – November	40 – 57 F	Demersal, 5-6 mm diameter/demersal
Round Whitefish	Near shore waters; stone, gravel, rocky reefs & honeycomb rock	October – December	32 – 40 F	Demersal, 2.9-3.5 mm diameter/demersal
Bloater	Open water, eggs broadcast pelagically	December – March	Not reported	Semi-buoyant, demersal, 1.9-2.3 mm diameter/demersal
Alewife	Shorelines, tributaries and protected near shore areas; eggs broadcast pelagically	May – August	55 – 70 F	Demersal, adhesive, 0.95-1.3 mm/pelagic
Gizzard Shad	Harbors and river mouths; eggs broadcast pelagically	May – August	60 – 77 F	Demersal, adhesive, 0.9-1.1 mm/pelagic
Spottail Shiner	Shallow inshore waters, typically over *Cladophora*	June – July	64 – 72 F	Demersal, adhesive until water-hardened, 1.0-1.4 mm/pelagic
Common Carp	Vegetated areas of inshore waters	May – August	59 – 77 F	Demersal, adhesive, 1.5-2.1 mm diameter/demersal
Longnose Dace	Streams and shoreline areas; sand, gravel and rubble	June – July	52 – 75 F	Demersal, adhesive, 2.1-2.7mm diameter/pelagic
Longnose Sucker	Streams; gravel or sand	April – May	36 – 59 F	Demersal, non-adhesive, 3 mm diameter/pelagic
White Sucker	Riffles and pools of streams; gravel	April – May	50 – 68 F	Demersal, non-adhesive,2-3.6 mm diameter/pelagic
Yellow Perch	Near shore reefs; boulder/rubble/cobble	May – June	40 – 60 F	Semi-demersal, non-adhesive, 1.9-3.5mm diameter/pelagic
Smallmouth Bass	Sheltered bays and tributaries; rock, gravel and course sand	May – June	55 – 75 F	Demersal, adhesive,1.8-2.8 mm diameter/demersal
Slimy Sculpin	On bottom in 30 – 90 meters of water; fine sand to mud	April –May	37 – 53 F	Demersal, adhesive, 2-3 mm diameter/demersal

1975-1976 impingement/entrainment study

A year-long impingement/entrainment study conducted by WEPCO at the Oak Creek Power Plant from March 1, 1975 through February 29, 1976 estimated that a total of 2,754,118 fish weighing 109,414 pounds were impinged at the plant during the sampling year. Alewife comprised 77.9 percent (2,145,500) by number and 88.6 percent by weight (97,000 pounds) while smelt accounted for 20.6 percent and 8.7 percent by number and weight, respectively. Eighty-five per cent of these fish were taken in May, June, and July coincident with the spawning period and the annual die-off (WEPCO 1976). Estimates for the monitoring year projected the impingement of 635 trout and 190 salmon. From impingement collections, it appears that almost all of these fish would be juveniles, probably freshly stocked.

It is estimated that 6,202,407 fish larvae were entrained during the April-October period. Of these, 17 percent were alewife, 76 percent smelt, and 2 percent were sculpin. Almost 90 percent of the larvae (juveniles) were entrained in August and September, before leaving the near shore zone. Total egg entrainment was projected at 9,281,370 with alewife comprising 98 percent of the total.

Ichthyoplankton sampling

In 2002, EA Engineering, Science and Technology conducted ichthyoplankton sampling for WEPCO using plankton tows and pumps at various depth contours, water depths and locations. A total of 384 ichthyoplankton collections were made at 14 Lake Michigan locations in the area of the Oak Creek and proposed Elm Road Power Plants. A total of 18,233 fish eggs and larvae were collected, 15,173 by the netting programs and 3,066 by pumping (EA Engineering, Science and Technology, 2002).

The net samples were dominated by alewife larvae (*Alosa pseudoharengus*) (79.5 percent), followed by alewife/spottail shiner (14.1 percent) and yellow perch larvae (4.5 percent). Total ichthyoplankton densities for depths combined were significantly different among the five depth contours. For contours combined there were no significant differences between surface, mid depth and bottom for total ichthyoplankton, larvae or egg densities. Statistical comparisons between months of mean ichthyoplankton densities showed that each month was significantly different for total ichthyoplankton and larvae densities while June and July had egg densities that were similar to one another and which were significantly higher than in August and September (EA Engineering, Science and Technology, 2002).

The bottom pump samples yielded 53 larvae and 3,013 eggs representing 5 taxa. The samples included 2,956 alewife/spottail shiner eggs (96.4 percent) and 57 trout-perch/common carp eggs (1.9 percent). Larval specimens were dominated by mottled/slimy sculpin and alewife. Total ichthyoplankton densities for pump samples were significantly different among the five depth contours and between months. For total ichthyoplankton and eggs, June and July densities were significantly higher than August and December (EA Engineering, Science and Technology, 2002).

Invertebrates

Benthic macroinvertebrates

A 1998 survey of the Great Lakes identified 20 taxa of benthic macroinvertebrates in Lake Michigan with an average of about seven taxa per sampling site (Barbiero and Tuchman, 2000). As a whole, the amphipod *Diporeia* (formerly *Pontoporeia*), tubificid oligochaetes, and sphaeriid snails dominated the Lake Michigan benthic macroinvertebrate community. However, in near shore areas, oligochaetes were the dominant taxonomic group. The density of benthic macroinvertebrates typically ranged from 1,500 to 6,500 organisms per square meter. Additional surveys performed during 2002 within the project area by the Great Lakes

Water Institute reveal oligochaetes and chironomidae as present, as well as fresh water sponges, Ectoprocta, mayflies, leeches, isopods, and amphipods. Zebra mussel infestation was also confirmed on most suitable habitat.

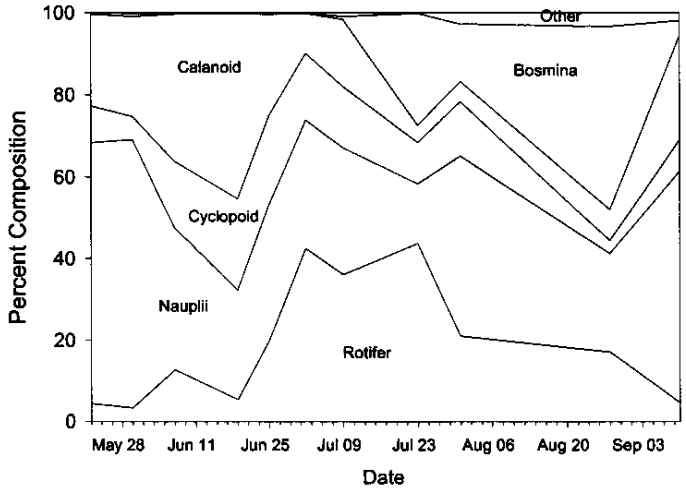
Over the past several decades, Lake Michigan's southern basin has undergone major shifts in nutrient loading and has been invaded by the zebra mussel. Reductions in nutrient loadings have reduced the overall productivity of the lake and produced a decline in the density of benthic macroinvertebrate fauna, particularly oligochaetes and snails, observed between 1980 and 1987 (Nalepa, et al. 1998). The year 1988 marked the beginning of colonization of southern Lake Michigan by the zebra mussel and the beginning of a decline in the abundance of *Diporeia*. Nalepa et al. (1998) hypothesized that the filtering feeding by zebra mussels in near shore waters decreased the amount of food available to the amphipod.

Zooplankton

The Illinois Natural History Survey has conducted spring and summer zooplankton tows off Waukegan Harbor for the past decade. Zooplankton was generally sampled weekly from May 22 to September 10 and on the same nights as larval fish collections (June-July) in 2001. Replicate vertical lifts were collected at two 10-m sampling sites with a 0.5-m diameter, 73-μm mesh net. Mean volume of water filtered in each vertical lift was 1.9 m^3.

In 1988, mean zooplankton density for the same period was 54 individuals per liter. In comparison to previous mean June-July zooplankton densities, the 2001 value was lowest at less than 10 individuals per liter. Zooplankton density varied seasonally in 2001. During early June densities were low, but by July densities increased, largely due to the appearance of rotifers.

Figure 8-3 Percent composition of zooplankton found in near shore Illinois waters of Lake Michigan near Waukegan during May through September 2001.



Copepod nauplii and calanoid copepodites dominated the near shore zooplankton assemblages during May and June (Figure 8-3). By late June, rotifer composition increased to 40 percent of the species composition and

continued at this level through late July. In late July rotifer composition decreased and *Bosmina* increased. Other cladocerans (e.g., *Polyphemus, Ceriodaphnia, Leptodora, Diaphanosoma, Chydoridae*) which were commonly found in samples during 1988-1990 have been rarely observed in samples collected since 1996. Additionally, the exotic Spiny water flea, *Bythotrephes cederstroem* has become established in Lake Michigan.

Overall, studies undertaken between 1983 and 1992 on Lake Michigan as a whole collected 71 different species, representing 38 genera of zooplankton (Makarewicz, 1994). Rotifera accounted for the largest number of species, with Cladocera, Calanoida and Cyclopoida as a group having the greatest biomass. Using biomass, Makarewicz classifies Lake Michigan's trophic state between the oligotrophic and mesotrophic.

Plants

Macrophytes

Lakebed surveys within the project area were undertaken in 2002 by the Great Lakes WATER Institute. Those studies show no aquatic macrophytes within the project area. Most of the project area is in water depths deeper the maximum rooting depth of macrophytes (Eurasian Watermilfoil, Coontail, and Elodea) commonly found in Lake Michigan. Those areas that are shallow enough to normally support macrophytic growth are subject to long-shore drift and high-energy wave action.

Algae

Free-floating algae are present in Lake Michigan, dominated by the diatoms, represented by *Synedra, Fragilaria, Tabellaria, Asterionella, Melosira, Cyclotella* and *Rhizosolenia,* among others. Concentrations of free-floating algae fluctuate during the year, subject to the availability of sunlight, water temperatures, and in the cases of diatoms, bio-availability of silicon.

Algae typically found attached to substrate are also present in Lake Michigan. These include *Cladophora, Ulothrix, Tetraspora, Stigeoclonium,* and red algae *Asterocytis.* The presence of *Cladophora* has been confirmed within the project area.

Existing off-shore facilities

Breakwater and coal dock

The existing structures located along the shoreline of the ERGS include a 19-acre coal dock constructed some time in the early 1950's, two breakwater structures and shoreline revetment south of the existing coal dock. A 600-foot breakwater extends out from the southeastern corner of the coal dock. This breakwater was installed in 1998 to reduce the migration of littoral material drifting into the intake channel. The intake channel, which was built during the initial plant construction, is formed to the north by the existing coal dock and a 900 foot long breakwater to the south. The existing shoreline revetment begins just south of the intake channel and continues to the northern edge of the rifle range property. The revetment consists of steel sheet pile walls which have large fieldstone or quarrystone in front of the sheet pile.

Intake structure

Prior to 1985, the OCPP consisted of two separate plants with four boiler/turbine units in two buildings. Units 1-4 were located in the north plant, and units 5-8 were in the south plant. The condenser cooling water system employed a "once-through" design to condense the boiler steam after it passes through the turbine. The complete condenser cooling water system consisted of a common on-shore intake channel, two pumphouses, eight traveling screens (five in the south plant and three in the north plant), eight

circulating water pumps, eight condensers, and five discharge points. The four circulating water pumps serving units 1-4 were rated at 110,000 gpm each. The four circulating water pumps serving units 5-8 were rated at 198,000 gpm each.

The existing intake structure, shown in Figure 8-4 consists of a 900-foot long, approximately 200-foot wide, and 25-foot deep approach channel along the south side of the existing coal dock.

Existing impingement and entrainment levels

Impingement refers to the contact between an aquatic organism, usually an adult or juvenile fish, and a screening structure that removes debris from the cooling water as it enters the intake system. At the Oak Creek Power Plant, organisms can be impinged first at the bar racks, and then at the traveling screens.

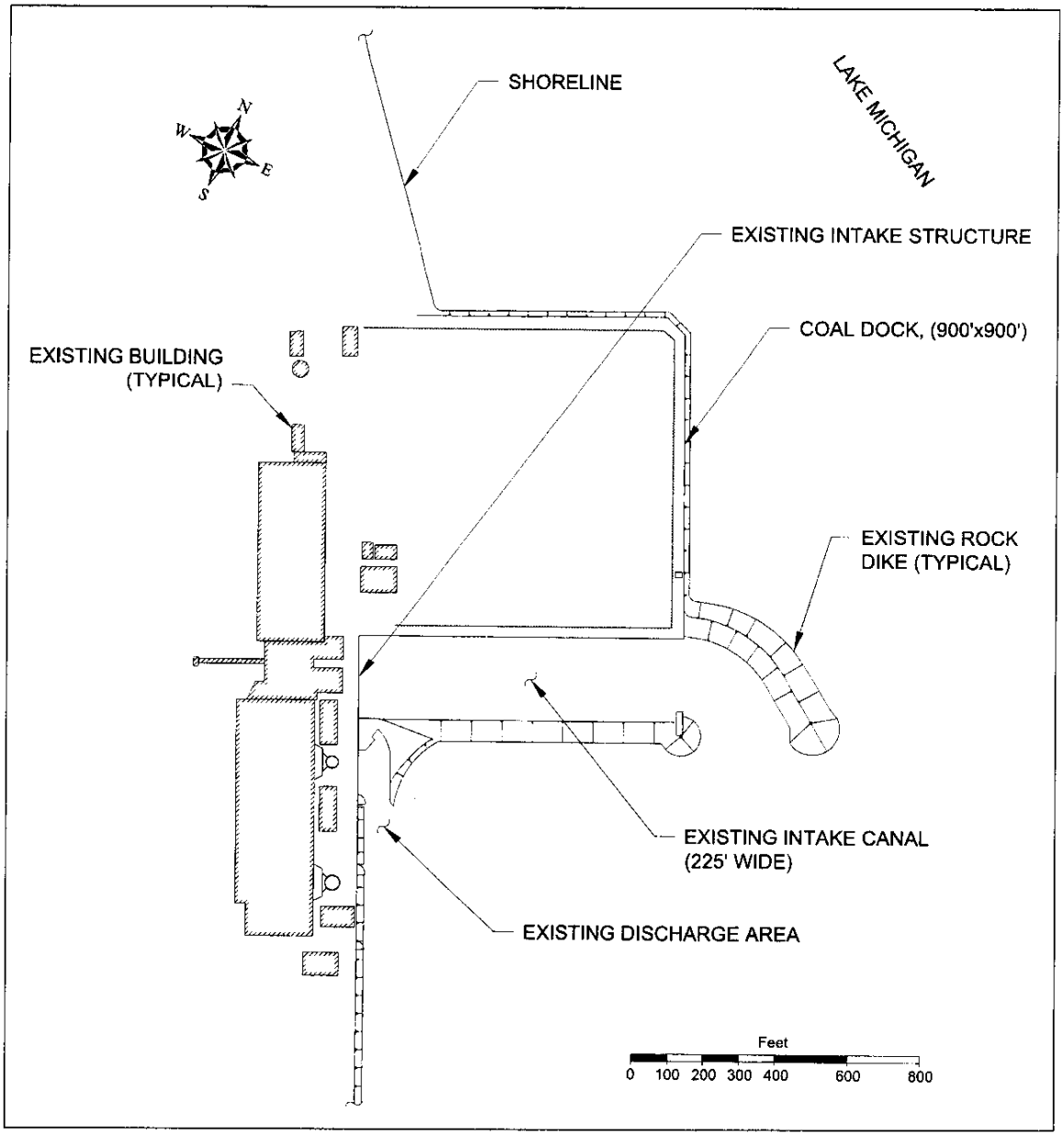
One of the requirements of the WPDES (discharge) permit that the DNR issued was a monitoring study to determine the environmental impact of the power plant's cooling water intake system. The study was conducted from March 1, 1975 to February 29, 1976. During the study period, all eight of the coal-fired units were in operation. Maximum velocities approaching the traveling screens ranged from 1.04 to 1.36 feet per second, depending on lake level.

Impingement sampling was conducted by collecting all fish backwashed off of the three traveling screens in the north pump house. The trash rack was not observed to have any impinged fish. For this study, it was assumed that all impinged fish suffer 100 percent mortality. It was estimated that 2.8 million fish weighing 109,000 pounds were impinged. Alewife comprised 78 percent of the catch by number and 89 percent by weight. Smelt accounted for 21 percent and 9 percent by number and weight, respectively. Forage fish added 1 percent and 2 percent by number and weight. Salmonids were negligible.

Entrainment sampling was conducted using plankton nets. Sampling occurred between the trash rack and traveling screens. For this study, it was assumed that all entrained organisms suffer 100 percent mortality. Sampling was also conducted for larvae and fish eggs at in the near shore zone, beyond the influence of the approach channel. It is estimated that 6.2 million fish larvae were entrained during the April – October period. Of these, 17 percent were alewife, 76 percent smelt, and 2 percent sculpin. Almost 90 percent of the larvae were entrained in August and September, before leaving the near shore zone. Total egg entrainment was projected at 9.3 million, with alewife comprising 98 percent. *Pontoporeia* and *Mysis* entrainment was estimated at 12.6 and 3.0 million, respectively.

The absolute magnitude of the number of fish, larvae, or eggs impinged or entrained is not a measure of the significance of the impact. Rather, the losses must be evaluated relative to the sizes and productivity of the affected populations. The report concluded that, relative to the Lake Michigan fishery, the impacts of entrainment and impingement were inconsequential to aquatic life in Lake Michigan. The DNR concurred with that conclusion.

Figure 8-4 Existing cooling water intake structure



North Oak Creek units 3 and 4 were retired in 1988, and units 1 and 2 were retired in 1989. Therefore, as a result of the reduced intake flow rate, the minimal localized impacts associated with the eight-unit operation have been mitigated.

Existing thermal effect

Section 316(a) of the Clean Water Act requires thermal wastewater discharges to demonstrate and assure the protection and propagation of a balanced, indigenous population of shellfish, fish, and wildlife in and on the

body of water where the point source is located. Dischargers of thermal wastes can be granted a less stringent alternate thermal effluent limitation if the discharger can satisfactorily show that the current effluent limitation, based on water quality standards, is more stringent than necessary.

Chapters NR 102, 104, and 209, Wis. Adm. Code, establish water quality standards, use designations, and procedures for the establishment of thermal effluent limitations for all surface waters of the state. The DNR has established a goal that water quality shall provide for the protection and propagation of fish, shellfish, and wildlife in all of the waters of the state. All surface waters classified for the support of "Great Lakes communities" of fish and aquatic life must meet water quality standards, including thermal standards, for protection of fish and aquatic life (s. NR 104.25).

Results of a 316(a) study completed by Oak Creek Power Plant (OCPP) in 1976 included a demonstration for the eight-unit operation, which concluded that the heated discharge had no significant environmental impact. At that time, the DNR found that the results of the OCPP study demonstrated that operation of the once-through condenser cooling system at OCPP did not preclude maintenance of a balanced, indigenous aquatic species population in the receiving waters of Lake Michigan at Oak Creek.

Results of the 1976 OCPP 316(a) study and several other 316(a) studies performed for large power plants on Lake Michigan in the late 1970's indicated that no significant impacts on phytoplankton, zooplankton, and benthos were found. Localized responses of periphyton (*Cladophora*) sometimes occurred, but did not result in nuisance levels of algal growth. Localized influences on fish distribution were noted in and near the thermal plumes. However, it was concluded that operation of the power plants did not significantly affect fish populations in the general vicinity surrounding each facility, or in the far-field areas that were studied beyond thermal plume limits. These studies indicated that both the individual and the aggregate impacts of power plant cooling water discharges on the Lake Michigan ecosystem were insignificant, and were limited to localized shifts in fish distribution and periphyton growth in areas immediately associated with the thermal plumes.

The above-mentioned studies have consistently indicated a lack of significant impact of heated water discharges to Lake Michigan, and have found that localized influences are largely limited to slight changes in the areal distribution of resident fishes.

(*Source; North Oak Creek Power Plant 316(a) Demonstration Information Review, November 1992)

Biocides/additives

Currently, intake water is treated by an electrolytic dissolution system for zebra mussel control. This system releases dissolved copper and aluminum into the intake water, and has proven to be an effective molluscicide. Copper and aluminum concentrations have, and continue to be, monitored in the effluent. The concentrations have been below the DNR's level of concern that would trigger effluent limitations. No other additives or biocides are used.

Existing water use

The existing OCPP units 5 - 8 have a maximum once-through cooling water flow rate of 1,165 mgd. The consumptive water losses for units 5 - 8 are:

Ash removal system losses	22,000 gallons per day
Coal unloading and pile spray	11,000 gallons per day
Demineralized water losses	15,000 gallons per day
Total:	48,000 gallons per day

Existing on-shore facilities

Existing discharge and storm water facilities

Operations that currently contribute wastewater which discharges from the cooling water outfalls without treatment include: condenser cooling water, unit 5 and 6 bottom ash hydrovactors, unit 5 and 6 fly ash hydrovactors backup system, condensate (from unit 5 and 6 drip tank and surge tank drain and overflow), roof drains, miscellaneous equipment non-contact cooling water, and the fire protection system.

The average flow from the four units combined total 977.6 mgd, with nearly 100 percent of the flow due to the condenser cooling water. The other contributors are low flows. The intake water flows through a trash rack and traveling screen to remove debris, and is subject to continuous molluscicide treatment as previously discussed.

Plant wastewater streams that require treatment prior to discharge are processed through a treatment system. Operations contributing process wastewater that discharge from the treatment system outfall include: low volume wastewaters (ash hopper overflows, unit 7 and 8 bottom ash transport systems, pyrite removal systems, miscellaneous equipment cooling water, floor drains, unit 5 and 6 bottom ash tertiary collectors, air compressor drains, fly ash sump overflows, air preheater washwater, boiler blowdown and drains, unit 7 and 8 surge tank drain and overflow, chemical storage area drains, and deionization regeneration wastewater), coal pile runoff (coal dock, upper reserve coal pile, car dumper floor drains, tower A and B roof and floor drains, coal tunnel sump, and lower junction tower wash down), nonchemical metal cleaning waste, light weight aggregate facility drainage, storm water (yard area runoff, unit 5 - 8 transformer bay drains) and ash landfill leachate.

The average flow is 3.4 mgd. The wastewater treatment system processes consist of:

- Bar screen
- Grit removal system
- Chemical precipitation by the addition of $FeCl_3$
- Sedimentation in two parallel basins of 1.7 and 1.8 million gallon capacity
- Sludge disposal at WEPCO landfill off site

Outfalls 006, 008, 009, and 010 are for emergency overflow when precipitation exceeds the 10-year 24-hour storm event. No monitoring of these outfalls is required. They are subject to the standard bypass requirements of the permit.

The permit regulates the intake water traveling screen washwater discharge at outfall 012. Flow monitoring is required. The backwash water consists of lake water, so any substances from this outfall (such as dead minnows or plant material) originate from the lake. The permit doesn't regulate the disposal of any accumulated substances.

Storm water discharges are regulated under the tier two general storm water permit issued to the OCPP.

Table 8-9 provides an overview and summary of the water discharge points and outfall locations for the existing OCPP facilities.

Table 8-9 Summary of the location and description of current OCPP outfalls (points of discharge to Lake Michigan):

Outfall/Sample Point Number	Location and Description
001	Alternate condenser cooling water outfall to recirculate effluent back into the water intake channel to prevent ice in the winter
003	Generator Unit 5 condenser cooling water, bottom ash hydrovactor, flyash hydrovactor backup, drip tank, surge tank drain & overflow, roof drains, miscellaneous equipment cooling water, and fire protection system
004	Generator Unit 6 condenser cooling water, bottom ash hydrovactor, flyash hydrovactor backup, drip tank, surge tank drain & overflow, roof drains, miscellaneous equipment cooling water, and fire protection system
005	Generator Unit 7 condenser cooling water, roof drains, miscellaneous equipment cooling water, and fire protection system
006	Generator Unit 8 condenser cooling water, roof drains, miscellaneous equipment cooling water, fire protection system, and wastewater treatment system pump station emergency overflow
007	Wastewater treatment system effluent Sources of wastewater: low volume wastewater, coal pile runoff, nonchemical metal cleaning waste, light weight aggregate facility drainage, storm water, and ash landfill leachate
008	Emergency overflow and north yard runoff
009	Emergency overflow from yard area around crusher house, surface drainage west of plant, and upper reserved coal pile runoff
010	Coal dock pump station emergency overflow
012	Water intake traveling screen backwash

Potable/sanitary water supply

The existing OCPP is supplied with potable and sanitary water from the city of Oak Creek.

On-shore water resources (WEPCO property)

Wetlands

There are 85 delineated wetlands within the project site that total about 83.2 acres (see Figures Vol. 2-12, 2-14, and 2-16). Most of these wetlands (76 of 85) are less than two acres in size and account for 33.5 acres. The remaining nine larger wetlands represent about 50 acres and the largest wetland on the property, a wet meadow/hardwood swamp, is more than 12 acres in size and is located along the western edge of the property.

Many types of wetlands can be identified within the WEPCO property, including shrub-carr, hardwood swamp, fresh (wet) meadow, shallow marsh, deep marsh and sedge meadow. Each wetland has different degrees of functional value in terms of floral diversity; fish and wildlife habitat; flood protection; water quality protection; shoreline protection; groundwater recharge and discharge; and aesthetics, recreation and

education. Comparisons with Figures Vol. 2-13, 2-15, and 2-17, show that many of the larger wetlands are associated with Southeastern Wisconsin Regional Planning Commission (SWRPC) designated Primary Environmental Corridors (PECs), Critical Species Habitats (CSHs), and Isolated Natural Resource Areas (INRAs). These areas of biological concerns are discussed in more detail in Chapter 10. A number of the wetlands have been previously disturbed to some degree, by silitation or sedimentation from stormwater runoff, past filling, ditching, dredging, and impacts related to past agricultural land use.

North of Elm Road

Twenty-two wetlands have been identified within the project boundaries north of Elm Road. These wetlands range in size from 0.1 to 9 acres and typically consist of fresh (wet) meadow, shallow marsh, sedge meadow, shrub-carr, clay bluffs with spring seepages or wet to wet-mesic lowland hardwood forest. The plant communities in these wetlands were surveyed and no endangered, threatened, or special concern plant species were found. Of the total plants surveyed within these wetlands, 11 to 33 percent were non-native or alien species. All but seven of these wetlands are located within a SWRPC-designated PEC. Of note is a 6.1-acre wetland with high functional values including floral diversity and wildlife habitat. It is located just north of Elm Road, along Lake Michigan bluffs, extending some 1,600 feet inland. It contains spring seepages on eroding clay bluffs which support shallow marsh and fen-like plant assemblages, ranging from deep and shallow marsh to fresh (wet) meadow and secondary growth, southern wet to wet-mesic lowland hardwoods.

West of the railroad tracks

Twenty-nine wetlands have been identified within the property boundaries west of the railroad tracks and south of Elm Road. These wetlands range in size from 0.02 to 12 acres and typically consist of fresh (wet) meadow, shallow marsh, shrub-carr and wet to wet-mesic lowland hardwood forest. No endangered, threatened, or special concern plant species were found within the surveyed wetland plant communities. Non-native or alien species comprised 7 to 71 percent of the plant species within the wetland indicating a range of wetland quality in this part of the property. Fifteen of these wetlands are located either completely or partially within two INRAs. The largest wetland surveyed (12 acres) is located within this area.

East of the railroad tracks

Thirty-four wetlands have been identified within the property boundaries east of the railroad tracks and south of Elm Road. Three of the wetlands are larger than one acre, with the largest being 3.8 acres. The remaining wetlands are between 0.2 and 0.3 acres. The majority of the wetlands consist of fresh (wet) meadow and shallow marsh. The vegetation surveys for these wetlands did not identify any endangered, threatened, or special concern plant species. Twelve of these wetlands are located within areas of biological concern (PEC, INRA, and CSH).

Streams

Within and adjacent to WEPCO's property, there are also a number of existing waterways, most of which are unnamed tributaries to Lake Michigan. The DNR has conducted site investigations to determine the substrate and general habitat characteristics of the streams and have determined if the waterways met the criteria for navigability, under Wis. Stat. ch. 30. The site investigations have identified a total of eight creeks and tributaries, the majority of which are navigable at some location within the property boundary. Navigable streams range from 3 to 16 inches in depth and from 3 to 17 feet in width. The watershed for

these tributary systems is primarily agricultural with some areas of residential, commercial, and industrial development.

Two streams are located north of Elm Road. The northernmost stream has a number of tributaries that drain portions of Bender Park. A large complex of wetlands is hydraulically connected with this stream located with a PEC. This stream was found to contain a good range of macroinvertebrate habitat due to the presence of gravel beds in the lower reaches. Habitat limitations include intermittent flow and shallow water depth. The other stream, located closer to Elm Road lacked defined riffle/run/pool structure, but may support seasonal use of available habitat by forage fish species and macroinvertebrates.

Another waterway located along the northwestern boundary of WEPCO's property is an unnamed tributary to the Root River. Within the property, the waterway has been severely impacted by past dredging, ditching, and runoff from the adjacent landfill. Silt is the predominant substrate in this stream, limiting the amount of suitable fish or macroinvertebrate habitat. The waterway flows southwest under STH 32, crosses the county line and converges with a larger tributary flowing northwest to the Root River.

The other streams on the property are located within the southern portion of the property. The main branch of this waterway emanates from a large wetland complex located southwest of WEPCO's property and west of STH 32. This branch of the stream flows northeast across STH 32 and the railroad corridor and onto the site near a horse farm on Seven Mile Road. The main branch of this stream and its tributaries flow through the Ravine Woods Natural Area (as defined by SWRPC) within one of the PECs (see Figure Vol. 2-14). It has a substrate of mixed sand and gravel upstream, with gravel/clay dominating in lower sections. Gravel beds, riffle/run structure are present throughout, resulting in good macroinvertebrate habitat. Steep gradients are present in the downstream sections as it flows into Lake Michigan. Although no fish were collected during the assessment, they may be present in the headwater wetlands off-site.

Railroad corridor

Wetlands

Although a few native prairie plant species are still present, the railroad corridor appears to be a highly disturbed area supporting many invasive and non-native species.[100] Vegetation along the corridor consists primarily of shrubs, prairie plants, and grasses in upland areas. Numerous intermittent drainage ways cross under the railroad through drainage culverts. Wetlands have developed in association with these drainage ways and the manmade ditches that parallel the track.

A total of 25 wetlands, totaling 11.0 acres, have been identified within the three-mile rail corridor. Most of these wetlands appear to be hydrologically connected to drainage ways and wetlands outside of the railroad corridor. The wetlands vary in size as well as community type. Community types include shallow marsh, fresh (wet) meadow, shrub carr, and sedge meadow. A majority of the wetlands are degraded and dominated by reed canary grass.

[100] In the Midwest, railroad corridors often harbor remnants of the native prairie communities that were once widespread in this area. This is because the rail corridors were never cultivated and experienced periodic burning caused by friction and sparks produced by the train wheels on the tracks.

Streams

Streams cross under the railroad corridor in five places, all of which are navigable at some location within the WEPCO property. Both Turtle Creek and an unnamed tributary to Lake Michigan are habitats sufficient to support a moderately diverse community of macroinvertebrates. In-stream plants are most likely limited to algae, bryophytes and cattails

New and Modified Off-shore Facilities and the Potential Impacts on Lake Resources

Water use

An overall water schematic for the ERGS is shown in Figure 8-5. This schematic integrates the two new SCPC units and the IGCC unit with the existing Oak Creek Power Plant. Currently, the OCPP takes in 1,015.3 mgd of water from Lake Michigan, and discharges 987.5 mgd.

As previously discussed, an off-shore intake would be constructed approximately 9,000 feet out into Lake Michigan. It is anticipated that the new intake would be operational at the same time that the first SCPC unit becomes operational; and that the existing units 5 - 8 of the OCPP would be tied into the new intake at that time. Ultimately, the three new units and the existing OCPP would be served by the new intake structure.

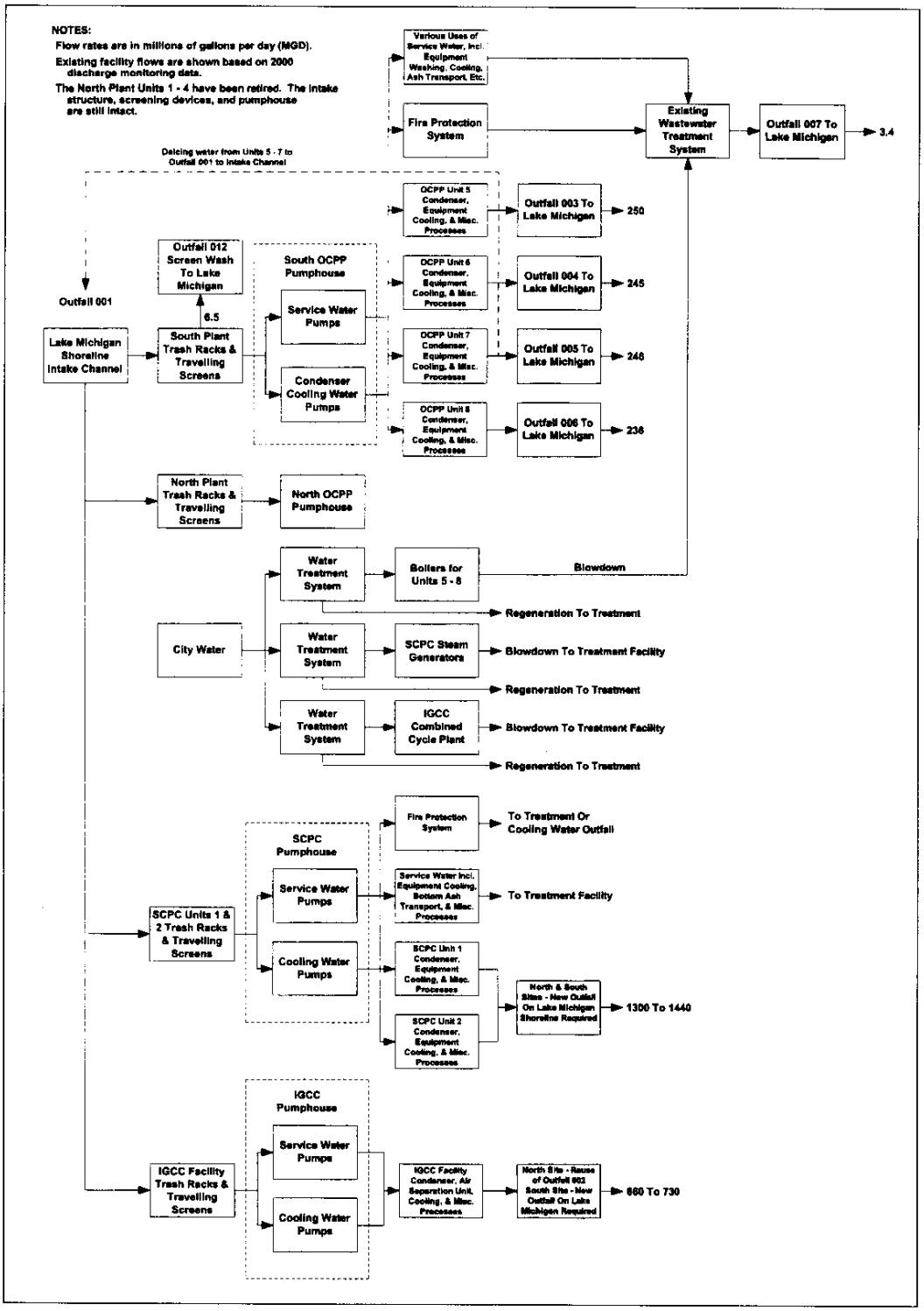
SCPC units

The first SCPC unit would withdraw about 700 mgd[101] of lake water at maximum loading. Added to current OCCP water demands, the combined withdrawal of lake water would be about 1,865 mgd. When operating, units 5 - 8 of the South OCPP and the first SCPC unit would "consume" lake water (i.e. use Lake Michigan water and not return it to the lake via a discharge outfall):

Ash removal system losses	184,000 gpd
Coal unloading and pile spray	18,500 gpd
Demineralizer water losses	101,700 gpd
Flue gas desulfurization losses	590,000gpd
Total	894,200 gpd

[101] 700 mgd is about 485,000 gallons per minute. This flow rate is a conservative estimate and the exact value would be determined during detailed design of the plant. The 2-01-02 CPCN Volume 3 submittal included a range of once through cooling water flow rates in Table 5 on page 46. The low end of the range is for anticipated rated load operations and the high end of the range is for maximum capacity operations.

Figure 8-5 Water flows for the entire ERGS and the existing OCPP



The second SCPC unit would withdraw an additional 700 mgd of lake water at maximum loading. Added to the first SCPC unit and the existing OCCP water demand, the combined withdrawal of lake water would be 2,565 mgd. All of these operations combined would consume lake water in the following quanitity:

Ash removal system losses	346,000 gpd
Coal unloading and pile spray	28,500 gpd
Demineralizer water losses	188,400 gpd
Flue gas desulfurization losses	1,160,000 gpd
Total	1,722,900 gpd

A full water balance diagram for the two SCPC units burning Pittsburgh #8 bituminous coal is shown in Figure 6-7.

IGCC unit

The IGCC unit would have a maximum cooling water flow rate (power block, air separation unit and process cooling) of about 700 mgd.[102] Added to the two SCPC units and the OCCP water demand, the combined withdrawal of lake water would be 3,265 mgd. The operations of the IGCC unit would "consume" lake water in the following amounts:

Slag removal system losses	615,000 gpd
Syngas process consumption	503,000 gpd
Demineralized water losses	108,000 gpd
Total	1,226,000 gpd

A full water balance diagram for the IGCC unit burning Pittsburgh #8 bituminous coal is shown in Figure 6-10. If the combined water loss of the existing South OCPP units and the first two SCPC units are added to this total, the cumulative water loss would be 2,948,900 gpd.

Cumulative use

The combined open-cycle cooling water demand in 2011 is estimated to be about 2,250,000 gpm and would be allocated as follows:

Existing OCPP units 5 - 8	(792,000 gpm)
Two SCPC plants	(970,000 gpm)
IGCC plant	(485,000 gpm)

A new pump house would be installed on the southwest side of the proposed SCPC facilities (on the North Site). OCPP units 5-8 would utilize the existing South plant pump house that would withdraw water from the planned forebay area that would enclose the western end of the intake channel. Both the forebay and

[102] This flow rate is a conservative estimate and the exact value would be determined during detailed design of the plant. The 2-01-02 CPCN Volume 3 submittal included a range of once through cooling water flow rates in Table 6 on page 48. The low end of the range is for anticipated rated load operations and the high end of the range is for maximum capacity operations.

new SCPC pump house locations would be connected to the proposed intake tunnel by means of a vertical dropshaft.

New circulating water pumps would be installed. These new pumps would have the capacity equal to the highest optimum flow for the seasonal range of lake temperatures, heat rejection rates, and desired discharge temperature. Cooling water would be piped to the main condensers of the first and second SCPC units via an underground large diameter piping system. Discharge water from the condensers for both proposed units also would be piped underground to the north side of the new dock extension and then east along the shoreline.

Cooling water intake structure

A combined cooling water intake supply is planned that would accommodate the needs of both existing OCPP units and the proposed three new units. The off-shore intake tunnel and structure and the on-shore pumping station and screening equipment are described in sections below.

Section 316(b) Clean Water Act

Section 316(b) of the Clean Water Act and Wis. Stat. § 283.31(6), requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impacts. A major goal of this regulation is to minimize the impingement and entrainment of fish and other aquatic organisms as they are drawn into a facility's cooling water intake. Impingement occurs when fish and other aquatic life are trapped against cooling water intake screens. Entrainment occurs when aquatic organisms, eggs and larvae are drawn into a cooling system, through the heat exchanger, and then pumped back out. Cooling water intake structures have the potential to cause adverse environmental impact by pulling large numbers of fish and shellfish or their eggs into the cooling system. There, the organisms may be killed or injured by heat, physical stress, or by chemicals used to clean the cooling system. Larger organisms may be killed or injured when they are trapped against screens at the front of an intake structure.

In December 2001, U.S. EPA published final regulations under s. 316(b) that established requirements that apply to the construction of intake structures for "new" facilities, as defined in that rule. Subsequently, in April 2002, U.S. EPA proposed regulatory language under the authority of s. 316(b) for **existing** power producing facilities that employ a cooling water intake structure and that withdraw 50 mgd or more of water from rivers, streams, lakes, reservoirs, estuaries, oceans, or other waters of the U.S. for cooling purposes [Federal Register: April 9, 2002 (Volume 67, Number 68)]. The proposed rule constitutes Phase II in EPA's development of section 316(b) regulations and would establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at existing facilities.

According to the proposed rule language, a facility may choose one of three options for meeting best technology available requirements. These options include demonstrating that the facility currently meets specified performance standards; selecting and implementing design and construction technologies, operational measures, or restoration measures that meet specified performance standards; or demonstrating that the facility qualifies for a site-specific determination of best technology available because its costs of compliance would be significantly greater than the environmental benefits of compliance with the proposed performance standards. The proposed rule also provides that facilities may use restoration measures in

addition to or in lieu of technology measures to meet performance standards or in establishing best technology available on a site-specific basis.

On November 22, 2002, EPA extended the deadlines for final action on regulations under section 316(b) of the Clean Water Act to minimize the adverse environmental impact of cooling water intake structures at existing facilities. Under the revised schedule, the new deadlines for Phase II regulations governing existing facilities include a final action date of February 16, 2004.

The DNR would require the new intake structure to meet BTA requirements proposed by U.S. EPA for "existing facilities" in the April 9, 2002 Federal Register. When the final regulations are published by U.S. EPA, those final regulations would be applied to this facility.

EPA delegation

On August 28, 2002, WEPCO requested that the U.S. EPA make a determination of applicability of regulations under s. 316(b) of the Clean Water Act for the Oak Creek Power Plant and the proposed Elm Road Generating Station (OCER). On October 30, 2002, G. Tracy Mehan, U.S. EPA Assistant Administrator for Water issued a letter to WEPCO indicating that the DNR, as part of the administration of the National Pollution Discharge Elimination System (NPDES) program in Wisconsin, would be responsible to make the s.316(b) determination for the ERGS facility.

DNR Determination

The DNR's January 28, 2003 determination is attached as Appendix C to this draft EIS. In summary, the Department has determined that the ERGS proposal, including the additional units and the currently proposed intake configuration, is not a "new facility" for purposes of implementing the requirements of 316(b) and associated regulations. The DNR's determination also indicates that the ERGS facility must meet BTA for minimizing adverse environmental impacts and that the performance standards to be used in designing an intake system must meet the BTA requirements proposed by U.S. EPA for "existing facilities" in the April 9, 2002 Federal Register. When final regulations are published by U.S. EPA, those final regulations will be applied to this facility.

Outcomes

At this time, U.S. EPA has not provided concurrence with the DNR determination that the proposed ERGS project is not a new facility in the context of the 316(b) regulations. However, U.S. EPA and the DNR do agree that the proposed offshore intake structure must be designed to minimize environmental impacts caused by impingement and entrainment of aquatic organisms. This is true for units that are currently operating at the existing power plant and also for the proposed new units. The proposed ERGS project and the modification of the cooling water intake is an opportunity to attain the BTA requirements. WEPCO has provided conceptual information about the cooling water intake and BTA. WEPCO will need to submit specific design information to the DNR during the WPDES permitting process to demonstrate how the BTA performance standards would be met. There may be changes (size, geometry, intake rate, etc.) to the conceptual cooling water design as specific information is reviewed during the DNR's WPDES permitting process.

WEPCO, DNR and U.S. EPA are in continuing discussions to determine the applicability of existing or proposed federal regulations to the proposed changes to this facility. A final determination of the applicable design criteria will be made prior to the issuance of the WPDES permit.

Description and location of proposed water intake system

The proposed water intake system is comprised of an intake structure and a water transport system that would move the water from the intake to the plant facility on the shore. The water intake system is designed to comply with s. 316(b) of the Clean Water Act and s. 283.31(6), Wis. Stats. The proposed design would pump the water from an offshore intake structure. The intake system would consist of four timber cribs through which water would be drawn. This water would then travel through a tunnel or a set of pipes to the screening facility onshore. The pipes or tunnel of the offshore portion of the intake system are proposed to extend into the lake approximately 9,000 feet. The final depth of the offshore intake crib would be about 43 feet. Photos of a typical timber intake crib can be found in Figure Vol. 2-10.

The dimensions and specifications of the forebay, screening facilities, pump houses, intake cribs or the velocity caps, would be the same regardless of the final intake length, depth or construction method. The existing intake channel would be modified as part of this project and would include the installation of a sheet pile wall to enclose 50,000 square feet of the existing intake channel (200 ft. wide by 250 ft. long). The enclosure of this portion of the intake channel would continue to be utilized for intake purposes. The remaining intake channel would be utilized for the mooring of barges.

Construction methods for the water intake transport system

WEPCO is currently investigating the construction of a tunnel below the lakebed that would move the water from the actual intake structure to the shoreline. The tunnel would be 32 feet in diameter and would be approximately 200 feet below the bed of the lake. The tunnel would be constructed by creating a construction shaft onshore and excavating down 200 feet. Tunneling equipment would then excavate a tunnel horizontally out to a 40-foot water depth. The design for the tunnel would require connection to four intake cribs that would each connect to a 14-foot diameter tunnel leading to a drop shaft that is 32 feet in diameter.

The total amount of dredging involved with this alternative would be approximately 10,000 cubic yards of unconsolidated material by clam shell bucket method. There would be an additional 400,000 cubic yards of rock excavated and removed from below the lake bottom via the onshore drop shaft. WEPCO conducted a geophysical investigation of the bedrock at this location and performed tests to determine if the bedrock was suitable for the construction of a tunnel. In addition, these tests would assist WEPCO in determining if the tunnel should be concrete lined to prevent leakage. The preliminary conclusions of the Geotechnical Data Report conducted by Montgomery Watson Harza and Associates dated November 2002 indicate that the bedrock is suitable for tunnel construction and would require minimal concrete lining. This method of construction would also require a permit under Chapter 30, Wis. Stats., in addition to compliance with NR 102, 346 and 347, Wis. Admin. Code.

For a 9,000-foot long intake tunnel, the approximate depth of soil and rock between the intake structure and the tunnel would be 60 feet and 68 feet respectively. The intake structure would be about 40 feet below the lake surface.

Potential impacts of construction of the water intake system

Construction of the intake structure would involve some degree of dredging regardless of which construction method is implemented. The alternative that WEPCO prefers, the construction of a tunnel in the bedrock, would have far less impacts on the bed and fewer temporary impacts on Lake Michigan. If the

tunnel is constructed through the bedrock, the only areas of lakebed disturbance would be the areas where WEPCO would dredge for construction of the drop shafts. If the intake is constructed by dredging a trench and placement of four large pipes, the degree and extent of impacts to the bed and temporary construction impacts on Lake Michigan from dredging would increase significantly.

In general, mechanical dredging and placement of the intake structure on the bed of Lake Michigan would have a number of temporary impacts within that localized environment of Lake Michigan. These temporary impacts include local increases in turbidity within the water column, reductions in local dissolved oxygen levels, and reductions in local light penetration. The construction would temporarily disrupt the local fish population.

During construction it is expected that there would be 100 percent mortality of the benthic invertebrates within the construction zone. In addition, sediments suspended that eventually sink within the water column would likely impact some local benthic invertebrates which are in the vicinity of the construction site. Post-construction, it is likely that the benthic communities in these areas would re-establish. The dredging could also create an increase in local nutrient levels and could cause a local increase in planktonic growth. However, it is unlikely that the construction of the intake structure would increase the density of the existing zebra mussel population.

The long-term impacts of the intake structure include a modification to the bathymetry and could change the local fisheries populations and habitat adjacent to the project site. Many of these long-term impacts relate to the operation and possible maintenance of the intake structure which is discussed later in this section.

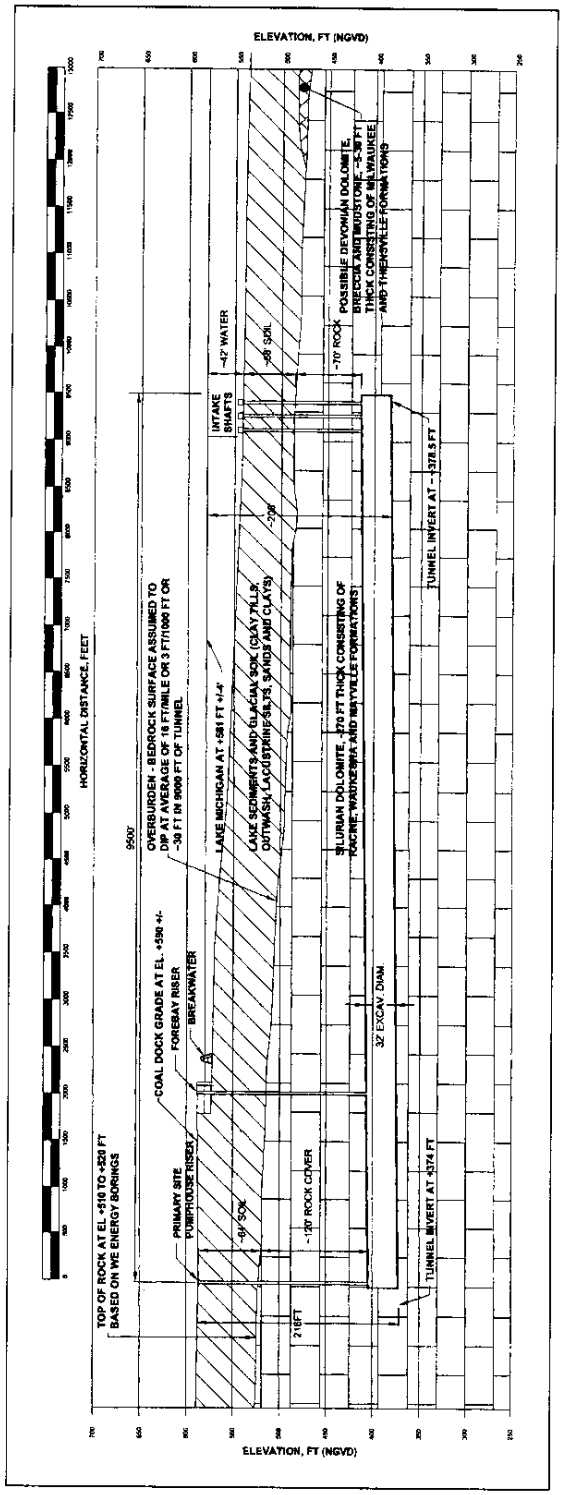
WEPCO is working with the DNR to determine the final location of the intake in order to minimize the intake structure impact on aquatic species. Measures such as silt curtains or turbidity barriers would be required to reduce the extent of the temporary impacts to Lake Michigan during construction.

Potential impacts of operation of the water intake structure

In February 2003, the applicants submitted a report, titled "Oak Creek Power Plant and Proposed Elm Road Station Cooling Water Intake and Lake Monitoring Study, February 2003." The report describes the results from the first year of a two-year program, which will be used to determine the abundance of fish eggs and larvae in the vicinity of the existing on-shore intake structure and the site of the proposed new off-shore intake structure. The data presented in this and the final report will be used to help establish location, design, and operational parameters for achieving compliance with the impingement and entrainment reduction criteria in the proposed EPA regulations for intake structures at existing facilities.

This report summarized data from icthyoplankton collections collected from June through September 2002, at transects near the present intake (in the intake channel and at an 18-ft depth contour) and the site of the new intake (30-35 ft contours at about 3,500 feet offshore and a 40 ft contour at about 9,000 feet offshore). The data clearly shows a marked reduction in total icthyoplankton densities at the 40 ft contour (the depth of the probable new intake structure site) in comparison to near-shore contours. Offsetting the benefit of reduced icthyoplankton density at the far-shore intake site is the fact that the cooling water demand would increase incrementally as new units are added to the intake.

Figure 8-6 Tunnel profile for a 9,000-foot long water intake pipe



The second phase of the study will involve near-shore and far-shore icthyoplankton collections from early May through September, 2003. Off-shore icthyoplankton sampling will be focused more precisely at the proposed intake location.

This February report gave calculated intake velocities at the present nearshore structure ranging from 0.5 to 1.8 ft/second (one to four pumps, respectively). The proposed design velocity at the entrance to the proposed offshore structure (whether consisting of intake cribs or velocity caps) is 1.0 ft/second; however, a velocity range of 0.5 ft/second to 1.0 ft/second is under consideration as detailed design for the caps or cribs is finalized. It should be noted that limiting intake velocity is not the sole factor in determining how best to design an intake structure to minimize adverse environmental impacts to fish and other aquatic life. If the velocity is reduced, there is a proportional increase in the intake area needed. This would require additional cribs or caps. Since the location selected is a sandy featureless area of the lake bottom, the potential impacts of adding more structure to the lake bottom must be weighed against the potential benefits of reducing the approach velocity.

Based on Electric Power Research Institute report,[103] a velocity of 1 ft/second has the potential to pull in salmon that are less than 10 cm in total length. This is based on EPRI's review of all published or otherwise available fish swim speed data. These data generally show that small (under 10 cm in length) salmon have sustainable swimming speeds that are less than 1 ft/second.

Small salmon greater than 10 cm in length size have swimming speeds that are typically greater than one ft/second. Thus, these larger fish should be able to avoid the currents surrounding the intake structure caps/cribs. Data are not available for trout, but the swimming speeds are expected to be similar to salmon. If fish enter the tunnel and reach the pumphouse, fish removal will occur at the traveling water screens. The traveling water screens for this project have not yet been selected, but there are designs and operations (low pressure and/or continuous screen wash) that can increase fish survival if impingement occurs.

Harbor construction activities

Description of proposed activities

As described in previous chapters, WEPCO proposes to increase the rate of coal delivery to fuel the new coal generating stations. Currently there are two alternative methods of coal delivery that are being considered by WEPCO. WEPCO's preferred alternative is to increase the rate of train delivery, which is discussed further in Chapters 10 and 12. A second option is to deliver the coal by ship. To allow for the navigational mooring of ships, WEPCO proposes to construct a harbor, which involves the expansion of the existing coal dock, construction of a breakwater and dredging of a navigational channel. Each element of the proposed harbor facilities plan is discussed in more detail below. See Figure Vol. 2-1 for an overview of the proposed harbor facilities.

[103] Technical Evaluation of the Utility of Intake Approach Velocity as an Indicator or Potential Adverse Environmental Impact under Clean Water Act Section 316(b). Electric Power Research Institute. Palo Alto, CA. Final Report, December, 2000. Report No. 1000731

Lakebed fill

Purpose, dimensions, and location

WEPCO proposes to place fill on the bed of Lake Michigan to expand the existing coal dock. The expansion of the dock would fill in an area of Lake Michigan immediately north of the existing dock. The dimensions of the fill would be approximately 340 feet wide and 900 feet long; the dock expansion would fill in approximately seven acres of Lake Michigan. This area would be utilized for the storage of coal, limestone and gypsum and would aid in the loading and off-loading of the barges or ships delivering materials to the site. The dock expansion would require approximately 200,000 cubic yards of fill material.

Construction methods and fill source (material characterization)

The preliminary plans for the dock expansion anticipate that the dock would be created by constructing a stone dike to enclose the reclamation area. The outside of the dike would be protected with a quarried stone revetment designed to protect the dock from wave action. The reclamation area would be filled with clean, granular materials to the water line. Above the water line, clean compacted fill would be used to provide an adequate working surface. The final construction of the dock expansion would be designed to prevent the loss of fill material into the lake, as well as provide hydraulic stability for the dock from coastal processes.

Breakwater

Purpose, dimensions, and location

WEPCO proposes to construct a breakwater to shield incoming ships and barges from large waves and to reduce the rate at which the proposed navigational channel would fill with fine-grained material carried by littoral processes. The preliminary plans for the proposed breakwater structure show that the breakwater may extend up to 1,900-ft. further into the lake than the existing coal dock and could be up to 150 feet wide. The proposed breakwater may fill an area of up to seven acres of Lake Michigan. WEPCO would undertake and submit additional studies to determine the optimal length, width and location prior to DNR permitting.

Construction methods and fill source

The construction of the breakwater would likely involve the construction of a rubble mound structure of quarried stone designed to withstand coastal processes and provide the desired protection to shipping traffic. The quarried stone would likely be obtained from an off-site source.

Navigational dredging

Purpose, dimension, and location

The required draft of a ship is typically 28 feet. Adjacent to the coal dock, the current water depth is approximately 10 feet from the Low Water Datum for Lake Michigan. WEPCO proposes to dredge a navigational channel and turning basin out to the 30 foot water depth to aid in the navigation of ships or barges. The creation of this navigational channel and turning basin would involve the dredging of approximately 900,000 cubic yards of material from the bed of Lake Michigan by means of a mechanical clamshell bucket. The navigational channel and turning basin would be approximately 2,300 feet long, 30 feet deep and range from 400 to 1,000 feet wide. Approximately 20 acres of lake bottom would be disturbed by the removal of 900,000 cu. yards of lake bottom material. The navigational channel widens to facilitate a turning basin near the coal dock. Under an existing permit, WEPCO conducts periodic maintenance dredging of a portion of this area that supports its existing navigation channel.

Material characterization of dredged material

A number of regulatory guidelines and regulations relate to the evaluation, characterization, and disposal of dredged materials. US EPA and US ACOE have developed a testing manual titled "Great Lakes Dredged Material Testing and Evaluation Manual," dated September, 1998. This manual is a refinement of the methods described in the joint EPA/US ACOE entitled Evaluation of Dredged Material Proposed for Discharge in Waters of the U.S. – Testing Manual. Both of these publications describe a tiered decision making approach for evaluating the environmental impacts associated with dredging activities.

The National Oceanic and Atmospheric Administration (NOAA) has developed Screening Quick Reference Tables (SquiRTs, 1999) that are intended for preliminary toxicant screening of substances that are present in the area of concern. They are used as guidelines only, useful for identifying general levels of increasing toxicity to benthic organisms. The tables do not represent official NOAA policy.

Several state regulations including Wis. Admin. Code ch. NR149 and NR 219 establish standards, procedures, and registration criteria for laboratories conducting sediment testing. Wis. Admin. Code ch. NR 347 protects the public rights and interest in the waters of the state by specifying definitions, sediment sampling and analysis requirements, disposal criteria, and monitoring requirements for dredging projects.

The DNR Bureau of Watershed Management has prepared document WT-732-2002, titled "Consensus-Based Sediment Quality Guidelines - Recommendations for Use and Application" dated February, 2002. These guidelines are used to compare on-site sediment quality with consensus-based lower and upper effect values for contaminants of concern. These lower and upper effect values are based on the analyses of a large number of studies, investigating toxicological effects of contaminants on a wide range of organisms. These studies indicate chemical concentration levels below which minimal impacts to benthic macroinvertebrate communities may be expected, and concentrations above which there are probable impacts to benthic macroinvertebrates communities.

Results of sediment quality investigation

Within the proposed dredge area, two studies were completed to characterize the existing sediment quality. The first study was undertaken in 1998 as part of WEPCO sediment characterization study associated with its application to the DNR to dredge the existing intake channel and construct a breakwater on the lakebed. The second study was undertaken in 2002 by WEPCO to characterize the sediments within the proposed dredge area for the ERGS project. These results are discussed below.

1998 Sediment Investigation

Sediment sampling was undertaken by W.F. Baird & Associates, Ltd. of Madison, Wisconsin for WEPCO on December 29, 1998, within the existing intake channel. Four borings were taken with stainless steel boring equipment, then preserved and tested for contaminants.

The 1998 data indicate low to undetected amounts of chlorinated organic compounds such as PCBs and pesticides tested for within the project area. In most cases, reported levels were below the laboratory level of detection. Metals concentrations were at or below mean concentrations from other locations on Lake Michigan. (Cahill, 1981).

2002 Sediment Investigation

Sediment sampling was undertaken on November 4 and 5, 2002, within and adjacent to the proposed dredging area. Eleven split-spoon borings were taken, with samples then preserved and tested for contaminants. Sieve analysis was also performed on these samples. Full sediment analysis results are shown in Tables 8-8. A total of four borings were taken near the existing coal dock, six borings were taken in deeper water, and one boring was taken north of the existing plant, near the shore and potential cooling water outlet. Each boring was taken down to core material, plus two feet. In addition, boring extended through the bed material to the proposed dredge depth, plus two feet. Core material is defined as the clay layer expected to underlie the coarser depositional material. All bores were then separated into two-foot sections, with each section undergoing analysis. Sediment analysis was performed by Great Lakes Analytical, Buffalo Grove, Illinois.

Polychlorinated biphenyls (PCBs) are mixtures of individual chlorinated compounds, historically used as coolants and lubricants in electrical equipment such as transformers and capacitors. PCBs are known carcinogens, and bio-accumulate in the fatty tissue of mammals, birds, and fish. Currently, there is a WDNR issued fish consumption advisory for salmon, trout, perch, whitefish, chubs, smelt, and carp caught from Lake Michigan due to elevated PCB levels.

The 2002 sampling protocol required sampling for PCBs in two locations adjacent to the existing coal dock within the dredge area. The sampling coverage was limited, due to knowledge of likely areas of PCB deposition and the negative results of previous sampling within the immediate area. No PCBs were detected in this sampling effort.

Metals are present naturally in the sediment of Lake Michigan, so trace levels of metals were detected at all sample sites. The levels of trace metals found at all boring locations are close to or below the mean individual metal concentrations of sediments taken from other locations on Lake Michigan (Cahill, 1981). Based on toxicant screening with SquiRT and CBSQG tables, and the naturally occurring background concentrations of metals in Lake Michigan, the trace metals present on site do not present a risk to aquatic organisms.

Polycyclic aromatic hydrocarbons (PAHs) are 2-7 ring cyclic hydrocarbon compounds. These compounds are associated with oil, coal, forest fires, cigarette smoke, and municipal waste streams, among others. Of the eleven locations sampled, PAHs were detected at three of them, specifically sites within the intake channel and near the southeastern corner of the existing coal dock. It is reasonable to expect that the concentration levels of certain PAHs detected near the sampling areas are at high enough levels to negatively effect nearby resident benthic macroinvertebrate populations. It is likely that the PAHs are associated with the nearby coal dock.

Organochlorides are pesticides historically used to control insects. These substances include DDT (and it's breakdown products DDE and DDD), Endrin, and Chlordane, among others. Sampling for organochlorides was not undertaken due to previous negative results within the sample area.

Excavation methods

The common dredging methods are mechanical dredging, hydraulic dredging, or a combination of the two. Within any given method, there are many variations of approaches and equipment type that will affect the efficiency of the excavation and the effects on the waterbody. Dredging techniques and methods can be

specifically tailored to meet the needs of a particular site and manage the risk associated with disturbance of the bottom sediment and impacts on habitat. Further decisions on specific dredging techniques would be reached prior to obtaining a ch. 30 dredging permit.

Disposal of dredged material and fill sources

Four methods of dredge material disposal are possible. These options are: landfilling the dredge spoils on WEPCO property, landfilling off-site in a licensed landfill, using the spoils on-site as construction fill, and using the spoils as beach nourishment. The ultimate disposal options would be decided on prior to obtaining a ch. 30 dredging permit and an exemption from the Solid Waste section. It is estimated that a combination of these disposal options would be applicable, depending upon sediment characterization done under recent and future sediment sampling activities.

Potential impacts of harbor construction activities

Dredging of the lake bottom to 30 feet below Low Water Datum, the depth necessary to accommodate lake freighter drafts of 28 feet, would take place east of the coal dock. The dredge area ranges from 400 to 1,000 feet wide, and extends approximately 2,300 feet out into the lake, to approximately the 30-foot contour. Approximately 35 acres of lake bottom would be disturbed by the removal of 890,000 cubic yards of lake bottom material.

Coastal processes impacts

The Coastal Analyses Report prepared by Baird & Associates for WEPCO states that the proposed harbor would block the extimated 3,000 m^3 of material which currently bypasses the OCPP site on a yearly basis. The report concludes that existing structures within this littoral cell, such as the existing coal dock at the OCPP facility, have had significant impacts on littoral drift since their construction and are likely one of the factors that has contributed to shoreline erosion south of the existing coal dock.

Baird's analysis concludes that the small amount of very fine littoral material, which is currently bypassing the site, would not provide adequate protection to the shoreline south of the exitsing power plant and the complete interruption of this littoral drift from the construction of the harbor, would not cause significant impacts on downdrift properties. The construction of the harbor would cause some minor changes to local circulation patterns and may cause some changes to wave characteristics adjacent to the site due to changes in bathymetry, fetch and wave refraction or reflection off of the proosed structures.

Physical impacts

The creation of the harbor would impact the local bathymetry, and create dramatic changes in gradient between the coal dock, breakwater and navigational channel. Additionally, the diverse benthic habitat within the harbor area would be reduced from a mixture of micro-habitat areas to a uniform zone of sand and silt or large rock riprap from the breakwater and dock. During construction of the harbor, especially during dredging operations, sediment sorting will occur, with larger heavier particles such as boulders, cobble, and gravel settling first, followed by a blanket of sand, muck, and silt. The dredged area would then slowly fill in with sand from seasonal variations in long-shore sediment transport or slumping of the channel boundaries. Periodic dredging of this area would be needed to maintain adequate draft depth.

Figure 8-7 DNR sediment sampling table – Part 1

ug/g = ppm = mg/kg
ng/g = ppb = ug/kg
all values reported as dry weight

Core			A1	A2	A3	A4	B1	B2	B3	B4	B5	B6A	B6B	B7	C1	C2	D1	D2	D3	D4
Parameter		Units	0-2 ft.	2-4 ft.	4-6 ft.	6-8 ft.	0-2 ft.	2-4 ft.	4-6 ft.	6-8 ft.	8-10 ft.	10-11 ft.	11-12 ft.	12-14 ft.	0-2 ft.	2-4 ft.	0-2 ft.	2-4 ft.	4-6 ft.	6-8 ft.
TOC		ug/g	2860	654	991	2650	953	557	1570	721	1500	1940	2860	2880	918	2820	1080	694	1040	2860
PAHs	Acenapthene	ug/kg			181	879			1330		156									
	Acenaphthylene	ug/kg																		
	Anthracene	ug/kg																		
	Fluorene	ug/kg																		
	Naphthalene	ug/kg																		
	2-Methylnapthalene	ug/kg			138	132														
	Phenanthrene	ug/kg			183	116														
	Benzo(a)anthracene	ug/kg		73.8	87.5															
	Benzo(a)pyrene	ug/kg	22.8	96.8	109	42.9			13.1	7.46	14.5	9.48		5.22	5.72		8.77			13.5
	Benzo(b)fluoranthene	ug/kg		78	87.6															
	Benzo(k)fluoranthene	ug/kg																		
	Benzo(g,h,i)perylene	ug/kg			103	166														
	Chrysene	ug/kg			107															
	Dibenz(a,h)anthracene	ug/kg		13.8	13.4	39.5						10.3		6.89						
	Fluoranthene	ug/kg			225															
	Indeno(1,2,3-c,d)pyrene	ug/kg		67	72.9															
	Pyrene	ug/kg		139	234															
Particle Size	gravel	%	76.3	71	37.8	3	84.5	78.9	44.5	6.6	13.4	63	8.8	9.1	28.4	3.2	78.9	60.3	93.8	0.5
	sand	%	23.7	29	62.2	97	15.5	21.1	55.5	93.4	86.6	36.7	91.2	90.9	71.6	83.5	21.1	9.7	5.7	53.5
	silt	%																		46.5
	clay	%																		
METALS	Aluminum	mg/kg	1740	1800	2440	8380	1670	1520	1290	1260	1770	1210	7570	7770	1260	6720	911	1110	1740	3270
	Arsenic	mg/kg																		
	Barium	mg/kg				46.9							35.3	36.9		35.1				
	Cadmium	mg/kg																		
	Chromium	mg/kg	5.04	8.51	20.7	15.4	4.02	4.63	3.8	6.09	11.4	16.3	10.4	10.5	4.87	8.52	2.85	3.82	3.03	6
	Copper	mg/kg	10.3	11	14	17.4	8.22	7.81	9.7	9.9	9.83	7.25	12.8	15.3	6.1	12.2	6.37	7.86	5.08	6.77
	Cyanide	mg/kg																		
	Iron	mg/kg	5,530	5,360	7,770	15,800	5,180	5,160	5,790	6,060	5,890	4,360	14,100	4,090	5,490	12,100	4,220	4,990	9,960	7,540
	Lead	mg/kg	6.76	10.2	11.9	5.19	3.69	4.56	6.99	5.88	9.42	4.96	4.96	5.08	4.88	4.49	3.83	6.09	2.79	4.06
	Manganese	mg/kg	214	200	303	301	181	205	202	232	258	153	349	373	206	300	193	170	782	222
	Mercury	mg/kg		0.0548	0.0748					0.0426	0.0668						0.0752			
	Nickel	mg/kg	5.09	6.17	6.98	15.9	3.57	3.39	3.65	4	4.65	3.4	14.6	15	3.86	13.3		3.63	4.43	7.03
	Selenium	mg/kg																		
	Zinc	mg/kg	31.5	38.7	33.8	25.8	30.3	38.2	45.4	32.2	39.8	25.8		39			28.1	37.9		44
Sulfate as SO4		mg/kg																		53.7

NO DETECT
NOT TESTED

For complete analysis results, refer to Elm Road Generating Station - Application for Water Regulatory Permits and Approvals, Additional Information, December, 2002.

Figure 8-7 DNR sediment sampling table – Part 2

ug/g = ppm = mg/kg
ng/g = ppb = ug/kg
all values reported as dry weight

Core		E1A	E1B	E2	F1A	F1B	F2	G1	G2	H1	I1	I2	I3	J1	J2	J3	J4	J5A	J5B	J6	J7	K1	K1B
Parameter	Units	0-1.5 ft.	1.5 - 2 ft.	2 - 4 ft.	0 - 2 ft.	2" - 2 ft.	2 - 4 ft.	0-2 ft.	2 - 4 ft.	0-2 ft.	0-2 ft.	7-8.5 ft.	9-11 ft.	0-2 ft.	2-4 ft.	4-6 ft.	6-8 ft.	8-10 ft.	8-10 ft.	10-12 ft.	21-23 ft.	0-2 ft.	1.4 - 2 ft.
TOC	ug/g	1200	3160	2940	514	2710	3220	2040	3100	3680	587	678	3820	696	1030	3900	1050	501	3760	3530	2640	547	2050
PAHs																							
Acenapthene	ug/kg					see F1B																see K1	
Acenaphthylene	ug/kg													228						207			
Anthracene	ug/kg																						
Fluorene	ug/kg																						
Napthalene	ug/kg																						
2-Methylnaphthalene	ug/kg																			136			
Phenanthrene	ug/kg																			1160			
Benzo(a)anthracene	ug/kg																			127			
Benzo(a)pyrene	ug/kg		15.5								8.86			9.03	12.1	51.9	48.8	6.96	12.9	15.2			
Benzo(b)fluoranthene	ug/kg																54.1						
Benzo(k)fluoranthene	ug/kg																						
Benzo(g,h,i)perylene	ug/kg																			143			
Chrysene	ug/kg															143							
Dibenz(a,h)anthracene	ug/kg														9.22	30.6				51.3			
Fluoranthene	ug/kg															121							
Indeno(1,2,3-c,d)pyrene	ug/kg																						
Pyrene	ug/kg																			282			
Particle Size																							
% gravel		0.5	1.5	see F1B	2.5	0.8				24.1			3			0.2			1.8	1		0.3	
% sand		90.4	9.8	7.8	11.6	10.6	2.6	13	21.3	21.3	94.7	90.7	7.9	82.4	85.7	88.5	90.9	96.2	6.2	34.8	0.7	78	0.9
% silt		9.6		90.7		85.9	88.6	97.4	78	54.6	5.3	9.3	89.1	17.6	14.3	13.3	8.9	3.5	92	64.2	99.3	20.9	99.1
% clay																							
METALS																							
Aluminum	mg/kg	1460	6490	7310	1040	9020	7110	2610	6260	7230	878	1140	7250	1060	1340	1770	1080	1090	5270	4820	6830	3590	see K1
Arsenic	mg/kg																						
Barium	mg/kg		33.4		44.2	32.6			33	38.7			37.2						25.1	30.1	30.5		
Cadmium	mg/kg																						
Chromium	mg/kg	6.28	9.25	10.5	2.07	13.4	10.2	3.25	8.85	10.4	3.69	10.9	10.8	3.17	3.53	4.66	3.68	4.05	7.26	9.03	9.18	3.89	5.04
Copper	mg/kg	9.06	11.5	13.1	2.57	13.4	11.5	10.6	11.5	12.3	8.07	8.47	13.7	4.93	6.49	8.07	5.61	7.63	12.8	21.1	12.3	4.24	9.48
Cyanide	mg/kg																						
Iron	mg/kg	5,150	12,400	13,800	16,800	14,700	13,500	9,650	12,700	13,300	5,380	5,780	13,100	4,640	4,800	5,650	5,100	5,560	12,800	10,300	13,300	5,390	10,900
Lead	mg/kg	6.59	7.32	4.71	5.41	5.43	5.7	4.72	4.92	4.77	4.35	12.3	5.09	3.91	5.02	6.3	6.83	6.64	5.52	12.1	4.77	4.27	4.71
Manganese	mg/kg	178	371	329	697	297	338	395	365	327	181	232	336	162	174	196	180	173	378	220	311	141	352
Mercury	mg/kg	0.319										0.0666								0.0811			
Nickel	mg/kg	4.62	13.2	14.8	4.42	17.8	14.8	8.25	13.6	14.4	2.94	4.26	15.8	2.99	3.62	4.33	3.83	5.51	12.1	10.9	13.3	2.91	10.2
Selenium	mg/kg																						
Zinc	mg/kg	36.4	28.9			28.4				74.3	71.7	41.6		28.5			27.4	56.7		32		26	
Sulfate as SO4	mg/kg																						

NO DETECT
NOT TESTED

For complete analysis results, refer to Elm Road Generating Station - Application for Water Regulatory Permits and Approvals, Additional Information. December, 2002.

Turbidity within the water column would increase within and adjacent to the dredged area and may result in local temperature increases and diminished light penetration. The creation of the breakwater and dock expansion would eliminate the habitat that once existed in those areas.

Chemical Impacts

Nutrient loadings of phosphorus may increase in and near the project area, as sediments and settled detritus are disturbed by dredging. These released nutrients may increase planktonic growth on a local scale, but larger scale blooms due to dredging activities would not be expected.

Oxygen demand within and adjacent to the project area may temporarily increase as sediments are disturbed and re-deposited. No impacts to aquatic organisms would be expected, due to the large mixing zone.

Biotic Impacts

Benthic invertebrates

Currently, the project area may be assumed to have four types of bottom habitat. They are: rock and boulder fields, mixed cobble/gravel/sand bottoms, hard clay outcrops, and sand/silty bottoms. This assumption is based on characterization of the lakebed further east of the proposed dredge area, undertaken by the Great Lakes Water Institute. Their findings are published in Great Lakes Water Institute Technical Report 2003-1. The dredging would impact benthic invertebrates within the project area by direct removal of the organisms, and removal of their habitat. One hundred percent mortality could be expected. Post-dredging, macroinvertebrate communities would reestablish within the dredged area. However, the community diversity would be reduced, reflecting the transition from rock/boulder/sand substrate to a monotypic sand substrate. Zebra mussel densities within the project area would be expected to be reduced after dredging due to removal of hard substrate.

Benthic communities adjacent to the dredge area would also be temporarily impacted due to burial by settling of sediments suspended into the water column by dredging activities. These communities would re-establish via expansion from surrounding macro-invertebrate populations.

Fish

The fish community within the dredge area would be temporarily impacted due to disturbance from dredging operations. Additionally, more severe, longer-term impacts to the bottom dwelling fish in the dredge area would occur. This would be due to habitat removal of species associated with rocks and boulders, including sculpins, Johnny darters, yellow perch, and lake trout

Rooted aquatic plants and algae

Lakebed surveys within the project area were undertaken in 2002 by the Great Lakes WATER Institute. Those studies show no aquatic macrophytes within the project area. Most of the project area is in water depths deeper than the maximum rooting depth of macrophytes (Eurasian Watermilfoil, Coontail, and Elodea) commonly found in Lake Michigan. Those areas that are shallow enough to support macrophytic growth are subject to long-shore drift and high-energy wave action. There is an existing peripyton community, dominated by the green algae Cladophora. The periphyton community would be impacted directly by physical removal. Limited recolonization of the dredge area would occur where suitable hard substrate is available.

Toxicity to water column organisms

Sediments within the project area have the potential to release certain toxicants to the surrounding water column during dredging activities. Organisms that cannot avoid the dredge area, such as zooplankton and phytoplankton, may potentially be exposed to these contaminants. However, these polar compounds are strongly attracted to particulates, and those compounds freed into the water column would be expected to rapidly rebind with suspended sediment and settle out of the water column, removing the risk of chronic exposure to water column organisms. Likewise, freed PAH contaminants would also not be expected to significantly impact water column organisms due to dilution, particulate attraction, and by comparing sediment concentrations to effect concentrations.

Drinking water impacts

South Milwaukee and Oak Creek Water Utilities have drinking water intakes located on the bed of Lake Michigan. These locations are northwest of the proposed dredging area. Depending upon the drift of sediment suspended by dredging activities, there is a slight risk of impacts to these utilities. Due to water treatment processes, no serious problems with drinking water quality would be expected to occur. However, to minimize risk, it is advised that WEPCO notify these facilities prior to initiating dredging activities.

Other impacts

The natural scenic beauty and aesthetic enjoyment (both visual and auditory) of Lake Michigan in the project area would be temporarily affected by the presence of construction equipment, as well as decreased local water quality during construction operations. The project area is located in an area associated with heavy recreational boating and fishing. Dredging would temporarily interfere with navigation within the project area and the overall harbor construction may permanently alter recreational navigation within this local area due to the increase in ship and barge traffic and changes in navigational patterns.

New and Modified On-shore Facilities and Potential Impacts on Wetlands and Streams

Impacts of new facilities

A majority of the wetland impacts would occur through the placement of fill for the proposed soil stockpiles. As discussed in Chapters 10 and 11, WEPCO proposes to excavate a maximum of five to ten million cubic yards of soil, which would be used on-site for berms and grading. The impacts to the wetlands would vary depending upon the different siting alternatives. WEPCO has identified the locations for the placement of the excavated soil for each of the site alternatives proposed in its CPCN application (see Figures Vol. 2-1, 2-2, and 2-3). Table 8-10 shows the acres of wetland impacts for the proposed alternatives. Regardless of the alternative chosen, four of the eight larger wetlands (two acres or more in size), would not be filled in. The remaining four larger wetlands would be reduced in size by at least 12 to 20 percent depending upon the alternative.

The wetland and stream impacts described here for the North Site are for the original site layout in the CPCN application. Wetland and stream impacts related to the CUP Option site layout are discussed in Chapter 12.

Table 8-10 Acres of wetland filled for proposed alternatives

	Estimated wetland acres filled	Percentage of wetland acres filled
North Site	18.78	22.5
South Site	15.84	19.0
South Site-Exp	15.19	18.2

The proposed alterations to the site would result in a major change to the site topography and hydrology including water quality and amount of stormwater runoff. A number of wetlands would be filled completely and many of the remaining wetlands would either be partially filled or would experience secondary impacts as a result of the construction. Wetlands that would be completely filled in include the high-quality 6.1 acre wetland located due north of Elm Road. Secondary impacts would include changes to the area's hydrology, impacts to water quality, wildlife habitat, and the introduction or encouragement of the proliferation of non-native invasive species.

Currently most of the wetland acreage on the property is dominated by native non-invasive species. Included in the mix of wetland types are some high-quality wetlands in terms of their functional values. Comparing WEPCO's proposed construction plans to the location of delineated wetlands shows that many of these high-quality wetlands would be either partially filled in or directly adjacent to berms with a constructed height of 50 or more feet. Wetlands adjacent to these new topographic features would most likely be impacted by sediment-laden stormwater runoff and erosion. These impacts would result in changes to the size, type, and quality of the wetlands.

The placement of fill in a wetland requires a Water Quality Certification from the DNR under s. 281.22 and s. 281.37, Wis. Stats. and NR 299, Wis. Adm. Code. Applicants must comply with NR 103, Wis. Adm. Code which requires the applicant to submit a Practicable Alternatives Analysis that evaluates alternatives which would avoid or minimize wetland impacts taking into consideration cost, available technology and logistics in light of the overall project's purpose. The DNR will make a determination whether WEPCO has shown that no practicable alternative exists that would avoid or minimize impacts to the wetlands and whether the activities would result in significant adverse impacts on wetland functional values. DNR staff would work with WEPCO during the permitting process to evaluate the functional values of all wetlands and would encourage WEPCO to avoid or minimize the wetland impacts where practicably possible.

Treatment and discharge of cooling water

Description and location of proposed water discharge structure

The proposed discharge structure would provide control for the discharge of non-contact cooling water. The structure would involve the construction of a seal well structure with concrete retaining walls and a rock-lined dredged channel. The rock lined channel would control erosion and reduce the velocity of the discharged water. The channel would be approximately 200 feet wide and would extend approximately 750 feet into the lake. To create the discharge channel approximately 10,000 to 15,000 cubic yards of material would need to be dredged from the bed of Lake Michigan.

The final design and location of this structure could be modified depending upon whether the North Site or South Site is the final location of the proposed SCPC and IGCC units. There could also be changes to the discharge structure that reflect requirements of state or federal regulations relating to the flow regime, erosion control and energy dissipation.

Storm water drainage from common areas of the property and the coal pile runoff would be handled by a common treatment facility shared with all the proposed ERGS units.

Site differences

The proposed discharge structure for the North Site would be located north of the existing coal dock (see Figure Vol. 2-1). The shoreline at this location is characterized as a wide sand beach, which provides good aquatic habitat, and habitat for various shore species.

If the ERGS facilities are built on the South Site or the South Site-Exp the discharge structure would be located south of the existing coal dock directly east of the facility along the Lake Michigan shoreline. At this location the shoreline has been modified with the placement of sheet pile and riprap. The water is much deeper at this location in comparison to the northern location and at this location the proposed discharge would be in the vicinity of the existing discharge structure (see Figures Vol. 2-2 or 2-3).

Description of construction methods for the water discharge structure

It is anticipated that the discharge structure would be constructed by initially creating the seal well structure with concrete wing walls and the necessary utilities for operation. WEPCO would then mechanically dredge the discharge channel from either the nearshore area or from a barge. Rock riprap would then be placed in the discharge channel. Final construction methods would be discussed during the permitting process and construction would occur in a manner that meets State Statutes and Administrative Code.

Potential impacts of construction of the water discharge structure

The impacts to Lake Michigan from the construction of the discharge structure include temporary impacts such as local increases in turbidity within the water column, reductions in local dissolved oxygen levels, and the reductions in local light penetration. The construction of the discharge structure would also temporarily disrupt and possibly destroy the local flora, fauna and aquatic habitat, including fish. Measures such as silt curtains or turbidity barriers would be required to reduce the extent of these temporary impacts. The long-term effects of the placement and operation of the discharge structure include a loss or modification to the existing aquatic and nearshore habitat in the area, and changes to local water quality. If the discharge structure is placed north of the existing coal dock the presence of the discharge structure may disrupt local wildlife species which utilize the sand beach in this area and would likely require more frequent maintenance dredging of the discharge channel due to littoral drift in this area.

Potential impacts of operation of the water discharge structure

The anticipated maximum flow through rate for each SCPC unit and the IGCC is 485,000 gpm with a temperature rise of 12 °F. The maximum heat rejection rate for the three units combined would be 8,740 million BTU/h.

The primary effluent from the OCPP is once-through cooling water from the steam condensers. No chemicals are added to the water; therefore, temperature is the only water quality parameter significantly

affected by the discharge of cooling water. Heated effluent from the two proposed SCPC units would be discharged north of the coal dock through either a single or combined outfall structure. Heated effluent from the IGCC facility would be discharged through a single new outfall structure or combined with the SCPC outfall.

The DNR has proposed new water quality criteria that would apply to thermal discharges from steam electric power plants. Specific acute and sub-lethal temperature criteria have been developed for Lake Michigan that are a function of the 90th percentile monthly ambient lake temperature (proposed NR 102.24, 102.25). The acute temperature criteria are used to calculate end-of-pipe limits, expressed as a "daily maximum temperature" limitation in a wastewater discharge permit. The sub-lethal criteria are used to calculate limits at the edge of the mixing zone, expressed as an "average temperature" limitation. The averaging period has not yet been established, but will likely be a three-day, seven-day, or monthly average.

The equation for calculating effluent limitations is:

$$\textbf{Limitation} = [(WQC - T_b)/e^{-a}] + T_b$$

where: WQC is the water quality criterion,
T_b is the background temperature, and

$$a = [A \cdot (54.7 + (B \cdot 150))]/[8{,}360{,}000 \cdot Q_e]$$

where: A is the allowable surface area of the mixing zone,
B is the heat loss coefficient, and
Q_e is the effluent flow rate.

Based on the anticipated maximum flow rate of 700 MGD for each of the three new units, the temperature rise of 12^0F above the ambient lake temperature, and the default mixing zone area of 3,125,000 ft^2 for an onshore discharge, the combined discharge of the three units would exceed the calculated daily maximum temperature limit for the months of July, August, and September (refer to figure 8-7). The discharge would also exceed the calculated average temperature limit for the months of May through November (refer to figure 8-8). Providing a separate cooling water outfall structure for the IGCC unit would still result in daily maximum and average temperature limitations exceedences for the months indicated above; and the excedences would occur for both the IGCC outfall and the combined SCPC outfall.

The formula (shown above) for calculating temperature limitations is very conservative because only heat loss to the atmosphere is considered. Heat loss caused by entrainment and mixing of receiving water is not included. The proposed regulations, however, allow for other scientifically defensible methods of calculating effluent limitations (proposed NR 106.24(6)).

WEPCO and its consultants are developing thermal models of the proposed discharge to include the effect of mixing due to naturally-occurring near-shore currents. EPA's CORMIX model will be used for the near-field region. The MIKE 21 2-dimensional hydrodynamics model, developed by the Danish Hydrologic Institute, will be used for the far-field region. Output from EPA's GLERL existing model of Lake Michigan currents will be used as input to both the CORMIX and MIKE 21 models.

Modeling results could be used either to demonstrate that calculated temperature limits can be met within the default mixing zone or, alternatively, to support a request for alternative temperature limits through a 316(a) demonstration.

Figure 8-8 Calculated daily maximum temperature limits (acute temperature criteria)

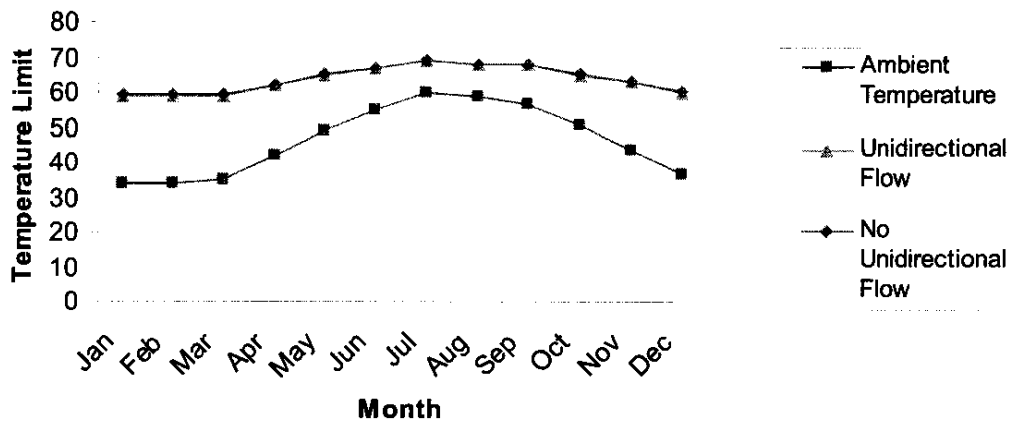
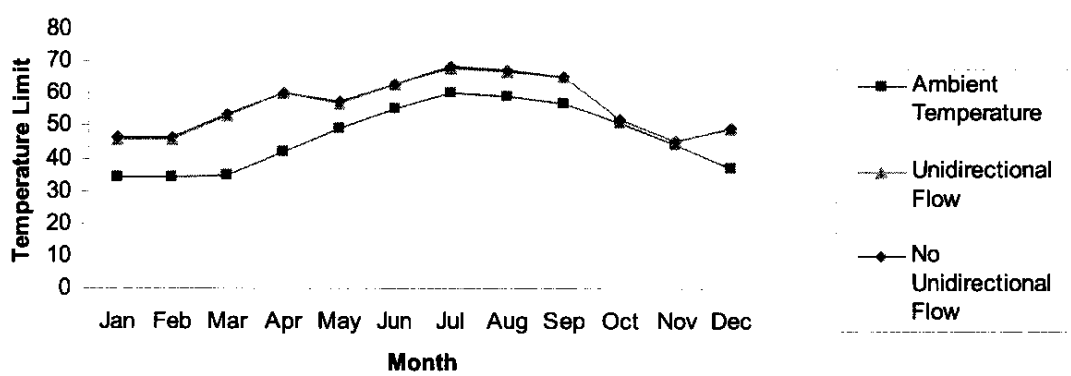


Figure 8-9 Calculated average temperature limit (sub-lethal temperature criteria)



Zebra mussel control

At the lake bottom intake structure, the only option for zebra mussel control would be manual cleaning by divers. The intake drop shafts and tunnels should not have significant zebra mussel accumulations because velocities would be too high (over six feet per second) for mussel settlement to occur.

Pump house wet wells, frames for the traveling water screens, pump bell housings and other on-shore equipment would also need to be periodically manually cleaned. Plant service water would be treated using the copper ion generator that has been successfully used at the existing OCPP units 5 - 8. This device involves the electrolytic dissolution of a low level of copper ions and also releases an aluminum floc. Parts-per-billion levels of copper cause the mussels to be agitated and the inside of the plant water system becomes less habitable. Mussels likely would continue to free float through the system and ultimately be returned back to the lake. Furthermore, the aluminum floc forms a coating on the inside of piping, heat exchangers and other equipment using service water which helps inhibit zebra mussel settlement.

The copper ion generator is located downstream of the traveling water screens. Condenser cooling water zebra mussel treatment is not anticipated based on operational experience at other WEPCO facilities on Lake Michigan. This could differ at the ERGS units depending on the water quality from the off-shore intake location and metallurgy of the condenser tubing. At this time, there is not a specific plan for controlling zebra mussels in the condenser cooling water.

Treatment and discharge of storm water

NR 216 rules require that a storm water pollution prevention plan (SWPPP) be in place before commencement of construction activities that result in the disturbance of 5 acres or more of land and the operations phase of the proposed plants. Existing OCPP units 5 - 8 have a SWPPP in place and are permitted under NR 216 as a "Tier 2" facility. In general, under the requirements of the Wisconsin Pollution Discharge Elimination System (WPDES) storm water permit, an amendment of the plan must be done when changes to the facility result in a significant increase in the exposure of pollutants to storm water that are discharged to waters of the state or to storm water treatment devices. Most of the land area included in the SWPPP for the Tier 2 storm water permit are lands that have minimal potential for storm water contamination.

Therefore, the majority of the storm water management is regulated by the WPDES industrial discharge permit and not the NR 216 storm water permit. NR 216 requires that various types of best management practices (BMP's) be implemented to prevent storm water from contacting materials that can potentially contaminate it. Decisions on what BMP's are used are based upon site-specific information. Periodic inspections are performed to ensure that BMP's are performing at levels expected by the SWPPP.

Description and location of proposed storm water facilities

The quality of storm water discharged from the ERGS would be addressed through the development and implementation of site-specific construction site erosion control and post-construction storm water management plans. State and local regulations establish the design criteria, standards and specifications used to develop and implement these plans.

Construction site erosion control plan

The purpose of the erosion control plan is to minimize the discharge of sediment from the site to waters of the state (e.g., rivers, lakes and wetlands) during construction. This plan identifies specific erosion and sediment control practices that would be used to reduce the dislodging of soil particles and remove soil particles suspended in runoff.

State regulations require the erosion control plan to be designed to achieve an 80 percent reduction of the sediment load that would be discharged from the construction site if no sediment or erosion controls were in place. The Wisconsin Construction Site Best Management Practice Handbook contains the design criteria, standards and specifications for erosion and sediment control practices that are approved for use at construction sites in Wisconsin. Unfortunately, not all of the erosion and sediment control practices found in the Handbook are capable of controlling or removing sediment at an efficiency of 80 percent This means that the erosion control plan for the ERGS must include a combination of practices in order to achieve the 80 percent sediment reduction requirement.

It is anticipated that the erosion control plan for the ERGS would need to include the following critical elements in order to achieve the 80 percent sediment reduction requirement:

- As much of the construction site as possible should drain to sediment basins during all phases of construction. Changes in site topography and drainage patterns that would occur over time must be considered when determining the specific location of sediment basins. In addition, temporary diversion berms/swales may be needed to make sure the sediment basins are not bypassed.
- The area of bare soil exposed at any one time should be minimized. Any disturbed areas left inactive for seven days must be temporarily or permanently stabilized by seeding, mulching, erosion matting or other equivalent stabilization practices. Stabilization practices identified in the plan must be appropriate for site conditions and time of year.

Post-construction storm water management plan (excluding coal pile runoff)

The purpose of the post-construction storm water management plan is to minimize the discharge of pollutants from the developed site to waters of the state (e.g., rivers, lakes and wetlands). This plan identifies specific permanent storm water management practices that would be used to treat runoff from roadways, parking lots, rooftops and other significant sources of storm water pollutants.

State regulations require the storm water management plan to be designed to achieve an 80 percent reduction of the total suspended solids load that would be discharged from the developed site if no storm water treatment practices were in place.

Five wet detention basins would be used to treat storm water from the developed ERGS site and discharge treated storm water to Lake Michigan at two outfall locations. Wet detention basins designed in accordance with Wisconsin Department of Natural Resources Wet Detention Basin Technical Standard (Code 1001) can achieve the 80 percent total suspended solids reduction requirement. For optimum pollutant removal, a wet detention basin should have five-foot deep permanent pool of water with a surface area that is approximately 2 percent of drainage area to the basin. In addition, the wet detention basin outlet structure should be designed to provide a slow release of the runoff volume produced by the one-year 24-hour design storm.

Description of construction methods for storm water facilities

Construction site erosion controls

Critical sediment control practices including sediment basins, silt fence, and diversion berms/swales must be constructed or installed before land disturbing activities begin in other areas of the site (including clearing, grubbing and topsoil removal). Some sediment control practices would need to be re-installed or adjusted as appropriate during different phases of construction.

Temporary erosion control practices including seeding and/or mulching must be installed any time disturbed areas of the site are left inactive for seven days. Permanent erosion control practices including seeding and mulching or erosion matting are installed when final grades have been achieved and topsoil has been re-spread on unpaved areas and areas not covered by permanent structures.

Erosion and sediment control practices are installed or constructed by hand or using standard grading, excavating and landscaping equipment. Practices like erosion bales and erosion matting are installed by hand. Sediment basins are constructed with heavy equipment including scapers, dozers and backhoes. Soil stabilization practices are typically installed with the assistance of landscaping equipment including seeders and straw mulch blowers.

Post-construction storm water management facilities

Wet detention basins could be constructed at any time during site construction. Typically, wet detention basins are constructed first and used as sediment basins during site construction. As with sediment basin construction, wet detention basins are constructed with heavy equipment including scrapers, dozers and backhoes.

Potential impacts of construction

Disposal of excavated materials

Approximately five to ten million cubic yards of soil would need to be excavated to construct the ERGS. This soil would likely be stockpiled on-site. All soil stockpiles must be addressed in the erosion control plan including practices that would be used to minimize the impacts of trucks used to haul the excavated material (e.g., dust, sediment tracked on public roads). Changes in drainage patterns must be considered when siting soil stockpiles to make sure that changes in wetland hydrology are minimized.

Erosion control

State and local erosion control regulations do not establish water quality based effluent limitations for construction site runoff. However, the Wisconsin Department of Natural Resources considers the 80 percent sediment reduction requirement to be protective of waters of the state. The construction site should not have a significant adverse impact on waters of the state as long as the erosion control plan is designed to achieve 80 percent sediment reduction and the plan is properly implemented during all phases of construction.

Potential impacts of operation

State and local storm water regulations do not establish water quality based effluent limitation for new developments. However, the Wisconsin Department of Natural Resources considers the 80 percent total suspended solids reduction requirement to be protective of waters of the state. Storm water runoff from the

developed ERGS should not have a significant impact on waters of the state as long as the storm water treatment facilities are designed to achieve 80 percent total suspended solids reduction. In addition, the Storm Water Pollution Prevention Plan (SWPPP) for the existing facility would need to be modified to include the new facility. The SWPPP would need to identify practices that would be used to minimize the amount and kind of materials exposed to storm water.

Differences among alternative sites

The three site alternatives proposed in the CPCN application (the North Site, the South Site, and the South Site-Exp) are similar in regards to construction site erosion control and post-construction storm water treatment. It is not anticipated that the erosion control and storm water treatment facilities would be significantly different for each alternative other than the actual location of the practices on the property. However, the city of Oak Creek recently adopted a storm water ordinance that would require storm water discharge quantity control for the ERGS. As a result, wet detention basins for the North Site would likely need to be somewhat larger than wet detention basins for the South Site and the South Site-Exp in order to provide the quantity control required by the city of Oak Creek.

Treatment and discharge of process wastewater

Wastewater sources would be similar to those of the existing units and would include yard drainage, coal pile runoff, neutralized demineralizer backwash, steam generator blowdown, non-chemical metal cleaning wastewater, floor drains, and other typical discharges present at a coal-based steam electric power plant. Treated wastewater would be discharged into Lake Michigan as currently done. Both federal (40 CFR Part 423) and state (Ch. NR 290, Wis. Admin. Code) regulations establish effluent limitations for power plants. Parameters typically limited for power plants utilizing once-through cooling are suspended solids, oil and grease, pH, and various metals. A WPDES wastewater discharge permit would limit the concentrations of potentially harmful constituents, and would include all of the requirements of the federal and state regulations. By meeting both federal and state water quality standards, adverse impacts to aquatic life would not be expected from the discharge of this treated wastewater. Treated discharges would also be required to pass whole effluent toxicity tests.

SCPC process wastewater

WEPCO plans to install a new wastewater treatment system that would treat the wastewater generated by the existing units 5-8 and the two new SCPC units. The proposed new wastewater treatment system would be designed to meet or exceed the discharge requirements under the WPDES permit. Ch. NR 108, Wis. Admin. Code, requires DNR review and approval of the treatment system before it can be put into operation. In general, the collection and treatment system would consist of coal pile runoff equalization and solids settling, ditches and pipes to convey wastewater, and the wastewater treatment equipment.

IGCC process wastewater

The IGCC process wastewater would be routed to either a treatment facility that also handles the existing units or a new facility to process only IGCC-related wastewater. The current plans are to construct a separate wastewater treatment system to handle discharges that are unique to the IGCC facility. Wastewater from the gasification process would be routed to a zero discharge wastewater treatment system dedicated to

the IGCC facility. Discharges from other parts of the IGCC facility, mainly composed of flows from the combined-cycle power plant such as boiler blowdown, demineralizer regeneration wastewater and yard runoff, would be handled through a separate conventional treatment system and discharged to a Lake Michigan outfall.

Coal pile runoff

Coal pile runoff would be collected in ditches around the coal pile area and directed to a collection basin for flow equalization and solids settling. If additional wastewater treatment is necessary to further improve water quality, the collected runoff would be routed to a wastewater treatment plant and also may be used for coal pile dust control.

Limestone storage runoff

Limestone would be stored as-received on an open pile in a segregated area located on the existing coal dock. The storage pile would provide a supply of about 120 days for both SCPC units. The limestone would be pushed into a reclaim hopper and transported by conveyor to the crushers. Storm water runoff from the limestone storage pile is expected to be treated with the coal pile runoff.

Sanitary wastewater

Sanitary wastewater from plant bathrooms, showers and other employee areas would continue to be pumped into an on-site sewer that feeds the local Oak Creek sewer system. The local sewer is connected to the Milwaukee Metropolitan Sewerage District (MMSD) system. MMSD regulates and periodically monitors plant discharge quality.

New Railroad Facilities and the Potential Impacts on Wetlands

Description of facilities

Proposed changes to the Union Pacific (UP) railroad extend from just south of Elm Road to a location about 1,700 feet south of Five Mile Road. The proposed work includes realignment of the mainline track and the addition of several sections of new railroad tracks or sidings. One of the new sections on-site would be designated for the repair of coal train cars. All of the proposed work would be done on existing UP railroad right-of-way or WEPCO property. A new road underpass beneath the railroad grade has also been recommended by the applicants at Six Mile Road. Less certain, but still under consideration, is a vehicle underpass at Seven Mile Road. Both of these projects would require the acquisition of property.

Impacts of new facilities

There would be temporary impacts to the streams that cross under the railroad tracks during construction of new roadway and railroad facilities. These existing waterways and drainage ways would be maintained by extending existing culverts with either steel or concrete box culvert.

At Six Mile Road, where construction of an underpass is proposed, water drains or flows under Six Mile Road through culverts located west and east of the railroad tracks. These drainage flows connect to a navigable tributary that flows to Lake Michigan. The footprint of the new underpass would interfere with the culvert on the west side of the railroad tracks. The removal of this culvert would most likely be addressed by construction of a new drainage ditch along the north side of the new underpass.

With respect to drainage at Seven Mile Road, there is a stream (Rifle Range tributary) located about 200 feet east of the crossing. If an overpass or underpass were constructed at Seven Mile Road, enclosure of this stream for a distance of roughly 200 feet would be required. This stream has good macroinvertebrate habitat throughout the system which would be impacted by the proposed enclosure. The creation of new drainage ways for both Six and Seven Mile Road would impact on the quality of the streams and the habitat they provide.

The expansion and realignment of the reailroad tracks would result in the filling of 9.32 acres of wetland located alongside the railroad corridor. Plans also call for the construction of new drainage ditches, which would impact the remaining 25.61 acres of wetland during and after construction. Without implementation of a specific re-vegetation plan, these newly constructed ditches would most likely be filled in by invasive and non-native species, further degrading any adjacent wetland or stream habitats. Erosion caused by construction activities could have additional impacts to wetlands hydraulically connected to the drainage ditches. Impacts to wildlife within the railroad corridor are expected to be minimal due to the current degraded nature of the vegetation, especially if construction activities were limited to the railroad corridor.

For information regardin the DNR wetlands permitting regulations and procedures refer to the previous section under "New and Modified On-shore Facilities and Potential Impacts on Wetlands and Streams."

The placement of fill in a wetland requires a Water Quality Certification from the DNR under s. 281.22 and s. 281.37, Wis. Stats. and NR 299, Wis. Adm. Code. Applicants must comply with NR 103, Wis. Adm. Code which requires the applicant to submit a Practicable Alternatives Analysis that evaluates alternatives which would avoid or minimize wetland impacts taking into consideration cost, available technology, and logistics in light of the overall project's purpose. The DNR will make a determination whether WEPCO has shown that no practicable alternative exists that would avoid or minimize impacts to the wetlands and whether the activities would result in significant adverse impacts on wetland functional values. DNR staff would work with WEPCO during the permitting process to evaluate the functional values of all wetlands and would encourage WEPCO to avoid or minimize the wetland impacts where practicably possible.

9

Chapter 9 - Solid and Hazardous Waste Disposal and Remediation

A coal-fired power plant produces solid and hazardous wastes. In the case of the ERGS project, the most important solid wastes generated would include ash from the coal combustion, gypsum from the capture of SO_2 emissions, gasifier slag, and elemental sulfur or sulfuric acid. Because the plant would use once-through cooling technology which returns water to Lake Michigan and the make-up water for the boilers would come from the municipal water supply, no water filtration or treatment would occur. Solid wastes from the shops and offices on site would be recycled as much as possible. Waste that could not be recycled would need to be collected and taken away by waste management contractors.

This chapter addresses the potential disposal sites for solid by-products of coal combustion and gasification, the potential for beneficial re-use of those by-products. It also discusses on-going remediation efforts on the OCPP site.

Existing Environment

The existing OCPP solid waste environment includes the coal piles, coal combustion points, handling areas, early ash disposal areas, and three existing landfills on the OCPP property. Two of the existing landfills are now closed. Two additional off-site landfills are also associated with the waste produced at the existing OCPP. Active landfills are discussed in the following section.

Active landfills

There are three active landfills to be considered when examining the potential destinations of the ash that would be produced by the ERGS.

Pleasant Prairie Power Plant Ash Landfill
(DNR License #2786 – Facility Identification Number 230056310)

This landfill is located in the village of Pleasant Prairie in Kenosha County (see Figure 9-1), approximately 1 to 1.5 miles north of the existing WEPCO Pleasant Prairie Power Plant. It currently accepts bottom ash, fly ash, and sludges from electric and process steam generating facilities. Waste generated at the Pleasant Prairie plant is hauled by truck using roads owned by WEPCO to the landfill. The landfill haul route crosses Bain Station Road. Private contractors also haul this by-product material from the power plant or from the landfill

to various beneficial use projects. All truck traffic serving the landfill and the power plant enters and exits the public roadways at the main plant entrance on 95th Street.

The landfill was approved in 1978 for 25 "cells" with a total design capacity of 4,569,090 cubic yards. The first cell was constructed in 1980. Four cells have been constructed at this time. In 2002, no waste was placed in this landfill. Its remaining capacity as of January 1, 2003 was 4,035,666 cubic yards. The volume of waste in the landfill has been decreasing because utilization efforts have been successful. Under DNR approval, previously landfilled material has been reclaimed as a sand or gravel substitute. At the current rate of waste disposal and reclamation, this landfill's site life is estimated to be greater than 100 years.

Caledonia Ash Landfill
(DNR License #3232 -- Facility Identification Number 252108450)

This landfill is located in the town of Caledonia, approximately one mile west of the OCPP (see Figure 9-1). It currently accepts bottom ash, fly ash, and sludges from electric and process steam generating facilities. Waste generated at the OCPP is hauled by truck to the landfill using roads owned by WEPCO. There is a temporary stockpile of Valley Power Plant ash, from Milwaukee, located in the Caledonia Ash Landfill. Valley Power Plant ash is added to the stockpile when the re-burn system at the Pleasant Prairie plant is unavailable. This temporary stockpile is permitted under Wis. Admin. Code ch. NR 538 and is used as a fuel source (reburned) for the Pleasant Prairie plant under a cooperative agreement. Private contractors also haul by-product from the OCPP plant or from the landfill to various beneficial use projects. All truck traffic serving the landfill and the power plant enters and exits the public roadways at the main plant entrance on Elm Road, or at the STH 32 entrance adjacent to County Line Road. Figure 9-2 illustrates the internal power plant trucking routes for ash to the Caledonia Landfill. A discussion of WEPCO's flyash reburning propgram is found under "Fugitive Dust" in Chapter 11.

The Caledonia landfill was approved in 1987 for 18 cells with total design capacity of 4,048,000 cubic yards. The first cells were constructed in 1990. Six cells have been constructed at this time. In 2002, 34,354 cubic yards of waste was disposed of in the landfill. The remaining capacity as of January 1, 2003 was 2,629,685 cubic yards.

At the current rate of waste disposal and reclamation, the site life is estimated to be 66 years.

Highway 32 Ash Landfill
(DNR License #2801 -- Facility Identification Number 246049100)

This landfill is located in the town of Grafton, approximately four miles southwest of the existing WEPCO Port Washington Power Plant (PWPP). Its location and potential haul route from the ERGS are shown in Figure 9-1. It currently accepts bottom ash, fly ash, and sludges from electric and process steam generating facilities. Waste generated at the PWPP is hauled by truck over public roads to the landfill. There is a temporary stockpile of the PWPP ash located in the Highway 32 Ash Landfill. The temporary stockpile is permitted under NR 538. Periodic withdrawals from the stockpile are used as a fuel source (reburn) for the Pleasant Prairie plant under a cooperative agreement or are delivered to other beneficial users. Private contractors haul byproduct out to various beneficial use projects either from the landfill or directly from PWPP.

Figure 9-1 **Locations of Pleasant Prairie, HWY 32, and Caledonia landfills, including potential haul routes from ERGS**

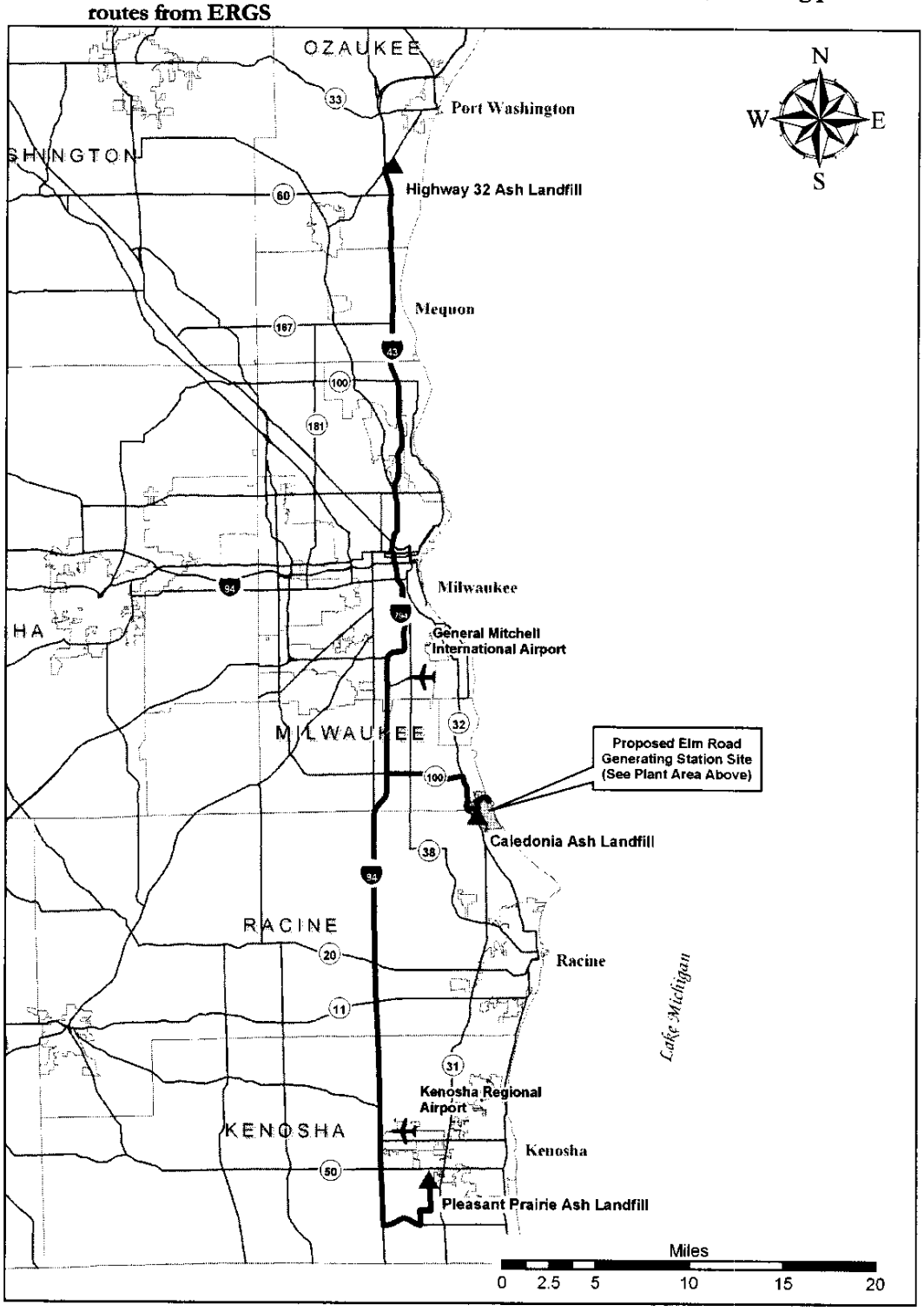
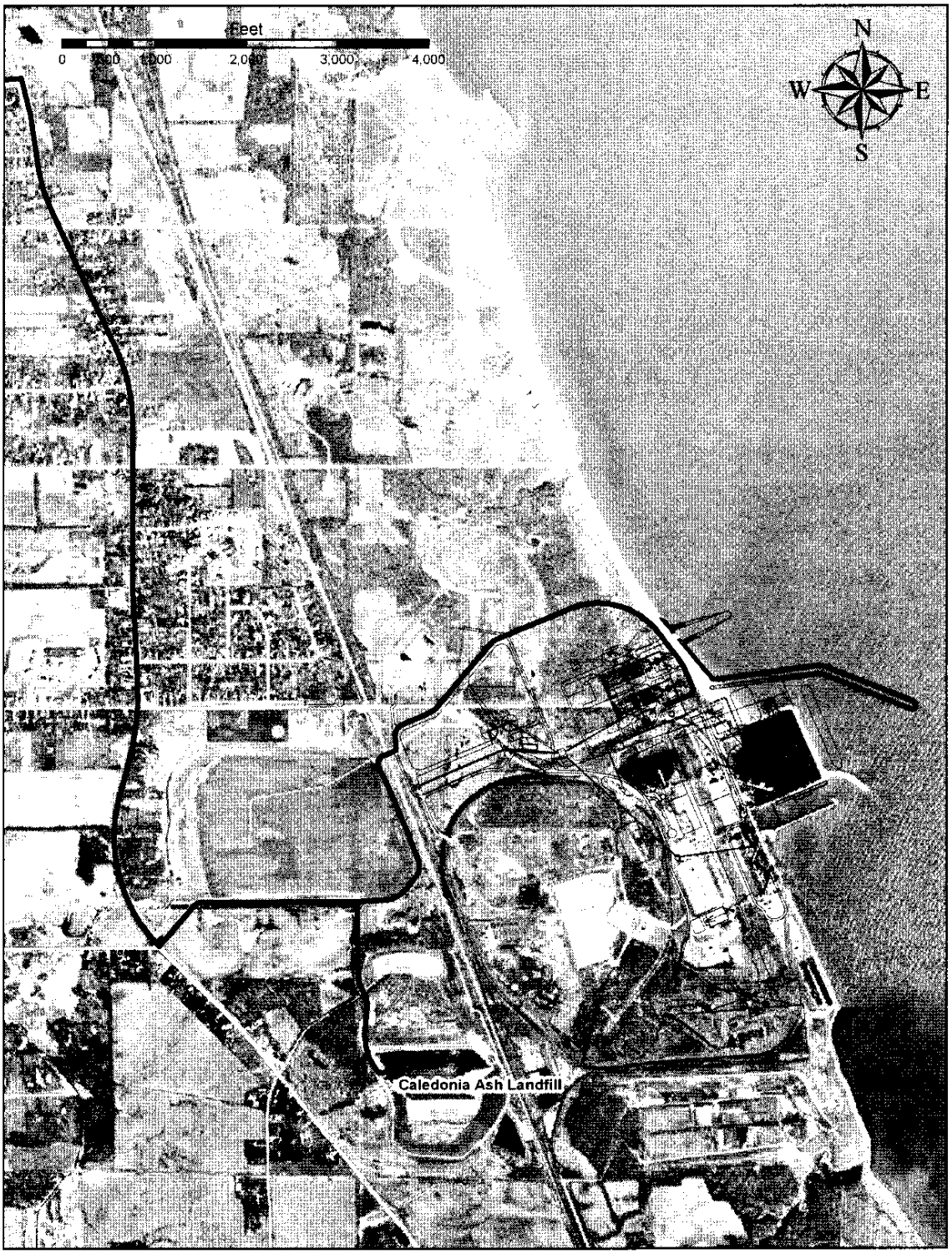


Figure 9-2 Existing OCPP facilities showing on-site ash hauling roads



The landfill was approved in 1978 for 12 cells with total design capacity of 1,999,950 cubic yards. The first cell was constructed in 1978. Ten cells have been constructed at this time. In 2002, 3,119 cubic yards of waste was disposed in the landfill. The remaining capacity as of January 1, 2003 was 685,062 cubic yards.

At the current rate of waste disposal, the site life is estimated to be 35 years.

Closed landfills

There are two closed landfills on the WEPCO's OCPP property. These landfills are called North Oak Creek and South Oak Creek. Closed landfills are not permitted to accept waste.

Early ash disposal areas

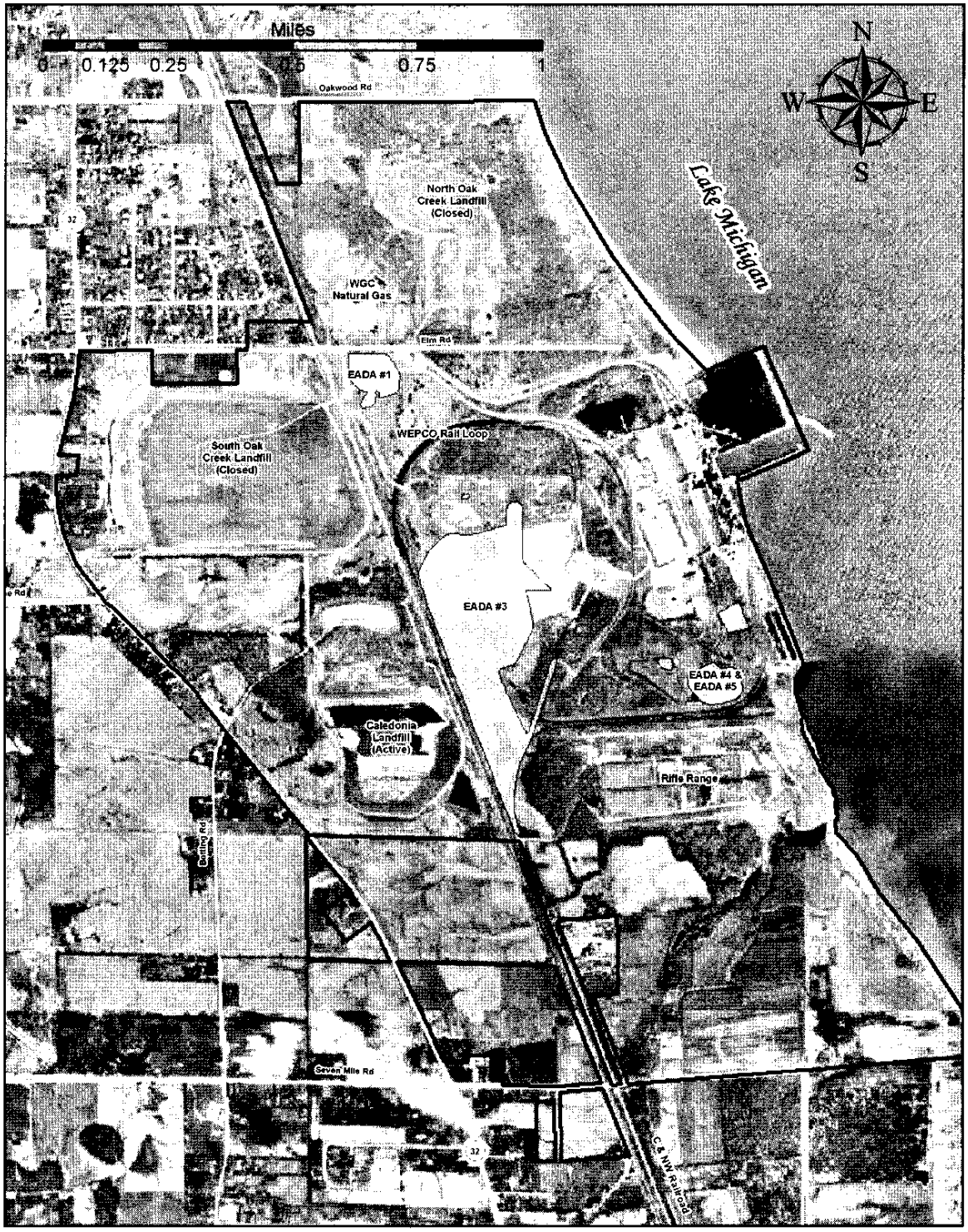
In addition to the two closed landfills and one open landfill, four early ash disposal areas (EADAs) were identified on the OCPP property. These are four places on-site where OCPP ash was buried in the early years of plant operation. Each area is of an irregular shape, and present locations are not completely precise. Figure 9-3 shows the approximate locations and extents of the EADAs located on the plant site currently.

EADA #1 is about 5.5 acres in size and is located just southwest of the present main gate to the Oak Creek plant, south of Elm Road. The ERGS bituminous coal pile is proposed for the area now covering this place.

EADA #3 is much larger, about 40 acres, and is located along the eastern side of the Union Pacific rail line, with its northern end extended eastward from the railroad tracks to the existing OCPP electric transmission switchyard. For the ERGS project, it is proposed as a soil stockpile location for the material excavated to build the ERGS units (refer to Chapters 10 and 11 for detailed information on soil stockpiling). The southern half of this EADA lies underneath what is now designated an Isolated Natural Resource Areas of woodland and wetland. Isolated Natural Resource Areas and Primaray Environmental Corridors are also described in Chapter 10. Some of this EADA also lies under the proposed location of new coal yard facilities and a relocated electric transmission switchyard, discussed as part of WEPCO's CUP Option in Chapter 12.

EADA #4 and EADA #5 are adjacent to each other in an area south of the existing South Oak Creek power plant units and just north of the shooting range property. Each of them is about 0.75 acre in size. They would be part of the excavated area if the South Site or the South Site XP options were approved by the Commission, and under the area projected for a wallboard plant if the North Site were approved. These EADAs would be qualified as waste sites when excavated and would have to be addressed as described below in the section on "Excavation Debris."

Figure 9-3 Locations of Early Ash Disposal Areas and current on-site landfills



Present methods of hauling ash

Ash is often "conditioned" by adding water to it so that it does not become airborne. If it is not conditioned, it must be put in an enclosed container for hauling. Ash is hauled to utilization outlets in covered quad axle and semi dump trucks when conditioned, and in bulk tankers when dry. The haul routes for the Caledonia, Highway 32, and P4 landfills are shown in Figure 9-2.

Present methods of re-use

WEPCO's existing plant currently creates two main by-products: fly ash (class C and F) and bottom ash. Class C fly ash is produced by newer boilers and has more calcium. It is used as a cementitious material and is very good for making concrete. Class F fly ash comes from older boilers and has less or no calcium and a high carbon content. It has little to no economic value at this time.

At this time, over 96 percent of these by-products are recycled. Class C fly ash is used as admixtures in concrete and soil stabilization beneath paved surfaces. Bottom ash is primarily used in construction, as sub-base below paved surfaces and beneath commercial buildings. Most of the high carbon Class F fly ash is utilized as a supplemental fuel at Pleasant Prairie Power Plant (see the discussion under "Fugitive Dust" in Chapter 11) or utilized for manufacturing Portland cement.

Reburning of existing landfill material

WEPCO also recently began excavating old landfills and reburning the material in the Pleasant Prairie Power Plant. These previously landfilled by-products were generated from old and inefficient boilers. WEPCO has realized that portions of these by-products still contain valuable fuel. By excavating and burning these by-products, it has also regained additional space in licensed/active landfills.

Expected Changes Due to Proposed Project

Projected volumes of by-products

SCPC units

Since WEPCO's two SCPC units would burn bituminous coal, the primary coal combustion by-products materials generated would include fly ash, bottom ash, and synthetic gypsum.

Fly ash and bottom ash

Table 9-1 illustrates the potential components of the ash by-products from the proposed ERGS SCPC units for both washed and unwashed coal. (Although WEPCO stated in its comments on the draft EIS that it intends to use washed coal for the new ERGS facilities, its air permit application for the South Site and the South Site-Exp is based on the use of unwashed coal.)

Based on the characteristics reported in Table 9-1, the use of washed coal, and an 85 percent capacity factor for the new SCPC units, WEPCO estimates that the amount of coal combustion by-products materials produced by each unit would be:

Fly ash	103,100 tons/year per unit
Bottom ash	25,800 tons/year per unit

Thus, a total of 206,200 tons per year of fly ash and 51,600 tons of bottom ash would be produced each year by the two SCPC units. Using the standards in Wis. Admin. Code § NR 520.15 (20) and a field capacity conversion factor of 1.2 tons/cubic yard, the respective volumes of the fly ash and bottom ash would be calculated at 171,899 cubic yards and 42,975 cubic yards. The total volume of fly ash and bottom ash together would be 214,874 cubic yards per year.

Table 9-1 Potential coal fuel sources and ash content

Fuel Analysis:	Units	Pittsburgh #8 Unwashed Bituminous	Pittsburgh #8 Washed Bituminous
Coal Ultimate Analysis			
Carbon	%	64.24	72.67
Sulfur	%	3.10	2.69
Oxygen	%	4.19	4.84
Hydrogen	%	4.13	4.89
Nitrogen	%	4.15	1.38
Chlorine	%	0.09	0.10
Ash	%	17.61	7.73
Moisture	%	5.50	5.71
Coal Proximate Analysis			
Moisture	%	5.50	5.71
Volatile Matter	%	32.55	35.73
Fixed Carbon	%	44.34	50.84
Ash	%	17.61	7.73
Gross (Higher) Heating Value	Btu/lb	11,500	13,100
Hardgrove Grindability	HGI	56	55
Coal Ash Analysis			
Silica	%	49.16	43.17
Ferric Oxide	%	15.55	21.17
Alumina	%	20.95	21.95
Titanic Oxide	%	0.84	0.93
Calcium Oxide	%	5.13	5.18
Magnesia	%	0.90	0.90
Sulfur Trioxide	%	3.18	4.28
Potassium Oxide	%	1.99	1.45
Sodium Oxide	%	0.65	1.06
Phosphorous Pentoxide	%	0.70	0.59
Undetermined	%	0.95	(0.68)
Total	%	100.0	100.0

Synthetic gypsum

As discussed in Chapters 6 and 7, the ERGS SCPC units would utilize limestone or organic-acid promoted limestone to control and reduce SO_2 emissions. The use of limestone versus organic-acid-promoted limestone would depend upon the fuel sulfur content. Synthetic gypsum by-product would be generated in

this operation regardless. WEPCO estimates that about 271,800 tons/year per unit[104] would be generated by each unit. The two proposed SCPC units would then create a total of 543,600 tons of gypsum per year.

IGCC unit

As discussed in Chapter 6, the proposed IGCC system would include: two or three oxygen blown, coal gasifiers; an air separation unit; a gas conditioning system for removing sulfur compounds and particulates; two combustions turbines with heat recovery steam generators; a steam turbine generator; and coal handling and preparation equipment. The primary by-products of this system would be slag and sulfuric acid.

Gasifier slag

The gasification process would result in the formation of about 100,000 tons/year of slag at the bottom of the gasifier.

Elemental sulfur and sulfuric acid

In the sulfur recovery plant, the sulfur-containing gases from the Acid Gas Removal (AGR) system would be converted to either elemental sulfur or sulfuric acid. Elemental sulfur and sulfuric acid production would be directly related to the sulfur content of the coal. Based on the proposed fuel, the sulfur content of the coal would yield about 33,200 tons/year of elemental sulfur. The quantity of sulfuric acid produced would amount to approximately 60,000 tons/year, or 62,400 gallons per day. This material may be considered hazardous waste.

Characterization of by-products

Fly ash and bottom ash

WEPCO is expected to submit the actual fly ash and bottom ash chemical and physical characterizations for DNR review as soon as the proposed SCPC units are operational. The SCPC units would use sophisticated air pollution units that remove more pollutants from the air discharge. Consequently, the removed pollutants would end up in the solid waste. Since these by-products would be much different than the currently available fly ash and bottom ash, any predication on how the ash would be recycled and how much ash could be recycled is premature.

Gypsum

WEPCO is expected to submit the actual gypsum chemical and physical characterizations for DNR review as soon as the SCPC units are commercially operational. Synthetic gypsum would be a new by-product for WEPCO. The pollution control equipment on the existing OCPP units 5 - 8 does not generate it. WEPCO has expressed confidence that this material could be used in a wall board plant, as discussed near the end of this chapter.

Gasifier slag

This material is not expected to be generated until the year 2011. Its true chemical and physical characterization, therefore, is not available at this time. The full recycling potential of gasifier slag would not be known until after its production and characterization. It would probably require some processing for

[104] This amount is based on the use of Pittsburgh #8 washed bituminous coal.

economic use. Based on the IGCC design and the operations of existing IGCC plants, the slag is expected to be an inert, vitreous (glass-like) material as described in Chapter 6.

Elemental sulfur and sulfuric acid

These materials are now commercially produced and available. The materials produced by the IGCC would be very similar to the material now being sold commercially. The characteristics of this by-product are better known than those of the other expected by-products. These by-products may be classified as hazardous waste. If it is determined to be hazardous waste, an exemption under hazardous waste rule would be required for beneficial use.

Storage and Handling of Construction and Operation By-Products

Fly ash

Fly ash collected in the fabric filter hoppers and the air heater hoppers (see Figures Vol. 2-1 to 2-3) would be conveyed to the fly ash storage silo via a pneumatic transport system using low-pressure air from a blower. The fly ash would be discharged through a wet or dry unloader and conveyed through a telescopic unloading chute into a truck for disposal or utilization.

Bottom ash

Bottom ash from the boiler would be collected and transported on a submerged scraper conveyor and dewatered. The ash would then be collected in a dump truck and hauled to a storage pad on site (see Figures Vol. 2-1 to 2-3). The ash collected on the storage pad could be loaded into a truck using a front-end loader. It could then be taken to a landfill or recycled as permit allows.

Gypsum

A gypsum (calcium sulfate, or $CaSO_4$) slurry would be produced by the injection of oxygen into the calcium sulfite produced in the absorbed reaction tank (See discussion in Chapter 6.) The gypsum slurry, at approximately 15 percent solids, would be pumped to dewatering equipment. Dewatering of the gypsum slurry would be accomplished in two stages. The first stage (primary dewatering) would be accomplished using hydroclones, which would use centrifugal force to concentrate the slurry. Underflow from the hydroclones, which would typically have 35 to 50 percent solids, would be sent to vacuum filters for secondary dewatering. Overflow from the hydroclones, which would have 3 to 5 percent solids, would be returned to the absorbers.

Secondary dewatering would involve vacuum filters. Either rotary drum or horizontal belt filters might be utilized, depending on the end user's requirements for the gypsum. The vacuum filters would reduce the gypsum filter cake moisture content to 10 percent or less.

A belt conveyor system would transport the gypsum from the vacuum filters in the dewatering building to an adjacent storage shed. In its air permit, WEPCO has proposed a storage shed that could contain three days of gypsum by-product. The storage would be provided to allow a wallboard manufacturing plant to continue production during periods of equipment-related power plant outages. The wallboard plant would not be a WEPCO facility; it is described in more detail near the end of this chapter. Sites for a wallboard plant, however, have been designated by WEPCO in each alternative plant layout (see Figures Vol. 2-1 to 2-3) and therefore have been considered in the cumulative environmental impact assessment of this project.

The current licensed landfill at the OCPP (Caledonia Landfill) is not permitted by the DNR to accept gypsum. WEPCO must contract with commercial landfills for gypsum disposal until a wallboard plant is available to accept it or until existing WEPCO landfill permit modifications could be sought and approved.

Gasifier slag

Slag produced in the IGCC process is a vitrified product with glass-like properties. It would be removed from the bottom of the gasifier and transferred to a holding tank. The tank would be dewatered, and the material would be removed and transferred to on-site storage.

Elemental sulfur or sulfuric acid

Either elemental sulfur or liquid sulfuric acid would be produced as part of the AGR process for the IGCC unit. WEPCO proposes an on-site, three-day storage for liquid sulfuric acid. Based on production of 62,400 gallons of sulfuric acid per day; a bulk liquid storage of 200,000 gallons would be needed.

WEPCO has stated its intention to haul 30 truckloads (at 3,000 gallons per truckload) per day from the power plant on a Monday through Friday basis. Rail cars hold a capacity of 10,000 to 11,000 gallons and could be considered for longer distance shipments. This sulfuric acid may be classified as a hazardous material. The storage and transportation of this solution would be regulated as a hazardous material like conventionally manufactured sulfuric acid.

Excavation debris

As discussed in Chapter 10, extensive site work (excavation, grading, and relocation of soils) would be needed during the construction of the ERGS to reshape the bluffs and create a relatively flat site to build the new power plant units.

If the excavation material were to be all clean soil, brick, concrete, and similar materials, the excavation and disposal could be done without additional regulation. However, past studies indicate that ash and other solid waste materials were buried on the OCPP property before they were regulated. Some of these unregulated disposal sites are known to WEPCO staff, and some are yet to be identified. These sites or EADAs are described in an earlier section of this chapter.

When a waste site or a contaminated site is encountered during construction, a site remediation is needed before construction on that location can continue. The DNR must be notified and a remediation plan must be submitted for the DNR approval. It is anticipated that approximately two million cubic yards of material

would have to be managed either on site or off site during the construction. WEPCO would need to develop a comprehensive material handling plan to manage the excavated material. The plan, to be submitted to the DNR for approval, would have to include soil and waste characterization, temporary storage information, off-site transportation, and other items.

WEPCO has stated its intention to use most of the materials on site for alterations at the two closed landfills. These activities are explained later in this chapter.

Structure demolition debris

If the North Site were approved WEPCO would demolish the former North Oak Creek Power Plant buildings to make room for the proposed IGCC plant. An environmental assessment of the buildings would be needed first to determine clean-ups that would be required before demolition could begin. WEPCO would need to work with the DNR during every step of the demolition process. It would be required to recycle as much of the building material as possible.

Dredged materials from Lake Michigan

Dredging activities necessary for construction in Lake Michigan are discussed in Chapter 8. Decisions would need to be reached on specific dredging techniques and on the ultimate disposal options for the dredged material before a Wis. Stat. ch. 30 dredging permit could be issued. WEPCO is discussing four methods of dredge material disposal:

- Landfilling the dredge spoils on WEPCO property.
- Landfilling the material off site in a licensed landfill.
- Using the spoils on site as construction fill.
- Using the spoils as beach nourishment.

DNR believes that a combination of these disposal options would be applicable, depending on the results of recent and future sediment sampling and characterization activities. However, dredged material is considered solid waste in Wisconsin. Under Wis. Admin. Code ch. NR 500, solid waste may be disposed of only in an approved landfill. Since WEPCO intends to deposit dredge materials in other places in addition to landfills, the company would also need an official DNR exemption from the requirements of NR 500.

Changes in hauling methods and timing

WEPCO does not anticipate any substantial changes in the hauling methods or routes for solid waste from the new facilities if the North or South Sites are used as proposed in the CPCN application. However, use of the North Site under the CUP Option negotiated between WEPCO and the city of Oak Creek in May 2003, would alter the ash haul routes on the OCPP property. The relocated ash haul roads are shown and discussed in Chapter 12.

Regardless of the site or plant layout selected, there would be an increase in truck traffic for transportation of ashes and other by-products from the ERGS to other WEPCO-owned landfills, if the Caledonia Landfill capacity is exhausted. There would also be a great increase in hauling traffic during construction for the

dredged and excavated materials that would be deposited on the OCPP site. The impacts related to noise and traffic associated with moving dredged and excavated materials to the deposit site are described in Chapter 10. Figures Volume 2-1 to 2-3 shows the expected locations for the deposit of dredged and excavated materials.

Impacts on operating landfills

Disposal in local landfills

As discussed at the beginning of this chapter, WEPCO operates three licensed landfills in the southeast region. The three active landfills are not near capacity and are expected to remain operational for many years. As noted above, the SCPC units are expected to generate 257,800 tons/year (128,900 tons per unit per year).

Need for changes in landfill operating plans or licenses

WEPCO is required to submit plan modifications to the DNR for any of the landfills they plan to use for disposal of newly generated by-products. WEPCO may also be required to update the design of these landfills to provide better protection for the groundwater.

Impacts on existing closed landfills

WEPCO has closed several landfills in southeast Wisconsin over the past years. The two closed ash landfills on the OCPP property, Oak Creek North and Oak Creek South, are not permitted to accept waste. WEPCO is responsible for monitoring these landfills and making sure that they do not adversely impact the environment. There would be changes to both of these landfills if the ERGS project is approved. These changes are explained below and can be seen in Figures Volume 2-1 to 2-3.

Oak Creek North (OCN)

Existing conditions

The OCN landfill was originally opened in the mid-1960s and has been covered and closed for more than 20 years. The operating license for the OCN landfill was allowed to expire in 1988. The landfill covers 40 acres and contains 1,000,000 cubic yards of ash. The landfill top is relatively flat with 2:1 side slopes.

This is not an engineered landfill, and it does not meet current landfill design standards. The flat top and the lack of a liner have resulted in several adverse environmental impacts. Rainwater has entered the landfill from the top and has built up in the waste. Leachate (liquid that has come in contact with the waste) has been leaving the toe of the landfill to the east and southwest of the landfill slope. There is no existing leachate collection system at these locations, so leachate has been entering several wetlands around the landfill. In addition, leachate appears to be entering the groundwater. Concentrations of boron exceeding the groundwater standards have been detected in the monitoring wells outside of the landfill.

WEPCO plans for the landfill

Current plans for the ERGS project include the construction of access roads and temporary parking facilities over the majority of the footprint of the OCN landfill. In addition, a significant amount of fill generated by

the excavation for the construction of the two SCPC units would occur in the OCN area. Proposed modifications to the OCN landfill would be in two phases:

Phase I – Ash would be removed and relocated from the south section to the north section of the landfill to accommodate construction of a truck access road in the southeast corner of the existing area.

Phase II – Fill would be placed and temporary parking facilities would be constructed. These actions would also result in changes in surface drainage off of the landfill. See the discussion in Chapter 8 on stormwater discharge. Long-term plans for the OCN site include source removal for use as a supplemental fuel in the proposed generating units.

Environmental monitoring

Although OCN is closed and no longer accepts solid wastes under the closure license approval, it is being monitored to ensure ground and surface waters of the state are protected. The original monitoring system includes a total of nine piezometers (Figure 9-4). Of the nine piezometers, six were located within ash disposal areas. The groundwater monitoring system was evaluted in the early 90's and upgraded. At the present time, there are four monitoring wells and a nest of wells located outside of ash areas. There are also two leachate head wells.

The data collected from the monitoring wells indicates that the groundwater is flowing mainly to the northwest and partially to the east toward Lake Michigan. A horizontal gradient of 0.05 ft/ft was calculated between well B29A and Lake Michigan. WEPCO has been monitoring the groundwater for many years. Analysis of groundwater samples taken from well MW33 showed elevated concentrations of ash parameters boron and sulfate (see Figures 9-5 and 9-6).

Figure 9-4 Oak Creek North Landfill with mapped groundwater monitoring peizometers and leachate head wells

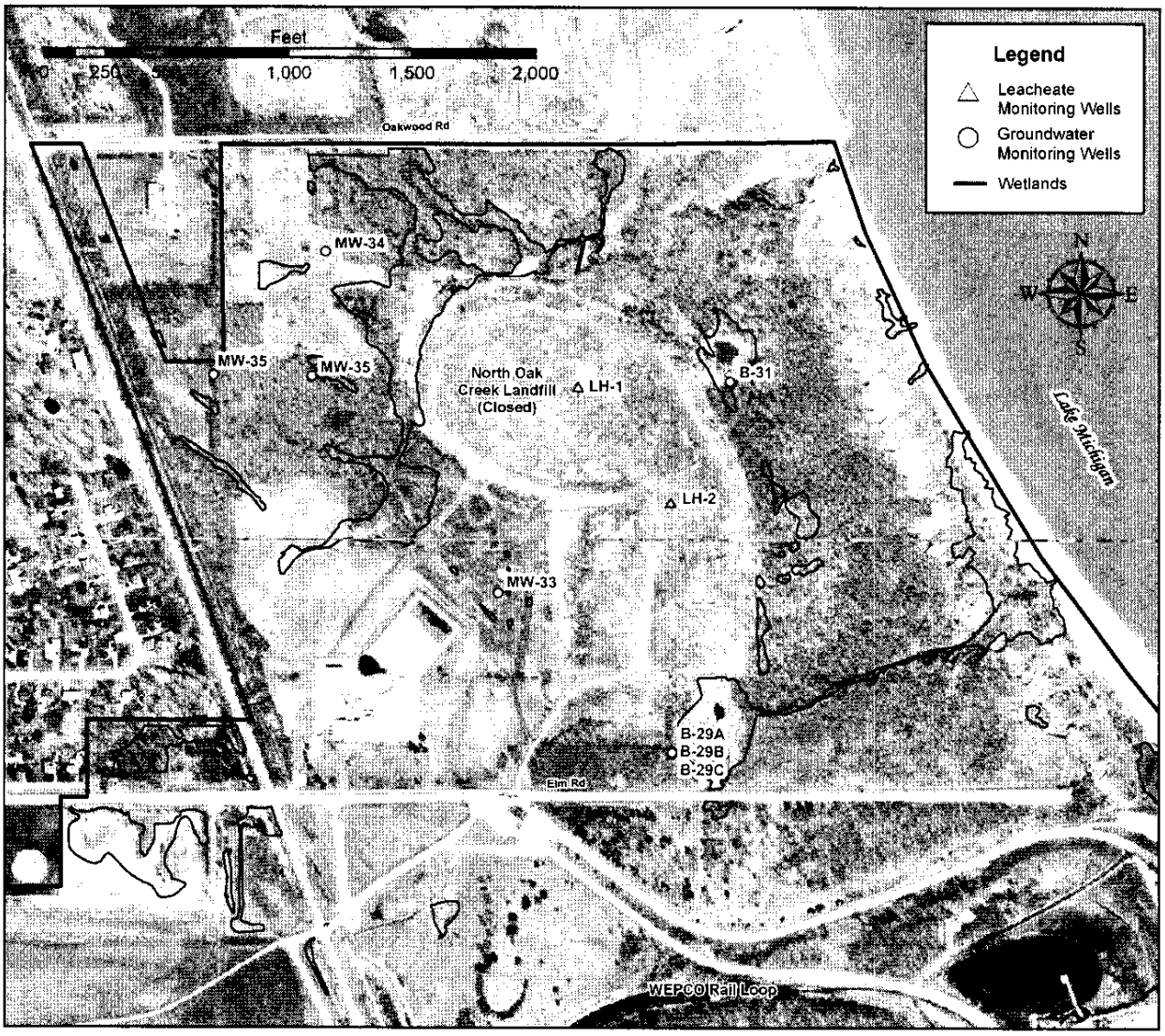


Figure 9-5 Boron concentrations at MW33 in mg/liter between 1994 and 2003

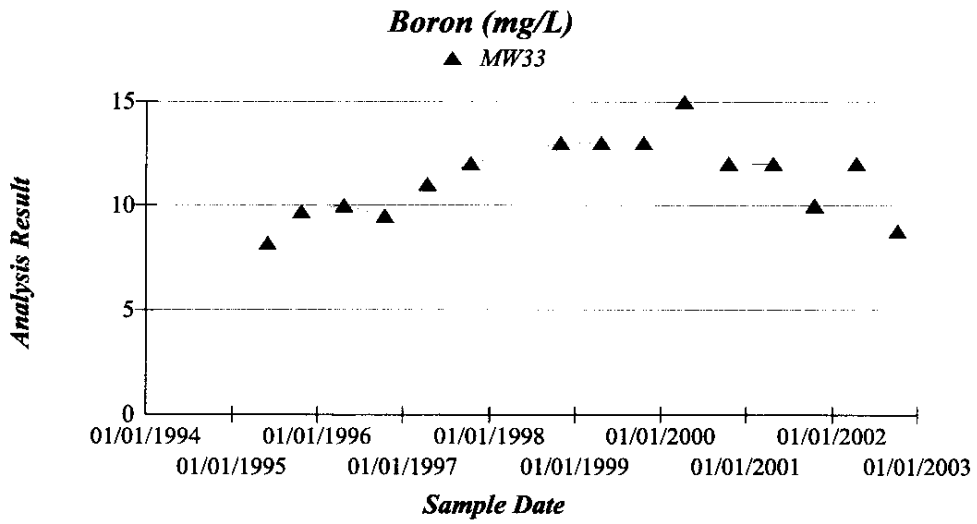
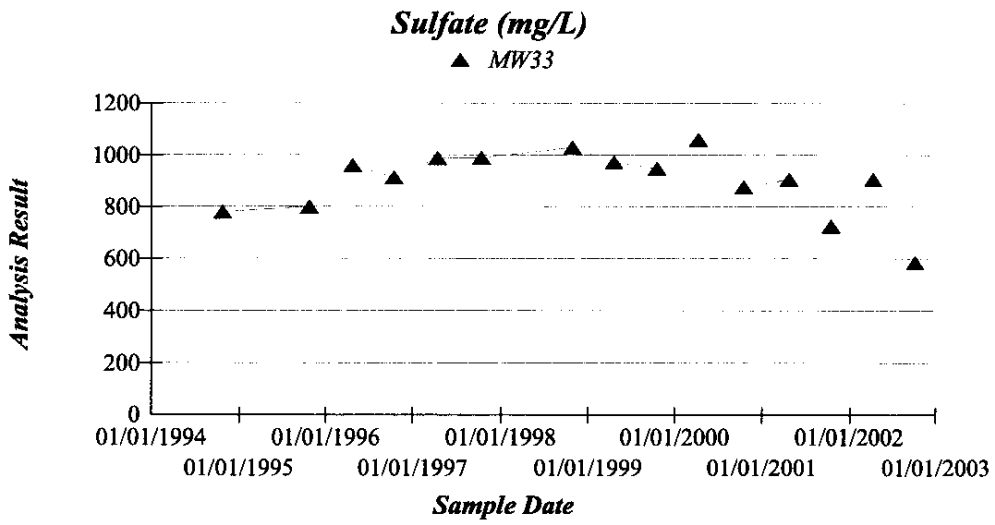


Figure 9-6 Sulfate concentrations at MW33 in mg/liter between 1994 and 2003



Data also show exceedance of boron in monitoring well B-31. The two monitoring wells located northwest of the landfill have shown no impacts from the ash landfill based on current groundwater monitoring.

The DNR would require additional groundwater monitoring in response to changes proposed in the ERGS project. The additional monitoring would determine if the construction activities at this property are having adverse impacts on the groundwater and help determine what steps needs to be taken to correct them.

Oak Creek South (OCS)

Coal combustion by-products generated by the OCPP were disposed of at the OCS beginning in 1974 when it was licensed until it reached its capacity in May 1992 and was covered. The OCS landfill covers 80 acres and contains 3,760,000 cubic yards of ash. Cover improvements were made primarily on the north and west slopes in 1995 in substantial conformance with the 1974 Plan of Operation for the site and Wis. Admin. Code ch. NR 506. The final cover consists of a minimum of two feet of fine-grained soil covered by six inches of seeded, fertilized and mulched topsoil. In 1999, a leachate collection system was installed near the toe of the west slope.

As discussed in Chapters 10 and 11, construction of the ERGS would require excavation of a significant amount of native soil for construction of the new power plant units and other features. The proposed modifications to the OCS landfill involve:

- Placement of soil on the top. Fill would be placed at a minimum thickness of eight feet over the cover of the OCS.
- Compaction and grading of the newly placed soil to prepare a construction laydown area. Following the relocation of soil, predominantly clay in composition, from the ERGS excavation areas to the top of the OCS, a construction laydown area would be placed as the final surface.
- Construction of access roads and development of short- and long-term stormwater management facilities.

Remediations

- Several remedial activities may be needed during or after completion of construction of the ERGS facilities.
- EADA - Disturbances near or in the areas of the early ash disposal areas would require full investigation of these areas. WEPCO would be required to submit remedial plans in accordance with Wis. Admin. Code ch. NR 700.
- Unidentified contaminants - The construction of the ERGS would require disturbance of a large portion of the OCPP property. If contractors encountered any contaminants, WEPCO would be responsible to document and prepare a remedial action plan to clean up the contaminants before any work could continue in that area.
- Landfills - There are two closed landfills located on the OCPP property. These landfills have impacted the local groundwater. WEPCO is proposing to use these landfills for either soil storage or other construction activities. WEPCO would be required to upgrade the groundwater monitoring system for these landfills and propose remedial action to improve the groundwater quality.
- Shooting range - Disturbance of the parcel used for a shooting range would require full investigation of environmental impacts on these areas. WEPCO would be required to submit remedial plans for lead and other pollutants of concern in accordance with NR 700.

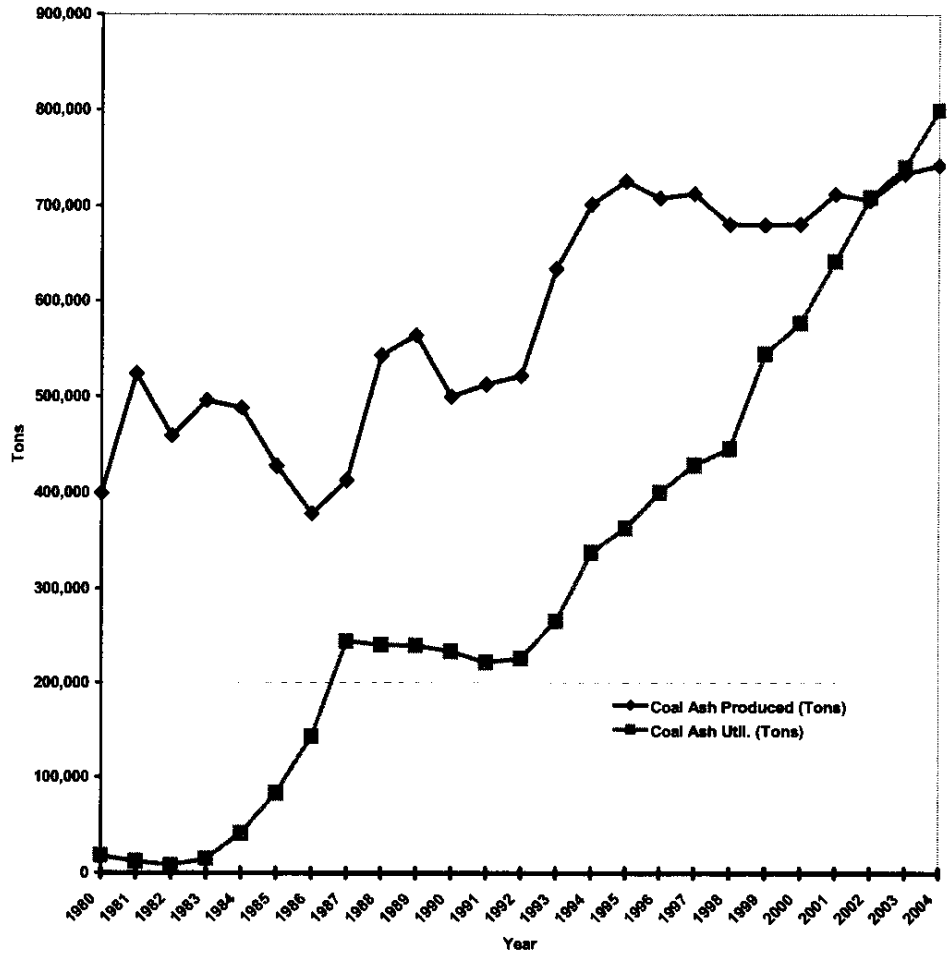
Beneficial Re-use

Ash

WEPCO has a beneficial ash re-use program in place. Companies have been working with WEPCO since 1980 to market fly ash and bottom ash from WEPCO's existing coal-fired plants. Since 1980, re-use of the ash has increased until about 96 percent of the by-products from its power plants are now beneficially used. Figure 9-7 illustrates this increase and WEPCO's hope to utilize more than it produces after 2003. WEPCO is now proposing, based on past experience and recent contacts with by-product marketers, to increase utilization of the ERGS by-products from zero percent to full utilization within 10 years on a straight line basis from the start of commercial operation of these new generating units.

Bottom ash is now being utilized as base or sub-base material for building floors and foundations, paved roads, and parking lots. Fly ash is now being utilized in cements as a raw feed material for portland cement production, soil stabilization, cold in-place recycling of asphalt pavements in controlled low-strength materials, and as a supplemental fuel.

Figure 9-7 **WEPCO coal combustion by-product (ash) production and utilization, in tons, between 1980 and 2002 and projected to 2004**



Although the ash re-use companies' projections are more optimistic, WEPCO projects full utilization of ashes within ten years of each unit's commissioning. WEPCO's projections are illustrated in Table 9-2 for the ashes and slag. Even with these projections, WEPCO assumes that the market for recycling of ash and slag will grow and remain available to handle the ERGS waste. It also assumes that all synthetic gypsum would go to wallboard production and all sulfur or sulfuric acid would be utilized for commercial uses from the time when it is initially produced.

WEPCO has approached marketers for their projections on reaching full utilization of the fly ash and bottom ash and has received optimistic replies (these are filed at the PSC as part of WEPCO's CPCN application). A.W. Oakes & Son of Racine, Wisconsin has indicated that it could utilize 100 percent of the bottom ash within two years of the commissioning of each unit. Mineral Solutions, Incorporated has indicated that it could utilize 100 percent of the fly ash within three years of the commissioning of each unit. This would require working to expand the market for Class F fly ash. Class F fly ash can be used to produce high performance concrete if it meets ASTM standards and has consistent quality from a base load power plant. WEPCO's current sources of Class F fly ash have high carbon content and thus are not suitable for use in concrete.

Table 9-2 WEPCO's projected annual coal ash and slag quantities for landfill between 2007 and 2021, in tons[105]

Year	SCPC Unit 1		SCPC Unit 2		IGCC	Total
	Fly ash	Bottom ash	Fly ash	Bottom ash	Slag	
2007	103,100	25,800	0	0	0	128,900
2008	92,790	23,220	0	0	0	116,010
2009	82,480	20,640	103,100	25,800	0	232,020
2010	72,170	18,060	92,790	23,220	0	206,240
2011	61,860	15,840	82,460	20,640	100,000	280,800
2012	51,550	12,900	72,170	18,060	90,000	244,680
2013	41,240	10,320	61,860	15,840	80,000	209,260
2014	30,930	7,740	51,550	12,900	70,000	173,120
2015	20,620	5,160	41,240	10,320	60,000	137,340
2016	10,310	2,580	30,930	7,740	50,000	101,560
2017	0	0	20,620	5,160	40,000	65,780
2018	0	0	10,310	2,580	30,000	42,890
2019	0	0	0	0	20,000	20,000
2020	0	0	0	0	10,000	10,000
2021	0	0	0	0	0	0
Total	567,050	142,260	567,030	142,260	550,000	1,968,6-0

Gypsum

WEPCO has approached several companies on its projections for reaching full utilization of the synthetic gypsum from the SCPC units and has received favorable replies. The synthetic gypsum produced by the wet scrubbers in the SCPC units could be used to manufacture wallboard (also called "drywall" or "sheet rock"). WEPCO indicates that wallboard producers would be competing for the ability to build a manufacturing

[105] Using the Wis. Admin. Code § NR 520.15 (2) standard in-field conversion factor of 1.2 tons per cubic yard would yield a landfill volume requirement of 1,390,527 cubic yards.

plant near the ERGS plant. LaFarge Gypsum, for example, has indicated that it could utilize 100 percent of the gypsum from the ERGS SPCC units within one year of each unit's commissioning.

Ideally, there would be enough gypsum produced that it could be conveyed to a dedicated commercial wallboard plant located on or near the power plant property. Example locations of such a plant are shown in the plant layouts for each site option in Figures Volume 2-1 to 2-3. WEPCO has indicated that a company interested in building a wallboard plant could build it on the ERGS site. The commercial wallboard plant would likely be about 500 feet wide and 2,000 feet long, and would use up about 100 acres of the property if the storage shed were included.

If smaller quantities of gypsum are produced, they could be transported to existing wallboard producers to supplement their natural gypsum supplies. Nearby, in Waukegan, Illinois, is the National Gypsum plant which currently uses natural gypsum. It could also take the synthetic gypsum.

Gasifier slag

WEPCO has approached Mineral Solutions, Incorporated on its projections for reaching full utilization of the gasifier slag from bituminous coal, and has received a favorable reply. Full utilization could occur within two or three years of the commissioning of the IGCC unit. Slag produced in the IGCC process would be a vitrified, glass-like product. It could be used potentially for roof shingles, blasting grit, chip seal material for roads and parking lots, or as an alternative sand, gravel, or crushed stone for pavements, parking lots, or foundation bases. WEPCO's projection for full utilization is illustrated in Table 9-2.

Sulfur or sulfuric acid

WEPCO has approached several companies on its projections for reaching full utilization of the sulfur or sulfuric acid produced by the AGR process, and has received favorable replies. The market for sulfuric acid appears to be better at this time than the market for elemental sulfur. The area around Chicago, Illinois, for instance, has become an import market for sulfuric acid. WEPCO predicts that the sulfuric acid from the proposed IGCC unit could be marketed within southeast Wisconsin, northeast Illinois, and northwest Indiana.

New landfills

WEPCO might not be able to dispose of all the by-products that are generated in its own landfills. If it could not, outside disposal would have to be considered.

WEPCO is not proposing new landfills at this time. However, if the recycling projections turn out to be too optimistic, additional landfill spaces could be needed.

10

Chapter 10 - Land Resources

Introduction

This chapter focuses on WEPCO's property and potential impacts on the natural resources that are part of its landscape.

The chapter consists of six main sections, beginning with a description of the existing environment on WEPCO's property, followed by a discussion of the potential impacts on the OCPP property in general. Then, three sections follow describing potential impacts for the North Site, the South Site, and the South Site Exp. The last section discusses the railroad corridor. A description of the potential impacts of the CUP Option are included in Chapter 12.

The landscape on WEPCO's property is biologically significant, serving an important role in the plant and wildlife ecological systems along that section of Lake Michigan shoreline. Interspersed with the existing power plant facilities is a diversity of habitats and environments. Lake Michigan bluffs extend 80 to 100 feet above the shoreline. Ravines carved out by streams flow into Lake Michigan, draining the OCPP property, other properties, and farmlands to the west. Habitats represented within the property include old farm fields, woodlands, wetlands, riparian areas, lakeshores, beaches, bluffs, and grasslands. Areas within WEPCO's property range in type from tracts of land with minimal human disturbance to former landfills, now serving as important habitat for grassland birds. These lands are home to numerous plant communities, mammals, reptiles, amphibians, and wintering and migrating birds. Though no federally protected species were found within the project area, several state endangered/threatened species are documented.

Despite the fact that no virgin forest areas exist on WEPCO's property and that many areas have experienced some degree of disturbance from past and current land use, the property has continued to contain significant habitat for numerous species. Two large blocks of habitat, designated by the Southeastern Wisconsin Regional Planning Commission (SEWRPC) as primary environmental corridors (PECs), have been fragmented to some extent by the existing power plant. PECs are complex ecosystems that link blocks of environmentally sensitive habitats providing protection for migrating and breeding wildlife. These natural resources are part of the larger PECs that extend along the Lake Michigan shoreline to the north and south. They include uplands, wetlands, fields, and forested habitats, and they surround the streams that cut inland beyond the shoreline. SEWRPC-designated Critical Species Habitats (CSHs) are environments that provide long-term support of state-listed rare, threatened, and/or endangered species. The northern PECs contains three Critical Species Habitat areas. The southern PEC contains the SEWRPC-designated Ravine Woods

Natural Area, a biological and environmental resource of local significance that contains intact native plant and animal communities.

Outside of the PEC areas, SEWRPC has identified a total of six Isolated Natural Resource Areas (INRAs) which contain four additional CSHs. INRAs are defined by SEWRPC as areas between five and 100 acres in size and at least 200 feet wide. They contain some key environmental features but are not connected to the larger environmentally significant blocks. The designated INRAs on WEPCO's property are important because of the quality of plant communities and the habitat they provide for state endangered/threatened species. One of the property's more significant INRAs is the large wooded parcel located inside the northern edge of the existing rail track. It is designated as both an INRA and a CSH because the train tracks physically separate it from the other environmental corridors and it contains state-protected species. A part of this woodland is dominated by large beech trees (with diameters more than 30 inches) and a well-developed understory of diverse woodland flora.

Later in this chapter, the PECs, CSHs, INRAs, and other notable biological areas are discussed in more detail.

The first sections of this chapter describe the topography, geology, vegetation, wildlife, and archeology of the OCPP/ERGS property. This is followed by an analysis of the potential impacts of the proposed ERGS on those same property characteristics.

Existing Environment - WEPCO's Property

Topography

The proposed sites for the ERGS are all within the Eastern Ridges and Lowlands Geographical Province of the state.[106] Surface topography depends on the occurrences and types of glacial till that overlies the bedrock in the area. Elevations in the region range from 580 feet above mean sea level (msl) at Lake Michigan to 1,280 feet msl in Washington County. Bluffs are commonly developed along the Lake Michigan shoreline.

Natural erosion of the bluffs occurs on this side of Lake Michigan. The underlying cause of bluff erosion is erosion of the toe of the bluff and the near shore lake bed caused by the action of waves on Lake Michigan. The surface erosion on the face of the bluffs occurs because the soil slopes above respond to the erosion stress below at the toe of the bluff. This is compounded by surface and groundwater flow on the bluff. If the underlying retreat of the toe of the bluff is halted, the bluff erosion eventually reaches a naturally stable rate and the slope and configuration come into dynamic equilibrium with the forces of erosion. As the bluff slope stabilizes, a process of natural re-vegetation occurs. Naturally stabilized and vegetated bluffs can be found in many locations along the lakefront where toe erosion has been stopped or is not currently a factor. Milwaukee County is utilizing this natural process for the southern portion of Bender Park, just north of the OCPP property.

The land designated for the SCPC units at both the North and South sites would be primarily on what is currently a bluff about 100 feet above the Lake Michigan shore. The shore is at about 580 to 590 feet above

[106] Martin, Lawrence. *The Physical Geography of Wisconsin.* University of Wisconsin Press, Madison.

msl. The first 100 to 350 feet of land west of the lakeshore along the length of WEPCO's property is relatively flat and about 20 feet above lake level. Westward from there, the land climbs the bluff that is parallel to the lakeshore. Elevations above the bluff are about 700 feet above msl in the areas of the proposed sites. Existing topography of the WEPCO property is shown in Figure Vol. 2-12.

South and west of the operating South OCPP, the bluff has less relief, rising from about 610 to about 670 feet above msl. From there westward, the increase in elevation is more gradual to the switchyard, rail tracks, and coal unloading facilities.

Two large ravines extend from the bluff top to the lakeshore. The northern one contains the existing OCPP access road. The other ravine, located south of the existing shooting range property, is the Ravine Woods Natural Area, discussed later in this chapter. No new construction is planned for this area.

A berm about 50 feet high has been built between WEPCO's property and the current shooting range. At the lake side, it slopes all the way to the shore, a drop of about 130 feet over a distance of about 350 feet.

Three landfills create another set of prominent topographical features. The North Oak Creek Landfill is now closed and appears north of Elm Road as a flat-topped pad of grassy land about ten feet or more above surrounding woodlands and wetlands. The South Oak Creek Landfill is also closed and appears as a larger flat-topped pad south of Elm Road, about 50 feet above the surrounding grade at its highest point. The top of this landfill is at about 740 feet above msl. The Caledonia Landfill is currently operating south of the South Oak Creek Landfill with some land built up beyond 700 feet above msl.

Geology

Rock

Regional geology on the property consists of unconsolidated quaternary glacial deposits over gently sloping, sedimentary bedrock layers. The glacial deposits are quite thick, as discussed below. The bedrock formations lie on the western side of a large structural basin (the Michigan Basin) and slope to the east at approximately 10 to 15 feet per mile. The uppermost bedrock formation is the Silurian Niagara Dolomite. The aquifer in this dolomite is the major source of drinking water for domestic wells in the area. The formation varies in thickness because of variations in erosion of its upper surface, but overall it is relatively thin beneath the project sites (about 75 to 100 feet thick). Below the Niagara Dolomite is the Ordovician Maquoketa Shale, a 200-foot thick dolomitic shale layer that acts as an "aquitard" between the Niagara aquifer and the deeper sandstone aquifers. An aquitard slows the movement of water between surrounding aquifers. The sandstone layers under the aquitard are the St. Peters Sandstone, the Fanconia and Galesville sandstones, and the Mount Simon Sandstone. The aquifer in these Ordovician-Cambrian sandstones is often tapped for industrial and public water supplies.

Glacial till

Glacial drifts overlie most of southeastern Wisconsin. These deposits consist primarily of unsorted glacial till, deposited as ground and end moraines, and of sorted and stratified outwash and glacial lake deposits. Ground moraine covers much of the region and is composed primarily of clayey, silty till with deposits of stratified sand and gravel. End moraines, consisting primarily of till, form discontinuous bands of hills

paralleling Lake Michigan. This series of end moraines are collectively known as the Lake Border Morainic System.

Glacial lake deposits of clay, silt, and sand deposits occur along the shores of Lake Michigan and in the depressions between end moraines. The glacial deposits of the Oak Creek Formation consist of fine-grained calcareous till and are believed to be derived from sediments scoured from the glacial Lake Milwaukee basin. This formation is approximately 200 feet thick and may include sand seams within the finer silt-clay matrix. The mineral illite accounts for more than 70 percent of the clay-sized fraction. The Oak Creek till contains characteristic shale pebbles apparently derived from erosion of the Maquoketa shale in what is now the Lake Michigan basin.

Soils

Major soils series

There are two main soil series in the vicinity of each ERGS site option: the Morley silt loam covers about 90 percent of the OCPP property, and the Blount silt loam covers a smaller portion. Both appear to be series that could include wetlands.

Soils in the Morley series are well-drained silty soils over calcareous silty clay loam glacial till. The surface layer is about four inches thick and dark grayish-brown silt loam. The subsurface layer is brown silt loam also about four inches thick. The subsoil is about 20 inches thick. The Morley soils have moderately slow permeability and high available water capacity. The groundwater is less than five feet below the surface in wet periods. Runoff is medium and the hazard for erosion is slight. Slopes range from 2 to 12 percent. The Morley soils generally occur with somewhat poorly drained Blount soils.

Soils in the Blount series are somewhat poorly drained and nearly level. The soils have formed in a thin layer of silt and in calcareous silty clay loam glacial till. The surface layer is about three inches thick, a very dark grayish-brown silt loam. The subsurface layer is about five inches thick and is brown silt loam. The subsoil is about 26 inches thick. The Blount soils have moderately slow permeability and high available water capacity. Groundwater is less than three feet below the surface in wet periods. Runoff is slow and erosion is not a hazard. Slopes range from 1 to 3 percent.

Shooting range property

Because this property is not owned by WEPCO, but is part of one of the proposed sites (South Site-Exp) described in the application, it is covered in all discussions related to how the property appears currently and how it would be affected by construction of the ERGS facilities on the South Site-Exp option.

The shooting range property is a target range consisting of a relatively flat area at the top of the lakeshore bluff, sloping approximately 1.5 percent to the southeast, with three berms up to 60 feet in height built on its north, east, and south borders. The eastern berm is located immediately above the natural coastline bluff. The other two, smaller, berms extend east to west through the middle of the target range.

The target range was constructed in the 1940s for weekend National Guard and Army unit training. At that time, the Oak Creek and Caledonia area was relatively unpopulated. Consequently, the range was not constructed with safety berms. Safety berms were determined necessary when the area became more populated and the firing distance of the weapons lengthened. In 1964, the WEPCO reached an agreement

with the National Guard to construct berms and bunkers of compacted fly ash on the north, east, and south sides of the property. The berms were covered with approximately two feet of soil for vegetation growth and seeded in 1972. Low areas on the site were also filled with ash, and drainage ditches and culverts were installed to drain surface water in the area. In all, about 1,000,000 tons of fly ash and bottom ash were placed at the site.

In 1996 and 1997, improvements were constructed to mitigate erosion including: grading of berm, lakeshore bluff, and ravine slopes; covering of ash berms with soil; installing groundwater and stormwater drainage systems; installing a bluff protection system; and restoring the site vegetation and roads.

If the South Site-Exp were selected by the Commission in the CPCN process, construction on the government-owned, 70-acre shooting range property might reveal one or a number of contamination situations that would need to be managed in accordance with regulatory requirements. An environmental assessment by STS Consultants Ltd. (STS), in 1994 commissioned by the Department of Military Affairs (DMA), showed that the property still has berms constructed of fly ash and bottom ash that was hauled to the site from the OCPP. These assessments also document that demolition materials have been found at the site. No asbestos has been found in sampled areas, but could exist in demolition materials elsewhere. Metals, including lead, from weapons casings, shot, and bullets fired at the site may have had an effect on the quality of the soils. Petroleum contamination was discovered in the mid-1990s and was remediated at that time. An existing groundwater drainage system on the site has the potential to affect the surface water quality of Lake Michigan. The site may be affected, in turn, by the railroad line located west of the site.

In 2000, following remedial actions, STS issued a report documenting field observations and test results for site improvements completed in 1996 and 1997. The work conducted by STS appears to meet or exceed the level of investigation required for a Phase II environmental assessment effort. At WEPCO's request, a Phase I investigation has been completed by Natural Resource Technology (NRT) to determine if the site was used for activities other than a rifle range or had environmental conditions beyond those already known by WEPCO and documented by the STS reports. It turned up no evidence that the property was used for industrial activity or any other non-residential or non-agricultural purposes, so the results of the STS work appear to characterize the condition of the target range accurately. The property is identified in the Registry of Waste Disposal Sites in Wisconsin.

Designated biological areas

Primary environmental corridors

WEPCO's property has two large blocks of habitat, totaling 200 acres near the lakeshore, identified as Primary Environmental Corridor (PEC) by SEWRPC. These are shown in Figures Vol. 2-14, 2-16, and 2-18. Corridors are linear habitat areas that provide general habitat and link blocks of habitat together as avenues for wildlife travel and plant and seed dispersal. These corridors provide cover, food, and protection from weather and predators for resident wildlife and for traveling wildlife. Corridors linking habitat areas increase the potential for genetic variability within plant and animal species and populations, improving their ability to respond to changes in habitat.

A corridor's size, shape, and location dictate its importance to wildlife. SEWRPC describes primary environmental corridors to include a wide variety of the most important natural resource and resource-

related elements and to be at least 400 acres in size, two miles long and 200 feet wide. Corridors narrower than 200 feet in width are less valuable to wildlife due to the relatively high amount of edge habitat.

Corridors, like habitat blocks, contain edge and interior portions. Corridors with more edge habitat than interior habitat are more suitable as general habitat for edge species (e.g. raccoons, skunks, and white-tail deer) and not for area-sensitive species. On WEPCO's property, the area-sensitive species are mainly birds and amphibians. Impacts to area-sensitive birds include increased nest predation and cowbird nest parasitism. The main impact to amphibians is increased predator pressure.

Corridors help to link habitat blocks and allow wildlife to find mates, food, nesting or den sites, and cover. If these corridors are reduced in size or interrupted, some wildlife species (ovenbirds or salamanders, for example) could be prevented from traveling to other habitat blocks. A reduction in corridor size may allow predators to range deeper into the corridor. An interruption in the corridor may prevent an animal from traveling to the next habitat block because of increased exposure to dangers such as hawks, cars, or extreme temperature or moisture variations.

The two PEC blocks on WEPCO's property, as shown in Figures Vol. 2-14, 2-16, and 2-18, are part of a larger PEC that runs along the Lake Michigan shoreline. The corridors on the property are made up of hardwood woodlands, old field, and wetlands. The corridor on the OCPP property is mainly used as a travel corridor by mammals and birds. All forms of wildlife -- birds, mammals, reptiles, amphibians, and insects, for example -- use the corridor blocks as habitat as well.

Natural areas

The OCPP property contains one Natural Area as designated by SEWRPC[107] and identified in the Natural Heritage Inventory, the Ravine Woods Natural Area. Located within the southern PEC and south of the Rifle Range property, it contains native plant and animal communities, a waterway, higher species diversity, and is of significant size.

Isolated natural resource areas

There are six INRAs scattered throughout the property, some containing CSHs. INRAs are used by SEWRPC to describe isolated quality areas that provide habitat for endangered/threatened species or species of special concern; or areas that have been so little modified by human activity that they contain intact native plant and animal communities believed to be representative of pre-European settlement landscape. The designated sites on the OCPP property are important due to quality of plant communities and the habitat they provide for state endangered/threatened species. There is no specific protection for these areas through the state or federal government.

Critical species habitat

Areas designated as CSH by SEWRPC are located within the PECs and INRAs. They consist of tracts of land or water that support federally or state-listed rare, threatened, or endangered plant or animal species. These areas contain the necessary components of habitat for long-term support of critical species population.

[107] SEWRPC, Regional Natural Areas and Critical Species Habitat Protection and Management Plan for Southeastern Wisconsin, Sept., 1997.

Habitat fragmentation

On the WEPCO property, there are several habitat types scattered around the existing power plant facility. These areas are divided into large blocks that are bordered by roads, railroad tracks, clearings, and other disturbance. While the habitat blocks have been fragmented somewhat, they still have adequate acreage to provide habitat for both generalist and specialist wildlife species. However, continued fragmentation of these habitat blocks will affect their ability to support certain specialist wildlife species. Specialist wildlife species present on WEPCO's property include forest interior birds, some grassland songbirds, and amphibians.

Habitat fragmentation affects the size and shape of a habitat area, which affects the types of wildlife that can use the area successfully. Habitat "blocks," such as a woodland or prairie, contain an edge and an interior portion. Edges are the outer portions of a habitat block bordering with other habitat types. The interior portion is the inner portion of a specific habitat block. If habitat blocks have more edge habitat than interior habitat, they may suffer detrimental impacts on their area-sensitive wildlife. (Area sensitive species are those species whose occurrence or reproductive success is reduced in small habitat patches). This is a concern because there are no longer many large tracts of, for instance, consistent forest, prairie, or wetland habitat. The places for area-sensitive wildlife like forest interior birds or large predators to use are becoming smaller and fewer.

One of the major effects of the existing OCPP facilities is on habitat for forest interior birds. Edge-related impacts to these birds (ovenbirds, scarlet tanagers, for example, and others) include increased nest predation and nest parasitism. Forest interior birds that may be present on the OCPP property include: American redstart, veery, ovenbird, black and white warbler, and least flycatcher. Edge habitat areas support a high number of wildlife species, including an increased number of predators like crows, blue jays, cats, dogs, or raccoons. Forest interior birds have not developed behaviors to deal with many of these predators, behaviors such as nest camouflage, or nest location. Therefore, their nests are more susceptible to predators. Forest interior birds in edge-dominant habitat have lower nest success rates. The lower nest success could potentially push these birds out of edge-dominant habitats like smaller woodlots or long, narrow woodland blocks.

An important example of edge effects in woodlands is nest parasitism by brown-headed cowbirds. Brown-headed cowbirds lay their eggs in other bird species' nests, and the cowbird nestling is typically the only nestling to fledge. Bird species found in edge habitat have developed behaviors to deal with brown-headed cowbirds, by pushing cowbirds out of the nest or by building a new nest. Forest interior birds have not developed these behaviors and are more susceptible to cowbird parasitism.

Edge also impacts non-bird wildlife species, mainly as increased predator pressure. As the sizes of woodlands are reduced, predators such as cats, dogs, or crows, that are not associated with woodlands normally or that use woodland edges, are able to venture further into the smaller woodlands and prey on woodland specialist species.

On the OCPP property, the largest woodland habitat areas are about 20 to 30 acres. These areas still have the potential to provide some habitat for area-sensitive species like forest interior birds[108] and amphibians (e.g. salamanders, eastern gray tree frog, etc.). Several of the smaller woodland areas on the OCPP property are in close proximity to each other or near a larger block of woodland habitat. Because of the close proximity to other similar habitat, area-sensitive or specialist wildlife species can and will use these smaller areas.

Existing vegetation

Most areas near the communities of Oak Creek and Caledonia have been cleared for agricultural, industrial, or residential uses, and the native vegetation has been reduced to scattered old fields and stands of second-growth, mixed hardwoods. Activities and operations related to operating the existing OCPP facilities in addition to previously agricultural practices have disturbed much of the property. However, old fields, woodlands, grasslands, presently farmed cropland, wet meadows, and marsh or pond habitat are present.

Fieldwork to identify wetlands and vegetation communities present on the OCPP property has recently been completed.[109] Wetlands are discussed in Chapter 8 of this EIS. The discussion of existing vegetation that follows can be supported by referring to the figures showing the existing plant layout (Figure 6-2), existing topography (Figure Vol. 2-11), existing wetlands (Figure Vol. 2-13, 2-15, and 2-17) and a Natural Area, PECs, CSHs, and INRAs (Figures Vol. 2-14, 2-165, and 2-18).

North of Elm Road

Much of the northern portion of WEPCO's property, along the lake and north of Elm Road to Oakwood Road (about 175 acres), has been allowed to revert from cultivated to permanent vegetative cover. Old field vegetation exists here, in successional stages ranging from early old fields dominated by grasses and other herbaceous species to late old fields dominated by shrubs and saplings. In the earlier successional areas, a variety of grasses and forbs such as goldenrod (*Solidago* sp.), aster (*Aster* sp.), Queen Anne's lace (*Daucus carota*), other composites, sweet clover (*Melilotus* sp.), and other legumes are present. In the later successional old fields, woody vegetation has invaded, including hawthorn (*Crataegus* sp.), white ash (*Fraxinus americana*), dogwood (*Cornus* sp.), Chinese elm (*Ulmus pumila*), and box elder (*Acer negundo*). The inactive North Oak Creek Ash Landfill, also in this part of the property, is flat-topped and currently supports grasses and other herbaceous species. Its steeper slopes are planted in crown vetch (*Coronilla varia*). Toward Oakwood Road, near Elm Road, and east of the landfill are wooded areas with white ash, aspen (*Populus* spp.), and hawthorn. Much of that area has been allowed to revert from cultivated to permanent vegetative cover. Woody vegetation has invaded, and a variety of grasses and forbs are still present.

About half the area between Elm Road and Oakwood Drive is SEWRPC-designated PEC land (Figures Vol. 2-14, 2-16, and 2-18). This includes the area all along the lakeshore and bluff top extending westward north and south of the North Oak Creek Landfill. This land is mostly wooded old field, large wetland complexes associated with streams, and smaller wetlands surrounding the inactive landfill. In the northeast corner of

[108] Forest interior birds prefer larger blocks of woodland habitat, 100-250 acres, but will use smaller woodland blocks if they are close to larger woodland areas (over 100 acres in size); if the smaller woodland blocks are in close proximity to each other; or if there are larger blocks of habitat available.

[109] By the Southeastern Wisconsin Regional Planning Commission (SEWRPC) north of Elm Road and by Graef, Anhalt, Schloemer & Associates south of Elm Road.

the property, within the PEC are two CSH areas. One is an 11.5-acre good quality upland Southern mesic forest with some disturbances due to selective tree cutting and small footpaths. However, over 100 plant species, including the state-designated endangered, blue-stemmed goldenrod (discussed later in this chapter), were observed. The other CSH is a small (0.02-acre) arrow grass wetland on the bluff face with ground water seepage.

South of Elm Road and east of the railroad

About 400 acres lies south of Elm Road, extending between the lake and the railroad to Seven Mile Road on the south. This area includes the operating South OCPP and the retired portions of the older North OCPP. It also includes the government-owned shooting range and land north and south of the range. Except for some privately farmed property in the south, most of this parcel is occupied, as in the north, by old field vegetation in various stages of succession. The shooting range property (about 70 acres) is in mowed grass.

A second SEWRPC-designated PEC is located in the area south of the OCPP facilities, along the lakeshore and bluff top and extending inland, south of the shooting range to include the Ravine Woods Natural Area (Figures Vol. 2-14, 2-16, and 2-18). The Ravine Woods Natural Area is 22 acres of good quality Southern mesic hardwoods. It has experienced some impacts due to selective tree cutting, small foot paths, and agricultural activities at its margins but contains over 117 different plant species. This includes the state-endangered blue-stemmed goldenrod and state-threatened cream gentian (discussed later in this chapter). There are also several other wooded areas and wetland communities. Dominant vegetation in the wooded areas includes sugar maple (*Acer saccharum*), American beech (*Fagus grandifolia*), shagbark hickory (*Carya ovata*), basswood (*Tilia americana*), hawthorn, red and white oak (*Quercus* spp.), and white ash. As shown in Figures Vol. 2-13, 2-15, and 2-17, there are three other woodland areas designated as CSHs, north of the shooting range near the shoreline, the area enveloping the northern end of the curved rail track, and the overlapping western quarter of the shooting range. Located just south of Elm Road is another CSH, a small upland meadow.

The largest wooded parcel (approximately 17.5 acres) on the property is located south and inside of the OCPP rail track, west of the existing power plant units. This woodland is easily identifiable on numerous map figures in a variety of EIS chapters and in Volume 2. As shown in Figures Vol. 2-14, 2-16, and 2-18, it is a designated CSH and an INRA. Basswood and beech are co-dominant species and account for more than half of the trees in this woodland; at least ten beech trees have a diameter of greater than 30 inches. Approximately 90 plant species have been recorded in these woods, including the state-endangered blue-stemmed goldenrod (discussed later in this chapter). The herbaceous layer also includes numerous jack-in-the-pulpit (*Arisaema tripyhllum*) and white avens (*Geum canadense*), and some lady fern (*Athyrium filix-femina*), blue cohosh (*Caulophyllum thalictroides*), mayapple (*Podophyllum peltatum*), and bedstraw (*Galium* sp.). These are all common species in southeastern Wisconsin woodlands.

West of the railroad

West of the C&NW Railroad tracks and south of Elm Road is additional WEPCO property extending westward towards STH 32. The area includes two landfills, three areas designated as INRAs, and one designated CSH within one of the INRAs. (See Figures Vol. 2-14, 2-16, and 2-18.) South of Elm Road is the closed South Oak Creek Ash Landfill. This landfill has been reclaimed and planted as grassland with perennial grass and herbaceous species. WEPCO-owned areas surrounding the landfill are old fields to the

west and agricultural lands rented out to the south. Spanning the north and south sides of Rifle Range Road and northwest of the active Caledonia ash Landfill is an 18-acre woodland designated as a CSH. About 55 plant species have been identified in the woods north of Rifle Range Road with more than 70 species identified in the southern portion. Sugar maple, white oak (*Quercus alba*), basswood, beech, and white ash are dominant in the northern woods, with basswood, sugar maple, and shagbark hickory dominant in the southern portion.

Wildlife

Wildlife use of the property

The OCPP property has several habitat types -- woodland, wetland, riparian land, lakeshore, grassland, and old field -- that support many different wildlife species. Many of these species use several of these habitat types for different stages of their life cycle, such as nests or dens, foraging, or cover. The following tables (Tables 10-1 through 10-6) are listings of wildlife species that are likely to be found in different habitat types on the property. Some species may be listed in more than one habitat type because they use different habitat types for different parts of their life cycle.[110]

In woodland

The woodlands provide den and nesting areas, cover, and feeding areas for wildlife like the mammals, birds, reptiles, and amphibians listed in Table 10-1. In the larger patches of woodlands, dead trees or snags provide dens for mammals like squirrels or raccoons and nesting areas for birds like woodpeckers or screech owls. Branches of trees and shrubs are used by birds like warblers or vireos as nesting sites and by squirrels as den sites. Birds like ovenbirds or black and white warblers can use the leaf litter for nest sites. Downed logs serve as cover and dens for salamanders, small mammals and snakes. Burrows dug in the woodland floor serve as den sites for mammals like opossums, foxes, skunks, or mice. Amphibians and snakes also may use abandoned burrows as den areas.

Table 10-1 Species likely to be found in OCPP woodlands

Type	Species
Mammals	White-tailed deer, red fox, gray fox, coyote, raccoon, opossum, gray squirrel, southern flying squirrel, cottontail rabbit, bat, chipmunk, shrew, skunk, and mice
Birds	Cooper's hawk, sharp-shinned hawk, great horned owl, screech owl, American robin, northern cardinal, common grackle, mourning dove, downy woodpecker, hairy woodpecker, American crow, blue jay, black-capped chickadee, house wren, blue-gray gnatcatcher, cedar waxwing, northern flicker, red-bellied woodpecker, eastern wood-pewee, red-eyed vireo, warbling vireo, scarlet tanager, white-breasted nuthatch, eastern towhee, American redstart, indigo bunting, brown headed cowbird, red breasted grosbeak, great crested flycatcher, veery, blue-winged warbler, golden-winged warbler, wood thrush, black and white warbler, ovenbird, northern oriole, and wood duck
Reptiles	Northern redbelly snake, common garter snake, and brown snake
Amphibians	American toad, eastern gray treefrog, spring peeper, and tiger salamander

[110] This list is based on DNR professional opinion on habitat type, personal observations, and local survey data from county surveys.

Woodlands provide a variety of food sources. Trees such as oaks, ash, and birch and shrubs such as nannyberry, elderberry, and dogwood provide seed and berry sources for birds like blue jays and mammals like squirrels or deer. Dead trees and downed logs are homes to insects, which provide food for woodpeckers and for mammals like raccoons, squirrels, or skunks. Woodlands support a variety of insects that are food sources for birds like wood pewees or flycatchers, amphibians like salamanders or American toads, and reptiles like eastern garter snakes. Deer and rabbits browse on the wood vegetation itself. Predators like the sharp-shinned hawk, Cooper's hawk, great horned owl, or fox feed on small mammals, small birds, and other animals that use the woodland.

In old field

The old field area provides nesting locations or burrows, cover, and feeding areas for wildlife like the mammals, birds, and reptiles listed in Table 10-2. Scattered trees, shrubs, and grassy patches provide nesting locations for birds such as gray catbird, field sparrow, and song sparrow. Burrows dug in the old field floor serve as burrows or den sites for mammals such as woodchuck, mice, vole, or shrew. Amphibians and snakes may also use these den sites when abandoned.

Table 10-2 Species likely to be found in OCPP old field habitat

Type	Species
Mammals	White-tailed deer, red fox, coyote, raccoon, opossum, cottontail rabbit, skunk, weasel, meadow vole, shrew, and mice
Birds	Shrike, red-tailed hawk, European starling, song sparrow, goldfinch, chipping sparrow, field sparrow, mourning dove, eastern kingbird, gray catbird, eastern phoebe, black-capped chickadee, blue jay, brown thrasher, eastern blue bird, yellow warbler, blue-winged warbler, golden-winged warbler, brown headed cowbird, and house finch
Reptiles	Garter snake, eastern milk snake and fox snake

Old fields provide a variety of food sources. Trees like box elder or ash and shrubs such as sumac, dogwood, and buckthorn provide seed and berry sources used by birds and mammals. Predators like the red-tailed hawk, sharp-shinned hawk, fox, and coyote feed on the small birds, small mammals, and other small animals that use the area.

In grassland

The grassland area provides nesting and burrow locations, cover, and feeding areas for wildlife like the mammals, birds, reptiles, and amphibians listed in Table 10-3. The grass vegetation structure provides nesting locations for birds. Burrows provide den sites for mammals and reptiles.

Table 10-3 Species likely to be found in OCPP grassland

Type	Species
Mammals	White-tailed deer, red fox, coyote, raccoon, opossum, cottontail rabbit, weasel, skunk, woodchuck, meadow vole, shrew and mice
Birds	Kestrel, red-tailed hawk, northern harrier, house sparrow, goldfinch, song sparrow, field sparrow, chipping sparrow, savannah sparrow, eastern meadowlark, bobolink, barn swallow, tree swallow, eastern kingbird, mourning dove, killdeer, mallard duck, blue-winged teal, red-winged blackbird, Henslow's sparrow, and dickcissel
Reptiles	Fox snake, garter snake, eastern plains garter, and eastern milk snake
Amphibians	Tiger salamander and chorus frog

Grassland areas provide a variety of food sources. The grasses and flowers provide seeds for birds and mammals. The flowers attract insects that birds, mammals and amphibians feed on. Predators like the kestrel or red-tailed hawk also feed on animals like small mammals or insects that use this area.

In wetland

The wetland areas (See Figures Vol. 2-12, 2-14, and 2-16) provide nesting and den locations, cover, and feeding areas for wildlife like the mammals, birds, amphibians, and reptiles listed in Table 10-4. The sedges, shrubs or fringe vegetation in a marsh provide nesting locations for birds such as the song sparrow, marsh wren, or sora rail. Muskrats will create lodges made of cattails in deep marshes. Amphibians like frogs and salamanders will use the open waters in marshes for egg laying.

Table 10-4 Species likely to be found in OCPP wetlands (shrub-carr, sedge meadow, shallow marsh, deep marsh)

Type	Species
Mammals	Raccoon, red fox, weasel, muskrat, shrew, and vole
Birds	Greenback heron, great blue heron, yellow warbler, common yellow throat, song sparrow, red-winged blackbird, willow flycatcher, barn swallow, tree swallow, swamp sparrow, marsh wren, sora rail, yellowlegs, American woodcock, snipe, Canada goose, mallard duck, and blue-winged teal
Reptiles	Painted turtle, snapping turtle, fox snake, common garter snake
Amphibians	Chorus frog, American toad, spring peeper, wood frog, tiger salamander, green frog, and leopard frog

Wetland areas provide a variety of food sources. Wetland vegetation like bulrushes, cattails, or duckweed, and aquatic seeds and tubers, such as from arrowhead, provide food for birds and mammals. Insects found in wetlands also provide a food source for frogs, reptiles and birds. Other wildlife like frogs or muskrats serve as food for predatory wildlife like the great blue heron or mink.

In riparian habitat

Riparian areas are areas bordering streams. The riparian area provides nesting and den locations, cover, and feeding areas for wildlife like the mammals, birds, reptile, and amphibians listed in Table 10-5. The trees and shrubs provide nest sites for birds. Mammals like mink can make dens in the bank of a stream.

Table 10-5 Species likely to be found in OCPP riparian habitat

Type	Species
Mammals	Raccoon, opossum, mink, white-tailed deer, red fox, cottontail rabbit, weasel, skunk, shrew, vole, and mice
Birds	Kingfisher, greenback heron, great blue heron, yellow warbler, common yellow throat, song sparrow, red-winged blackbird, willow flycatcher, barn swallow, tree swallow, swamp sparrow, yellowlegs, mallard duck
Reptiles	Common garter snake
Amphibians	American toad, bullfrog, green frog, leopard frog

Riparian areas provide a variety of food sources. The trees, shrubs, and wetland vegetation provide food for birds and mammals. Insects that use the riparian places are sources of food to birds, amphibians, and reptiles. Kingfishers can feed on any fish in the stream, and great blue herons can feed on frogs.

In beach or bluff habitat

The Lake Michigan beach area provides nesting and den locations, cover, and feeding areas for wildlife like the mammals, birds, and reptiles listed in Table 10-6. The beach and bluff areas provide nest sites for birds and turtles.

Table 10-6 Species likely to be found in OCPP bluff or Lake Michigan beach habitat

Type	Species
Mammals	Raccoon, white-tailed deer, and coyote
Birds	Herring gull, spotted sandpiper, yellowlegs, mallard duck, Canada goose, black duck, American coot, barn swallow, and tree swallow
Reptiles	Snapping turtle and painted turtle

The beach and bluff areas provide food sources. The vegetation provides seeds. Insects that use the beach provide food for birds.

Bird habitat

Bird migration stopover habitat

The large blocks of habitat on the OCPP property also provide "stopover sites" for migrating birds like hawks, falcons, owls, shorebirds, waterfowl, gulls, terns, sparrows, warblers, thrushes, and songbirds. In particular, the CSH located along the beach area north of the current power plant has the potential for providing critical habitat, nesting, foraging, roosting, and/or migration habitat for three of Wisconsin's endangered species: the Caspian tern, the common tern, and the piping plover. All three of these birds have been observed in Milwaukee County and have likely stopped at the OCCP property; however, nesting at this property has not yet been documented.

Other possible migrants include: red-throated loon, common loon, pied-billed grebe, horned grebe, eared grebe, double-crested cormorant, American bittern, least bittern, great egret, snowy egret, turkey vulture, snow goose, mute swan, tundra swan, gadwall, American widgeon, blue-winged teal, northern shoveler, northern pintail, green-winged teal, canavasback, redhead, ring-necked duck, greater scaup, lesser scaup, harlequin duck, surf scoter, oldsquaw, bufflehead, common goldeneye, hooded merganser, common merganser, red-breasted merganser, ruddy duck, osprey, bald eagle, red-shouldered hawk, rough-legged hawk, merlin, peregrine, yellow rail, king rail, Virginia rail, black-bellied plover, American golden plover, semi-palmated plover, solitary sandpiper, ruddy turnstone, sanderling, pectoral sandpiper, dunlin, bonaparte's gull, ring-billed gull, herring gull, Thayer's gull, glaucous gull, forester's tern, black-billed cuckoo, nighthawk, whip-poor-will, ruby-throated hummingbird, red-headed woodpecker, yellow-bellied sapsucker, golden-crowned kinglet, ruby-crowned kinglet, Tennessee warbler, orange-crowned warbler, Nashville warbler, northern parula, magnolia warbler, black-throated blue warbler, yellow-rumped warbler, black-throated green warbler, blackburnian warbler, yellow-throated warbler, pine warbler, prairie warbler, palm warbler, bay-breasted warbler, cerulean warbler, prothonotary warbler, mourning warbler, hooded warbler, Canada warbler, yellow-breasted chat, scarlet tanager, vesper sparrow, grasshopper sparrow, Henslow's sparrow, field sparrow, American tree sparrow, fox sparrow, Lincoln's sparrow, white-throated sparrow, white-crowned sparrow, dark-eyed junco, and snow bunting.

Migration for birds involves long journeys twice a year between their northern breeding grounds and their southern wintering grounds. Spring migration occurs in Wisconsin from March to May and involves birds traveling from the wintering grounds to the breeding grounds. The fall migration occurs in Wisconsin from mid-August to mid-November and involves birds traveling from the breeding grounds to the wintering grounds. During migration, over 300 species and millions of individual birds travel thousands of miles, using the Lake Michigan shoreline as a guide to reach their destination.

In preparation for the long migratory journey, birds spend time building up fat reserves for the flight. During the migration, birds will make several stops to replenish fat reserves and rest. Stops will be made in blocks of habitat where birds will be looking for food (for example, berries, insects, birds, small mammals, etc.), shelter or roosting areas, and protection from hazards such as predators or extreme weather conditions. The places where the birds stop are called stopover sites. These habitat blocks can be natural communities such as woodlands, grasslands, beaches, backyards, or parks. Natural communities are more valuable as stopover sites than backyards and parks because of the more diverse habitat structure and food sources.

Stopover sites need good cover to provide protection for tired birds. Each area of cover should have diverse layers, such as shrubs and trees or grasses and shrubs. Suitable cover will protect the birds from extreme weather conditions or predators. When migrating birds are forced to use marginal stopover sites without suitable cover, these birds are exposed to increased dangers, affecting their survival and fitness.

Sites also need ample, diverse food supplies for birds to replenish fat reserves. Sites with diverse food sources (insects, fruits, and seeds, for example) give the birds a variety of options. If the sites lack ample or diverse food supplies, the birds may be forced to continue the journey not fully charged, which potentially lowers their survival rate or results in them reaching the breeding grounds in poor condition. If they reach the breeding grounds in poor condition, their nesting attempts and reproduction success are adversely affected.

The lack of food resources could also force the birds to stay at the stopover site longer in attempts to fully replenish their fat reserves. This could result in the birds arriving too late on the breeding grounds. If they arrive too late, they might:

- Not find breeding territory.
- Be forced to use marginal breeding habitat, lowering nest success.
- Eliminate nesting attempts altogether.

The OCPP stopover sites include not only the beach area but also the woodland, wetland, old field, and grassland. The OCPP stopover habitat in general is part of the larger corridor of habitat that runs along the Lake Michigan shoreline, mainly right along the lakeshore. SEWRPC has identified quality habitat (isolated natural areas) and primary and secondary corridors that can potentially serve as stopover locations for migrating birds. In 1985, small, scattered, isolated blocks of habitat and corridors along waterways were the only locations of quality habitat remaining near the lakeshore in Kenosha, Racine and Milwaukee Counties. Eighteen years later, by 2003, there has likely been a further reduction in isolated habitats and corridors as a result of development pressures.

Wintering habitat on Lake Michigan

During the winter months, nearby Lake Michigan serves as a wintering area for migrating waterfowl and gulls. Several species of duck rest offshore in large rafts or small groups, resting and feeding in open freshwater. The birds feed mainly on crustaceans, aquatic insects, vegetation, and fish. Species found on Lake Michigan during the winter months include bufflehead, oldsquaw, greater scaup, lesser scaup, common merganser, red-breasted merganser, goldeneye, and ruddy duck.

Grassland habitat

The proposed North Site for the ERGS has two major grassland areas, both fly ash landfills. These areas provide suitable habitat for grassland songbirds, a bird group in decline nationwide. The decline of grassland songbirds has been attributed to loss and fragmentation of habitat, changes in farming practices, urban development, and increased predation. In Wisconsin, less than 0.1 percent of the original prairies remain.[111] Suitable habitat includes open areas dominated by grasses with flowers and minimal woody vegetation.

Of the 105 bird species found in Wisconsin to use grasslands as one part of their breeding cycle[112] (for courtship, nesting, foraging, rearing young, and roosting or resting), seventeen of these species use grasslands for most or all parts of their breeding cycles. Of these seventeen species, five of them have been found on one or both of the grassland areas at the proposed North Site. During a morning survey conducted on both the North and South Oak Creek landfills on June 20, 2002 by WEPCO and DNR, four of these five bird species were heard: bobolink, savannah sparrow, eastern meadowlark, and dickcissel. The fifth species, the Henslow's sparrow, was not heard during the survey but has been heard on the grassland site on the South Oak Creek Ash Landfill south of Elm Road in past years. In a follow-up survey conducted on June 27, 2003 on the two closed Oak Creek Landfills, the species heard and seen were similar to the past year, except for the dickcissel. Species included bobolink, eastern meadowlark, gold finch, red-winged blackbird, savannah sparrow, barn swallow, tree swallow, and willow flycatcher. On one area of the South Oak Creek Landfill, a group of twenty-one male bobolinks were counted. On the North Landfill, the Henslow's sparrow is a state threatened species in Wisconsin and will be addressed in more depth in the following Endangered and Threatened Species section of this chapter. The Henslow's sparrow, bobolink, and dickcissel are species of concern for Partners in Flight, the U.S. Fish and Wildlife Service Region 3, and the Wisconsin DNR.

Insects

The varied habitat types on WEPCO's property support a large insect population. Insect life on the property plays a role in many aspects of the ecology of the site - serving as a food source for wildlife (e.g. birds, amphibians, reptiles, other insects, and small mammals) and as pollinators. The insect types found on the property range from water boatmen, backswimmers, dragonflies, and water striders in wetlands and ponds to grasshoppers, crickets, orange sulphur butterflies, cabbage white butterflies, monarch butterflies, eastern tiger swallowtail butterflies, leafhoppers, mosquitoes, yellow jackets, and ants in grasslands to wolf spiders, flies, luna moths, little wood-satyrs, and northern walkingsticks in the woods.

[111] DNR Technical Bulletin No. 191, 2000
[112] Sample, David W. and Mossman, Michael J., Managing Habitat For Grassland Birds- A Guide For Wisconsin, DNR Bur. Of Integrated Science Services, 1997, pages 8-10, 22.

Similar to other wildlife species on the property, the loss of habitat would force insects to relocate or be destroyed if they have limited mobility (e.g. water striders in shallow marsh). Insects that do relocate to similar habitat on or off WEPCO's property could face dangers that affect their health or survival.

Threatened/endangered species

No species listed as threatened or endangered by the U.S. Fish and Wildlife Service are known to occur on the property or in the project area.

A number of species of plants, birds, crustaceans, insects, reptiles, and fish are listed with the DNR as endangered, threatened, or of special concern in Milwaukee and Racine Counties. Those present or suspected to be present on the OCPP property are discussed below.

State endangered species

Blue-stemmed goldenrod

Each proposed ERGS siting arrangement on WEPCO's property contains the same three forested mixed hardwood sites that provide habitat for the state-endangered blue-stemmed goldenrod, (*Solidago caesia*). These are wooded areas ranging from 7.5 to 17.5 acres in size, with second-growth hardwood forest dominated by sugar maple, basswood, white ash, American beech, and shagbark hickory. Blue-stemmed goldenrod populations of 150 to 600 plants are present in each area.

Blue-stemmed goldenrod is classified as critically endangered in Wisconsin because of the rarity of its habitat, scattered remnants of second-growth mesic mixed hardwood stands in southeastern Wisconsin. This habitat type has been greatly reduced in extent by clearing of land for agricultural and other uses. Blue-stemmed goldenrod is at the periphery of its range in southeastern Wisconsin, but exists in appropriate habitat in much of the central and southern U.S., and is not listed as endangered or threatened on a national level.

Peregrine falcon

The state endangered Peregrine falcon (*Falco peregrinus*) has nested in the recent years in an artificial nest box placed on the stack for OCPP Units 7 and 8. WEPCO has had a long-standing commitment to assist in the recovery of the peregrine falcon. It has indicated that the presence of the falcon at the existing power plant is valued. WEPCO has indicated that it expects to accommodate the falcons' residency throughout the ERGS construction period and thereafter.

State threatened species

Yellow gentian

The Yellow gentian (*Gentiana alba*) is a Wisconsin threatened species. It was found in the woodland/prairie area just south of Elm Road. Its habitat includes the clay soils in wooded ravines; thin soil on dry, open woodlands and edges; ridges and bluffs; wet sandy prairies; railroad rights-of-way; and roadside ditches.

Henslow's sparrow and other grassland birds

In June 2001, a Henslow's sparrow (*Ammodramus henslowii*) was found on the inactive South Oak Creek Landfill grassland. This state threatened species is a candidate for federal listing. Henslow's sparrows breed in a variety of grassland habitats with tall, dense grass and herbaceous vegetation. The state threatened

dickcissel (*Spiza americana*) is also likely to be found in the OCPP property grasslands, as well as the eastern meadowlark (*Sturnella magna*), field sparrow (*Spizella pusilla*), bobolink (*Dolichonyx oryzivorous*), and other species listed in the above section on Wildlife. The meadowlark, field sparrow, and bobolink are listed with the DNR as species not actively tracked but for which data is being collected.

While nesting has been known to occur in grasslands that are mowed every year, studies generally indicate that less frequent mowing results in more favorable habitat for this species. Periodic mowing, however, is a viable option at this time for maintaining suitable grasslands, provided that mowing is done after the breeding season is concluded and the sparrows have dispersed.

Reptiles or amphibians

Species that could be found in wetlands, woodlands, and old field habitat on the property include three state-threatened reptile and amphibian species. The Blanding's turtle (*Emydoidea blandingii*) prefers shallow and deep marshes, the shallow bays of lakes and reservoirs, shallow and slow moving streams and rivers, and backwater sloughs with soft bottoms and aquatic vegetation. There are marshes and small streams on the OCPP property, as discussed in Chapter 8. This turtle is also a candidate for federal listing. The Butler's garter snake (*Thamnophis butleri*) is also a candidate for federal listing. It prefers wet-mesic prairies, marshes, roadside grassy areas, and vacant urban lots, so there are several habitat opportunities on the OCPP property. The bullfrog (*Rana catesbeiana*) is likely to be found on the property in riparian situations.

The Blanding's turtle and Butler's garter snake have not been seen on the OCPP property. The bullfrog is a likely resident. If any of these species is found to be present on the project site, WEPCO has stated its intention to take appropriate steps to discourage the animals from entering the construction areas, and would hire a qualified professional to consult and assist in this effort under DNR oversight.

State special concern species

Special concern species are those species about which some problem of abundance or distribution is suspected but not yet proved. The main purpose of this advisory category is to focus attention on certain species before they become threatened or endangered.

Vegetation

The OCPP property is habitat for three species of Special Concern for the state of Wisconsin. Seaside spurge (*Euphorbia polygonifolia*), American searocket (*Cakile edentula*), and Slender Bog Arrow-grass (*Triglochin palustris*) were all found along the beach and bluff area. The state ranks these plants as rare or imperiled in Wisconsin with less than 100 occurrences. The seaside spurge occurs in Wisconsin only along Lake Michigan and is particularly sensitive to the destruction of beach and dune habitat.

Great blue heron

The state special concern species great blue heron (*Ardea herodias*) is a species likely to be found in wetland or riparian habitat on the OCPP property. Since the heron is highly mobile and since most of the wetlands would remain on the property, the frogs that the herons feed on would probably still be present though possibly reduced in abundance. Heron appearances on the property might also decrease.

Species not actively tracked but under state observation

Most of the species and natural communities on the endangered, threatened, and special concern lists are actively tracked.

The DNR also has a list of species that are not officially endangered, threatened, or of special concern, but for which the DNR is collecting data. Several species on this list are likely to be found on the OCPP property in different habitat areas. As discussed above, these species include the bobolink, field sparrow, and eastern meadowlark on grasslands. They also include the Cooper's hawk (*Accipiter cooperii*), veery (*Catharus fuscescens*), golden-winged warbler (*Vermivora ruficapilla*), and wood thrush (*Hylocichla mustelina*), all likely to be found in OCPP woodlands. The blue-winged teal (*Anas discors*), likely to be found in OCPP wetlands and grasslands, is also on this list.

Archeology/historic properties

Wisconsin law – protection of listed historic properties

Under Wis. Stat. § 44.40, the PSC as a state agency must determine if project construction or operation could adversely affect "historic properties" listed with the Wisconsin Historical Society (WHS). Listed historic properties could be buildings, burials, archeological sites, cultural areas, or sacred areas. Historic properties, including archeological sites, are considered by the WHS to be a natural resource. If a listed historic property appears potentially affected, the PSC must consult with the WHS, who determines whether there would be an adverse effect on it from the project. If the WHS determines that the proposed project would have an adverse effect on a historic property, the PSC and WHS must negotiate methods to reduce or avoid the impact. The PSC is then authorized to include the results of that consultation and negotiation in its order to the applicant, as a condition on the order if necessary.

The PSC and WEPCO have examined the WHS listings of historic properties in compliance with Wis. Stat. § 44.40 and found several archeological sites listed on the OCPP/ERGS property. Of eight located sites, however, five do not appear to be near areas of expected disturbance from ERGS construction for the North Site or the South sites. They appear to be one church cemetery and four campsite/home sites of different ages, including a historic Euro-American cabin, in places near the wetland INRA west of the operating Caledonia ash landfill. Of the three sites that appear to be in areas potentially affected by ERGS North Site, South Site, or South Site Exp construction, two are campsite/village sites located on the west side of the main railroad line northeast of the Caledonia landfill, and one is a projectile point discovery site located just inside the western portion of the WEPCO rail loop, in the CSH located there.

There is also one WHS-listed home on the south side of the OCPP property, north of Seven Mile Road and east of STH 32, on Douglas Avenue.

Federal law – surveys to locate and evaluate historic properties

Under Section 106 of the National Historic Preservation Act, the federal agencies with an interest in the project must consult with the State Historic Preservation Officer (SHPO) and appropriate Tribal Historic Preservation Officers (THPO) to determine if there are historic properties eligible for the National Register of Historic Places that might be adversely affected by the project. Federal interest would include permitting and other activities delegated to the states. The potential for public participation in this separate review

process is described in Chapter 1. Often, the CPCN applicant begins (and often completes) the work on the consulting, survey, and evaluation requirements during the CPCN process so that the Section 106 requirements are met and the appropriate alternatives are considered during the siting process rather than at a later time.

In this case, there appear to be direct and indirect EPA, FAA, and Army Corps interests related to the ERGS project. WEPCO has been asked to consult with the SHPO (the WHS fulfills this role) and THPOs and to follow their direction under Section 106. So far, the WHS/SHPO has determined to handle the project under state law. However, since the PSC issued the draft EIS on the project, the Army Corps has shown substantial interest related to the ERGS project as a whole. The PSC has suggested to the WHS and to WEPCO that a Section 106 review process may be more appropriate.

In April 1986, the Great Lakes Archaeological Research Center, Inc. (GLARC) had conducted an archaeological survey to ensure compliance with Section 106 for proposed construction related to the North Oak Creek Power Plant (Units 1 to 4). The area surveyed was for a six-acre parking lot, a ten-acre construction laydown area, and a construction workforce stairway. Those survey results concluded that there were no archaeological resources eligible for inclusion in the National Register of Historic Places and no further investigation was warranted. WEPCO had also received concurrence on the survey findings from the State Historical Society of Wisconsin (as the WHS was previously named).

Potential Impacts on WEPCO's Property

Topography

The topography of the present property would be greatly altered to accommodate the proposed ERGS. Large amounts of soil excavation, transport, and deposition would occur, regardless of the site option chosen. Soil from the land excavations would be used to create new berms or would be placed in soil repository piles at various points around the site. See Figures Vol. 2-12 through Vol. 2-17.

A summary of the excavated and deposited soil materials is shown in Tables 11-12 and 11-13 in the next chapter. For locations of the proposed ERGS units and proposed repositories of excavated soil, refer to Figures Vol. 2-13 through Vol. 2-18. This section of Chapter 10 on general potential impacts is followed by similar sections looking at each of the three sites individually.

One of the largest movements of soils is related to the construction of the two SCPC units at the lakeshore. Due to the topographical relief between the bluff along the Lake Michigan shoreline and the shoreline itself, major excavation work is proposed. The SCPC units would be dependent on once-through cooling, using water from the lake. It would be difficult and expensive to move the water up the bluff for this purpose, so the applicants have proposed to excavate an area by the lakeshore to accommodate the SCPC units. For the IGCC plant, the combined-cycle facility and air separation unit would need to be close to lake level to allow for open-cycle cooling. Other buildings could be built at higher elevations. Depending on the site selected, one SCPC unit would require excavation of 4.6 to 6.2 million cubic yards of soil. Two would require excavation of 5.8 to 7.3 million cubic yards. Adding the IGCC would require excavation of 7.3 to 10 million cubic yards.

All of the excavated soil and lake bottom dredging material would be relocated within the OCPP property in a series of berms around the perimeter of the property. There would be areas that would be screening berms and other areas that would be a combination of screening berms and soil stockpiles. As discussed in Chapter 11, the purpose of the screening berms would be to lessen the visibility of the power plant facilities and operations from off-site locations. Creation of the berms and other stockpile areas would also facilitate construction of the project as soil repositories.

The dredged material from the lake bottom for the harbor, discussed in Chapter 8, would probably be placed in the area near the closed North Oak Creek Landfill on the north end of the site.

The majority of the water intake tunnel spoils, also discussed in Chapter 8, would be utilized to create the new dock area north of the existing dock in the lake.

Geology

The area's rock geology would likely not be altered by construction of the new ERGS facilities on WEPCO's property. Excavations would occur only into the quaternary glacial deposits. These glacial deposits would most likely be relocated to new places on the property, as described in Chapter 11.

(The tunnel work to create the new water intake structure would burrow through the sedimentary rock under the bed of Lake Michigan and deposit the broken rock as an addition to what is now the on-lake coal dock.)

Soils exposed during construction would be susceptible to erosion and runoff into the existing surface water drainage system. Construction site runoff and erosion control requirements of Wis. Admin. Code ch. NR 216 would need to be attained. To minimize soil erosion, a variety of BMPs for erosion and sediment control would be used. These practices would include a sequencing of construction to expedite the project and minimize the length and duration of soil disturbance and exposure. Temporary erosion and sediment controls would include slope breakers, sediment barriers, and mulch. All erosion and sediment controls would be monitored and maintained throughout the construction process. After construction, all areas not in pavement or buildings would be seeded with permanent varieties of grass. The grass crop would be monitored for one year and additional restoration activities would take place if necessary. Techniques described in the DNR's *Wisconsin Construction Site Best Management Practice Handbook* would be used. Excess soil accumulated during construction of foundations would be either used on site or hauled off the site.

Since the soils are relatively fine-textured and tend to hold water in their natural state, they may tend to puddle after being relocated on site and could eventually create new wetlands if drainage is a problem and the appropriate plants seed into them. This wetland development appears to have occurred in the past at smaller scales from earlier soil transport and deposition.

Fugitive dust might be generated from exposed soil during construction. To avoid this, the applicants would employ water wagons regularly to spray access roads and construction areas to reduce dust. Fugitive dust as it could affect neighboring landowners and residents is discussed in more detail in Chapter 11.

Designated biological areas

As discussed in the previous sections, SEWRPC has identified a north and south PEC, nine CSHs, six INRAs, and the Ravine Woods Natural Area on the property. The PEC lands within the property total approximately 180 acres. Divided by existing power plant structures, the two PECs are part of a larger corridor that continues north and south along Lake Michigan. All three site options would require eliminating between 42 and 48 percent of the PEC lands.

Table 10-9 Estimated PEC impacts of the three siting options

Environmental Area (and approximate location)	Area (acres)	North Site Impact (acres)	South Site Impact (acres)	South Site-Exp Impact (acres)
PEC-(north)	114.2	69.6	65.5	65.5
PEC-(south)	65.8	9.6	9.6	21.7
Total	180.0	79.2	75.1	87.2

An examination of the proposed power plant layouts in Figures Vol. 2-1 through 2-3 and the proposed excavations in Figures Vol. 2-13, 2-15, and 2-17 show where large areas of natural areas would probably be removed, disturbed, or smothered during construction. None of the proposed layouts would impact the Ravine Woods Natural Area. However all three ERGS siting options proposed in the CPCN application would significantly impact some of the PECs, CSHs, and INRAs of the OCPP. Protected species are known to exist or are likely to exist in these designated biological areas.

Habitat fragmentation

The OCPP property provides several large blocks of varied habitat. All three ERGS siting options would fragment and eliminate habitat on the property. This fragmentation would likely impact area-sensitive species such as forest interior birds and amphibians, eliminating them over time or forcing them off the property because of edge effects. Area-sensitive species would have few locations to move to because the surrounding natural landscape is highly fragmented by development and agriculture. Generalist wildlife species like raccoon, deer, or opossum, gray squirrel, robin, starling, sparrow, and house finch would still use the area, but even the habitat for these species would be reduced by the project. The loss of the relatively large blocks of habitat would be locally significant.

The loss of the PEC in this area would reduce the travel corridor, forcing wildlife to travel longer distances to reach other similar habitat areas. It could also force wildlife to travel in marginal or unsuitable habitat, such as roads or mowed grass, increasing exposure to factors such as predators, weather, cars, or people's pets, that could lower survival rates.

Vegetation and wildlife

Impacts to vegetation would result regardless of the site selected by the Commission for construction of the plant. In addition, impacts would result from construction of a commercially-owned wallboard plant, which would likely be sited at the opposite end of the property from the generation units. All three sites would

also result in excavation and deposition of bluff soils, but there are some differences in amounts and locations for the deposition that affect which vegetation communities are impacted.

All three site options would lead to the removal of the old field habitat that would result in the loss of habitat for birds like blue jays or song sparrows in addition to species of mammals, amphibians and reptiles. Many of the species that use this old field are generalists and can use a variety of habitat types. Generalist wildlife species should be able to find other sites to use, mainly off of the OCPP property. However, where old field habitat is discussed below, it often relates to the PECs.

The woodland habitat on the OCPP property would be the most affected by the proposed ERGS. Of the three siting options, the South Site appears to have the most significant impact, but all three options would have similar levels of impact. Because large woodland areas are lacking in the surrounding landscape, the loss of medium-sized woodlands would have a large impact on forest interior bird habitat locally.

Selection of any of the three site options would require filling about 2.9 acres of woodland west of the railroad, due to soil stockpiling.

Pollutants

As discussed in Chapter 7, the ERGS power plant stacks would emit pollutants such as NO_x, SO_2, mercury, and particulates during operation. These pollutants have been associated with several environmental impacts that can affect wildlife. Some of these impacts include acid rain, vegetation defoliation, and mercury deposition. SO_2 and NO_2 have been tied to acid rain.

Acid rain increases the acidity of soil and/or waterways, lowering pH levels (that is, increasing their acidity). The lower pH levels in waterways result in fish and aquatic insect deaths, reducing the food for wildlife species that feed on those fish (such as herons or mink) or insects (such as waterfowl). Reducing food sources impacts the health of the animals and their reproductive capabilities. Acid rain can also affect the regeneration and quality of vegetation on the landscape. Vegetation provides many things to wildlife: cover from predators and weather, breeding or nesting areas, and food sources. A decrease in the regeneration of a certain plant species, such as an oak, could result in a decline of a food source for a certain animal, again potentially impacting the animal's health or reproductive capabilities.

Emission stacks can also deposit mercury particles in waterways and surface waters that are absorbed by fish and fish-eating species. The buildup of mercury toxins can impact the animals' health and reproduction capabilities and, in rare cases, can cause death.

Exhaust stacks

Tall man-made structures pose a potential hazard for local and migrating birds. Structures 200 feet or taller have the potential to cause deaths through blind collisions or confusion created by the structure lights in cloudy or foggy weather. Most documented collision cases have involved communication towers, but there have been cases of collisions with stacks as well.

FAA regulations[113] require that the structures over 200 feet tall have lights to signal passing planes of the structures' presence. Structures between 200 and 350 feet tall require one level of medium white intensity strobes with no marking or one level of 300-millimeter red beacons at the top plus red obstruction lights at mid-level. Structures between 350 and 700 feet tall require four levels of red obstruction lights or two levels of medium white intensity strobes.

During migration, birds fly day and night at varying elevations depending on weather conditions. Smaller bird species travel at night, making them more susceptible to the danger of structures. On clear nights, these birds will migrate at elevations of 2,000 to 3,000 feet above sea level but will also travel lower. During overcast skies, the birds are forced to travel at lower elevations, between 500 -1500 feet, bringing them in potential contact with the tall structures.

The structures cause mortality in birds in two ways: through blind collisions and by an aurora of light. In the case of a blind collision, a bird simply flies into the structure. In these cases, the structure is obstructed by cloudy or foggy weather conditions. This can occur during the day or night. In the case of an aurora of light, the lights on a structure (this has mainly been observed on communication towers), in cloudy or foggy weather conditions, refract off of water particles in the air and create an illuminated area around the structure. In these conditions, migrating birds will lose their navigational cues (stars or landmarks, for example) and will actively try to relocate them. When the birds pass a lighted area, the increased visibility draws them in and holds them close to the structure. Mortality then occurs when birds run into the structure or collide with other birds crowding into the lighted space.

It is estimated that millions of birds, of over 300 different species, use the Lake Michigan shoreline during migration. It is also estimated that around 100 million birds in North America are killed each year in collisions of all kinds (that is, with cell phone towers, exhaust stacks, cars, or windows, for example). A catastrophic collision incident occurred in January 1998, when an estimated 10,000 Lapland longspurs died on a foggy, snowy night in western Kansas after colliding with a 420-foot tall television broadcast tower. In Eau Claire, Wisconsin, collisions were documented at a 1000-foot television broadcast tower from 1957 to 1995.[114] During that period, 121,560 birds, of 123 different species, died at the tower.

The additional tall structures would have the potential to cause bird collisions. The OCPP currently has two stacks, only one is over 200 feet tall. The proposed expansion would add two stacks over 650 feet tall, two buildings 270 feet tall, and a 180-foot coal silo on top of a 60-foot structure (totaling 240 feet in height). The number of structures over 200 feet in height would increase from one to six. Two of these towers would be three times as high as the current stack. The number of collisions cannot be predicted and would depend largely upon weather conditions, time of year, and bird migrating patterns.

The use of a strobe white light, with a long gap between flashes, could help to reduce the collisions.

Migrating bird stopover habitat

Several of the vegetation communities on the OCPP property provide stopover habitat for migrating birds. The ERGS would impact all habitat types, especially woodland and wetlands, affecting the amount and quality of stopover sites. All three site options would result in significant impacts from elimination and

[113] "Stack Design" – www.warrenenvironment.com/html/stack_design.html, February 17, 2003
[114] Malakoff, David, "Faulty Towers," Audubon vol. 3 no. 5, September/October 2001, pages 78-83.

reduction of habitat. The South Site appears to result in the greatest impact. Current local urban development patterns threaten stopover sites both inland of and along the Lake Michigan shoreline. The fact that Lake Michigan is an important traveling corridor for migrating birds increases the value of the stopover site habitat on the OCPP/ERGS property. The loss of this habitat would be a significant loss.

Regardless of the power plant site selected, the ERGS would result in the elimination of over 50 percent of the migration stopover habitat, wetland, woodland and grassland. Reducing the amount of stopover habitat would in turn adversely affect migrating birds by:

- Forcing them to continue their migration flight to find other, more suitable stopover sites.
- Forcing them to use the suitable but already crowded stopover sites.
- Forcing them to use marginal stopover sites.

Additional stopover sites do exist along the Lake Michigan shoreline in Milwaukee, Racine, and Kenosha Counties. These include the Schlitz Audubon area, Grant Park, Wind Point, the Racine Zoo, Carthage College, Chiwaukee Prairie, and existing undeveloped shoreline. However, development pressure near and on the Lake Michigan shoreline is still continuing to reduce the areas of suitable stopover habitat.

Archeology/historic properties

A survey was conducted for WEPCO by AVD Archeological Services, Inc. to comply with the PSC's requirements under Wis. Stat. § 44.40. Two of the three archeological sites identified in the process and described earlier in this chapter were surveyed and evaluated for eligibility in the 1985 study and found to be not significant in that respect. The third site was found to be based on an amateur artifact collector's finding and had not been field checked by a qualified archeologist. In the AVD study, none of the three sites were found. They were presumed destroyed by earlier disturbance activities on the property. The archeologist recommended no further archeological work related to those sites.

With the WHS's acceptance of the AVD report, it appears that potential impacts on known historic or archeological sites on WEPCO's property would not be significant regardless of the site selected by the Commission if it approves the project.

However, there is still the potential for impact on archeological sites that have yet to be discovered. If the ERGS project is considered under Section 106 of the NHPA, the SHPO or THPOs could require additional surveys and evaluations as well as consultations with interested parties, including Native American Tribes. If the findings of the surveys and consultations resulted in discoveries of potentially affected archeological or cultural resources, the Section 106 process would require agreements to protect the newly discovered resources. If there were significant modifications to the ERGS project (e.g. facility layout changes), the Commission would need to be notified. Otherwise, the compliance with Section 106 would rest with the Army Corps and, of course, WEPCO.

The information related to the CUP Option (a new site layout) has added some § 44.40 responsibilities because of the potential for impact to additional listed sites on WEPCO's property. The CUP Option is discussed in Chapter 12.

Potential Impacts - Site by Site

North Site

Topography and soils

SCPC units

Most topography-altering construction activities would occur where the new SCPC generating units would be built, on land north of the currently operating OCCP units. This can be seen in Figure Vol. 2-13, which shows the topographical changes expected from the plant's construction at the North Site. The other area that would have construction activity would be where the new coal storage and handling areas would be located, west of the proposed SCPC units. For the proposed IGCC facility, WEPCO would use the former North Oak Creek Power Plant site and the surrounding land previously used for power production and related activities, plus some land inside the eastern part of the WEPCO rail loop.

As Figures Vol. 2-12 and 2-13 also show, important changes in local topography would occur in areas where the soil from the excavation would be deposited. Quantities of the various cuts and fills for the North Site have been estimated (See Table 11-10). The excavation needed to build the two proposed SCPC units at the lakeshore would total about 7.3 million cubic yards. The newly excavated area would be about one million square feet (approximately 23 acres) at the base, sloping upward on three sides about 120 feet in elevation over a distance of about 300 feet to give an overall excavated area of about 1.92 million square feet (about 44 acres). The change in elevations at the North Site and the six locations where excavated soil would be placed can be seen in Figures Vol. 2-13 and 2-14.

The excavated soil would be deposited onto several places on the OCPP property, as described below and quantified in Table 11-10 in the Fugitive Dust section of the next chapter.

1. Screening berms south of Elm Road and north of the South Oak Creek landfill. The existing vegetation in this area is primarily old field and wetland.
2. South Oak Creek landfill. The entire landfill is currently grassland. After the soil is deposited, it would be used as a lay-down area for ERGS plant construction. Following its use as a lay-down area, the area would be seeded to establish new grassland.
3. South of the primary transmission line corridor, north of the proposed entrance road on the west side of the OCPP property, and just east of STH 32. This site is primarily active cropland and also includes approximately six acres of woodland.
4. North Oak Creek landfill with screening berms to the north and west. The landfill portion of this site is grassland. Vegetative cover types around the landfill include several stages of old field and wetlands.
5. East of the primary C&NW railroad corridor and west of the switchyard. This area is mostly industrial but does contain some old field vegetation and wetlands.
6. East of STH 32 and west of the primary railroad corridor. The current land use of this approximately 42-acre parcel is active cropland. Using this area would eventually convert the area from agriculture to permanent grassland.

IGCC unit

Although the IGCC would not require the same amount of excavation as the SCPC units, it would require excavation of approximately 2.7 million additional cubic yards, mainly behind what is now the North Oak Creek plant building. The ERGS plant at the North Site with the IGCC included would utilize all six of the soil deposition sites listed above. If some soil were trucked off site, WEPCO would not pile soil at the stockpile area in the southwest near STH 32 and the railroad north of Seven Mile Road and would reduce the amount of soil deposited in the berm to the north along STH 32 and south of the transmission corridor.

Regardless of the site utilized, WEPCO proposes to install toe protection at the base of the bluff and to allow the bluff to take its natural course of stabilization.

Figures Vol. 2-13 and 2-14 also show the potential wallboard plant location just north of the shooting range property. The wallboard plant might require additional stabilization of the bluff south of the ERGS North Site. For the purposes of the proposed project, WEPCO has made clear its intent to provide preliminary information on the surface environment and air quality impact of a hypothetical wallboard facility, but to defer addressing bluff stabilization for such a facility until a construction application would be filed at a later time.

Designated biological areas

The SCPC and IGCC building sites would potentially eliminate a large portion of the PEC along the lakeshore including bluff/beach, grasslands, old fields, wetlands, and woodland areas. The buildings' excavations would account for the majority of PEC impacts (79.2 acres). The new coal piles and the construction parking would account for most of remainder. Loss of the PEC would further fragment the remainder of the existing PEC that included both the property lands and those beyond the property boundaries.

The construction of the wallboard plant would result in impacts to the majority of one INRA/CSH and a smaller CSH located north of the rifle range and along the terminus of the rail road loop. Designated biological areas are illustrated in the maps in Figures Vol. 2-13, 2-15, and 2-17 for the three siting options.

Vegetation

In the northern end of the property, most if not all, of the existing vegetation near the bluff and lake would be removed for the excavation of the bluff and to provide space for the new SCPC units, coal storage areas, and other ancillary facilities. South of the existing power plant units, another community of old field vegetation would need to be cleared if the wallboard plant for the North Site were to be built.

Woodland

Selection of the North Site for the SCPC and IGCC units would eliminate the woodland area south of Elm Road and divide the woodland area north of Elm Road.

In addition to the loss of designated biological areas in the PEC, some of which is now wooded, on the north side of the property, the expansion of the existing rail loop and the construction of a new rail car dumper and indexer for the ERGS at the North Site would affect the CSH and INRA-designated 17.5-acre wooded parcel located inside of the rail loop. If the North Site were selected, the new track and car dumper would be constructed on the inside of the existing loop track, affecting 1.65 acres of the existing wooded

area. Some large sugar maple, beech, and basswood trees would be removed from the rail loop woodland, including about six trees with diameters of at least 24 inches. The blue-stemmed goldenrod, an endangered species, is not located within the area to be impacted by the proposed rail work connected with use of either site.

A majority of the woods would be lost from the INRA/CSH at the existing terminus of the WEPCO rail loop if the wallboard plant is built later. The exact amount would depend on the size and shape of the plant.

Wetlands

The majority of wetland impacts would be caused by the removal of the bluff area for construction of the SCPC units. This construction would require elimination of some of the property's highest quality wetlands located within the PEC. The construction of the ERGS would require approximately 18.78 acres or 22.5 percent of the current wetlands be filled. Vegetation in many of the remaining wetlands would experience secondary impacts including changes to the area's hydrology, impacts to water quality, wildlife habitat, and the introduction or encouragement of the proliferation of non-native/invasive species. ERGS impacts to the wetlands are further detailed in Chapter 8.

Grassland

Regardless of the site selected for the ERGS, the grassland areas on the fly ash landfills would be disturbed during construction by using them as soil repositories, laydown areas, and construction parking. These alternatives would result in the removal of grassland habitat either permanently or temporarily.

The former Oak Creek South Landfill has been closed and reclaimed by planting with perennial grass and herbaceous species. This area would be covered with soil stockpiled from the excavation of the proposed ERGS SCPC units. It would then be used as a construction laydown area. Vegetation impacts in and around the former landfill would be heavy during the term of the plant construction while the berms are built. However, vegetation similar to that on the closed landfill would eventually be established on the stockpiled soil berm, and re-established on top of the closed landfill after its use for construction laydown.

No determination has been made yet as to which plant species might be used to reseed the grasslands or to seed the new soil stockpiles and berms. The composition of the grassland seed mix chosen for replanting, must comply with the DNR Bureau of Solid Waste guidelines. WEPCO has had success for two decades in using a heavy rate of Kentucky 31 tall fescue to seed its ash landfill facilities. It has had success in establishing grasslands at WEPCO landfills using a seed drill. The grassland areas would likely be seeded using an appropriate technique necessary to establish a good ground cover for the edaphic conditions found at each area. However, the benefit might not be enough to be considered as a mitigation action to offset habitat losses elsewhere. Projected wildlife impacts and recommendations for minimizing them through grassland care are discussed in chapter sections below.

Any grassland formed following the creation of these soil placement areas would be mowed periodically to maintain herbaceous plant species dominance. Mowing at the South Oak Creek Landfill has not occurred earlier than mid-July in recent years and typically it is done after August 1. Whenever possible, the entire grassland on a parcel would not be mowed during any one year and would not be mowed prior to August 1. The intervals between mowing could possibly be made longer, every second or third year for example. On the closed landfills, while the option of using longer intervals between cuttings can have benefits to certain

wildlife species (see the discussion under Wildlife impacts), the DNR Bureau of Solid Waste currently requires annual mowing. Using an annual cutting cycle also prohibits the option of only cutting a portion of the site in any given year, a strategy that can have positive wildlife value.

The cropped field of approximately 30 acres located just west of the railroad, east of STH 32, and north of Seven Mile Road would be partially covered by the new soil stockpile to be added. Although there would first be a soil buildup, the conversion of any of the agricultural parcels to grasslands should have a positive impact on wildlife populations in the local area. The soil stockpile would probably be planted in grassland species.

All disturbed areas on the site would be re-vegetated with various trees and grasses to stabilize the site. WEPCO's overall approach to the re-vegetation of the property would be to create an "aesthetically enhanced" landscape while preserving woodlands, streams, and other existing natural features if possible. Trees, shrubs and grassy areas would be planted. Also new physical features would be formed to enhance the aesthetics of the site. For example, one purpose of the new soil berms would be to block the main elements of the plant from public view. These berms would be shaped, compacted, and seeded, probably to grassland species and plants suited for slope stabilization.

Wildlife

Construction of the ERGS units, particularly the two SCPC units, would potentially destroy bluff and beach, woodland, grassland, old field, riparian, wet meadow and shallow marsh habitat. The wildlife species that use these areas would be forced to relocate to other habitat areas on or off the WEPCO property.

Habitat Fragmentation

Selection of the North Site for the SCPC and IGCC units would eliminate approximately 80 acres of PEC consisting of old field, woodland, bluff, beach and wetlands. Part of this acreage would be lost to the new coal piles and new soil berms. The remaining PEC land would be split into two main areas on either side of the existing North Oak Creek fly ash landfill. These blocks of PEC would be oddly shaped and smaller than their present situations, creating more edge that would have a negative impact on area-sensitive wildlife species such as forest interior birds and amphibians. The smaller habitat areas would still support generalist wildlife species and force the area-sensitive species to find new areas, mainly off-property. In addition, the proposed screening berm on the north side of the OCPP property would potentially create a barrier for smaller wildlife species like frogs and salamanders trying to reach habitat areas off property.

Part of the PEC would be lost in the southern part of the property if the wallboard plant were constructed. The wallboard plant would eliminate 5.4 acres of the PEC, mainly old field and shallow marsh. This would force wildlife to travel longer distances in marginal or unsuitable habitat to reach other suitable habitat blocks. This additional traveling would increase the exposure to predators and human factors that could lower survival rates. However, the portion of PEC to be removed would not be significant to the overall PEC in the property because the portion to be removed is located on the edge of the corridor. This impact would not increase the amount of edge habitat significantly, and the remaining habitat block south of the existing power plant units would still be suitable habitat for area sensitive species.

Loss of the PEC in these two areas would further fragment the remaining PEC and increase the amount of edge habitat. This would increase impacts on area sensitive species such as forest interior birds and

amphibians. For birds, the main impacts would be increased nest predation and nest parasitism, lowering nest success. For smaller wildlife species such as amphibians, the main impact would be to increase predator pressure, lowering survival rates.

Woodland

Selection of the North Site for the SCPC and IGCC units would eliminate the woodland area south of Elm Road and divide the woodland area north of Elm Road. The remaining woodland would still provide habitat for wildlife, but mainly for species that are accustomed to disturbance such as raccoon, opossum, or deer. It would be less suited for species that are more sensitive to disturbance and habitat size, such as forest interior birds or amphibians.

The woodland area on the north site around the North Oak Creek landfill has wetlands in and adjacent to woodlands. This combination of environments helps to support several amphibians that use woodlands, like salamanders, spring peepers, and eastern gray tree frogs. The woodland area provides cover and the wetland areas provide breeding areas. The North Site plan would divide the woods and create an open area between the remaining woodland blocks. This would reduce the amount of cover for the amphibians and would result in the remaining woodlands being separated from portions of the wetlands, limiting access to these breeding areas. This situation would have the potential to limit the amphibian population growth by reducing breeding opportunities.

About 2.9 acres of woodlands west of the railroad tracks would be removed. This woodland provides habitat for birds, mammals, amphibians, and reptiles. The loss of a portion of the woodland would increase the edge habitat, negatively affecting area-sensitive species such as forest interior birds and amphibians. Species (e.g., raccoon, deer, opossum, etc.) that are accustomed to disturbance, like raccoons, deer, or opossums, would adjust to the reduction in woodland habitat. The combination of the woodland and the adjoining shallow marsh provides good habitat for woodland amphibians like salamanders or spring peepers. The increase in edge habitat would have the potential to increase predation on the amphibians. However, the increase is not likely to be severe due to the small impact of the clearing.

Wetlands

As discussed in the Vegetation section of this chapter, construction of the SCPC units at the North Site would eliminate the shallow marsh and wet meadow habitat on the lakeshore, converting it into a storm water pond with deeper, open water and eliminating the existing plant structure. Wildlife use of the wetland would change. New species using the pond would include ducks, mergansers, geese, coots, snapping turtle, bullfrogs, leopard frogs, painted turtle, great blue heron, gulls, and shorebirds. It is likely that, eventually, the pond would become populated with game fish like bass and bluegills that would also provide food for herons and mergansers. On the other hand, the addition of fish like bass, blue gills, and so forth would adversely affect the amphibian population because the fish would eat amphibian eggs.

The soil relocation would fill in wetlands along the creek west of the railroad tracks, regardless of the power plant site selected. The removal of these wetlands would force the associate wildlife to relocate.

Grassland

Using any of the six soil placement areas on the OCPP property, regardless of site option selected, would affect wildlife habitat. Conversion of the agricultural parcels to grasslands would likely be considered to be

beneficial from a wildlife perspective. Conversely, wetlands converted to uplands would adversely affect some wildlife species while others respond in a positive manner. The South Oak Creek landfill grassland would be temporarily replaced with additional soil being added and used as a laydown area, but ultimately this area would be returned to grassland following site construction. Wildlife using the existing grasslands would be displaced during this construction period.

If the grassland habitat on the landfills were removed permanently, grassland songbirds and other grassland wildlife species would be forced to relocate. Because of the lack of grassland habitat in the surrounding landscape, wildlife would find it difficult to find suitable habitat in which to relocate. Wildlife would be forced to move into overcrowded habitat or use marginal habitat, potentially lowering reproductive and survival rates.

If these areas are only temporarily disturbed, it is possible that steps could be taken to enhance the area to support grassland songbirds again through plantings and a change in the mowing schedule. Grassland songbirds require areas with medium to tall grasses that are fairly dense. This could be achieved by re-planting these areas with cool season grasses like brome grass or Canada wild rye or warm season grasses like big bluestem or switch grass, with some species that flower and attract insects. The grasses would provide the birds with structure for nests, perches for singing, sources of food, and cover for resting. Other flowers would attract insects that provide an additional food source for the birds.

Changing the timing and frequency of mowing can potentially improve habitat for songbirds. The Oak Creek landfills are mowed one to two times a year to keep the areas free of woody vegetation. Grassland songbirds nest between April 15 and July 15. Any mowing during that time would destroy nests and possibly nestlings. Mowing prior to April 15th could also eliminate that year's potential nesting cover or delay nesting until the grass cover has reached a suitable height. The following mowing options, in order of DNR wildlife staff preference, can help grassland songbirds:

1. Mow the landfill sites in alternating years, every one to two years. This would promote more dense nesting cover for grassland songbirds and other grassland nesting birds like ducks.
2. If yearly mowing is necessary, divide the landfills into several units and mow one unit each year on each landfill. The remaining un-mowed units will still provide residual grass for in which birds can nest.
3. Mow only once a year, after July 15, to allow some grass cover to grow back for the following spring.
4. Mow after July 15 to avoid destroying nests or nestlings.

The loss of these grassland areas would also impact other wildlife species, like voles and snakes, forcing them to relocate during construction, temporarily or permanently. Many of the non-bird wildlife species that use the grasslands on the OCPP property (toads, weasels, vole, or foxes, for example) use multiple habitat types and might be able to re-locate into adjoining habitats temporarily. If the landfill grassland habitat were restored, these species could re-colonize the area.

If the cover were permanently removed or buried, the wildlife using the area would have to stay in overcrowded habitat or relocate off property. Relocation for specialist species would be very difficult due to the lack of grassland habitat in the surrounding landscape.

Bluff and beach

The SCPC units would require the elimination of 700 feet of the Lake Michigan beach. Its removal also is discussed above as related to removal of PEC land. The removal would take away habitat for gulls, geese, ducks, deer, raccoon, and opossum. It would also remove migration and wintering habitat for waterfowl, shorebirds, terns, and gulls. The loss of beach area would eliminate roosting and feeding areas for migrating birds like gulls or shorebirds. Shorebirds and gulls would have to find new locations for stopover during migration.

Riparian impacts

Construction on the North Site would replace a portion of the riparian area in the north end of the OCPP property by the proposed construction parking area. This would result in the loss of cover, food, and nesting or den sites for birds, mammals, reptiles, and amphibians. It would also reduce and interrupt the travel corridor that the stream serves.

South Site

If the South Site is selected, there would be losses to beach, bluff, grasslands, wetlands, and woodlands. Unlike the North Site, the excavations for the SCPC units would occur on already disturbed land. The IGCC unit would however impact designated biological areas and the proposed wallboard plant would be located over the majority of the northern PEC. Potential impacts to areas of biological concern are illustrated in Figure Vol. 2-16.

Topography and soils

The proposed South Site layout of excavation and soil build-up is shown on Figures Vol. 2-15 and 2-16. As with the North Site, excavation would be necessary for both the SCPC units and the IGCC unit.

SCPC units

Excavation for the two SCPC units would total about 5.8 million cubic yards. It would result in an excavated base for the units of about 34 acres. The slopes would climb about 80 feet over a distance of about 200 feet so that the overall excavated area would be about 48 acres.

The disposal of soil excavated for the SCPC units would be in the areas 1, 2, 3, and 4 as listed above for the North Site and shown in Figures Vol. 2-15 and 2-16.

IGCC unit

WEPCO's site grading plans for the construction of the IGCC facility at the South Site (with the IGCC facility located entirely on WEPCO property) would call for excavation of an additional 1.5 million cubic yards of soil.

The wallboard plant for the South Site would be located on the northern, Elm Road portion of the site, north of the existing OCPP plant. The bluff would be stabilized when and as needed if a company agreed to build such a plant at a later date. Such construction details are not a consideration at this time because there is no actual plan for WEPCO or anyone to build the plant.

The underlying cause of bluff erosion is erosion of the toe of the bluff and the near shore lake bed caused by the action of waves on Lake Michigan. This erosion would be addressed with a combination of stone revetment structures and retained beaches as required.

Designated biological areas

The South Site, if chosen would impact over half of the northern PEC and an additional 9.6 acres of the southern PEC. The excavation and construction of the IGCC would result in the removal of all of an INRA/CSH-designated area in the southern part of the property. The location chosen for the wallboard plant in this alternative would remove approximately half of the northern PEC, further dividing the corridor.

Vegetation

Woodland

If the South Site is selected, the new track and dumper could be constructed outside of the existing rail track, so the trimming of the woodland south of this area would affect only 0.16 acres of the wooded area.

The northern property woodlands, north of Elm Road near the lakeside, would be cleared if the prospective wallboard plant is built.

The construction of the IGCC and the portion of the railroad loop that would connect back to the main line would eliminate 6.3 acres of a 7.1-acre woodland and associated wetlands (sedge meadow, pond, and wet meadow) associated with a designated INRA./CSH and would completely remove a smaller CSH located near the Lake Michigan shoreline.

Wetlands

As discussed in Chapter 8, wetland losses would total 15.84 acres or 19 percent of the property's total wetlands. In addition to filling in some wetlands, other wetlands would experience secondary impacts.

Grassland

As with the North Site arrangement, the grasslands that would be affected would be those that are associated with the existing closed landfills on the property. The effects would be similar to those from the North Site arrangement except for small differences in the changes to the North Oak Creek landfill and for the lack of a projected new soil stockpile (and so lack of a projected new grassland) next to the switchyard.

Old field

The construction of the plant at the South Site would result in the loss of some old field in the southern portion of the OCPP property. The IGCC construction would lead to some old field loss as part of a loss of PEC land. The wallboard plant, if constructed, would eliminate additional old field PEC land in the northern end of the property.

Wildlife

WEPCO would place the SCPC and IGCC buildings directly south of the existing power plant facilities on the lakeshore. Locating the buildings in this area would directly impact woodland, pond, beach, wet meadow, shallow marsh, and old field habitats. Wildlife using these areas would be forced to relocate to other habitat areas on property or off property.

The new power plant buildings would isolate the south side of the OCPP from the north side for smaller wildlife species like frogs, salamanders, turtles, and voles. The proposed building site areas would be unsuitable travel corridors for smaller wildlife, exposing them to high levels of danger from equipment, cars, and so forth. This barrier would result in area-sensitive species becoming isolated in smaller blocks of habitat, increasing the potential for these species to be eliminated from the property if the specific habitat type continues to decrease in size.

Habitat fragmentation

The SCPC buildings and excavation would probably not affect the PEC in that area. However, the IGCC buildings along the lakeshore would result in the removal of the northern portion of the corridor along the lakeshore. The corridor impact is on the northern edge of the existing corridor, which would minimize impacts to the overall corridor. The potential building site and IGCC storm water facilities would eliminate a small acreage of PEC in that part of the property. The loss of this area would reduce the travel corridor for wildlife and force animals to travel a slightly longer distance in marginal or unsuitable habitat to reach similar habitat blocks. This additional traveling would increase exposure to predators and human factors that could lower survival rates.

The South Site could eliminate a total of approximately 66 acres of the PEC in the north end of the OCPP property, from the creation of construction parking, the potential construction of the wallboard plant, and the coal piles. The PEC areas consist of woodland, old field, and wetland along the lakeshore, and woodland and wetlands off the lake. The remaining corridor land, 49 acres, would be west of the existing North Oak Creek fly ash landfill and would consist mainly of wetlands and woodland. It would be shaped like an "L" with the width under 500 feet at its widest point. Although the remaining block of corridor would still provide good habitat for wildlife, the screening berm on the north side of the OCPP property would potentially create a barrier for smaller wildlife species trying to reach habitat areas off property.

Woodland

The construction of the IGCC and the portion of the railroad loop that would connect back to the main line would eliminate 6.3 of the 7.1-acre woodland and associated wetlands (sedge meadow, pond, and wet meadow) in the INRA/CSH at the southern end of the rail loop. The wildlife species that use this area would be forced to relocate to other sites on or off the property. The small portion of woodland left would likely be used by wildlife that are used to human activities, such as raccoons, opossums, squirrels, or robins. Area-sensitive species would likely be forced to relocate.

Selection of the South Site would also lead to the elimination of the majority of the woodland along the lakeshore in the northern end of the property, removing all habitats for wildlife, if the berms are built and the wallboard plant is constructed. A smaller portion of the woodland would be preserved off of the lake. This area would still provide habitat for wildlife, mainly species that are adjusted to human disturbance, but not for species sensitive to disturbance and habitat size. Area-sensitive wildlife would be subject to edge effects in the smaller woodland, such as increased predation, nest parasitism and nest predation.

Wetlands

Most of the wetlands that would be affected by construction on the South Site are small in size, under one acre. Typically these areas support generalist species, which use varied habitat types, and a few specialist species. The loss of these areas would force the wildlife to relocate to other areas.

The combination of the woodland and the wetlands in the woodland in the INRA/CSH near the rail loop terminus is likely to support woodland amphibians like salamanders, spring peepers, and eastern gray tree frogs. All three site options would require filling in the wetlands within the seven-acre woodland and clearing all or most of the woodland, eliminating potential habitat for the amphibians. Any amphibians using the area would be forced to relocate or be destroyed.

Individually, the loss of a small wetland might not have a significant impact on wildlife, but the cumulative loss of all these wetlands in the north and south ends of the OCPP property would have a significant impact on wildlife use in the area.

Bluff and beach

Use of either of the South Site options would result in minor impacts to the bluff or the beach. The shoreline where the SCPC units would be installed is now covered in rip rap.

Riparian habitat

Use of either of the South Site options would remove approximately 1,900 feet of the stream running through the woodlands, for the potential commercial wallboard plant. This would result in the loss of riparian habitat for birds, mammals, reptiles, and amphibians. The cleared area would also create a barrier between the remaining corridor and the beach area.

South Site-Exp

The only difference between the South Site option and the South Site-Exp option involves the utilization of the shooting range property. If the shooting range were purchased by WEPCO for construction of the ERGS facilities, environmental studies would be required, and the shooting range would be relocated to another property (probably necessitating additional environmental studies). A potential area for relocation is a former horse farm located on the north side of Seven Mile Road abutting WEPCO's property.

Topography and soils

SCPC units

As can be seen in Figures Vol. 2-17 and 2-18, the excavation dimensions and volume for the two SCPC units would be the same as that for the South Site described above. The placement of the SCPC excavation materials, the dredged materials from the harbor, and the material from the intake tunnel would be the same also.

IGCC unit

Figure Vol. 2-3 shows also, however, that the grading plan for the South Site-Exp has the IGCC facility sited on what is presently the shooting range property. For the South Site-Exp, soil placement would occur in repository areas 1 through 4 and 6 as listed above for the North Site (in other words, all but the repository site east of the railroad and south of the switchyard) and on a portion of the shooting range property south of the IGCC buildings. A new set of berms would be constructed about 40 to 50 feet high to frame a new shooting range south of the present location, on land presently owned by WEPCO north of Seven Mile Road.

The IGCC would require excavation beyond the volume generated by excavation for the SCPC units. About 9.8 million cubic yards total (for all three units) would be excavated, almost as much as required for the North Site. About 4.0 million cubic yards total would be excavated to accommodate the IGCC. Some of this material would come from excavating the bluff, and some would come from grading the present shooting range property.

Vegetation

There would be differences between the vegetational changes resulting from construction at the South Site and construction with the expanded IGCC footprint at the South Site-Exp.

In the southern portion of the OCPP property, the construction of the IGCC would result in removal of larger portions of the two southern INRAs/CSHs (south end of rail loop, and west end of rifle range), both of which are woodland and wetland associations.

Woodlands, wetlands, and old field vegetation north of Elm Road would also be removed to the extent that they were needed for coal pile construction and construction of the potential wallboard plant.

All three site options would require the removal of about 2.9 acres of woodland west of the railroad, from soil stockpiling.

Grassland

Grasslands would be affected by the construction at the South Site-Exp because there would be more soil excavated. Not only would the soil stockpile near the switchyard be used, but the soil stockpile on the existing cropland toward Seven Mile Road would be bigger than that for the South Site. Soil stockpile areas would be planted as grasslands.

Wildlife

Construction at the South Site-Exp would place the SCPC and IGCC buildings south of the existing power plant facility on the lakeshore and spread them southward over more acreage than the South Site. The buildings would affect both existing WEPCO property and the existing rifle range property. Habitat types affected would include woodland, old field, wet meadow, shallow marsh, bluff, and pond. Wildlife using these areas would be forced to relocate to similar habitat on the WEPCO property or off property.

Expansion of the power plant buildings on the south side of the existing power plant facility would increase the distance between the habitat blocks on the north and south sides of the OCPP property. This would make travel between the north and south sides of the property more difficult for smaller wildlife species like frogs, salamanders, turtles, or small mammals. The proposed building layout would not provide suitable areas for wildlife to travel northward, exposing them to increased levels of danger from equipment or cars, for example. This barrier would limit movement of the specialist species, potentially causing these species to be eliminated from the local habitats on the north or south sides of the OCPP property.

Habitat fragmentation

The potential building sites would eliminate the northern portion of the southern PEC that consists of old field, wet meadow, bluff and shallow marsh. The buildings would eliminate about twice as much PEC land as building on the South Site. The loss of this area would reduce the travel corridor opportunities, forcing

wildlife to travel a longer distance in marginal or unsuitable habitat to reach other suitable habitat blocks. This additional traveling would increase wildlife's exposure to factors that could lower survival rates, such as predators or human factor impacts like cars, cats, or dogs.

Removing this area would reduce the size of the migration stopover sites for birds on the property because of the loss of sedge meadow, old field, pond, shallow marsh, and the seven-acre hardwood woodland. The quality seven-acre woodland near the rail loop terminus (see Table 10-9) provides important stopover habitat.

While the woodland is not significantly large it is a natural community that provides the necessary diverse plant structure and food sources. Migrating birds would be forced to use other similar habitat for stopover sites on or off the OCPP property. Reductions in stopover habitat means migrating birds would be forced to use overcrowd existing stopover sites or marginal sites. Some of these areas might not have all the necessary food and shelter or might be overtaxed by other birds' use. Without the necessary resources, the bird's journey becomes more difficult and potentially fatal. The difficulties potentially could increase stress on fatigued birds, making them unfit to continue the journey or making them reach the breeding grounds in poor condition for breeding.

The plant constructed at the South Site-Exp would impact the PEC in two locations, on the north side and in the middle of the PEC south of the existing facility. The northern impact would remove approximately 10 acres of corridor consisting of shallow wetland and old field. The second impact, approximately four acres, would cut off a finger portion of the 33-acre woodland, interrupting the PEC. However, the woodland north of the impact would still be large enough to be used by specialists and would still be connected with the remaining portion of the corridor along the lakeshore.

The plant at the South Site-Exp would eliminate a 5.3-acre woodland, part of the INRA/CSH at the end of the WEPCO rail loop and approximately four acres of the INRA/CSH woodland and stream corridor at the west end of the Rifle Range.

Woodland

The woodland south of the proposed plant construction site is smaller and disconnected from the rest of the corridor by about 400 feet. This area would be more suited for generalist wildlife species. Wildlife would have to travel in marginal or unsuitable habitat to reach the remaining habitat area. This additional traveling would increase exposure to factors that could lower survival rates, such as predators like hawks or human factor impacts such as cars or pets.

The plant at the South Site-Exp would eliminate the 7.1-acre hardwood woodland with associated wetlands in the INRA/CSH at the terminus of the rail loop. It would also eliminate the woodland portion of the INRA/CSH west of the existing shooting range (5.3-acres) and a portion of the woodland INRA/CSH associated with the ravine south of the shooting range property. The wildlife species that use these areas would be forced to relocate to other sites on property or off property.

The above woodlands, smaller and by themselves not likely to provide much habitat for forest interior birds, are nevertheless in close proximity to a larger block of woods INRA surrounding the ravine south of the shooting range. For this reason, forest interior birds are likely to use the smaller woods. Loss of the smaller woodlands would force forest interior birds to find new locations.

The INRA west of the shooting range consists of a woodland and shallow marsh that provides cover and breeding areas for amphibians like salamanders, spring peepers, and eastern gray tree frogs. The elimination of the woodland would eliminate the local population of amphibians using the woodland and the wetland.

Wetland

Wetland impacts would be as described above.

Riparian

The power plant at this site would impact two stretches of stream, one 500 feet and the other 200 feet, and the woodland surrounding these streams. This would result in the loss of habitat for birds, amphibians, reptiles and mammals. In particular, it would remove good foraging areas for birds like swallows, flycatchers, kingfishers, or herons, which feed on insects and fish. It would remove good foraging areas for mammals like raccoon, opossum, or mink, which feed on fish and crayfish. It would also remove good foraging areas for amphibians like frogs, which feed in insects, and reptiles like turtles or snakes, which feed on fish and insects. It will also remove cover for birds, amphibians, reptiles and mammals.

Existing Environment and Potential Impacts in the Railroad Corridor

The railroad corridor runs through mixed residential and agricultural lands. The topography is generally level but gradually sloping downward to the south. The geology of this area is the same as that on adjacent lands. The railroad track lies on a raised bed of gravel with the ground surface sloping downward away from the track. Shallow ditches parallel the track on both sides. Soil types consist of primarily silt loams and silt clays. The railroad corridor is a highly disturbed area with many invasive and non-native species. Vegetation along the corridor consists of shrubs, wetland plants, and prairie plants and grasses in upland areas (refer to Chapter 8).

Wildlife within the railroad corridor is consistent with those species identified in the surrounding areas, mostly generalists because of the level of disturbance related to corridor maintenance. There are no identified endangered or threatened species known to occur within the railroad corridor. As discussed earlier in this chapter, archeological sites have been identified in the area, but the WHS has concluded that no adverse impacts would be expected.

The railroad corridor would change little with the exception of the proposed underpass at Six Mile Road and the overpass at Seven Mile Road. The geology of the corridor would remain unchanged. The primary vegetative impacts would be due to the proposed filling in of wetlands and the removal and reconstruction of drainage ways. The construction of new drainage ways for both Six and Seven Mile Road would impact the quality of the stream and habitat. The construction of new drainage ways within the corridor where wetlands would be filled in, would most likely increase the number and density of invasive and non-native species in the remaining wetlands. This, in addition to erosion caused by construction activities, would further degrade the wetlands and stream habitats adjacent to the railroad corridor. Impacts to wildlife within the railroad corridor would be expected to be minimal due to the current degraded nature of the vegetation and provided that construction activities were limited to the railroad corridor.

11

Chapter 11 - Community Impacts

The assessment of community impacts depends on identifying:

- the affected communities and types of impact
- short-term construction impacts, as well as long-term impacts
- ways to mitigate impacts
- ways to ensure that mitigation methods are followed through.

This chapter discusses a range of potential community impacts, and methods for mitigating these impacts.

Affected Communities

The affected communities can be divided into three categories. The potential impacts experienced by each community and the appropriate mitigation measures that might be applied vary by category.

Communities close to the power plant site

Communities closest to the site may experience increased noise, dust, traffic problems, and visual impacts. Communities more than one-half mile away are usually too far from a power plant site to experience most of these impacts, but there exceptions, especially with respect to visual impacts along the lakeshore.

Communities considered to be close to the power plant site include: homes along Elm Road, Barton Road, and Studio Lane in the Barton Oaks Subdivision, three private properties surrounded by WEPCO-owned land, and scattered housing closest to the proposed plant sites. More information about impacts specific to these properties is found in the section on Residential Impacts.

Communities close to associated facilities

Affected communities may be located not only near the power plant site, but near one of the facilities providing fuel to the site, locations where waste from the plant is disposed, along delivery routes, or near the electric transmission lines delivering power from the site.

For the ERGS proposal, some of the primary community concerns involve potential impacts related to these auxiliary facilities. For example, regardless of site, train traffic would increase along the Union Pacific (UP) Railroad, south of the site. Changes to the electric system would involve rebuilding of existing transmission

lines and the construction of one, new 345 kV line about four miles long. More information about how communities could be affected by these facilities can be found on the sections on Railroads and Electric Transmission Lines.

The larger community

Power plants may also affect communities at a distance through the need for increased services, such as water supply, or through shared revenue payments. Refer to the sections on potential impacts to Municipal Services and Shared Revenue payments for the city of Oak Creek and the town of Caledonia.

The entire OCPP property is divided by the boundary between Milwaukee and Racine counties. One of the proposed sites (North Site) is in the city of Oak Creek, while the other sites (South Site and South Site-Exp) are in the town of Caledonia. The proposed transmission line is in the town of Caledonia, and construction related to proposed rail changes would occur in the town of Caledonia.

Site History

Before beginning the discussion of potential community impacts, some general background information about the site and the demographics of the local communities are provided.

The history of the Oak Creek site is a part of the history of the city of Oak Creek. Construction of the first unit of the OCPP began in 1950. Because the power plant was considered a "financial plum," its construction was one of the factors that led to the transformation of the town of Oak Creek into the city of Oak Creek.[115] Before that, the site was agricultural since at least the 1930's.

OCPP generating units

Table 11-1 lists the coal units built as part of the OCPP over time. Refer to Figure 6-2 for their location.

WEPCO has no current plans to retire any of the active units. A generating unit usually has about a 40-year life for accounting purposes. However, with proper maintenance and upgrades, it is not unusual for a plant to operate far beyond this timeframe.

Landfills on site

The site has served as a landfill for the OCPP ash. There are three landfills on the Oak Creek site. Refer to Figure 6-2. These are the:

[115] From "Birth of a City" by Carolyn Haack, 1996.

Table 11-1 History of generation construction at the OCPP

Plant	Size	In Operation	Retired	
North Oak Creek Plant				
Unit 1	125 MW	1953	1989	The building that housed these units is currently used to support coal handling facilities
Unit 2	125 MW	1954	1989	
Unit 3	125 MW	1955	1988	
Unit 4	125 MW	1957	1988	
South Oak Creek Plant				
Unit 5	275 MW	1959	Active	
Unit 6	275 MW	1961	Active	
Unit 7	310 MW	1965	Active	
Unit 8	310 MW	1967	Active	
Internal Combustion Unit				
Unit 9	Primarily natural gas-fired; can also burn diesel	1969	Used about 3 hours/day on 24 days per year	

- North Landfill (located east of the Union Pacific Railroad tracks, across from the Barton Oaks Subdivision)
- South Landfill (located behind the buffer south of Haas Park, on Elm Road)
- Caledonia Landfill (located in Racine County, south of the existing plant)

The Caledonia Landfill is the only one still active. WEPCO periodically trucks ash stockpiled at this landfill to the Pleasant Prairie power plant, the newest WEPCO coal plant built in Wisconsin. This plant can burn, for fuel, any of the ash currently in landfills on the Oak Creek site. The proposed ERGS units could also burn this ash, and thus trucking of this ash would stop after the new plant is operational.

Pollution control upgrades

During the late 1980s, WEPCO installed new electrostatic precipitators on Units 7 and 8 in order to reduce particulate emissions. During the early 1990s, WEPCO installed low NO_x burners on Units 7 and 8 in order to reduce NO_x emissions.

During the mid to late 1990s, WEPCO installed equipment to allow the burning of 100 percent Powder River Basic Coal (PRB) in Units 7 and 8, and 60 percent PRB in Units 5 and 6. This reduced emissions of SO_2 and NO_x.

WEPCO started various NOx projects in 2000 that are scheduled for completion in 2005. These include installing new, low-NO_x burners and electronic control systems on Units 7 and 8, and equipment upgrades and new electronic control systems to enable Units 5 and 6 to burn 100 percent PRB coal. These projects will further reduce both NO_x and SO_2 emissions.

WEPCO-owned property

WEPCO has acquired surrounding land over the years, not only to provide room for its generating facilities, but also to provide a buffer zone between the plant and future urban development. Almost all houses

closest to the WEPCO site, including those in the Oak View #3 and Barton Oaks subdivisions were built after the existing OCPP. WEPCO also purchased corridors for transmission lines from the plant.

WEPCO owns about 1,084 acres, and is in the process of acquiring about 168 acres, for a total of about two square miles (1,252 acres) of contiguous property in the city of Oak Creek and the town of Caledonia, with about half of it in the city of Oak Creek and about half in the town of Caledonia. WEPCO's property includes most of the land bounded by Lake Michigan, Seven Mile Road, STH 32, and Elm Road. It also includes most land between the Barton Oaks Subdivision in Oak Creek and Lake Michigan. See Figure 11-1.

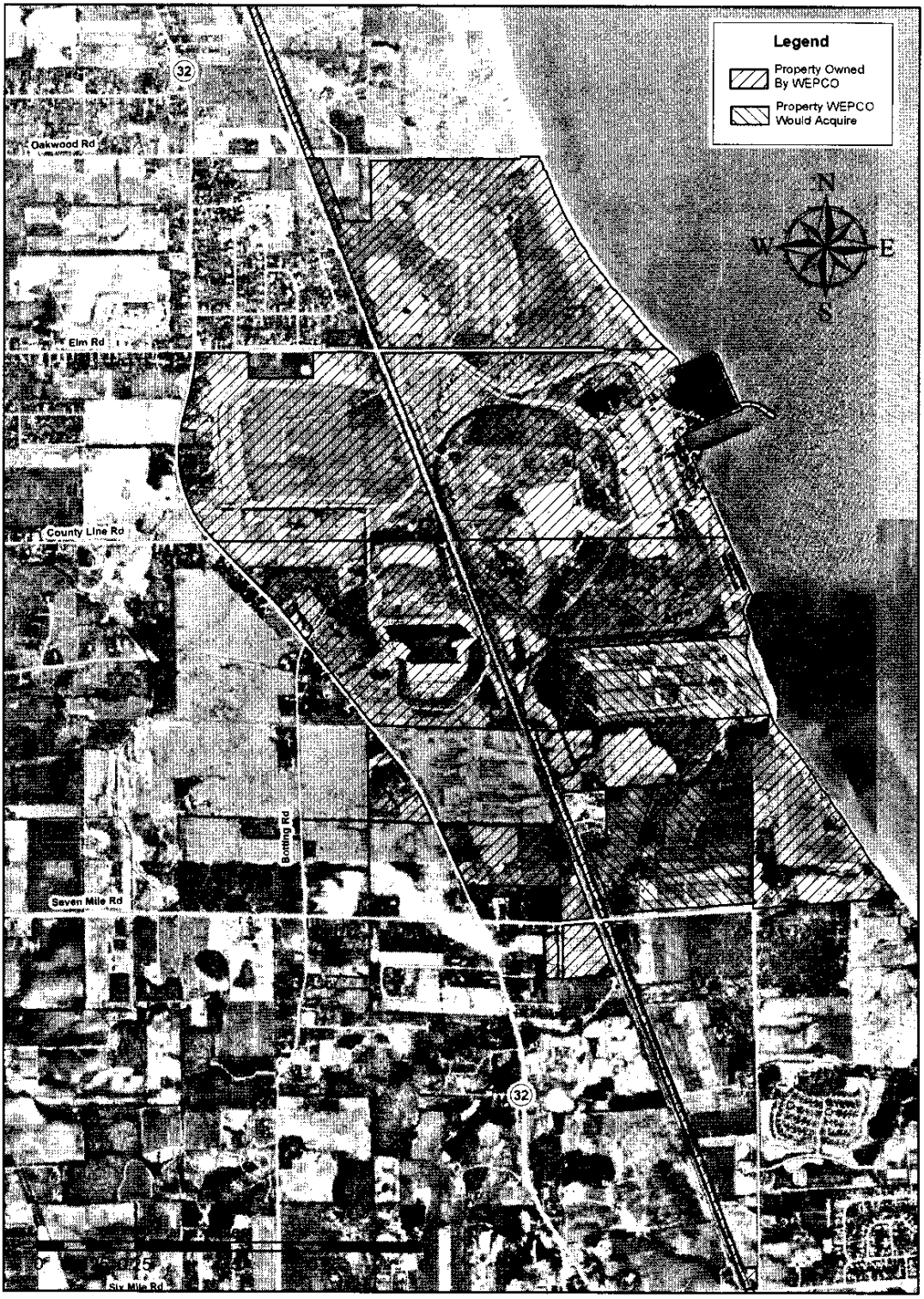
Land in this area, not currently owned by WEPCO, includes:

- Haas Park on Elm Road (donated to the city by WEPCO)
- a small cemetery along STH 32
- a federal/state shooting range
- a horse farm north of Seven Mile Road (being sold to WEPCO)
- Three properties, each with a house and barn, located north of Seven Mile Road and east of the railroad
- One property with a house, located north of Seven Mile Road and west of the railroad
- One business on the northeast corner of Seven Mile Road and STH 32

WEPCO is negotiating to acquire the horse farm north of Seven Mile Road. It has also signed an agreement with the Department of Military Affairs, so that if the Commission approves the South Site-Exp, the shooting range would be moved south onto the current horse farm property, and WEPCO would acquire the current shooting range property for placement of the IGCC facility.

WEPCO manages the land not used for power plant-related facilities as natural areas (wetland, woodland, grassland), or leases it as farmland. It also rents out several houses located on the property.

Figure 11-1 WEPCO-owned land

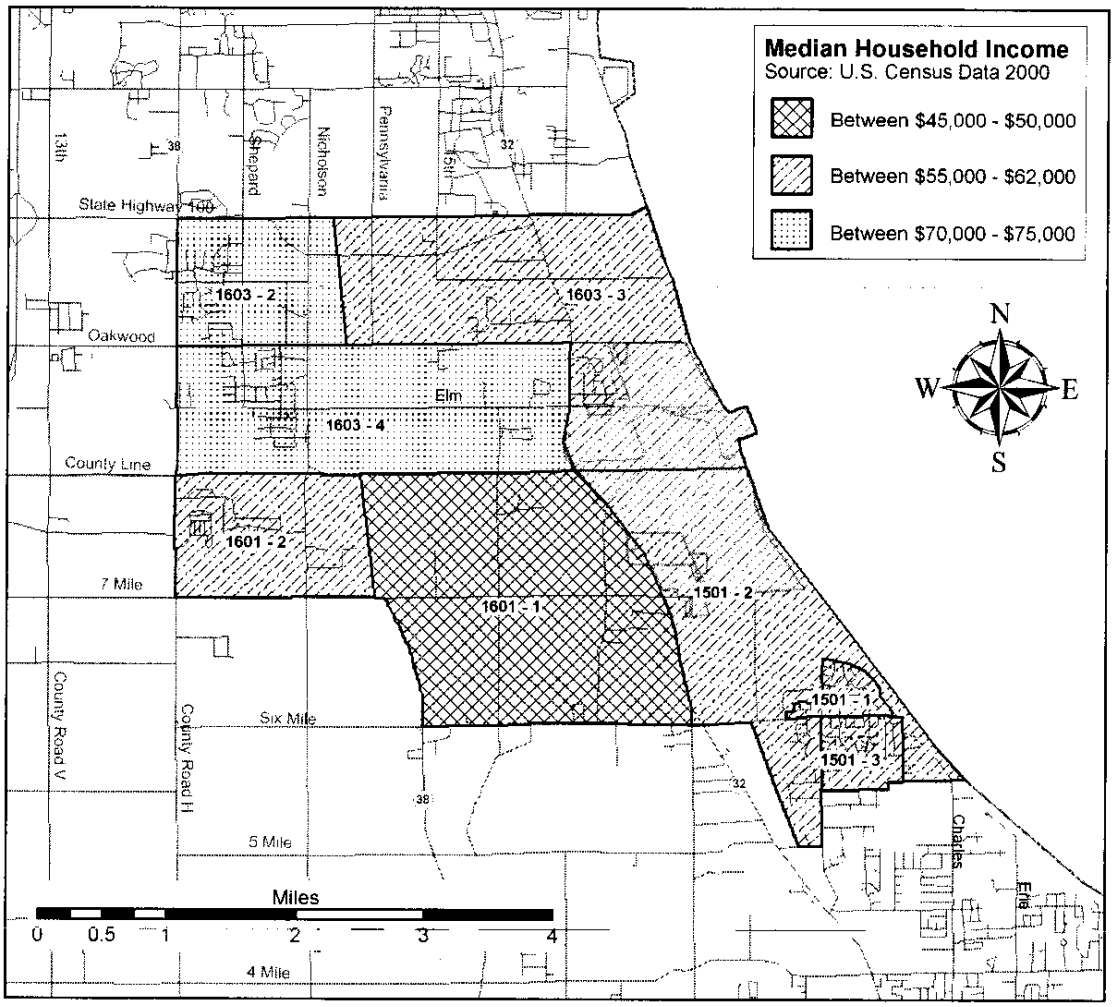


Community Characteristics

Demographics

PSC staff reviewed the data from the 2000 U.S. Census for eight census tract block groups for the area surround the proposed ERGS project site. The area was examined for median household income and race for the region located between two and four miles from WEPCO's property. Refer to Figure 11-2.

Figure 11-2 Ranges of median household income



The data showed that the median household income (in 1999) for the census tract block groups ranged from $47,000 to $74,000 annually. (Refer to Table 11-2.) The median household income for all areas was higher than the state's average median household income of $43,791. Additionally, the predominat race for the area was white, ranging from getween 92.1 to 98.9 percent of the total population.

Table 11-2 Median household income in 1999* (for areas surrounding the OCER sites)

Relation to OCER Sites	Geography	Total Population	Median household income in 1999
Closest Blocks	Block Group 3, Census Tract 1603, Milwaukee County	1266	$61,111
	Block Group 2, Census Tract 15.01, Racine County	1248	$55,500
Next closest block	Block Group 1, Census Tract 15.01, Racine County	1140	$61,620
	Block Group 3, Census Tract 15.01, Racine County	1584	$59,244
Outer blocks	Block Group 2, Census Tract 1603, Milwaukee County	2029	$73,529
	Block Group 4, Census Tract 1603, Milwaukee County	2598	$71,346
	Block Group 1, Census Tract 16.01, Racine County	499	$47,250
	Block Group 2, Census Tract 16.01, Racine County	814	$53,661

* Based on U.S. 2000 census

The average median household income (in 1999) for all areas was $60,408, and the predominant race was white at 97 percent of the total population (see Table 11-3).

Table 11-3 Predominant racial group* (for areas surrounding OCER sites)

Relation to Oak Creek site	Geography	Total Population	White alone	% White
Closest blocks	Block Group 3, Census Tract 1603, Milwaukee County	1,266	1,220	96.4
	Block Group 2, Census Tract 15.01, Racine County	1,248	1,149	92.1
Next closest block	Block Group 1, Census Tract 15.01, Racine County	1,140	1,129	99.0
	Block Group 3, Census Tract 15.01, Racine County	1,584	1,556	98.2
Outer blocks	Block Group 2, Census Tract 1603, Milwaukee County	2,029	1,926	94.9
	Block Group 4, Census Tract 1603, Milwaukee County	2,598	2,472	95.2
	Block Group 1, Census Tract 16.01, Racine County	499	487	97.6
	Block Group 2, Census Tract 16.01, Racine County	814	805	98.9

*based on U.S. 2000 census

Sensitive or vulnerable communities

Traditionally, these communities are defined as concentrations of people who are most susceptible to environmental stress, i.e. hospitals, schools, daycares, and retirement homes. Only one such concentration is located within one-half mile of the power plant site. Oak Crest, an assisted living facility, is about 0.25 mile (about 1,125 feet) northwest of the WEPCO's property boundary.

Additionally, the air quality in Milwaukee and Racine does not meet national ozone standards. The general population in these counties is therefore under respiratory stress during the summer months when ozone levels are particularly high.

Residents nearest to WEPCO-owned property

Figure Vol. 2-20 shows residential areas for a mile or more around the WEPCO-owned property. It does not show actual homes, or number of homes. In some areas, lot sizes are half an acre or more. Residents nearest to the site are most likely to experience the impacts of potential dust, noise, and traffic congestion. Those closest to the proposed site are in the Oak View #3 and Barton Oaks subdivisions, to the north and northwest of the site. As these two subdivisions are contiguous, they're referred to from here on as "the Barton Oaks subdivision." The residences potentially most affected include:

- Fifteen houses on Elm Road (three east of 2nd Avenue, eight between 2nd and 4th Avenue, and four between 4th Avenue and STH 32)
- Fifteen houses on Barton Road (eight houses that back up to the Union Pacific rail track, and seven houses across the street from them)
- Houses on the eastern end of Studio Lane (six houses on the south side of Studio Lane from Barton Road to 2nd Avenue and four houses across from them)

Houses to the south of WEPCO's property and closest to the South Site and the South Site-Exp are on Seven Mile Road, east of STH 32. These include:

- Four houses about a quarter mile north of Seven Mile Road (one owned by WEPCO)
- One house in the woods north of Seven Mile Road
- Five houses south of Seven Mile Road, west of the railroad track
- One house at the end of Seven Mile Road (owned by WEPCO)

On the west side of WEPCO's property, there are houses along STH 32. These include:

- Five houses east of STH 32, all owned by WEPCO (four between County Line Road and Botting Road, and one nearer to the intersection with Seven Mile Road)
- Twelve houses west of STH 32 (eight north of Botting Road and one south of Botting Road)

For residences potentially affected by increases in rail and vehicle traffic, refer to the Railroad and Traffic sections.

Land Use

Existing environment

Refer to Figure Vol. 2-18 for present land uses in the project area. Near WEPCO's property, both the town of Caledonia and the city of Oak Creek are a mix of land uses, including: farm fields, scattered residential and commercial developments, natural areas (woodlots, wetlands, and conservancy – or undeveloped –

parkland), recreation trails, rail corridors (both existing and abandoned), and transmission line corridors. WEPCO's property also supports these land uses. In the town of Caledonia, farmland is more predominant in this mix. The only residential concentration near WEPCO's land is the city of Oak Creek's Oak View #3 subdivision and the Barton Oaks subdivision, which are contiguous and generally referred to as the Barton Oaks subdivision.

Urbanization is spreading into this somewhat rural area, from both the north and south. The city of Oak Creek, in particular, is growing in population and housing. Population grew about 40 percent from 1990 to 2000, with about 2,500 new dwelling units built during that period. In 1999, the town of Caledonia noted a "very stable" grow rate of about 115 people (or 43 households) per year.

Land use plans

The city of Oak Creek adopted a comprehensive land use plan in April 2002. It identified nine planning goals, eight different planning districts, and 16 planned land use categories. The town of Caledonia created its first Planning Commission in 1995. In August 1996, the town adopted a land use plan, later revised in May 1999. Figure Vol. 2- 19 shows a compilation of the planned land uses. This map includes planned land uses for both the city and the town in the area of WEPCO-owned land. It also groups similar land uses (e.g. residential – single family and residential – two family) into categories, although the individual designations are used in the following discussion.

The city's map notes, "Shapes on map represent general recommendations for future land use at "build-out" of the city. Actual boundaries between different land use types and associated zoning districts may vary somewhat from representations on this map." The town of Caledonia map notes, "Plan subject to periodic revisions. Check with Town or Racine County for current updates." May 1999 is the latest update. The city's plan is a "2020 vision." The town's plan guides development through 2010.

Existing land use on WEPCO-owned land

WEPCO owns over 1,000 acres, about half in the city of Oak Creek and half in the town of Caledonia. WEPCO has left some land unused for power facilities and has allowed other land, previously used, to re-vegetate, resulting in areas of natural value. WEPCO-owned land includes 129 acres leased for farming (187 acres if WEPCO acquires a horse farm located on Seven Mile Road). WEPCO owns and rents seven houses east of STH 32: five along the highway between Seven Mile Road and Elm Road, one at the east end of Seven Mile Road, and one to the north of Seven Mile Road. For information on WEPCO-owned natural areas, refer to Chapter 10.

WEPCO's proposed changes to on-site land use

If WEPCO keeps all excavated soil on-site as proposed, 73 of the129 acres of farmland on WEPCO's property would change to grassland or landscape. If the South-Exp site is chosen and all three units are built, WEPCO would move the existing federal/state shooting range south onto what is currently a 58-acre horse farm. Keeping all excavated soil on-site would convert six acres of woodland to grassland or landscape, as well as affecting wetlands and old-field vegetation.

Two units at either the South Site or South Site-Exp would remove 31 fewer acres of farmland and preserve the six acres of woodland.

Refer to Chapter 10 for information on affected woodlands and wetlands. Refer to the section on Fugitive Dust impacts later in this chapter for impacts related to soil excavation and transport. Refer to Appendix E and the discussion in Chapter 12 for information on the effects of the Conditional Use Agreement granted by the city of Oak Creek.

Planned land use on WEPCO-owned land in the city of Oak Creek

Oak Creek's land use plan (Figure Vol. 2-19) identifies most WEPCO-owned land as "Institutional." There are two patches of Limited Development Area[116] located near the center of the site. These appear to correspond to portions of the environmental corridor. There are two areas designated Resource Protection Area,[117] one on STH 32 just south of three homes owned by WEPCO, and one close to Oakwood Road (located within an area identified in Oak Creek plans as Mixed Residential).

Oak Creek's land use plan shows WEPCO-owned land south of Oakwood Road as Mixed Residential near the railroad track and Active Recreation by the lakeshore. Forest and shrub land cover most of this area. Portions of both these planned uses overlay WEPCO's existing North Landfill. The three homes owned by WEPCO along STH 32 are in areas designated as single-family residential area in Oak Creek's plans.

Planned land use on WEPCO-owned land in the town of Caledonia

Caledonia's Land Use Plan identifies much of WEPCO-owned land as Public-Semi Public (refer to Figure Vol. 2-19). There is an environmental corridor located along the southern two-thirds of the lakeshore (between Seven Mile and County Line Road), with two environmental corridors connecting the corridor to the Union Pacific (UP) railroad tracks. In addition, there are at least four scattered natural areas further north, and a natural area on Seven Mile Road between STH 32 and the railroad tracks. North and east of a planned industrial area on STH 32 is another natural area. Refer to Chapter 10 for a discussion of potential on-site impacts to natural areas.

Caledonia plans also include an industrial area along STH 32, west of the UP railroad track. This industrial area starts north of Botting Road and continues south to the northern limit of the Sanitary Sewer Service Area, about 500 feet north of Seven Mile Road. WEPCO owns about half of this property.

On predominantly WEPCO-owned land east of the UP railroad track, continuing to an imaginary line extended north from Michna Road, the Caledonia Plan shows a block of Low-Density Residential land use. Caledonia defines low density as 0.7 to 2.2 dwelling units per acre. This block of land is bounded on the north by the shooting range and on the south by Seven Mile Road. Almost half of this land extends beyond

[116] Limited Development Areas include land in the flood fringe, isolated natural resource areas, natural resources sites, and critical species habitats. Detailed natural resource inventories and management plans are needed where any development is proposed within a property designated as Limited Development Area. Only very low density development is allowed in these areas.
[117] Resource Protection Areas include lands in public ownership, floodway, and wetland.

the Sanitary Sewer Service Area. Within this area are four homes (one owned by WEPCO), and a horse farm that WEPCO is in the process of acquiring. A mix of agriculture, grassland, shrub land, and lawns covers this land.

The Caledonia plan shows Park and Open Space for much of the land east of an imaginary line drawn north from Michna Road. Forest, brush, and grass cover most of this area.

Existing land use – adjacent to WEPCO property

Two county parks, Milwaukee's Bender Park and Racine's Cliffside Park, are located along the lakeshore, immediately to the north and south of WEPCO-owned land. Aside from state and municipal roads, the other land immediately surrounding WEPCO's property is predominantly farmland with scattered residential development. (There are a few commercial buildings and scattered residences in natural areas). The exception is the Barton Oaks Subdivision. The Barton Oaks subdivision (including Oak View #3 and Barton Oaks) is located along STH 32 and Elm Road, with WEPCO property to the south, and the UP Railway and WEPCO property to the east. The subdivision is close to Oakwood Road, on the north side. However, there is an area of farmland and forestland separating it from East Oakwood Road and its houses.

Planned land use – adjacent to WEPCO property

City of Oak Creek

Figure Vol. 2-19 shows a compilation of the city's planned land use, adopted in April of 2002. North of Oakwood Road, planned land use is Mixed Residential west of the UP railroad track, Two-Family/Townhouse Residential east of the track, and then Single Family Residential next to Bender Park. West of STH 32, the planned land use is Single Family Residential, with some Resource Protection Area. (All the residential areas are shown as one color on Figure Vol. 2-20).

In the city of Oak Creek, areas zoned as Single-Family Residential can vary from 2.0 dwelling units per net acre to 5.4 dwelling units per net acre. Areas zoned as Two-Family Residential cannot exceed 5.8 dwelling units per net acre. However, the April 2002 Summary of Volume III Plan Recommendations (Plan Summary) includes, "Adopt ordinance changes and new zoning districts to encourage innovative housing projects and subdivisions, such as condominiums near the lakeshore, mixed residential/retail buildings, cluster subdivisions, and traditional neighborhoods."

At the intersection of STH 32 and Oakwood Road and continuing south is an area planned for neighborhood business. There is a similar small area surrounding the intersection of STH 32 and Elm Road. For the most part, these reflect existing land uses.

Town of Caledonia

Figure Vol. 2-19 shows a compilation of the town's planned land use, approved in May 1999. Planned land use is commercial for the properties at the northeast and southeast corners of the intersection of Seven Mile Road and STH 32. The woods with the house north of Seven Mile Road, between STH 32 and the rail line, as well as an area along both sides of the northern portion of Michna Road (also with scattered houses), are delineated as natural areas. Other land east of STH 32 and south of Seven Mile Road is shown as Low-

density Residential (0.7 to 2.2 dwelling units per acre.) Along the UP railroad track is a bike trail, and along part of the trail is an area designated as an environmental corridor. West of STH 32, the land use plan has country lots (at 0.2 dwelling units per acre), except for a stretch north of Seven Mile Road. That stretch, and south of Seven Mile Road on both sides of STH 32 is an area shown as predominantly low-density residential.

Potential conflicts with land use plans

Existing land uses and land use plans have developed around WEPCO's existing OCPP. Because the applicants are proposing new units at an existing power plant site, the potential for land use conflicts should be minimal, if the new generation facility is properly designed. In addition, WEPCO-owned land extends beyond the amount of land needed for any of the sites. This allows for the use of distance and berms to buffer adjoining land uses from the industrial nature of electric generation.

WEPCO's decision to keep any land unused for generation facilities in a natural state fits in with the city's and town's intent to keep the appearance of this area as rural as possible. The city of Oak Creek's plan foresees rapid development. However, the residential areas planned in the vicinity of WEPCO's land would be extremely low-density. The summary of the town of Caledonia plan, while listing a loss of 9,603 acres by 2010 (from 1999) states, "The change in Agricultural land (2010) is somewhat misleading because the "Country Lot" area will remain an agricultural area, functionally and visually."

Both the city and the town land use plans attempt to guide development to avoid important resource areas, such as waterways, floodways, wetlands, and environmental corridors. The applicants have stated that they designed the proposed power plant layout so as to minimize impacts to resource areas on WEPCO-owned property. Descriptions of these resource areas and potential impacts are in Chapter 10.

Both parklands and power plants are common uses for the shoreline of Lake Michigan. There are eight power plants, in addition to the OCPP facility, located on the Wisconsin shoreline of Lake Michigan. There are also numerous state and county parks. The areas of WEPCO-owned land adjacent to the two main county parks are undeveloped, and the areas of the two main county parks adjacent to WEPCO-owned land are similarly undeveloped.

Roads bound WEPCO's property. On its western boundary, STH 32 is planned for expansion to a divided four-lane highway. Money has been placed (and taken out of) past budgets to accomplish this.

The UP railroad tracks cross WEPCO's property. In the past, train traffic on this line was much higher, and there were two tracks instead of one. Plans are going forward to increase rail traffic on this line, in addition to the increase caused by coal delivery.

Lakeview Village Concept Plan

One of the planning districts in the city of Oak Creek's Growth Concept Plan, is the Lakeview Village Mixed Use District. This district is adjacent to WEPCO-owned land, because it includes plans for Bender Park. It also suggests the possible expansion of Bender Park onto what is currently WEPCO-owned property. The city of Oak Creek has expressed concerns about potential land use conflicts between this proposed

development and the ERGS proposal. In particular, the concerns center on a possible Championship Golf Course north of Fitzsimmons Road, a possible clubhouse/restaurant on the south side of Fitzsimmons Road, and high-priced residential areas north of Ryan Road or possibly between Oakwood and Fitzsimmons Road and west of Bender Park. For further discussion of potential conflicts with the golf course, see the Recreation section later in this chapter.

Description of the Lakeview Village Mixed Use District

The land from Elm Road north to Puetz Road, from about STH 32 to the lakeshore, is part of the Lakeview Village Mixed Use District for which there is a Concept Plan. (The Plan Summary contains an illustration of this Concept Plan.) The Plan Summary states, "This District is located along the Lake Michigan shoreline and contains Bender Park. Recommendations include completing Bender Park, opening up lakeshore access, redeveloping Carollville as a mainly residential neighborhood, and creating a mixed use village center with retail and residential uses." Table 11-4 includes the descriptions for six areas identified in the plan.

Development Agreement

The Development Agreement signed by the city of Oak Creek and WEC on April 3, 2003 includes a provision that may address the city of Oak Creek's concerns about the potential impact of WEPCO's proposal on the Lakeview Village Concept Plan. Refer to items 2A and 2B in the Development Agreement, which is located in Appendix E.

Table 11-4 Some elements of the Lakeview Village District Concept Plan

	Office Transition Area
	Corporate or neighborhood offices
	Orient buildings east-south
	Transition between neighborhood and treatment plant
Carolville Neighborhood	
	Park as neighborhood focal point
	Residential redevelopment and expansion
	Strong green space connection to Lake Michigan
	Small scale neighborhood businesses
	Possible sites for institutional (i.e. church)
Lakeview Center	
	Connect STH 100 to Lake Michigan
	Strong public/civic lakefront identity
	Possible hotel/convention center site
	High-rise residential
	Lake oriented commercial destination
	Brownfield clean-up
	Bluff regrading & stabilization
Bender Park	
	Complete park development
	Championship golf course
	Possible marina
	Compatible development on adjacent properties
Transit Oriented Center	
	Multi-modal transit center
	Civic space

Office Transition Area	
	Mixed use
	Park & ride facility
	Urban character
Highway 100 Gateway Area	
	Maintain open space character along highway
	Larger scale commercial (i.e. grocery)
	Entry feature (signage, landscaping)

Zoning

Because the city of Oak Creek is a rapidly developing urban/suburban area, the city's codes are more specific than those for the town of Caledonia, which primarily identify the goals of different zoning districts. Both the city of Oak Creek and the town of Caledonia include provisions in their codes that allow land uses that existed at the time the codes were adopted, regardless of zoning. For the proposed project, the applicants would need conditional use variances from the city of Oak Creek and Racine County (with the approval of the town of Caledonia). Both the city (and town) could place special conditions on the ERGS project as part of the conditional use permit. These conditions could include a variety of items, such as noise standards, construction hours, and lighting.

On June 3, 2003 in Ordinance 2251, the city of Oak Creek granted WEPCO a conditional use permit (CUP) for the proposed project if built at the North Site. For construction at the South Sites, the applicants would need conditional use variances from Racine County (with the approval of the town of Caledonia). The city of Oak Creek placed special conditions on the proposed project as part of the CUP. These conditions include a variety of items, such as noise standards, construction hours, and lighting. A CUP in Racine County could impose similar condtions. Refer to Appendix E and Chapter 12 for more details about the CUP Option

The existing zoning for both the city and town does not reflect existing, long-term land uses, nor does it necessarily match city and town land use plans. It appears that the primary purpose of current zoning is to provide public notice and review of major projects, and to allow city and town officials to make sure that these projects meet local codes.

Zoning on WEPCO-owned property

Oak Creek

On June 3, 2003, the city of Oak Creek approved the rezoning of WEPCO's land along East Elm Road and East Oakwood Road to manufacturing (M-1). WEPCO property is currently zoned manufacturing south of East Oakwood Road, except for some Residential zoning along STH 32, where WEPCO owns and rents a few houses. In Oak Creek, WEPCO property is zoned Manufacturing south of Elm Road, except for some Residential zoning along Highway 32, where WEPCO owns and rents a few houses, the cemetery on STH 32, and Haas Park. WEPCO-owned property north of Elm Road is a mixture of zoning categories, including Park District (along the lake), Manufacturing (across from the Barton Oaks Subdivision), Agriculture, and Residential (along the UP railroad track). The Liquid Natural Gas storage tank is located on

land that is zoned for Manufacturing. The existing fly ash landfill is on land zoned Manufacturing, Agriculture, and Park District.

Caledonia

In Caledonia, WEPCO-owned property is zoned Agricultural, even though this area contains rail unloading facilities, electric transmission lines, and other industrial uses. This area also includes some natural habitat, as well as farmland. The northern 1,300 feet along the Lake Michigan shoreline is in the Structural Setback Overlay (SSO) District. This district requires all new development to be protected by erosion control measures. The SSO District may apply to the South Site and the South Site-Exp.

Zoning adjacent to WEPCO-owned property

Oak Creek

North of WEPCO property, Bender Park is zoned as Park District. In addition to Bender Park, the city has two properties zoned as Park District. One is west of STH 32, about halfway between Elm Road and Oakwood Road. The other is Haas Park, located south of Elm Road. Land is zoned Agriculture to the northwest of WEPCO's land. Property to the west of WEPCO's land is zoned Residential and Agriculture. The intent of Oak Creek's zoning for Agriculture is "to protect lands from urban development until their orderly transition into urban-oriented districts is required."

There are also about five areas zoned for Business within one-half mile of WEPCO-owned land. Four of these are along or close to STH 32 and one is on East Oakwood Road.

Two small areas within one-half mile are zoned Residential – Two Family. One of these is located at the northeast intersection of Elm Road and STH 32. The other is on East County Line Road about one-half mile west of STH 32. In addition, the Oak Creek Fire Station and the small cemetery on STH 32 are zoned Institutional.

Caledonia

In Caledonia, all land is zoned Agriculture to the west and south of WEPCO-owned land, except for Park District along the lakeshore.

Primary environmental corridor

The Southeastern Wisconsin Regional Planning Commission (SEWRPC) has identified land referred to as Primary Environmental Corridor. These are elongated areas in which concentrations of recreational, aesthetic, ecological, and cultural resources occur. This designation does not have the force of zoning, but is a guideline for development. An environmental corridor extends from the town of Caledonia onto WEPCO-owned land. Don Reed of SEWRPC conducted an investigation on WEPCO-owned land to determine the exact location of the environmental corridor. Chapter 10 describes the potential impacts to these resources.

Municipal authority and influences over the proposed project

Local governments, from counties to villages, have an important role in the design of any proposed power plant. The tools are negotiation (contracts), zoning, and administrative codes covering aspects of land development and building construction. The subjects addressed by local governments cover a wide range of topics important to local communities. They cover payments to the locality, both outside the revenue sharing statute (direct payments, payments for new municipal facilities to offset increased use of municipal services), and within the revenue sharing statutes (negotiations as to depreciation rates). They cover noise levels, drainage, commuting times, lighting, and landscaping.

On April 2, 2003, the city of Oak Creek entered into a tentative agreement with WEC (see Appendix E for a copy of the agreement). Topics that are covered by the agreement include air emissions, annual payments beyond monies which the city would receive as shared revenue payments, and funds to develop existing brownfield sites in the city.

On June 3, 2003 in Ordinance 2251, the city of Oak Creek issued a CUP for construction and operation of the proposed facilities to be built on the North Site. The conditions of this CUP are shown in Appendix E.

Proposed Construction and Operation Schedule

Most of the impacts to surrounding communities would occur during the construction period. This is when the potential for noise, traffic, and dust would be at its highest. Table 11-5 shows the activities and construction schedule that the applicants list in its application. Many of these dates are not accurate, and the length of certain activities is only an estimate. The length of the construction period depends somewhat on how many coal units are approved and built. The expected construction periods are: a minimum of four years for one unit, six years for two units, and eight years for three units.

The applicants recently updated the construction schedule and increased the estimated number of workers employed during the construction period. However, this data requires clarification and will be included in the final EIS.

Table 11-5 Site activity

Year	SCPC Unit 1	SCPC Unit 2	IGCC
2004	Earthwork (12 months) Common facilities (31 months) Rail upgrades (34 months) Material handling (54 months)		
	Transmission Phase I (47 months)		
2005	Common facilities Rail upgrades Material handling		
	Foundations (5 months) Sturctural steel erection (9 months) Transmission Phase I		
2006	Common facilities Rail upgrades		

Year	SCPC Unit 1	SCPC Unit 2	IGCC
	Material handling		
	Boiler erection (20 months) Turbine installation (12 months) Transmission Phase I	Foundatons (5 months) STurctural steel erection (9 months)	
2007	Material handling		Site development and demolition (10 months)
	Boiler erection Start-up and testing (13 months) Transmission Phase I	Boiler erection (20 months) Turbine installation (12 months)	
2008	Material handling		Site development and demolition Gasification facility erection (31 months) Combined-cycle erection (25 months)
	Start-up and testing **Begin Operation May 1, 2008**	Boiler erection Turbine installation Start-up and testing (13 months) Transmisson Phase 2 (8 months)	
2009	*Operating*	Start-up and testing Transmission Phase 2 **Begin operation May, 2009**	Gasification facility erection Combined-cycle erection Transmission Phase 3 (24 months)
2010	*Operating*	*Operating*	Gasification facility erection Combined-cycle erection Start-up and testing (17 months) Transmission Phase 3
2011	*Operating*	*Operating*	Start-up and testing (17 months) Transmission Phase 3 **Begin operation May, 2011**

Municipal Services

Water and sewer service

Currently the existing OCPP facility and all of the related onsite facilities receive potable water and sanitary sewer service from the city of Oak Creek.

The two proposed SCPC plants, regardless of site, also would use potable water from the city of Oak Creek for three purposes: employee use, demineralizer make-up water, and four percent of the water used for the sulfur scrubber. The total amount of city water used would be about 294.7 thousand gallons per day. Only nine thousand gallons per day (for employee use) would return to the city via the Oak Creek sanitary sewer. The remaining water would be lost through evaporation to the air, discharge to the lake, or through off-site disposal of waste products, (e.g. gypsum by-product). Water used by the IGCC would be comparable to one of the SCPC units, so the total volume of municipal water used would be approximately 443.0 thousand gallons per day. The proposal would require no construction of water pipelines off-site and no change in Oak Creek's existing water or sewer utility facilities.

Storm water

Storm water from the site would ultimately drain to Lake Michigan, not affecting any government costs. The city of Oak Creek would have to approve storm water drainage plans for the North Site and the town of Caledonia would have to do so for the South Site or the South Site-Exp.

Refuse collection

WEPCO would hire a private contractor for solid refuse disposal; no municipal services would be required.

Police

The applicants would depend on law enforcement services from the city of Oak Creek for use of the North Site or Racine County for the South Site or the South Site-Exp, during both construction and operation. It's unlikely that such services would perceptibly increase costs of service for government units.

Fire protection and emergency medical service

The Caledonia Fire Department would be responsible for fire protection and rescue services if the facilities were built on the South Site or the South Site-Exp, whereas the Oak Creek Fire Department would be called on for these services if the facilities were built on the North Site. In reality, because much of the power plant infrastructure such as the coal handling systems, coal storage piles, and ash landfills are shared with the OCPP facilities and are located in Milwaukee County, it is likely that the Oak Creek Fire Department would continue to serve the facility, to some extent, regardless of where the two SCPC units and IGCC plant are built. WEPCO would work with the Fire Department of either municipality, because the proposed plant would have some fire suppression measures of its own, as well as storage of hazardous wastes.

Refer to the section on Railroad Impacts for a discussion of emergency access to areas of Caledonia east of the UP tracks. WE Power has proposed to close Seven Mile Road east of the tracks, regardless of which site is used or the number of units constructed.

Schools and other social services

Given the existing high growth rate of Oak Creek's population, as well as its position relative to the cities of Milwaukee and Racine, an additional 100 to 300 permanent employees relocating to Oak Creek would not have a perceptible effect on the cost of the city of Oak Creek's services. Construction workers would commute to the construction site.

Shared Revenue

Existing shared revenue program

Through the shared revenue program, the state of Wisconsin distributes state tax revenues to municipal and county governments. The public utility distribution is only one component of the shared revenue program which is calculated under a formula that consists of four components. The state reimburses municipal and county governments for public utilities because they are exempt from local taxation. The public utility portion of the shared revenue compensates local governments for costs they incur in providing services to the public utility.

Currently, the public utility portion of the revenue sharing is based on the net book value of a public utility. The net book value is the value of the production plant (excluding land and general structures) minus depreciation, treatment plants, and pollution abatement equipment. Depreciation levels can range from 20 to 40 or more years. Total payments to the municipalities and how long the payments last greatly depend on the selected depreciation schedule.

The municipality receives shared revenue dollars for only the first $125 million of net book value of the public utility for the previous year. Additionally, the amount of dollars a municipality receives would depend upon whether the utility is located in a city, village, or town. If the public utility is located within the boundaries of a city or village, the municipality would receive a shared revenue payment of $6.00 per $1000 of the utility's net book value (6 mill) or a maximum payment of $750,000 and the county will receive $3.00 per $1000 of the utility's net book value (3 mill) or a maximum payment of $375,000. If however, the public utility is located within the boundaries of a town, the town would receive a shared revenue payment of $3.00 per $1,000 of the utility's net book value (3 mill) or a maximum payment of $375,000 and the county would receive $6.00 per $1000 of the utility's net book value (6 mill) or a maximum payment of $750,000.

Regardless of whether the public utility is located in a city or town, a total of 9 mills are applied to the value of all qualifying utility property. Payments to municipalities in any year can not exceed $300 times the population of the municipality and $100 times the population of the county.

Past adjustments to the shared revenue program

Provisions in the 2001 Wisconsin Act 16 (2001-03 biennial budget) suspended this distribution formula for payments to municipalities for the years of 2002 and 2003. Instead, each municipality's payment in 2002 and 2003 equaled 101 percent of the amount the municipality received in the prior year. Payments for counties in 2002 and 2003 continued to be calculated under the original formula.

Current legislative changes to the shared revenue program

Assembly Bill 378 vastly alters the method of calculation for the utility portion of the shared revenue program. Signed into law on July 15th, 2003, this new program bases payments on the MW capacity of new plants, instead of the power plant's net book value. Power plants that begin operation prior to December 31, 2003 will have shared revenue payments calculated under the current program. Municipalities and counties with power plants that begin operation after December 31, 2003 will receive payments under the new system starting in 2005. This applies to new power plants as well as "repowered" plants with a capacity of at least one MW. If the power plant is located in a city or village, the municipality will receive a payment equal to two-thirds of the plant's capacity (MW) multiplied by $2,000. The county will receive a payment equal to one-third the plant's capacity multiplied by $2,000. The two-third\one-third relationship will be reversed if the power plant is built in a town (rather than a city or village). The total dollar amount distributed can not exceed the municipality's population multiplied by $300 or the county's population multiplied by $100. Unlike the current shared revenue system, no payments will be distributed to the municipalities or counties during the construction phase of the power plant.

Multiple incentive payments are part of this new program. Municipalities and counties can qualify for more than one incentive payment which includes:

- $600 multiplied by the plant's MW capacity
  to both the municipality and county with a non-nuclear plant that is built on or adjacent to an existing power plant site, a former plant site, or a brownfield site
- $600 multiplied by the plant's MW capacity
  to both the municipality and county with a baseload plant that has a capacity of at least 50 MW
- $1000 multiplied by the plant's MW capacity
  to both the municipality and county with a plant that derives energy from an alternative energy source and the plant has a capacity of at least one MW
- $1000 multiplied by the plant's MW capacity
  to both the municipality and county with a cogeneration plant that has a capacity of at least one MW

Specifics for the ERGS

The Department of Revenue stated that the net book value of the OCPP in 2001 was $117.3 million, resulting in a 2002 shared revenue payment to the city of Oak Creek of $703,894 (6 mills) and $351,947 (3 mills) for the county of Milwaukee. Payment in 2003 will be 101 percent of the 2002 payment resulting in $710,933 for the city of Oak Creek. The amount the county of Milwaukee will receive will depend upon the net book value of the Oak Creek Plant in 2002. In the year of 2000, the OCPP net book value fell below the $125 million cap. Without new construction or capital improvements, the shared revenue payments to the city and county will continue to sharply decrease until the OCPP is fully depreciated.
The new shared revenue program will provide significantly more dollars to municipalities and counties with new baseload plants than under the past system. In the case of ERGS, annual payments to the municipalities and counties involved will increase by at least 200 percent. New to the shared revenue program are payments which do not decrease due to depreciation but continue at the same level for the life of the power plant. As shown in Table 11-6, shared revenue payments to the municipalities and counties would start when the first unit is operational in 2006 and continue at the same level until it is decommissioned.

Table 11-6 Projected ERGS shared revenue payments

Location	One Unit (2007 and 2008)	Two Units (2009 and 2010)	Three Units (2011 – until units are decommissioned)
	Annual Payments		
North Site			
City of Oak Creek	$1,560,000	$2,380,000	$3,200,000
Milwaukee County	$1,150,000	$1,560,000	$1,970,000
South Site and South-Exp Site			
Town of Caledonia	$1,150,000	$1,560,000	$1,970,000
Racine County	$1,560,000	$2,380,000	$3,200,000

Property Values

Whether people wish to purchase a specific property depends on numerous, inter-acting variables, which a number of studies have shown are extremely difficult to define. In the end, the cost of a house or condominium compared to its amenities is clearly of first importance to prospective buyers. Just as people build houses adjacent to existing electric transmission line rights-of-way, people build houses near existing power plants. The city of Oak Creek and the town of Caledonia are examples of this. Virtually all the

houses built nearest to WEPCO's property were built after the existing coal plant was there, and the existing coal plant has less environmental controls and less aesthetic features in its design than the proposed plant. The 2000 census tract showed the average median income of households near the plant site was $60,408 in 1999, and there was no pattern related to distance from the plant.

There are property value advantages as well as disadvantages related to the proposed plant. One advantage is location near property that provides natural visual buffers and a feeling of space. Another is location near a property that manages many of its areas for bird habitat and includes a recreational trail. Disadvantages include noise and traffic. Most properties are distant from the proposed power plant, and buyers may not be aware of its presence. Many people simply screen out any awareness of electric transmission lines or distribution lines, shapes on the horizon, or passing traffic.

Review of existing studies on property values near generation sites

Power plant impacts on property values have been the subject of discussion for many years. There has been significant debate regarding the perceived costs, stigma, and negative imagery claimed to accompany electric generation plants, although few studies have been actually conducted. Survey data often reveals a high percentage of respondents who, when given a choice, prefer not live near power plants. However, property value fluctuations are caused by a complex web of amenities and disamenities that vary significantly from location to location. When studies have tried to account for all of these many variables, whether at one location or by comparing power plants in different locations, the research is not conclusive. No study has shown a clear correlation between power plant location and reduced property values, much less a cause and effect relationship.

Glen Blomquist (1974)[118] conducted a much quoted statistical analysis of a coal power plant in Winnetka, Illinois and surrounding mean property values. His study concluded that residential property values increase in value 0.9 percent for every 10 percent increase in distance from the power plant up to a distance of 11,500 feet. Numerous other articles have applied this formula to other sites and other power plants, predicting millions of dollars of losses.[119] A closer examination of his study shows an extraordinarily weak correlation of variables. Whereas most accepted social science studies have correlations that approach 80 percent, Blomquist's study has a correlation of only 55.6 percent. Additionally, a review of 2002 property value trends show that residences located adjacent to and near the Winnetka power plant have some of the highest property values in the north suburban Chicago region. There has been continued investment by homeowners in remodeling and improvements indicating no value impact resulting from the plant or its visible 150-foot emission stack.

Clark and Nieves (1994)[120] investigated the intercity impact of a broad range of "noxious facilities" on 1970 local wages and property values. Eight types of facilities with undesirable land uses were analyzed including coal-, gas-, and oil-fired electric generation plants. Findings were inconsistent. Coal-fired plants produced a

[118] Blomquist, G., The Effect of Electric Utility Power Plant Location on Area Property Values, Land Economics, 1974, 97-100.
[119] Tolley, G.S., Effects of the Proposed Indeck Facility on Property Values, Land Use and Tax Revenues, Unpublished paper, RCF Economic and Financial Consulting, Inc. Reports, 2000.
[120] Clark, D.E. and L.A. Nieves, An Interregional Hedonic Analysis of Noxious Facility Impacts on Local Wages and Property Values, Journal of Environmental Economics and Management, 27, 1994, 235-253.

negative association with property values, as well as gas- and oil-fired plants. However chemical weapon storage and hazardous waste facilities had positive impacts on property values. This inconsistency may indicate that not all of the variables were accounted for or incorrect assumptions were used. Additionally, Clark and Nieves' analysis also had a very poor correlation of variables, only 57.9 percent.

Most recently, McCann of William A. McCann & Associates, Inc., (2002)[121] evaluated the sales trends of homes located near two newly constructed electric power plants in the northeast. He compared the real estate market in these towns prior to and after construction of the plants to home sales in nearby towns without plants. Two variables were evaluated as an indicator of market strength, the ratio of a property's list price to its actual sale price and the average marketing time for listed properties. As market demand increases, the ratio of a property's list price to its actual sale price approaches 100 percent and the average marketing time decreases. The plants went on-line mid-1999 and home sales were evaluated for the years between 1997 and 2001. The data indicated steadily increasing ratios and a shortened marketing time for all the towns reviewed. This indicated no measurable impact on the marketability or value of the homes in the towns, regardless of the existence of a power plant.

A review of the literature for other disamenities such as nuclear power plants, landfills, Superfund sites, and other air and water quality impacts, produce a wide array of results.[122] [123] Even with a heightened concern over the health and safety aspects of nuclear power, research results are not consistent.[124] For example, a study of the accident at Three Mile Island and its impact on housing prices (Nelson 1981)[125] showed no statistically significant effect.

Summary of literature review

There is no consensus on the degree to which electric generation power plants affect residential property values. The undesirable impacts attributable to the reduction of property values include air and water pollution, noise, traffic, and aesthetics. These can to some extent often be minimized or mitigated. The use of large buffer zones to reduce visual reminders of the existence of a noxious facility, appear to reduce perceived property value impacts. More importantly, the significant variables that determine property values at one location cannot be generalized to apply to all locations. In some locations, amenities such as proximity to lakefronts or parks appear to outweigh perceived disamenities. In summary, research has not conclusively determined if property values are impacted by an operating power plant, much less the dollar value of any potential impact.

[121] McCann, M.S., Property Value Impact Study, Proposed Sempra Energy Facility Northwest Corner of Gast & Lemon Creek Road, Lake Charter Township, Berrien County Michigan, Unpublished paper, William A. McCann & Associates, Inc., 2002.
[122] Boyle, M.A. and K.A. Kiel, A Survey of House Price Hedonic Studies of the Impact of Environmental Externalities, Journal of Real Estate Literature, 2001, 117-144.
[123] Ridker, R.G. and J.A. Henning, *The Determinants of Residential Property Values with Special Reference to Air Pollution*, The Review of Economics and Statistics, 1967, 49:2, 246-257.
[124] Clark, D.E., L. Michelbrink, T. Allison, and W.C. Metz, *Nuclear Power Plants and Residential Housing Prices*, Growth and Change, 28, 1997, 496-519.
[125] Nelson, A.C., J. Genereux and M. Genereux, *Price Effects of Landfills on House Values*, Land Economics, 1992, 68:4, 359-365.

Jobs and Employment

Existing environment

The existing OCPP employs about 300 people that live in the local area. The plant operates 24 hours per day with three shifts per day. Currently, about 70 percent of employees at the existing plant live north of the site, mostly in the city of Oak Creek.

Expected changes in on-site employment

During construction (temporary)

The electric utility industry has one of the lowest workers per dollar investment ratio. This means that investment in about any other project would create more jobs per dollar invested.

Each of the three units would take about four years each to construct. WEPCO has provided new employment numbers for the units that include supervisory and support personnel and that fit WEPCO's changes to the construction schedule. Refer to Table 7. It appears that the inclusion of supervisory and support personnel add about 100 workers to the monthly average. This would mean an increase of an average 300 workers per month (per unit) due to an overall compression of the construction schedule.

Table 11-7 WEPCO estimates of work force employed for one SCPC unit

	WEPCO estimate from original application*	Current WEPCO estimate**
Average # of employees	500***	900
Peak # of employees	1200	1500

*Craft labor only
**Includes supervision and support personnel, as well as schedule changes
***The estimate for the IGCC unit was 600 workers, and 500 for each SCPC

The type and number of craft employees is estimated by WEPCO in Table 8.

Table 11-8 Peak and Total Work Hours per Craft

	Peak	Hours
Boilermakers	251	1,855,861
Carpenters	133	1,004,213
Cement Mason	9	87,436
Electricians	162	1,511,574
Iron Worker	224	1,447,859
Labor	285	2,049,400
Millwright	165	1,220,109
Operator	191	1,410,585
Pipefitter	300	2,512,644
Teamster	76	652,228

	Peak	Hours
Insulator	79	383,611
Brick Layer	3	16,440
Painter	11	54,802
Sheetmetal	79	383,611
Field Non-Manual	170	1,801,263
Total	1,505	16,391,634

Most construction employees would come from southeastern Wisconsin and commute to the construction site. WEPCO provided the information in Table 11-9 to show where construction employees would originate. WE Power would only employ union workers for construction of the ERGS project.

Table 11-9 Average Monthly Workforce Projection by Region

Craft	SE Wisconsin		Wisconsin		Out of State		Total
Boilermakers	57	56%	14	14%	31	30%	102
Carpenters	46	84%	5	8%	5	8%	55
Cement Mason	5	100%	0	0%	0	0%	5
Electricians	58	70%	18	22%	7	8%	83
Iron Worker	58	73%	13	16%	9	11%	80
Labor	113	100%	0	0%	0	0%	113
Millwright	35	52%	25	38%	7	10%	67
Operator	54	69%	18	23%	6	8%	78
Pipe Fitter	84	60%	28	20%	28	20%	139
Teamster	36	100%	0	0%	0	0%	36
Insulator	14	64%	5	21%	3	14%	21
Brick Layer	1	100%	0	0%	0	0%	1
Painter	3	100%	0	0%	0	0%	3
Sheetmetal	15	71%	5	23%	1	6%	21
Field Non-Manual*	20	20%	5	5%	74	75%	99
Total	637	70%	155	17%	111	12%	903

*Field Non-Manual personnel include field supervision, management, buyers, clerks, quality assurance, start-up personnel , etc.

During operation (permanent)

About 100 people would be needed to operate each unit. Most long-term employees would likely re-locate to the city of Oak Creek, or possibly the town of Caledonia and the suburbs of the city of Racine. At WEPCO, employees that operate generators must be union members. Ninety-five workers would lose long-term employment due to the recently approved construction of the Port Washington plant. WEPCO plans to make transfer positions available to displaced employees, and it is possible that this would further reduce, directly or indirectly, the number of new long-term positions created by the proposed ERGS.

Supplier diversity program

WEC has a program for promoting supplier diversity called the Supplier Diversity Initiative. This program targets minority, women, and small business enterprises. Supplier Diversity objectives for WE Power's proposal include:

- Establishing attainable diversity goals up to 25 percent by product and service category.
- Establishing attainable goals for women and minority participation in the construction of the ERGS units.
- Creating processes and communication plans, including a citizen advisory council, to monitor supplier diversity activities and progress toward goals.
- Developing innovative and effective means to accomplish diversity participation with low administrative costs.

Fugitive Dust

Many people living near the existing power plant site are concerned about the potential for dust blowing into their yards, making houses, snow, clothes hung outside, and lawn furniture dirty, and requiring them to clean off their car windshields every day before leaving their homes. People are also concerned about health effects related to fugitive dust. This section and Chapters 6 and 7 discuss aspects of the potential for fugitive (blowing) dust. This section summarizes potential dust sources and possible mitigation strategies. (Blowing dust from railroad operations is discussed in this section and referenced in the Railroad section later in this chapter.) Chapter 6 discusses the coal handling system and coal dust suppression equipment. Chapter 7 discusses control of emissions and fugitive dust to protect health.

DNR regulation of fugitive dust

Existing rules

The DNR regulates fugitive dust under NR 415, and the applicants must obtain a construction air permit from the DNR. This permit would list required fugitive dust control measures. The DNR also can investigate complaints about fugitive dust. The DNR website suggests that the fastest remedy to fugitive dust problems is to contact the contractor. Regulations in section NR 415 require any contractor to take measures to prevent particulate matter from becoming airborne. The applicants should have an on-site contact to call in case of problems.

DNR analysis of suspected dust samples from existing power plants

The DNR is willing to analyze samples of suspected coal dust damage. The results of analysis of the three most recent DNR samples are described in Table 11-7.

In the Oak Creek area, a number of factors, including dust blown from farm fields, mold encouraged by damp air and particulates from vehicle traffic or nearby urban areas complicate the issue of coal dust. Since late 2001, WEPCO has also analyzed samples at homeowners' request but did not find any coal dust.Some long-term OCPP neighbors remember past problems, which have been corrected by new pollution control devices.

New rules specifically addressing coal dust

The DNR is in the process of addressing concerns related specifically to dust generated by transposrt and storage of coal. The Natural Resources Board considered a proposed rule at its April 2003 meeting. A likely outcome is draft rules and a 12-month study into best management practices for handling and storage of coal.

Requirements of local government

The city of Oak Creek and the town of Caledonia may also impose restrictions on blowing dust as part of their review of the applicant's request for a conditional use permit under local zoning codes.

Table 11-10 DNR analysis of dust complaints

Date	Sample	Analysis
12/02	Dust from pick-up truck	90% Mold, 5% calcium carbonate rock/mineral fragments (i.e. calcite, limestone, dolomite), 5% quartz mineral fragments, traces (1%) of fused, isotropic, glass, coal flyash spheres
02/03	Leaf	Oak Leaf in general displays abundant mold growth, and the gray spots appear to be caused by mold colonies.
02/03	Siding	The dark discoloration on the vinyl siding fragment is caused entirely by fungal growth

Potential fugitive dust sources

The greatest potential for blowing dust occurs during the construction period, due to the reshaping of site topography, including new cuts into the bluff. However, nearby residents are also concerned about dust from WEPCO's use of the active and reserve coal piles during plant operation. In the long-term, WE Power plans to mine both the North Landfill and the South Landfill, but that would occur after construction and operation of the proposed units.

Table 11-11 Potential sources of dust from the Oak Creek Site

During construction	During plant operation
Earth movement & soil stockpiling	Active & reserve coal piles
Trucks hauling soil off-site	Hauling ash to markets
Other construction activities	Mining ash landfills

Effect of site selection and number of units

The number of units built and site location would significantly affect the amount of soil excavated, trucked, and stockpiled during construction. Of the possible sites, use of the South Site requires the least amount of cut and fill. Construction of one or two units would require less soil excavation than three units.

Earth movement and soil stockpiling during construction

Table 11-12 shows the amounts of soil required to be excavated in order to build the facilities on the sites proposed in the CPCN application. Similar information related to the site layout for the CUP Option negotiated by WEPCO and the city of Oak Creek in May 2003 is found in Chapter 12.

Table 11-12 Amount of excavated material required for construction

	North Site	South Site	South Site-Exp
One new coal unit (one 615 MW SCPC)	6.2 million cubic yards	4.6 million cubic yards	4.6 million cubic yards
Two new coal units (615 MW SCPC)	7.3 million cubic yards	5.8 million cubic yards	5.8 million cubic yards
Three new coal units (two 615 MW SCPC units and one 600 MW IGCC unit)	10 million cubic yards	7.3 million cubic yards	9.8 million cubic yards

The applicants' would likely keep all excavated soil on-site due to the short construction period allotted for earthwork. Table 11-13 shows the tentative placement of soil for building various numbers of units at the different proposed sites. Moving this amount of soil from the "bowl area" near the lakeshore to the different soil deposition areas on-site could cause substantial wind-blown soil during dry, windy conditions.

Possible methods for controlling dust from construction traffic include wet suppression, control of vehicle speeds, sealants, and the paving and maintenance of roadways. In addition, the applicants plan to continue using water spray trucks for on-site roads.

If it was feasible to truck soil off-site, the most southern stockpile on STH 32 would be the first deposit site eliminated. This would preserve about 42 acres of leased farmland. Second, the stockpile between the access road and the transmission corridor would be reduced. If or when soil was moved off-site, the applicants have indicated a preference for using covered dump trucks.

Table 11-13 On-site placement of excavated soil (assuming no off-site disposal*)

Location of Soil Stockpiles (Refer to Figures Vol. 2-13, 2-15, 2-17 and 2-19)	Existing Land Cover	North Site		South Site		South Site- Exp	
		Two SCPC units only	w/ IGCC	Two SCPC units only	w/ IGCC	Two SCPC units only	w/ IGCC
1. Extend & add to screening berms around Haas Park & along south side of Elm Road	Grassland, old fields & wetlands	725,000 cubic yards	725,000 cubic yards	725,000 cubic yards	725,000 cubic yards	725,000 cubic yards	725,000 cubic yards
2. Extend & add to screening berms across RR tracks from Barton Road, northeast to Oakwood Drive, & south of Oakwood toward shoreline	Old fields & wetlands						
3. Place on South Oak Creek landfill	Grassland	2,475,000 cubic yards	3,797,000 cubic yards	2,474,000 cubic yards	3,797,000 cubic yards	2,474,000 cubic yards	3,797,000 cubic yards
4. Place on North Oak Creek landfill	Grassland	About 1,000,000 cubic yards	About 1,000,000 cubic yards	500,000 cubic yards	500,000 cubic yards	500,000 cubic yards	500,000 cubic yards
5. Create berm in area east of STH 32 along county line, south of the electric transmission corridor	31 acres of farmland, & 6 acres of woodland	1,213,000 cubic yards*	1,213,000 cubic yards*	NA	1,213,000 cubic yards	NA	1,213,000 cubic yards **

Location of Soil Stockpiles (Refer to Figures Vol. 2-13, 2-15, 2-17 and 2-19)	Existing Land Cover	North Site		South Site		South Site- Exp	
		Two SCPC units only	w/ IGCC	Two SCPC units only	w/ IGCC	Two SCPC units only	w/ IGCC
6. Stockpile in area east of STH 32, north of Seven Mile Road, & west of the railroad	42 acres of farmland	691,000 cubic yards	1,854,000 cubic yards	1,867,000 cubic yards	875,000 cubic yards	1,867,000 cubic yards	1,867,000 cubic yards**
7. Create berm west & south of switching station expansion, east of railroad	Parking, storage, old field, & wetlands	About 1,000,000 cubic yards	About 1,000,000 cubic yards	NA	NA	NA	NA
8 Berm around relocated gun range (south of present location)	Farmland	NA	NA	NA	NA	NA	1,142,000 cubic yards**

*Area 4 + Area 5 + Area 7 = 3,224,000 cu. yd
** Area 4 + Area 5 + Area 6 + Area 8 = 4,722,000 cu. Yd

Soil cover

The applicants propose to plant all new, and existing soil areas with a grassland seed mix, that is designed to attract and feed birds (see the Wildlife section in Chapter 10). The type of grassland planted would depend on soil conditions. WEPCO uses birdsfoot trefoil to prevent erosion on steep slopes. Ornamental plantings, such as trees and bushes, as well as lawn grass could cover areas most visible to neighboring residents. Neighbors across Elm Road have complained about thistle seeds invading their lawns from the WEPCO grassland cover of the South Landfill. Thistle seeds are not part of the seed mix and should be eliminated from the planting by the site manager. WEPCO would cut the grasslands once every one or two years in order to thicken the grass, and to promote and protect wildlife.

Of most concern to nearby residents is the blowing or erosion of soil during the site preparation process. The applicants intend to employ a number of temporary soil stabilization techniques. Soil control measures and the success of those measures are under the purview of the DNR, and also possibly the city of Oak Creek or the town of Caledonia. Measures to ensure soil erosion and windblown soil would be included in a plan submitted to the DNR as part of the permitting process.

Reserve coal pile

The purpose of the reserve coal pile is to provide a back-up source of coal in case of problems with fuel delivery or during outages at the car dumper or active storage building. WEPCO would take the car dumper and active storage building out of use for two weeks of planned maintenance each year. Under the best-case scenario, WEPCO would use the reserve coal pile for only these two weeks (14 days) a year. This assumes all coal delivery would be by rail car, as the applicants currently prefer. If coal is delivered by ship, the reserve coal pile would be used for three months out of the year when ships cannot reach the harbor. Ship delivery would require an expanded coal pile and construction of the rail upgrades that are proposed.

The reserve coal pile would be located southeast of the Barton Oaks Subdivision. The nearest house would be about 1,000 feet from the coal pile. A buffer of trees and a drop in topography from the railroad track to the house would separate the two. Refer to figures Figures Vol. 2-12 through 2-17. It would take about two months to create a reserve coal pile, with sealant applied as soon as a section is complete. Coal would be added or removed from the pile from the side farthest away from the subdivision.

The reserve coal pile would also be located about 600 feet from an existing storage tank for liquefied natural gas (LNG). Concerns have been expressed about the potential for fire or explosions due to this close proximity, however, the applicants state that these dangers would not exist because coal itself is not volatile, and because the coal pile would be sealed.

According to the CPCN application, coal arriving at the Oak Creek site, would be delivered to one of three places: directly to the units, to the active storage building, or to the reserve coal pile. The unit coal silos would be filled first, then the active storage building. Only when these two storage facilities were full or out of service would the coal be directed to the reserve coal pile.

The reserve coal pile would be stacked out, or filled, via conveyor with a telescoping chute. This chute could be raised and lowered to minimize the drop height to the pile, which minimizes fugitive dust. Wet suppression would be used to control dust during filling, moving, and reclaiming operations, weather permitting. From the drop point, the coal would be distributed onto the reserve pile with mobile dozing equipment.

During the initial construction of the reserve pile, the coal would be moved from the drop point to the farthest point of the reserve pile. The coal would continue to be moved in toward the farthest point until the pile was filled and compacted. The time required to initially construct the reserve pile was estimated to be two months.

The pile would be sealed as it was being created. Compaction and a chemical surfactant, which forms a hard crust on the surface of the pile, would be used to prevent dust from wind erosion. The control efficiency of the chemical surfactant is 80 percent. An alternative method of sealing the pile would be by planting grasses on the surface. The effectiveness of this method compared to the chemical surfactants has not yet been determined.

The coal would be reclaimed from the reserve pile by moving the coal to the underground reclaim hoppers with mobile dozing equipment. Coal could be reclaimed from any point on the pile, but it would usually be taken from a point closest to the reclaim hopper. The period of time required to refill the pile would be dependent on the amount of fuel reclaimed from the pile, the coal requirements of the unit (based on generation), and the coal delivery schedule.

Active coal pile

The applicants propose to place the active coal pile within an enclosure. See Figures 11-3 and 11-4. The coal-handling system would include equipment, such as the baghouse, to control dust. Refer to Chapter 6 for more detail about this building.

Figure 11-3 Enclosure for the active coal pile – interior

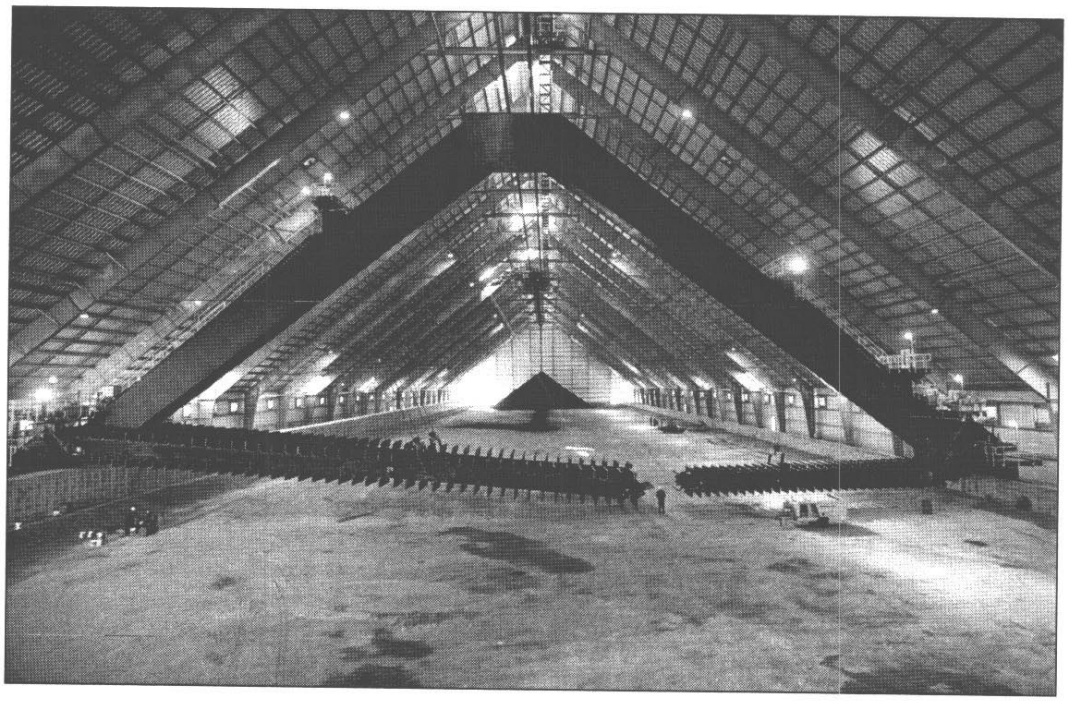
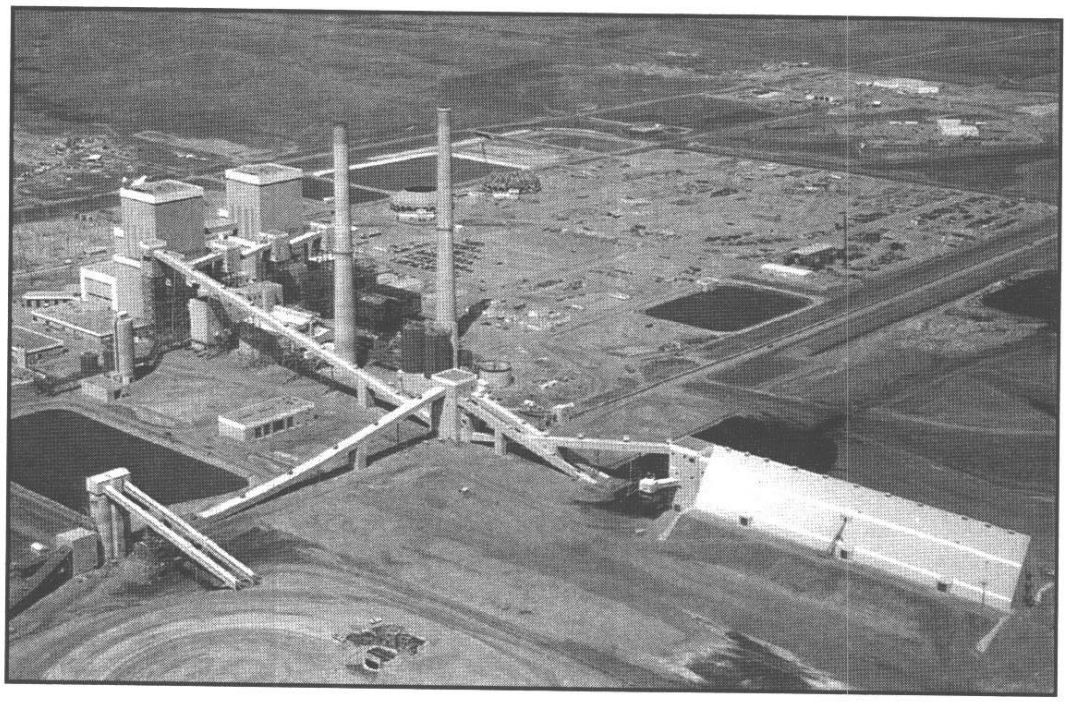


Figure 11-4 Enclosure for the active coal pile – exterior



Shipping ash to markets

Until markets are developed, WEPCO would stockpile the ash produced by the new units at the Caledonia Landfill. Covered trucks would carry the ash over internal site roads to this on-site landfill, where dust control and leachate treatments would be implemented. Following the development of beneficial-use markets for the ash, WEPCO would use tanker trucks and covered dump trucks to ship ash off-site. This would include the ash kept at the Caledonia Landfill.

The types of ash shipped include fly ash (shipped in tanker trucks), bottom ash (shipped in covered dump trucks), and slag from the IGCC unit (shipped in covered dump trucks). Sales of bottom ash are seasonal, so it would sometimes be temporarily stockpiled at the Caledonia Landfill. Slag is black, glassy, sand-like material that is highly non-leachable. Refer to the Traffic section for more information on the expected number of ash shipments. These shipments are included in the DNR air model used to predict fugitive dust.

Mining ash landfills

The proposed units could burn ash from two on-site landfills, the South Landfill and the North Landfill which are both currently closed. However, mining these landfills for ash would not begin until after the proposed units are built and operating, and markets have been found for the by-products created when this ash is burned. The DNR air models for fugitive dust include the trucks that would haul landfill ash, and its by-product. The applicants' air permit application includes the possibility for adding some ash to the fuel burned at the proposed plants. However, before mining begins, a permit would be needed from the DNR for opening these landfills.

The mining would be a gradual process, taking place over at least thirty years. The applicants would stockpile soil from the proposed construction on top of the North and South landfills. In the future, WEPCO would use this soil to replace ash mined from the landfills. Although ash recovery is not a significant part of the proposed project, it could be a positive effect. Due to public interest at the scoping meetings, the ash recovery process is described below.

Ash recovery is a gradual process. First, the covering soil is removed, then the ash is gradually removed, care being taken to get as much ash as possible. WEPCO does not expect to have any problems separating the soil cover from the ash landfill. Workers then push the recovered ash through a screening machine to make sure there are no foreign objects in it. Methods to control dust are used as necessary. However, mined ash is not powdery dry, but wet like ordinary soil. WEPCO would not allow newly exposed ash to dry out, as that would make mining and transport difficult, in addition to causing dust problems. The mined ash would be sprayed with water to give it a crust, or covered with a tarp. WEPCO has had experience in mining other existing ash landfills, including the Highway 59 landfill in Waukesha, the Kansas Avenue landfill in St. Francis, and the Pleasant Prairie landfill.

Based on information submitted in the air permit application for the CUP Option, the mined ash from the North Oak Creek Landfill would be moved via a 9,000-foot road to an ash reburn storage area near the base of the rail loop track. The proposed haul road cuts directly through the high-quality beech maple forest area at the northern end of the rail loop designated as a Critical Species Habitat area and other areas designated as Isolated Natural Resource Areas (see Chapter 10).

Traffic

Existing environment

The existing roads in the project area and on WEPCO's property are shown in Figures 6-1 and 6-2. Currently there are about 300 to 350 employees working at the existing OCPP facilities. They work during three shifts over a 24-hour period. There are also about 100 other vehicles that visit the site daily for purposes of making deliveries or equipment maintenance. Assuming no carpooling occurs, this would yield about 800-850 vehicle trips per day on the entrance road into the site and on Elm Road.

STH 32 plans

Under the 2020 Highway plan adopted by Racine County, Milwaukee County, and SEWRPC, STH 32 would become a four-lane, divided highway up to STH 100. The Milwaukee County portion of this widening would be complete in 2007. Racine County would widen the stretch between Five Mile Road and the Milwaukee County line by 2010.

Currently STH 32 is a four-lane highway from Three Mile Road to Five Mile Road. Further south, it conitnues into the city of Racine, but is still used as four lanes.

From Three Mile Road to Four Mile Road there is a fifth (turning) lane. North of Four MileRoad to Five Mile Roads there is a small grass median. From Five Mile Road north, the plan is to make STH 32 a divided highway with some type of grass median.

County plans for Four Mile Road and STH 32

Racine County just finished rebuilding the intersection of Four Mile Road and STH 32. There are five lanes in each direction. To the east and west, there are four lanes with a left turn lane in the middle. To the north and south, there are four lanes with a turning lane in the middle. About 200 feet to the east and west, the road tapers back down to a two-lane facility. To the east, buildings located near the road limit expansion of the road. To the west, road expansion is a possibility. At Four Mile Road, the UP rail track is to the west of STH 32, rather than to the east as it is at Seven Mile Road and Six Mile Road. If commuter trains become a reality, the County plans to put a rail depot on the west side of the tracks, north of Four Mile Road.

East of STH 32, Four Mile Road is now a county facility. West of STH 32, it is a town facility. Plans exist to exchange this ownership. When the County acquires Four Mile Road west of STH 32, it would rebuild it to two or four lanes, depending on current plans.

Under the County's current plan, Four Mile Road would remain a two-lane highway west of STH 32. However, this plan is part of the SEWRPC plan through 2020. SEWRPC is in the process of updating the plan to extend it to 2025. One of the items identified for review is the optimal number of lanes for Four Mile Road, west of STH 32 to STH 31.

Increased traffic

The sources of increased traffic during construction are: (1) truck delivery of equipment and supplies, and (2) additional employee vehicles. Hauling excavated soil offsite by truck would not be possible under WEPCO's currently proposed construction schedule.

Effects of site location and number of units on local traffic

The location of the site would not affect traffic patterns for construction vehicles, because construction vehicles would approach WEPCO's property from a number of locations at many different distances, and all would use the same two site access roads off STH 32.

Construction of one unit would create the least effect on local traffic. Construction of two or three units would have very similar effects, due to the differing construction schedules for each plant. Construction of two units would generate a maximum count of 3,680 vehicle trips, while construction of three units would generate a maximum count of 4,180 vehicle trips. The number of units would affect the number of years that construction traffic contributes to area traffic, since fewer units would take less overall time to build. The amount of traffic during plant operation is far less than the amount of traffic expected during the construction phase. Operation of two units would result in double the traffic of operating one unit and three units would triple the traffic of a single unit.

During the construction period

WE Power has increased their projections for the average number of people employed during construction of the proposed plant. These new estimates better match a slightly compressed construction period and include non-craft personnel, not all of whom would work on-site.

Several tables below include estimates of the total vehicle trips per day during the construction and operation phases of one, two, or three new coal units. The analysis assumes that all supplies would be delivered by truck (while some would come by barge and rail) and that no car-pooling would occur (although most construction firms offer incentives for car-pooling). Actual vehicle traffic to and from the site would vary, due to the varying construction activities for one to three units over an extended period. Actual traffic numbers are likely to occur that would be both higher and lower than the numbers used in this analysis.

During the construction period for the first SCPC unit, vehicle traffic would increase by about 1,840 vehicle trips per day. For two units, there is an overlapping period when both units would be under construction. During those years of overlapping construction work (about half of the total construction period), vehicle traffic would increase by about 3,680 average vehicle trips per day. For three units, the construction period would last about eight years, with peak traffic at 4,180 average vehicle trips per day (this would occur during the year when the second and third units are under construction, while the first is operating). NOTE: "Vehicle trips" accounts for vehicles entering and leaving the site and thus, is usually double the number of actual cars or trucks.

Table 11-14 Average daily traffic during the construction period for one SCPC unit

Year	Personal vehicles	Truck deliveries	Total vehicle trips
2004	900 workers (1800 vehicle trips)	20* deliveries (40 trips)	1840
2005	900 workers	20* deliveries	1840
2006	900 workers	20* deliveries	1840
2007	900 workers	20* deliveries	1840
2008	900 workers	20* deliveries	1840
Operation of Unit 1 begins**			
2008	100 workers	150 ***	500
2009	100 workers	150 ***	500
2010	100 workers	150 ***	500
2011	100 workers	150***	500

* The actual estimate is 15 to 20 trucks on average per workday, with a peak of about 40-50 trucks per workday.
** Routine maintenance, during a yearly 4-5 week period, could add an additional 200 average vehicles per workday or 400 trips.
*** This number does not include trucks required for ash shipment, which would begin about 5-10 years after plant operation. See Table 3-15

Table 11-15 Average daily traffic during the construction period for two SCPC units

Year	Unit 1		Unit 2		Total Vehicle Trips
	Personal Vehicles	Truck Deliveries	Personal Vehicles	Truck Deliveries	
2004	900	20* deliveries	Site preparation done. Dock extension begun.		1840
2005	900	20* deliveries	No activity	No activity	1840
2006	900	20* deliveries	900	20*	3680
2007	900	20* deliveries	900	20*	3680
2008	900	20* deliveries	900	20*	3680
Operation of Unit 1 begins**					
2008	100	150 ***	900	20*	2340
Operation of unit 2 begins**					
2009	100	150 ***	100	150 ***	1000
2010	100	150 ***	100	150 ***	1000
2011	100	150 ***	100	150 ***	1000

* The actual estimate is 15 to 20 trucks on average per workday, with a peak of about 40-50 trucks per workday.
** Routine maintenance, during a yearly 4-5 week period, could add an additional 200 average vehicles per workday or 400 trips.
*** This number does not include trucks required for ash shipment, which would begin about 5-10 years after plant operation. See Table 11-18.

Table 11-16 Average daily traffic during the construction period for two SCPC units and one IGCC unit

Year	Unit 1		Unit 2		Unit 3		Total Vehicle Trips
	Personal Vehicles	Truck Delivery	Personal Vehicles	Truck Delivery	Personal Vehicles	Truck Delivery	
2003	900	20*	Site preparation & dock extension				1840
2004	900	20*	No Activity				1840
2005	900	20*	900	20*	No activity		3680
2006	900	20*	900	20*	No activity		3680
2007	900	20*	900	20*	No activity		3680
Unit 1 begins operation**							

	Unit 1		Unit 2		Unit 3		
Year	Personal Vehicles	Truck Delivery	Personal Vehicles	Truck Delivery	Personal Vehicles	Truck Delivery	Total Vehicle Trips
2008	100	150***	900	20*	900	20*	4180
Unit 2 begins operation**							
2009	100	150***	100	150***	900	20*	2840
2010	100	150***	100	150***	900	20*	2840
Unit 3 begins operation**							
2011	100	150***	100	150***	100	150***	1500

* The actual estimate is 15 to 20 trucks on average per workday, with a peak of about 40-50 trucks per workday.
** Routine maintenance, during a yearly 4-5 week period, could add an additional 200 average vehicles per workday or 400 trips.
*** This number does not include trucks required for ash shipment, which would begin about 5-10 years after plant operation. See Table 11-18.

Increased traffic during operation could be due to: (1) truck delivery of supplies, (2) additional employee vehicles, (3) vehicles used in routine maintenance, (4) ash shipment to market, (5) vehicles needed for mining of landfill ash, and disposal of byproducts, and (6) gypsum shipments to market if a wallboard plant is not built onsite or if the gypsum is not barged offsite.

Increase in traffic for plant operation

Table 11-17 shows the estimated increase in traffic for operation of one to three units at the ERGS. The table shows truck traffic and employee traffic separately, as they would cause different wear on roads. Truck deliveries would mostly occur during the five-day workweek, from about 7:00 am to 5:00 pm. Employees would work around the clock, with the largest number on the day shift.

Table 11-17 Worst-case increase in traffic due to plant operation*

Traffic During Plant Operation (1 unit)	
Traffic source	Vehicle count
Operating personnel	100 vehicles per day (30-50/shift) 200 vehicle trips
Truck deliveries (assuming all shipments other than coal)	150 vehicles per day 300 vehicle trips
Additional vehicles during routine maintenance (occurs 4-5 weeks annually)	Additional 200 vehicles per day (maximum) 400 vehicle trips
Total traffic	500 average vehicle trips per day (900 per day during annual maintenance)
Traffic During Plant Operation (2 units)	
Traffic source	Vehicle count
Operating personnel	200 per day (100-150/shift) 400 vehicle trips
Truck deliveries (assuming all shipments other than coal)	300 vehicles per day 600 vehicle trips

Additional vehicles during routine maintenance (occurs 8-10 weeks annually)	Additional 200 vehicles per day (maximum) 400 vehicle trips
Total traffic	1000 average vehicle trips per day (1400 during annual maintenance)
Traffic During Plant Operation (3 units)	
Traffic source	Vehicle count
Operating personnel	300 per day (100-150/shift) 600 vehicle trips per day
Truck deliveries (assuming all shipments other than coal)	450 vehicles per day 900 vehicle trips per day
Additional vehicles during routine maintenance (occurs 12-15 weeks annually)	Additional 200 vehicles per day (maximum) 400 vehicle trips per day
Total traffic	1500 average vehicle trips per day (1900 during annual maintenance)

*Barge delivery during summer months could reduce truck traffic by 30 percent.

Ash shipments

The number of vehicle trips for shipment of ash to off-site beneficial-use markets or waste disposal sites is not included in Table 11-17. At first, the applicants plan to store ash at the on-site Caledonia Landfill. However, some off-site ash shipments could start following the startup of the first SCPC unit. WEPCO expects that 100 percent utilization would occur after markets for the ash are fully developed. Table 11-18 shows the ultimate amount of off-site ash shipment, although shipments are likely to start at a lower number and increase as markets develop.

Table 11-18 Average daily truck shipments of ash during plant operation

	One Unit	Two Units	Three Units
Fly ash shipments	16 tank trucks	32 tank trucks	32 tank trucks
Bottom ash shipments	5 dump trucks	9 dump trucks	9 dump trucks
Slag shipments	N/A	N/A	24 dump trucks
Shipping products of ash re-burn (fly & bottom)*	12 vehicles	19 tankers, 5 dump trucks	19 tankers, 17 dump trucks
Total shipments	**33 trucks (66 vehicle trips)**	**65 trucks (130 vehicle trips)**	**101 trucks (202 vehicle trips)**
Comparison with numbers used to calculate the effects of traffic during operation			
Total operational trips used in calculations	500-900**	1000-1400**	1500-1900**

* Assuming the new units can burn a mix of coal and ash, with up to 5 percent ash
** With and without traffic for 4-5 week annual maintenance

Effects on area roads

Method used to estimate the effect of increased traffic on area roads

The most likely route(s) were used to estimate the effects of increased traffic on area roads. Estimates for daily vehicle traffic (average annual) were compared to the daily traffic counts (average annual adjusted) on

area roads. These comparisons are expressed as a percentage increase in traffic. A percentage is calculated for the lowest construction traffic (1,840 vehicle trips - associated with construction of only one unit) and for the highest construction traffic (4,180 vehicle trips - associated with construction of all three units).

This method for estimating the effect of increased traffic on area roads produces very general estimates for the following reasons:

- Only the most likely traffic route(s) are analyzed, while in reality traffic is likely to follow a number of different possible routes (including all routes would decrease percentages)
- Estimates of construction traffic are very general
- Vehicle estimates for operation do not include shipments for ash (including ash shipments would increase percentages)
- Road vehicle counts are for current or recent years. Actual road counts in later years will probably be higher, thus decreasing the percentages.
- There are plans to widen Four Mile Road and STH 32 (becoming higher capacity roads would probably increase their use and thus decrease the percentages)
- Vehicle counts vary depending on the stretch of road sampled (the largest location-appropriate number is used, quieter stretches of road would see a larger percentage increase in traffic)
- Estimated traffic numbers are primarily for a five-day week (the exception is traffic caused by employees during plant operation), while road counts are for a seven-day week (spreading estimated traffic numbers over a seven-day week would decrease the percentages)

Traffic associated with the operation of the proposed plant is generally comparable or less than traffic related to plant construction. In addition, long-term employees are more likely to live near the plant site. For these reasons, the effects of increased traffic due to plant operation are described only for STH 32, assuming all units are in operation. Traffic associated with the first SCPC operating while the other SCPC is under construction is included in the estimates for construction traffic.

Traffic counts on roads are taken from the 2001 Wisconsin Highway Traffic Volume Data, published by the Wisconsin Department of Transportation.

Increased interstate traffic

Construction traffic is likely to enter the area by way of Interstate 94 (I-94), and then travel east to the site. I-94 is heavily trafficked. South of I-43, the average daily number of vehicles (AADT - adjusted for season and day of week) traveling in both directions was 146,600 vehicles in 2001. South of Seven Mile Road in Racine County, the AADT for 2000 was 82,400. If all three ERGS units were built and all traffic for the construction came from the south on I-94, then traffic on that portion of I-94 would increase by about 1 percent to 3 percent, using the least and most vehicle trips from Table 11-19. However, not all traffic would enter the area from the south on I-94. Traffic would likely also approach from the north on I-94, and from the north and south via STH 32, STH 38, and STH 36. Some may also come from west of I-94.

Roads bringing construction traffic east from I-94

The nearest I-94 exits to both ERGS site are at Seven Mile Road and CTH G (with access to Four Mile Road) in Racine County. However, STH 100 (north of the WEPCO property) and Seven Mile Road (south

of WEPCO's property) are the most likely exits, due to the location of the site access road (on STH 32 near County Line Road).

Existing traffic on STH 100

STH 100 (Ryan Road) connects I-94 and STH 32 in Milwaukee County (see Figure 6-1). Table 11-19 shows the amount of traffic on STH 100.

Table 11-19 Traffic counts on STH 100 - average annual daily traffic (AADT*) in the year 2000 (except as noted)

Location	AADT
West of STH 38	22,200
East of STH 38 (year 2001)	13,500
Between Shepard Avenue & Nicholson Road	11,300
Between Nicholson Road & Pennsylvania Avenue	10,200
Between Pennsylvania Avenue & 15th Avenue	9,600
Between 15th Avenue & STH 32 (Chicago Avenue) (year 2001)	10,300

*Adjusted for season and day of the week.

Existing traffic on Four Mile Road and Seven Mile Road: west of STH 32

Table 11-20 shows traffic on Seven Mile Road east of I-94 and west of STH 32. Table 11-21 shows traffic on Four Mile Road east of I-94 and west of STH 32.

Table 11-20 Average adjusted daily traffic (AADT)* on Seven Mile Road east of I-94 and west of STH 32 (year 1999)

Location	AADT
From interchange with I94 to CTH V	3,400
From CHT V to STH 38	3,300
From STH 38 to STH 32 (near STH 38 end)	1,400
From STH 38 to STH 32 (near STH 32 end)	1,000

*Adjusted for season and day of week

Table 11-21 Average adjusted daily traffic (AADT*) on CTH G/Four Mile Road east of I-94 and west of STH 32 (year 1999)

Location	AADT
East of I-94	2,800
East of Caledonia and west of CTH H	2,600
With STH 38 east of Husher	9,900
West of STH 32	6,900

*Adjusted for season and day of week

Increased traffic on STH 100, Seven Mile Road, and Four Mile Road due to construction vehicles

Seven Mile Road and STH 100 would bring the bulk of traffic east from I-94, although construction traffic would also approach the site from routes other than I-94. However, if all construction traffic came to the site via I-94 and exited on just one of these roads, there would be a noticeable increase in traffic. For example, if all construction traffic approached the site via I-94 and then came east on STH 100, traffic on

STH 100 would increase from five to twelve percent. If construction traffic used only Seven Mile Road, the increase would vary from 30 to 82 percent.

If all construction traffic approached the site via I-94, and then used both STH 100 and Seven Mile equally, the increase in traffic on STH 100 would vary from two to six percent, and the increase on Seven Mile would vary from 15 to 41 percent. If all construction traffic approached the site via I-94 and then used both STH 100 and Seven Mile Road in proportion to their existing capacities, the increase on each road would vary from four to eleven percent.
If all construction traffic approached the site via I-94, and then used STH 100, Seven Mile Road, and Four Mile Road in proportion to their capacities, the increase on these three roads together would vary from three to eight percent. Refer to the description of plans for Four Mile Road and STH 32 at the end of this section.

Construction traffic close to the site entrance
All construction traffic would use one of two proposed new access roads off of STH 32 when entering or exiting the site. This would hold true regardless of the site chosen or the number of generating units built.

Existing traffic on STH 32
Table 11-22 shows the traffic count on STH 32 (also called Chicago Road in Milwaukee County and Douglas Avenue in Racine County). Both Milwaukee County and Racine County have adopted a plan that would expand the existing STH 32 from two lanes to a four-lane divided highway. Refer to the description of plans for Four Mile Road and STH 32 near the end of this section.

Table 11-22 Traffic counts on STH 32 - annual average daily traffic (AADT*) in the year 2000, except as noted

City of Oak Creek	
Between STH 100 & Fitzsimmons (Year 2001)	13,000
Between Fitzsimmons Road & Oakwood Road	10,900
Between Elm Road & County Line Road	9,200
Town of Caledonia (Year 1999)	
Between County Line Road & Seven Mile Road	8,700
Between Seven Mile Road & Six Mile Road (also CTH G in stretches)	9,600

* Adjusted for season and time of day

Increased traffic on STH 32 due to construction vehicles
Assuming that half of the construction traffic approaches the site entrance from the north and half approaches from the south, and using an average of the available AADT counts on STH 32 north and south of the site entrance, traffic on STH 32 north of the site entrance would increase from about 5 to 12 percent. Traffic on STH 32 south of the site entrance would increase from about 6 to 15 percent. The smaller percentages correspond to a vehicle trip count of 1,040 per day and the larger percentages correspond to construction traffic at 2,780 average vehicle trips per day. The carrying capacity of STH 32 and the number of cars that use this highway may change if it is expanded according to county plans.

Increased traffic on STH 32 due to plant operation
For about nine months, there would be about 1500 vehicle trips per day for operation of all three units. Assuming half of this traffic comes from the north and half from the south, traffic on STH 32 would

increase by about six to eight percent from the north and eight to nine percent from the south. For the three to four months of additional traffic during routine maintenance, traffic on STH 32 would similarly increase by about seven to ten percent from the north and ten to eleven percent from the south.

Table 11-23 Maximum traffic during plant operation for all three units*

Traffic Source	Vehicle Count	Access Road
Operating personnel	600 vehicle trips per day	STH 32
Truck deliveries	900 vehicle trips per day	STH 32
Additional vehicles during routine maintenance (occurs 12-15 weeks annually)	400 vehicle trips per day	STH 32

*Does not include ash shipments.

Site access roads and traffic flow

Since release of the draft EIS, WEPCO has changed its proposed site access. The current proposal is described in the following WEPCO-written paragraphs.

"Our application includes a main truck entrance at our existing site road at Botting Road and State Highway 32, and an employee entrance via Oakwood Road. Our current plan, includes the Botting Road entrance from State Highway 32 and an entrance from State Highway 32 about 1500 feet south of Botting Road. Oakwood Road would be used for access to the visitor center and fishing pier only."

This road configuration is as shown on drawings submitted as supplemental information to the DNR with copy to PSC on June 2, 2003.

As stated (in DR-102), our current road arrangement includes two entrances to the site from State Highway 32. These two entrances are centrally located to the property, and would be used for either the north, south, or south-exp site arrangements.

Construction Phase:

During the first 12 months of the construction phase, all OCPP employees, all OCPP ash handling vehicles and all other miscellaneous OCPP vehicles will enter the site via Elm Road. All ERGS construction vehicles will enter the site via the plant entrance at County Line Road.

The Main Access Road will be created during the first 12 months of construction. The Main Access Road will enter the site from north of Botting Road and will travel easterly to the rail loop where a rail crossing will occur. The road will then continue to the excavation area at the bowl, to the construction laydown, to parking at the north ash disposal area and to the future ERGS employee parking lot located just west of the excavated ERGS bowl. Following creation of the Main Access Road, all traffic, including all OCPP traffic and all ERGS construction traffic will enter the site at the new Main Access Road. Elm Road will then be closed.

During the development of the new Main Access Road, another new access road will also be developed, called the Southern Access Road, south of the existing Caledonia ash disposal area. The road will travel in an easterly direction to a bridge crossing of the railroad tracks, south of the existing rail loop. Once across the tracks, the road will follow an existing rail spur road to the east where it will split to provide access for OCPP employee parking, OCPP deliveries and OCPP ash hauling needs. When completed, the Southern Access

Road will provide access to the site for all OCPP associated vehicles. All ERGS construction vehicles will continue to use the Main Access Road entrance.

Post Construction Phase:
Following construction of the ERGS units, all ERGS 1 and 2 related traffic will continue to access the site via the Main Access Road entrance. All OCPP related traffic will access the site via the Southern Access Road. All IGCC related traffic will be able to use either the Main Access Road or the Southern Access Road. An on site road will exist which will allow employee traffic to travel between the ERGS and OCPP.

Construction Roads for South Site or South Site-Exp:
If the South or the South Site-Exp were chosen, road construction would occur in the same phases as in the primary site. The road usage would change however following construction of the new roads. The new Main Access Road would be used for all OCPP traffic while the new Southern Access Road would be used for all ERGS and IGCC related traffic.

Potential major changes to Oakwood Road, Elm Road, Seven Mile Road and Six Mile Road
Residents on all four roads near the UP rail tracks east of STH 32 would experience the impacts associated with road construction, such as noise and dust. The applicants have proposed changes that would make Elm Road and Seven Mile Road dead-end at the UP rail tracks, remove the dead-end on Oakwood Road, and build a railroad underpass for Six Mile Road (while moving a portion of Six Mile Road to the north). Refer to the Railroad section for further information. See Table 11-22 for data on existing traffic on these four local roads.

East Oakwood Road
Oakwood Road, east of STH 32 is currently a dead-end road, with about five residences on it. Traffic is minimal. Under WEPCO's current plans, Oakwood Road would no longer be a dead-end, but would provide vehicle access to the proposed OCPP Visitor Center, vehicle access to the lakeside for anglers, and possibly bike trail access to Bender Park.

East Elm Road
Elm Road, east of STH 32, is the main access to the existing power plant facility, with an average of over 800 vehicles per day, both trucks and cars. During plant construction, after WEPCO installs a new main access road off STH 32, then Elm Road would be closed. Elm Road would become a dead end, which would eliminate current heavy truck traffic and the vehicles of Oak Creek plant employees.

Seven Mile Road and Six Mile Road
Due to the increased rail traffic that would occur for the proposed ERGS project, the applicants are willing to fund the proposed changes to Seven Mile and Six Mile roads. The proposal includes closing Seven Mile Road east of STH 32 with a cul-de-sac at the UP railroad tracks. The traffic on Seven Mile east of STH 32, currently estimated by WE Power's consultants at an average of 200 vehicles per day and by the Town of Caledonia at a higher number, would be reduced, and the traffic on Six Mile Road, at over 3,500 vehicles, would increase by about the same amount. Signage currently directs bikes and camping vehicles to Cliffside Park. This would have to change under WEPCO's proposal. WE Power proposes to build an underpass for Six Mile Road. Since WE Power is proposing to realign the current location of Six Mile Road to the

north, existing traffic would not be disrupted during construction of the underpass. For more information, refer to the Railroad section.

Table 11-24 Existing traffic volume on local roads

Wisconsin Highway Traffic Volume Data – Year 2000 (except as noted)	AAADT (Annual Average Daily Traffic) adjusted for seasons and days of week
East Elm Road	
Between Nicholson & STH 32 (near Nicholson end)	1,000
Between STH 32 & UP rail track to the east	810
East Oakwood Road	
Between STH 38 & Shepard Avenue	4,600
Between Shepard Avenue & Nicholson Road	1,400
Between Nicholson Road & Pennsylvania Avenue	1,100
Between Pennsylvania Avenue & STH 32	710
East of STH 32	Minimal
Seven Mile Road (year 1999)	
From interchange with I94 to CTH V	3,400
From CHT V to STH 38	3,300
From STH 38 to STH 32 (near STH 38 end)	1,400
East of STH 32 (estimated by Benisch)	200
Six Mile Road (year 1999)	
From STH 32 to Middle (near STH 32 end) West of RR tracks	5,200
East of Middle; east of RR tracks	3,500
Four Mile Road* (CTH G) (year 1999)	
Just east of STH 31	6,300
Near UP railroad crossing	11,300
Between STH 32 and Charles	9,300
East of Charles Road	10,200
East of Earle	6,700
East of Main	3,800

***For a description of county plans for Four Mile Road, see the following.**

Barge traffic for limestone and gypsum

The application states, "Barge traffic for delivery of limestone will be 30 barges per month for eight shipping months per year. Barge traffic for shipping of gypsum will be 50 barges per month for eight shipping months per year. Limestone delivery barges will leave the site loaded with gypsum."

Noise

Terminology and measurements

Everyday sounds are comprised of sound waves of many different frequencies. The frequency of a sound wave is measured in Hertz (Hz), with one Hz equal to one sound wave cycle per second. While the frequency range of human hearing is generally accepted to be 20 to 20,000 Hz, the ear is not equally sensitive to sounds through that entire range. The human ear is most sensitive to sound in the 500 to 8,000 Hz frequency range, however, it becomes increasingly sensitive to lower and higher frequencies as the intensity of the sound level increases.

Sound levels are measured with a device called a sound level meter in units known as decibels (dB).

When sound level measurements are taken, it is customary to use weighting systems in conjunction with the sound level meter to approximate the asymmetrical frequency sensitivity of human hearing. Three internationally standardized weighting characteristic curves, known as A, B, and C, are generally used for sound measurements. When sound levels are measured using a weighting characteristic, the measurements are designated by adding the characteristic curve letter after the abbreviation for decibels, such as 58 dBA.

The most commonly used weighting curve is characteristic A. The A weighting scale takes into account the human ear's variable sensitivity to frequency. The A characteristic deemphasizes both very low and very high frequency sound while leaving unaffected the mid-frequency ranges most sensitive to human hearing. The C characteristic does not filter out as much of the lows and highs as does the A characteristic. It approximates human hearing at higher sound levels and has been used, for example, for traffic noise surveys in noisy areas. The B characteristic filter is intermediate between A and C weighting. The B characteristic is rarely used.

Determining the noise impact of a new source

Noise level scales (as measured in decibels (dB)) are logarithmic rather than linear. This means that the decibel levels emitted by two different noise sources cannot simply be added together to determine the combined effect of those noise sources. As a generally accepted rule of thumb, two noise sources emitting sound at the same dB level would have a combined noise impact of 3 dB greater than either source alone. The same rule can be applied to weighted sound levels.

As a point of reference, sound experts generally agree that the human ear can detect changes in dBA roughly as follows:

- A change of 3 dBA or less is barely perceptible.
- A change of 5 dBA is perceptible.
- A change of 10 dBA is perceived as either twice or half as loud.

Noise also decreases with distance from the source. Assuming there are no obstructions between the noise source and receptor, the noise from a single source decreases by approximately 6 dBA for every doubling of the distance. For a noise source that is a continuous line, such as a highway, the noise levels will generally

decrease by about 3 dBA with a doubling of the distance from the source.[126] In addition to distance, noise levels can be affected by intervening structures or objects such as buildings, trees, and shrubs.

Sound levels experienced in most natural and human environments do not remain constant but can vary considerably throughout the day. Because of this fact, a single sound level cannot adequately describe the ambient sound environment. A variety of noise descriptors are typically used in order to accommodate the time-varying or temporal characteristic of environmental sound. One type, called percentile descriptors, are commonly used in noise studies. These descriptors identify A-weighted sound pressure levels that are exceeded for specific percentages of time within a noise monitoring period. Typically, the levels reported include those exceeded 10 percent, 50 percent, and 90 percent of the time and are reported as L_{10}, L_{50}, L_{90}. The L_{90}, or residual noise level, is defined as the nearly constant, low level of noise that is found in the environment and represents the lowest sound levels recorded during a monitoring period. The L_{10} is often called the intrusive noise level and represents the highest sound levels occurring in the area during the monitoring period. Another descriptor is the L_{eq} or equivalent sound level. The equivalent sound level uses the average A or C-weighted sound levels recorded. The L_{eq} is a better overall descriptor because it combines sound level, frequency, and temporal characteristics into a single-value. The US Environmental Protection Agency (EPA) has encouraged the use of the L_{eq} for representing environmental sound levels.

Applicable local ordinances

The city of Oak Creek and the town of Caledonia have noise ordinances regulating loud and unnecessary noise. These ordinances do not set specific noise level thresholds for noise sources or receptors and are not readily applicable to industrial sites.

The city of Oak Creek has negotiated a conditional use permit (CUP) with the applicant that would establish two permanent noise monitoring stations. Station 1 would be located near the eastern edge of the Barton Oaks Subdivision just north of Elm Road, about 600 feet west of the railroad tracks. Station 2 would be located within the plant boundaries immediately north of Elm Road and midway between the railroad tracks and the proposed North Site. The CUP sets noise limits for both the construction phase and operation phase of the project, measured at Station 1. During construction, allowable noise limits would be significantly higher than those allowed during actual operation of the plant. Construction noise limits outlined in the CUP vary from 0 to 75 dBA (one hour L_{50}) depending on the phase of construction, day of the week, and time of day. During operation of the plant, the CUP noise limit, measured at Station 1, would be 50 dBA (10 minute L_{eq}) and 60 dBC (10 minute L_{eq}). The CUP proposes a fine of $1,000 per day for non-compliance. No CUP has been negotiated with the town of Caledonia.

Existing noise environment

The existing noise environment around the proposed project sites and the estimated noise from the proposed facility have been analyzed in terms of A-weighted (dBA) and C-weighted (dBC) sound scales as well as the frequency bands from 16 Hz to 8,000 Hz. The dBA scale enables an estimate of the noise that people would hear. The dBC scale enables an estimate of low-frequency noise that people might hear or

[126] B. B. Marriott, Practical Guide to Environmental Impact Assessment.

feel. The frequency band analyses might reveal whether certain types of noise are prominent and need to be controlled in certain ways.

In accordance with the PSC's Noise Assessment Measurement Protocol, an ambient noise level survey was conducted around the project site. Sound level measurements were collected at five measurement points (MP1-5) to determine ambient sound levels prior to construction and operation of the proposed ERGS project (see Figure 11-3 and 11-4). The five measurement points were selected in order to characterize a variety of local environmental conditions, ranging from a park setting at MP1, to residential type settings at MP3 and MP4. Because the North and South Sites are relatively close to one another, the ambient sound level data collected from the five MPs are adequate for both sites.

Sound level readings were recorded between October 2 and October 4, 2001 over 10-minute periods during morning (6:00 – 8:00 a.m.), midday (12 noon – 2 p.m.), evening (6:00 – 8:00 p.m.) and late night hours (10 p.m. – 12 Midnight). At each MP, octave band (L_n) unweighted sound levels were measured in addition to A-weighted and C-weighted decibel levels.

The survey was conducted during calm weather conditions to reduce or eliminate noise from wind, rain, or other weather related factors. Predominant noise sources were also noted. Because the existing OCPP is a base load plant that is operating almost all of the time, the noise it generates was considered to part of the ambient noise setting. Thus, all ambient noise measurements were taken with the OCPP in operation.

Audible noise sources during the survey included natural sounds, such as the sound of waves from the lake at MP1 and fairly prominent traffic noise near residences along STH 32 (MP4). Noise from the existing OCPP was barely audible during the survey. Table 11-23 shows ambient sound measurements taken around the project site. The table lists the L_{eq} (equivalent continuous sound level-a measure of average energy representing the steady state noise level during the measurement period) reported in dBA and dBC and the L_{10}, L_{50}, L_{90} (sound levels exceeded 10 percent, 50 percent, and 90 percent of the time during the measurement period) all reported in dBA.

Background ambient sound levels (L_{90}) represent the lowest sound levels recorded during the survey period. These low intensity sound levels occur only for short periods of time during the day (L_{90} sound levels occur during 10 percent of the survey period and do not represent the predominant sound level in the area). The lowest L_{90} values typically occur during evening hours or at noon. The L_{90} values ranged from 41-45 dBA at MP1 which is in a park like setting located north of the project site. MP2 and MP3 are located adjacent to a dense residential area north of Elm Road and just west of the existing power plant boundary. Background ambient sound levels in this area ranged from 39 to 45 dBA. These sound levels are generally considered to be similar to those found in most normal suburban residential settings. At MP4, background sound levels were higher, reflecting a significant amount of noise from STH 32. At this location, background sound levels varied from 35 dBA after 10 pm to 52 dBA at 6 pm. The area near MP4 would be classified as a noisy urban environment during times when traffic levels are high.

The equivalent continuous sound level (L_{eq}) measured in dBA, as expected, are higher than L_{90} values and are more representative of the overall sound levels experienced around the existing power plant. The L_{eq} values ranged from 42 to 63 dBA. Near the residential area north of Elm Road the L_{eq} at MP3 ranged between 46 and 57 dBA and at MP2 the range was from 51 to 63 dBA (See Table 11-25). These values are higher than those typically found in quiet residential settings.

Figure 11-5 SCPC and IGCC noise contours and other noise emission sources – North Site

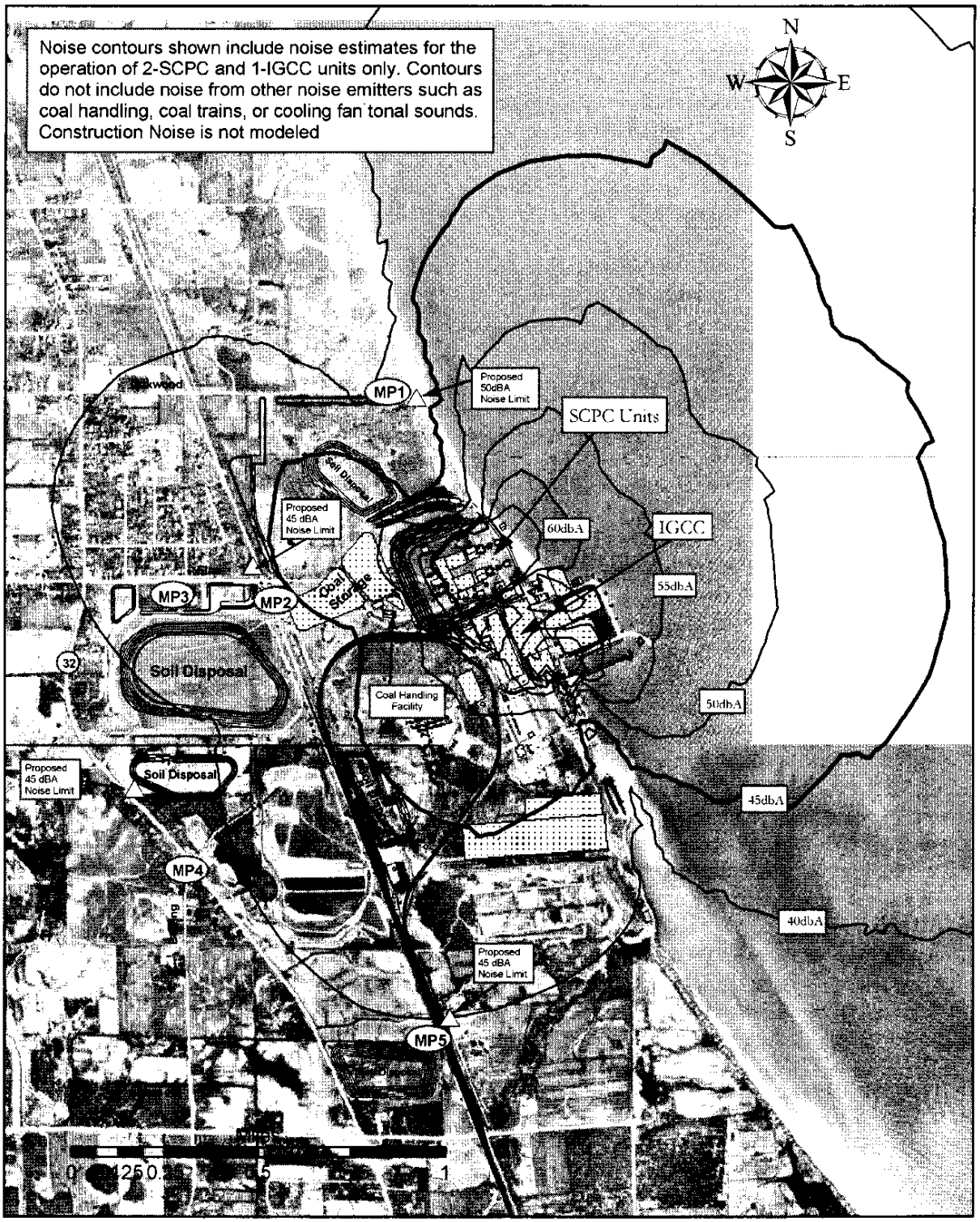
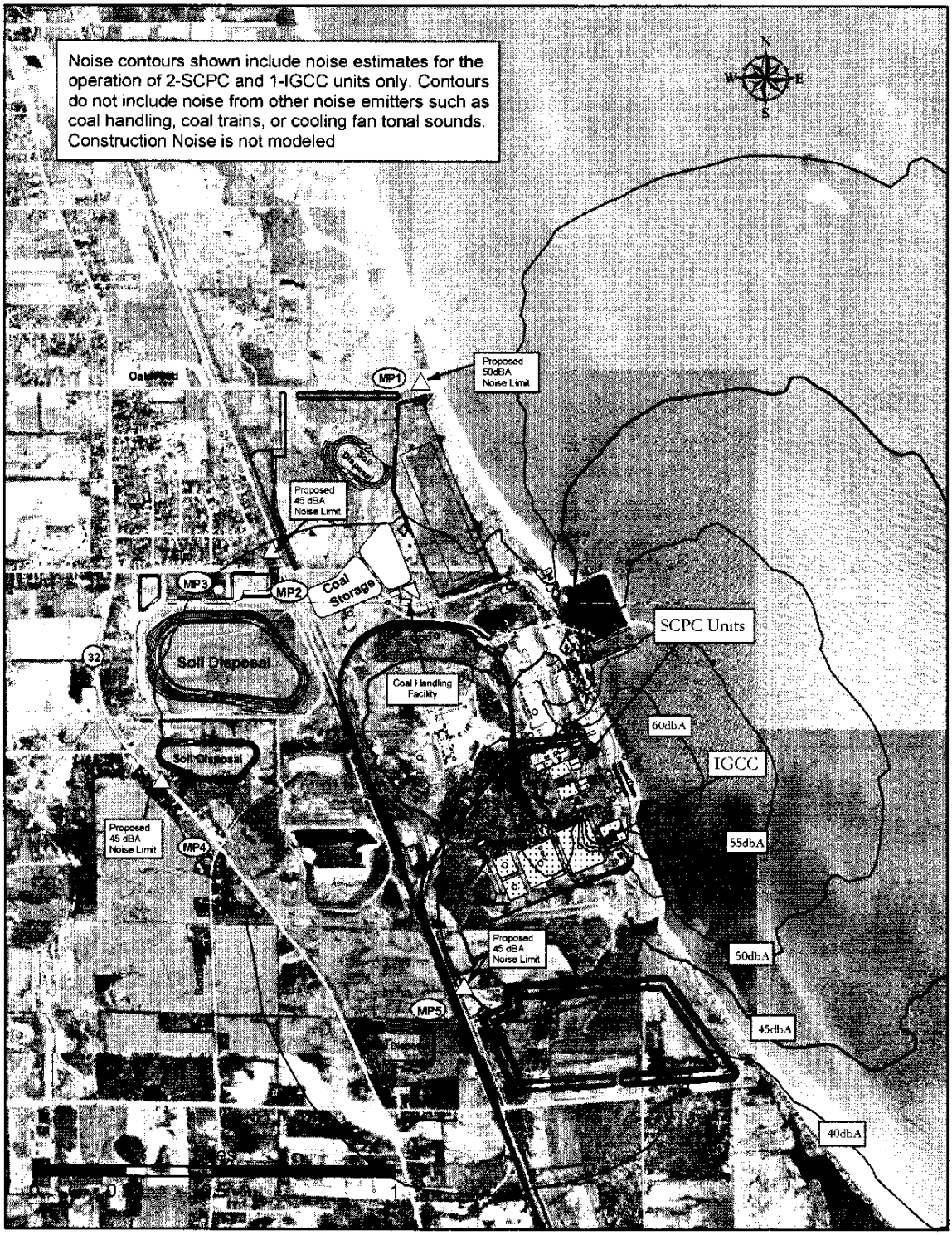


Figure 11-6 SCPC and IGCC noise contours and other noise emission sources – South Site



A comparison of the L_{eq} in dBA and dBC shows much higher dBC levels. The dBC levels measured at MP2, for example, ranged between 64 and 70 dBC. This results from relatively high levels of low frequency sound in the 16 to 250 Hz range. Sources of low frequency sound in the area are most likely from traffic noise; however, some portion of the low frequency component may originate at the existing power plant.

Table 11-25 Ambient sound measurements around the ERGS project site – measurements were taken between October 2 and October 4, 2001

MP	Time	L_{eq} (dBA)	L_{eq} (dBC)	L_{40} (dBA)	L_{60} (dBA)	L_{90} (dBA)	Arithmetic Average L_{90} dBA	New Plant Plus L_{90} dBA	Proposed Plant Increment dBA
MP1	6:00 AM	51	61	53	47	45			
	12:00 PM	50	58	49	47	45			
	6:00 PM	48	59	51	47	46			
	10:00 PM	49	60	51	45	41			
							44	51	6.8
MP2	6:00 AM	63	70	60	48	44			
	12:00 PM	57	67	54	43	39			
	6:00 PM	51	64	53	47	45			
	10:00 PM	62	69	61	46	40			
							42	46.8	4.8
MP3	6:00 AM	57	67	62	47	43			
	12:00 PM	56	66	59	48	42			
	6:00 PM	47	58	48	45	43			
	10:00 PM	48	57	47	42	40			
							42	46.8	4.8
MP4	6:00 AM	63	72	67	60	50			
	12:00 PM	62	74	65	58	51			
	6:00 PM	60	68	63	59	52			
	10:00 PM	55	65	59	44	35			
							47	49.1	2.1
MP5	6:00 AM	56	64	58	47	44			
	12:00 PM	43	58	46	41	39			
	6:00 PM	48	57	49	47	45			
	10:00 PM	42	55	44	41	38			
							42	46.6	5.1

Modeling the proposed project impacts

In order to estimate the sound levels likely to be produced by the proposed project, consultants for the applicant used noise levels produced by the Pleasant Prairie Power Plant in Kenosha County as a surrogate. Sound level measurements were taken around the Pleasant Prairie Power Plant on November 11, 2001.

The Pleasant Prairie power plant is a 1,200MW coal fired facility similar to what is planned for the ERGS. It was assumed that the proposed power plant would represent, in terms of sound produced, sound levels roughly equivalent to the Pleasant Prairie power plant. Since Pleasant Prairie is not an SCPC facility, the consultant included a 2 dBA adder to the noise level estimates.

The sound levels recorded at the Pleasant Prairie Power Plant were then entered into a site noise model in order to estimate the sound levels that might be produced by the proposed power plant. The Pleasant Prairie noise levels were recorded in dBA only. No octave band analysis was performed. This means that the surrogate sound levels used to represent the proposed power plant will not give any insight into the potential for low frequency sound impacts.

Surrogate noise levels were also used for the IGCC component of the proposed project. Since IGCC plants are not common, sound levels produced by such facilities are not readily available. For this case, consultants for the applicant used the sound profiles of a modern combustion turbine power plant of similar size.

Operational noise impact

The estimates for the sound levels produced by the proposed SCPC and IGCC units were entered into a computer model that calculated the estimated sound contours for sound levels that would be produced by the proposed project for each site (See Figures 11-5 and 11-6). The expected noise levels produced by the proposed plant were compared to the average L_{90} (dBA) ambient sound measurements. Comparing expected project noise levels to the L_{90}, as opposed to the L_{eq}, results in a more conservative or worst-case estimate of noise impact. This comparison to ambient noise levels provides an estimate of the likely increases to the local noise environment.

The sound profiles for the two sites are very similar. Impacts to the local community shift to the north for the North Site and correspondingly, move to the south for the South Site and the South Site-Exp. The North Site would potentially have a greater noise impact to the residential community immediately north of Elm Road. Using the South Site would shift some of the impact south to potentially affect residences along STH 32 near Botting Road and those residences located south of the property and just east of the UP tracks near MP5.

Table 11-25 lists the expected noise levels resulting from the new plant and lists the increment in dBA over the average L_{90} values from the ambient study. The expected increment for the operation of the SCPC and IGCC varies from an additional 6.8 dBA for MP1 to 2.1 dBA for MP4. Generation plant operation noise would be most noticeable at MP1 and barely perceptible during the quietest hours of the day at the remaining MPs.

According to this analysis, sound levels from the proposed project that are at or below 45 dBA are not expected to add perceptibly to the ambient sound environment. The applicant has identified at least two

locations along the 45 dBA sound contour line where it would be most appropriate to apply a voluntary noise emission limit. These emission limit points are identified in Figures 11-3 and 11-4. For the North Site a 45 dBA limit is suggested near MP-2 and for the South Site a 45 dBA limit is suggested near MP-5. In addition, a 50 dBA limit is suggested near MP1 and a 45 dBA limit north of MP4. The analysis identifies noise from the SCPC equipment as the dominant noise source for all sites.

The plant design currently calls for the SCPC unit to be placed below the existing grade at both sites. The excavation for the plant sites would create an embankment to the west and north of either site that would tend to attenuate sound emissions from the SCPC units.

The above analysis does not take into consideration other potentially significant noise sources associated with this project. Omitted from the sound contour analysis are noise emissions from the coal handling facility located on the northwest corner of the project site and additions to the noise environment that would be associated with significant increases in rail traffic.

Other noise sources

Tonal noise

Fans (centrifugal, axial, and propeller) produce a tone at a particular frequency known as the blade passing frequency. The tone is created as the rotating blade passes a vane or a strut which creates a pulsed frequency that results in a radiating tonal noise. Tonal noise is generally more noticeable than the atonal sounds commonly experienced in the environment. One source of tonal noise found at power plants is the wide variety of cooling fans that are often used. Tonal fan noise can be managed by designing cooling fans to strict limits for noise emissions.

Coal unloading and handling

While the noise produced by the proposed units would be relatively steady, noise from coal unloading and handling would vary considerably during the day. The coal handling facility would be located on the northwest side of the project site near Elm Road and would be between 1,200 and 2,600 feet from the nearest residences. Because the amount of coal used at the site would approximately double with the addition of the proposed generation, it can be assumed that coal handling and unloading activities would increase accordingly.

Potential noise sources at the coal handling facility would include dumper cars, coal crushers, and noise from the transfer tower, mobile crawlers, tractors, and bulldozers. Four potential noise sources were selected to represent noise at the coal handling facility. Estimates of dBA, dBC, and octave band sound levels were provided for enclosed rotary car dumpers, coal crushers, transfer tower, and mobile crawlers, tractors, and bulldozers. The estimated individual sound levels at a distance of 2,600 feet for these sources would vary from 37 to 47 dBA and from 52 to 58 dBC. The higher dBC levels indicate the presence of a distinct and prominent low frequency component to the sound sources. The closest coal storage area to residences would be the 45-day inactive storage pile. This coal would only be used when other coal sources are unavailable or cannot be delivered. The active coal storage area would be located in a building which would muffle coal handling noise under most conditions. Overall noise from the coal handling site could be higher than reported because of the cumulative effect when individual sound sources are combined.

At full capacity, two to four coal trains would be unloaded per day. It would take approximately six hours to unload a 135-car coal train. It is expected that in order to run the proposed facility at full load for any 24-hour period, at least two coal crushers would be required to run for at least ten hours per day. The total conveyor operating time would range from 12 to 24 hours per day.

The best estimate from the applicant's noise study indicates that the maximum noise level at the closest sensitive receptors, just north of Elm Road, would be from 50 to 55 dBA. This exceeds the voluntary noise limit of 45 dBA suggested in the applicant's noise assessment study. Because the noise from the coal handling operation would not be constant but transient and impulsive in nature, it is likely that it would actually be more noticeable especially in a residential setting. Noise from the coal handling facility would be in addition to the SCPC and IGCC noise emissions produced by the power plant itself.

Coal train traffic

Coal trains would approach the site primarily from the south and be routed along a looped rail spur just south of the coal handling facility. Rail delivery would be the applicants' preferred method for delivering coal to the site. Noise from train traffic include engine noise, rolling noise from rail cars, uncoupling and coupling noise, and starts and stops that result in noise as cars are engaged and begin to move. The applicant has not provided estimates on the likely intensity of these noise sources.

The number of coal trains would roughly double for a project that includes two SCPC units and one IGCC unit. This would require eleven 135-car or twelve 125-car coal trains per week. Currently, about five or six 125-car coal trains per week arrive at the plant. Coal trains can arrive at any time of day. Other rail users are responsible for an additional seven trains per week with 80-100 cars and two trains per week of about 20 cars each. If fewer units are built, the increase in rail traffic would be reduced. For example, if the IGCC plant is not constructed, the number of coal trains would drop from eleven to nine per week. At full capacity (two SCPC units and one IGCC unit) the proposed project would result in a roughly 40 percent increase in local train traffic. The most significant noise impact would be experienced by residences closest to the rail lines approaching the plant.

The applicant proposes to institute coal train handling changes that would reduce the level of noise from train traffic. These changes include:

- Install automatic switching to eliminate starting and stopping
- Reduce the number of on-site repairs (currently inspection pulls out an average of five cars on every train for maintenance. This requires additional stopping/starting and coupling/decoupling of cars)
- Install an indexer for dumping or unloading coal cars (eliminates starting/stopping car and engine noise and reduces the amount of time required to unload a train).

Coal delivery by boat has been proposed as an alternative to rail delivery. This is an expensive alternative that would require dredging of the lake to create a port capable of handling the coal ships. Because of inaccessibility during cold weather, rail deliveries would be required from January through March. This means that costs for the upgrades to the rail system on the project site would still be incurred. Using ship delivery would also require a doubling of the on-site coal storage and would require more use of the reserve coal pile. Because of the cost and difficulty in receiving coal by ship, the applicant prefers to rely on rail delivery for this project.

Shooting range

Use of the expanded South Site-Exp would result in the need to move and rebuild the gun range which is now located near the south boundary of the property. A new shooting range would be constructed south of the existing shoot range on the north side of Seven Mile Road on a property that was previously a horse farm. The new shooting range has not yet been designed; however, any new shooting range would be designed to meet military safety standards in order to eliminate any danger from stray rounds. Noise would be somewhat reduced by the standard safety design features. The shooting range would be used only for small arms (pistols and rifles) target practice. The range is presently used by local gun enthusiasts, law enforcement agencies, military reserve units, and the National Guard. Trees and other landscape features may also serve to reduce audible noise generated at a gun range. However, some noise impact would likely be experienced at the closest residences which include the four houses directly east of the railroad corridor north of Seven Mile Road, the homes between STH 32 and the railroad on the south side of Seven Mile Road, and the home at the east end of Seven Mile Road.

Construction noise impacts

Sources of construction noise include increased traffic to and from the construction site and noise created by construction machinery at the site.

Individual equipment noise

Construction noise is typically high intensity, intermittent, and can be impulsive. Impulsive high intensity sounds are noticeable especially when they are introduced into residential settings. The primary noise sources at a construction site are likely to be the diesel engine drive systems that power most construction equipment. Because of the size of this project the work schedule would most likely require six-day work weeks with work continuing 10 to 16 hours per day. This would suggest that noise impacts could continue into the evening hours and extend into the weekend. Typical construction noises, modeled for a power plant project in southeastern Wisconsin, are listed in Table 11-26. Some noises during construction could be very loud (ranging from 120 -134 dBA at 50 feet from the event) occurring during short-term steam or air blows.

Table 11-26 Estimated maximum noise levels for typical construction equipment (dBA)

Construction Equipment	Maximum Noise Level (dBA) Typical Range = 50 Feet
Steam blow off (4-8-inch line)	124-134
Air blow off (4-8-inch line)	120-130
Blasting	93-94
Dozer (250-700 horsepower)	85-90
Front end loader (6-15 cubic yards)	86-90
Trucks (200-400 horsepower)	84-87
Grader (13-16-foot blade)	83-86
Shovels (2-5 cubic yards)	82-86
Portable generators (50-200 kW)	81-87
Derrick crane (11-20 tons)	82-83
Mobile cranes (11-20 tons)	82-83
Concrete pumps (3-150 cubic yards)	78-84
Tractor (3/4 to 2 cubic yards)	77-82
Unquieted paving breaker	75-85
Quieted paving breaker	69-77

Noise from the construction of the generation buildings and units themselves would be significantly reduced because the SCPC units, for example, would be constructed in an excavated depression facing the lake. This is true for both sites. It is expected that it would require as much as four years to build the first SCPC unit. The closest residences to the North Site are about one-half mile from the SCPC unit construction site and almost a mile from the proposed IGCC site. General construction noise at the North Site would primarily affect residences located along and near Elm Road. Other construction noise sources that are likely to be noticeable to residences north of Elm Road would be from the construction of the coal handling facility and from activity at the spoil fill sites north and west of the North Site. Residences near these areas would be affected regardless of which site was selected. The applicant expects approximately 3.5 years to complete the coal handling facility.

For the South Site (or South Site-Exp), construction of the SCPC and IGCC units would take place at a considerable distance from the residences along Elm Road. The closest residences are between 0.5 and 0.75 mile south and west of the proposed IGCC plant and SCPC units. Use of the South Site would move the IGCC plant further away from residences that are located just south of the WEPCO property.

Both the distance to sensitive receptors and construction inside the excavated site would serve to reduce noise impact to the closest sensitive receptor.

New railroad construction

Extensive upgrades to the existing rail system would be required not only on the plant property but along the existing rail line south of WEPCO's property. From the new rail loop south to Five Mile Road, from one to four sets of new track would be added alongside the existing tracks. This would increase construction noise disturbance in the immediate vicinity of the rail construction area. The upgrades to the rail system are currently scheduled for 2004 and would take approximately 34 months to complete. The hours of construction are not known at this time. The type of work would most likely require the use of earthmoving equipment to properly prepare and grade new rail beds. Heavy equipment would also be used to deliver and install new track. Construction noise would be similar to that described for other phases of this project. Limiting construction to weekdays and day time hours would serve to reduce, to some extent, the overall annoyance associated with noise from rail construction. Homes along the railroad ROW would be most affected by this construction activity.

Traffic noise

An important and potentially significant source of noise during construction would result from increases in truck traffic along the roads leading to and from the site. STH 32 and Elm Road are likely to have significantly increased heavy truck traffic. Depending on how many units are built, traffic increases would be sustained over a period of five to eight years. For one SCPC unit, the construction period would last about five years and the traffic would increase by about 1,040 vehicle trips per day. If all three units are built, the construction period would be about eight years with a peak traffic increase of about 2,780 vehicle trips per day. A detailed account of the estimated increase in traffic can be found in the Traffic section of this chapter.

It is unclear at this time how traffic would approach the project. At present, plans include new access to the plant at the north end of the project site. Oakwood Road would be extended east into the project property.

Another access point is expected to be developed at Botting Road and STH 32. In addition, Elm Road could also be used during construction.

Because details on access points have not been finalized, it is difficult to assess noise impacts due to traffic. Traffic increases would result from the arrival and departure of the workforce and from heavy truck traffic delivering machinery and materials. Noise created by the increased truck traffic could be significant. Because traffic noise is mobile and moves along linear paths the noise impact tends to have a broader reach. Decibel reduction due to increased distance from the source is about half that for a stationary noise source. This means that noticeable changes to the ambient noise environment would extend further. Traffic noise impacts can be reduced by routing vehicle traffic through areas that have fewer residences and by limiting heavy truck traffic to weekdays between 7:00 am and 5:30 pm.

Earth moving

As proposed, an enormous amount of soil would need to be excavated in order to begin construction of the first SCPC unit. The total amount of excavation required for this project, assuming that at least two SCPC units are approved, ranges from 5,500,000 to 10,000,000 cubic yards of soil depending on the site and whether the IGCC unit is eventually built. This type of soil excavation would require the use of very large earth moving equipment. Noise levels associated with this kind of machinery are likely to be fairly intense with a predominant low frequency component. Low frequency sounds have longer wavelengths and tend to travel further than high frequency short-wavelength sounds. The noise from the excavation site would be mitigated, to some extent, by the distance to the nearest sensitive receptors which is about 3,400 feet for the North Site and about 3,000 feet from the South Site. In addition, as excavation proceeds, much of the work would take place below grade so that the noise produced would radiate east onto the lake rather than to the west and south where residences are located.

Excavated soil must be transported from the building site to the disposal site. At this time details on how this would be accomplished have not been provided by the applicant. A total of five on-site soil disposal areas would be utilized (see Figures 11-3 and 11-4). Regardless of the site selected for the new units, at least two soil disposal sites would be located near a relatively dense residential area located north of Elm Road and east of STH 32 (near the Barton Oaks Subdivision). One soil disposal site, the South Ash Landfill, is located just south of Elm Road in an area that has been used for ash disposal adjacent to Haas Park. The northern edge of this disposal site is about 700 feet from residences north of Elm Road. It is estimated that approximately 3,300,000 cubic yards of earth would be placed at this location alone. The other disposal site is located northeast of Elm Road and is about 1,800 feet from the same residential area. Between 500,000 and 1,000,000 cubic yards of fill would be placed at this site.

The applicant has estimated that all earthmoving activities would require about one year to complete. The applicant intends to use between 30 and 35 large earthmoving vehicles during the mass excavation phase of the project. Caterpillar 631G scrapers and/or 769D mining trucks with a rated capacity of approximately 31 cubic yards or similar machinery would be used. For the mass excavation operation the applicants plan to use a six-day work week with two 10-hour shifts per day. The nominal number of vehicle round trips per day is estimated at about 1,400.

The noise from the large number of heavy earthmoving vehicles moving constantly through the area would likely be significant for the Barton Oaks Subdivision and for residences located along Elm Road just west of

the South Ash Landfill. Once soil is deposited at the site, heavy earthmoving equipment must be used to spread the soil. In terms of elevation, the disposal site is above the residences to the north. There would be little to shield or block the noise from either disposal site. Over time, the deposited soil would rise approximately 45 to 50 feet above the level of Elm Road. With little to block the sound of heavy equipment, it is likely that the increase in noise from construction would be quite noticeable. Some reduction in noise impact could be achieved by first placing fill on the outside edges of the fill site to form a level of berm. Then fill could be brought in behind the newly created berm. Because of the amount of soil and the size of the disposal sites, this approach could only be done in stages. This could reduce some of the noise created while filling in behind the raised edge.

Screening berms are most effective in reducing high frequency (short wavelength) noise. Berms are less effective in blocking long wavelength (low frequency) sound. Noise impacts created during the earthmoving could also be reduced by limiting earth moving activities to five days a week between 7:00 am and 5:30 pm. However, given the large amount of soil to be moved, and the aggressive construction schedule, the project would require double ten-hour shifts during the mass excavation phase in order to meet schedule expectations. The CUP does set noise limits for the construction and earthmoving phases of the project. However, the limits defined in the CUP are dBA sound levels. A significant portion of the sound spectrum created by construction and earthmoving activities would be in the low frequency range. The A weighting curve deemphasizes low frequency sound.

Recreation

This section describes each of the local area parks as they presently exist and any possible changes to the park and adjacent lands due to construction of the proposed ERGS project. It also describes the potential for construction of a recreational trail and shoreline fishing access on WEPCO's property.

Haas Park

Existing environment

The city of Oak Creek's Haas Park, on the south side of Elm Road, is located on land given to the city by WEPCO. WEPCO-owned land surrounds the park on all three sides. The city of Oak Creek 1998 Park and Open Space Plan describes Haas Park as follows:

> "Haas Park is a 7.5 acre site located at 4215 East Elm Road and donated to the City by the Wisconsin Electric Power Company (WEPCO) in 1975 and named after the Haas family who owned and homesteaded this land prior to WEPCO's purchase of it."

This park has a play structure, and areas for basketball, baseball, volleyball, and tennis. There is also a wooded area at the western end of the park.

Elm Road currently has a lot of traffic, including truck traffic, because it serves as the main access road to the existing OCPP. This results in safety issues for families, and especially children, from the Barton Oaks Subdivision, that need to cross Elm Road when they walk to the park.

Proposed changes to lands adjacent to Haas Park

There is a screening berm to the south of the park that would be extended for the ERGS project. In the past, neighborhood children have used this hill for sledding. Berms would also be added just beyond the east and west ends of the park. To the south of the existing screening berm is the South Oak Creek Landfill, which is kept covered with grassland to encourage birds. The applicants plan to add soil to this landfill.

Under the applicants' proposal for all alternatives for the ERGS project, Elm Road would cease to be an access road to the OCPP, and would be closed east of the railroad tracks. This would increase the safety of Haas Park users and make the park more accessible to children.

The existing power plant chimneys are currently visible from Haas Park. Three new stacks or chimneys would be added if the entire ERGS facility is built. The new stacks for the SCPC units would be higher and larger in diameter than the OCPP stacks. Refer to the Visual Impacts section of this chapter for more information.

Bender Park

Milwaukee County's Bender Park serves a regional and metropolitan population. It is located north of and across East Oakwood Avenue from WEPCO-owned land. The entrance to Bender Park is on the north end of the park, at the end of Ryan Road (STH 100). The park has a marina along the lakeshore and trails through a northern upland area. The southern portion of the park is undeveloped. The city of Oak Creek 1998 Park and Open Space Plan recommends supporting major expansion of the marina at Bender Park, and development of a premier 18-hole championship golf course. However, county budget constraints and conflicts over the use of county land have limited development at Bender Park to date.

Proposed changes to land adjacent to Bender Park

The northern portion of WEPCO's property is covered in grassland and shrub land. Toward the center of this northern portion is the North Oak Creek Landfill, which would be used as a construction laydown area, and as a place to deposit excess soil. After construction of the proposed generating units is complete and the plants begin operating, WEPCO would remove the ash from this landfill to burn in the proposed SCPC units. This ash mining would be expected to occur over a 30-year period. The landfill and any disturbed surrounding land would be planted in grasslands with a seed mix chosen for its value to birds. WE Power would also construct a screening berm south of Oakwood Road. The end of Oakwood Road would be extended to the plant site to provide access to the ERGS and OCPP for fishermen if the new facilities are built on the North Site. It's also possible that it would provide access to Bender Park for hikers and non-motorized bikes, as part of the Milwaukee-Racine County recreational trail.

Figure 11-7 View of existing OCPP from Bender Park looking south

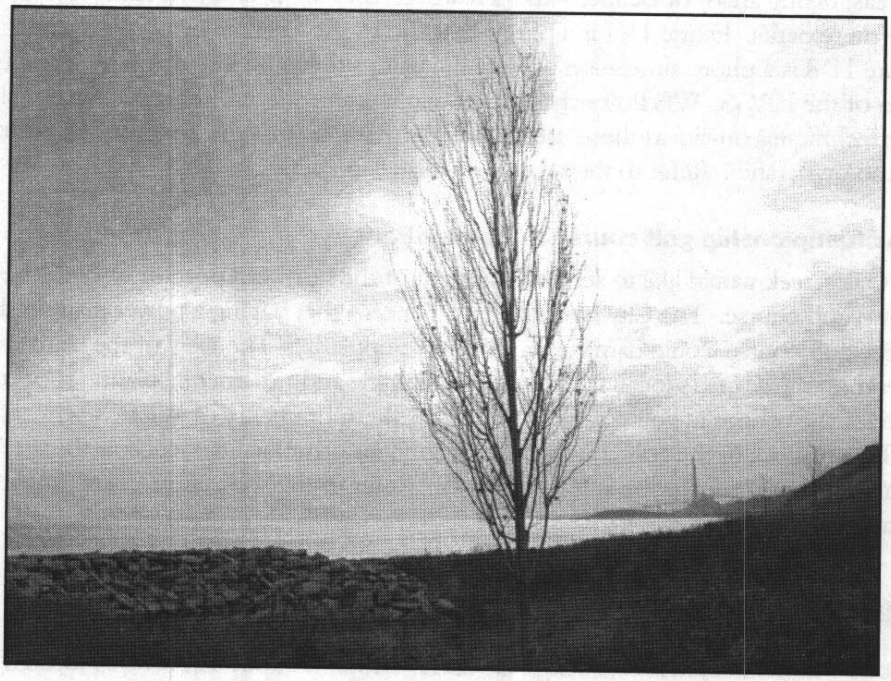
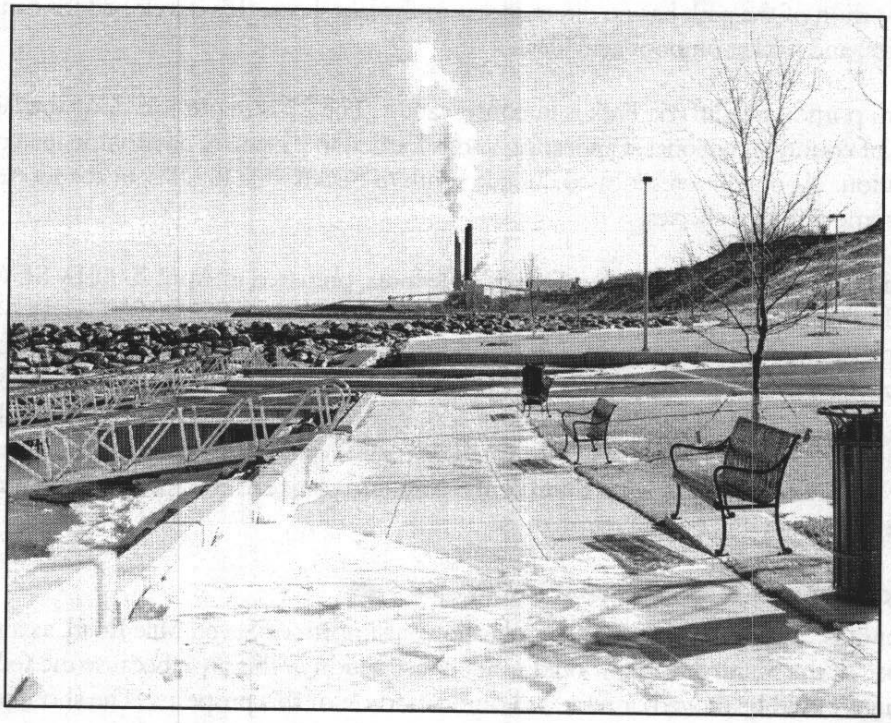


Figure 11-8 Photo simulation of the view from Bender Park after construction of the ERGS



The existing power plant facilities are either difficult or impossible to see from the developed facilities (camping areas, hiking areas) of Bender Park. However, they are prominent features as seen from the shoreline of these parks. Figure 11-7 is a photo that shows the existing view from Bender Park looking south. Figure 11-8 is a photo simulation of how the plant site would look from the park's shoreline, after the construction of the ERGS. WE Power has stated that it intends to use the same type of shoreline stabilization techniques on-site as those used at Bender Park, so that there would not be any visible sign of change in land ownership. Refer to the section on Visual impacts.

View from championship golf course in Bender Park

The city of Oak Creek would like to see development of the northern portion of Bender Park as a championship golf course. The City has expressed concern that having a power plant in the background view from the golf course would damage the course's popularity. The view of the plant from the course would depend on the course's location, layout, topography, and ornamental plantings of trees or shrubs. The distance of the proposed golf course from the northern boundary of WEPCO-owned property is about 0.75 mile. The distance of the golf course from prominent plant facilities, such as the turbine enclosures and chimney stacks, would probably be at least one mile. Refer to the section on Visual Impacts for further information.

Cliffside Park

Racine County's Cliffside Park serves a regional and metropolitan population. It's located south of and adjacent to WEPCO-owned land. The entrance to Cliffside Park is toward the southern end of the park, off Michna Road. The developed portion of the park is on the south side, adjacent to a high-density residential area. This portion of the park has no direct access to the lakeshore. It's developed for camping, baseball, tennis, picnics, and similar outdoor activities.

The northern portion of Cliffside Park is in conservancy. The 22-acre portion along the lake is classified as a natural area of county or regional significance, and is located in a primary environmental corridor, intended for preservation. About 60 acres located directly south of Seven Mile Road is an abandoned agricultural area, containing some rare bird species.

The Park and Open Space Plan for the town of Caledonia, prepared in April 2000, by SEWRPC recommends, that for parkland purposes, Racine County acquire an additional 305 acres of land along the Lake Michigan shoreline within the town of Caledonia. In addition, it recommends development, in Cliffside Park, of a nature center, a winter sports area, boat launch facilities, management or restoration of native plant communities, and additional parking lots, rest rooms, shelters, and trails for hiking, biking, and skiing. Racine County has a Master Plan for Cliffside Park that includes an interpretive center and nature trails on the northern, undeveloped portion of the park, but plans are currently on hold due to problems with high groundwater and budget constraints.

Proposed changes to lands adjacent to Cliffside Park

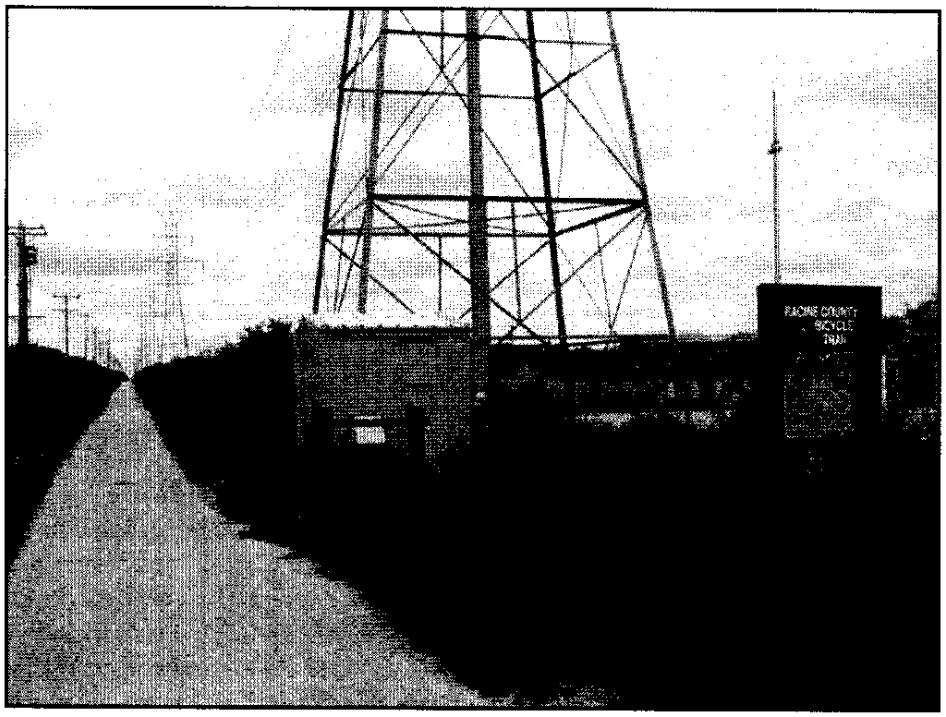
WEPCO intends to keep its land along the lakeshore, just north of Seven Mile Road, as a natural area. However, use of the South Site-Exp would result construction in this area, because the federal/state shooting range would be moved or relocated onto a portion of this property. The shooting range would be located far enough inland to avoid the environmental corridor along the lakeshore.

The existing power plant facilities are either difficult or impossible to see from some of the developed facilities (camping areas, hiking areas) of Cliffside Park. They are, however, prominent landscape features as seen from the shoreline of this park, although the shoreline is somewhat difficult to access. Again, WE Power has stated that it intends to use the same type of shoreline stabilization techniques as those used at Bender Park, so that there would not be any visible sign of change in land ownership. Refer to the section on visual impacts.

Milwaukee – Racine County Recreational trail

Milwaukee and Racine Counties both have recreational trails that use portions of the UP railroad corridor. Currently the Racine County trail ends at Seven Mile Road and the trail in Milwaukee County begins the boat launch in Bender Park. No connection across WECPO's property and adjacent lands to the north exists at the present time. This recreational trail is for bikers, hikers, and cross-country skiers, but not for motorized vehicles. Figure 11- 9 shows the recreational trail as it passes through northern Racine County. The possible connection of the two trails has been a subject of great public interest during the development of the ERGS application. More information about how the applicants are planning to accommodate that interest is discussed below.

Figure 11-9 Bike and recreational trail in northern Racine County (looking south from Seven Mile Road)



Recreational uses on WEPCO-owned property

The public currently uses WEPCO-owned land for some recreational purposes. Fishermen consider the warm water around the existing plant discharge to be a good place to fish year-round. Although Elm Road is owned by the city of Oak Creek, it is sandwiched between WEPCO-owned properties and provides access to the existing power plant site. Residents of the Barton Oaks Subdivision often walk to the end of Elm Road and back for exercise and pleasure. The road ends on the bluff above the shoreline, but walkers can see the lake at intervals along this road, and for much of the distance no power plant facilities are visible. (The top of the LNG storage tank is always visible.) Some residents are concerned about the loss of this pleasant walk with lake views.

Recreation-related proposals

WE Power has shown interest in promoting recreational use of the power plant site, after the new units are built, but it has made no long-term commitment at this time. Possible plans include:

- Use of WEPCO property to connect Milwaukee County's recreational bike trail to a similar trail in Racine County, including provision for bikes to cross over the existing rail tracks and any new highway bridge or underpass built to accommodate increased rail traffic.
- Possible use of WEPCO property to access the lakeshore and Bender Park - this would only apply if the North Site is used.
- Building facilities for fishermen, including parking, piers, and warming houses - this would only apply if the North Site is used.
- Developing an educational Visitors Center to provide information on energy issues in general and the OCPP and the ERGS in particular.

In addition, WE Power states that it plans to protect, as much as possible, existing wetland and wooded areas, and to plant grassland with seeds that encourage wildlife, especially birds. This may contribute to the enjoyment of neighborhood or area birdwatchers.

Recreational trails

A link across WEPCO-owned land is needed to connect the existing Milwaukee and Racine County recreational trails located near the OCPP. WE Power hosted a seminar on the possible location of a recreational trail on WEPCO property that would connect to the existing county trail systems. The seminar, including county and municipal planners, was held on April 23, 2002. The final details of trail development are not complete, but the planners approved a preliminary location for the recreational trail that the applicants are using in their site plans. For the most part, the new trail would cross from the railroad corridor to near STH 32 somewhere around Seven Mile Road, and then back to the railroad corridor on Elm Road. It would continue adjacent to the railroad track to Oakwood Road and then include a possible connection from Oakwood Road to Bender Park. Most of this distance would be on WEPCO property. If Milwaukee County's plans for Bender Park are not certain at the time that WEPCO would build a trial, minimum physical changes would be made to allow trail use, while maintaining flexibility for future plans.

It is likely that the trail on WEPCO property would look similar (asphalt-covered or paved) to the existing county trails, and that a planned Visitor's Center could provide a resting place for trail users. The applicants'

proposed railroad plan includes provision for bikers to cross Six Mile Road safely. Under the plan, Seven Mile Road would dead-end at the UP railroad track. Possible ways for trail users to cross the tracks safely at Seven Mile Road include a private road under the rail tracks or a raised, wooden bridge. Refer to the Railroad section for more information.

Connection of recreational trail to Bender Park

The recreational trail connection between Bender Park and the WEPCO property is the last piece of the recreational trail that would be built because WE Power intends to use the North Landfill as a laydown area throughout the construction period. The Milwaukee County parks representative at WE Power's April 23, 2002 meeting on the recreational trail, said that delayed construction would be good, as it would allow time for development of Bender Park plans. WE Power held another meeting on the recreational trail on March 27, 2003. More detail on the recreational trail is included below.

The city of Oak Creek requested that WE Power close Elm Road to the public (due to security concerns), and instead concentrate on providing access to Bender Park. WE Power currently plans to provide access from the intersection of Seven Mile Road and the UP railroad track through the power plant property to Bender Park.

Shore access and fishing

Concerns about the effect of the ERGS facility on local fish populations are addressed in Chapter 8. Based on interested generated by the public, the applicants have developed some initial ideas for fishing access on the north end of the property as close to the proposed warm water discharge (for the North Site) as possible. They have also sponsored meeting with local fishing groups to get feedback. Initial designs include an access road from the end of Oakwood Road, that would parallel an access road for plant workers eastward onto the plant site. The initial concept included a parking area for fifty vehicles, a warming structure, and a fish scaling area. At the first meeting, the fishing organization requested more parking and no fish scaling area. If either of the South Site options are utilized, WEPCO would place the warm water discharge further south along the shoreline, toward the middle of the plant site, and there would be no fishing access due to security concerns.

Visual Impacts

Visual effects are difficult to quantify, because ultimately they depend on the aesthetic tastes of individuals. Factors to consider include:

- The existing visual environment, or the context of the viewed object
- The vantage point of the viewer, i.e. from where the object is visible
- The probable activity of the person looking at the object
- Potential mitigation techniques, including distance, berms, plantings, and object design.

Existing visual environment

Figures 11-10 to 11-13 show some of the visual features of the area surrounding WEPCO's Oak Creek property. These include examples of the wetlands/woodlands, farmlands, residences, and trails.

Electric transmission lines are also a strong element in the visual landscape surrounding the ERGS and OCPP sites. See Figures 11-14 to 11-16. The existing power plant stacks are visible as a remote feature on the horizon from the northern boundary of WEPCO-owned land (Elm Road and Barton Road), and the southern boundary (Seven Mile Road). Refer to Figures 11-17 to 11-18. To the west, along STH 32, there are some areas where the stacks are not visible due to the rolling topography. From the lake and lakeshore, the whole, existing power plant is visible.

Figure 11-10 Agricultural land and small woodlot

Figure 11-11 Wet meadow/shrub carr complex

Figure 11-12 Caledonia Green Space Trail

Figure 11-13 Nearby residential neighborhood

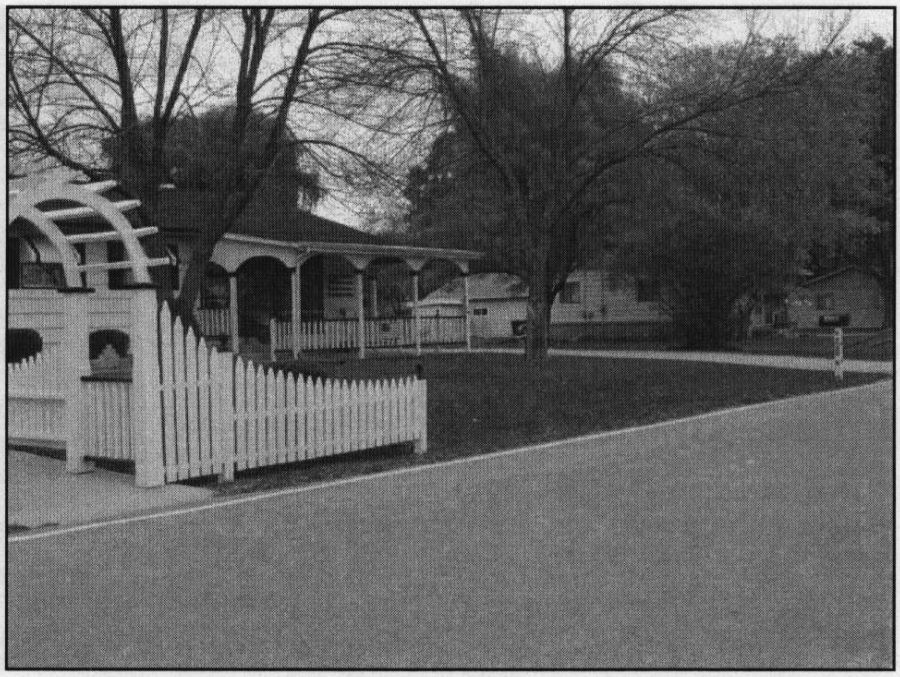


Figure 11-14 Transmission lines on STH 32 at the entry to the city of Oak Creek

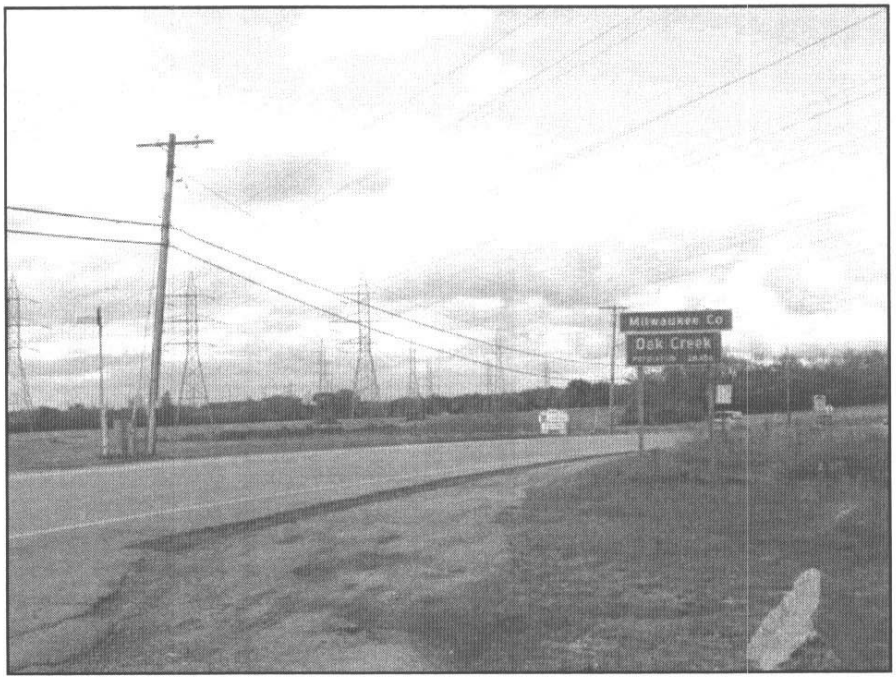


Figure 11-15 Transmission lines adjacent to the bike trail and the railroad corridor

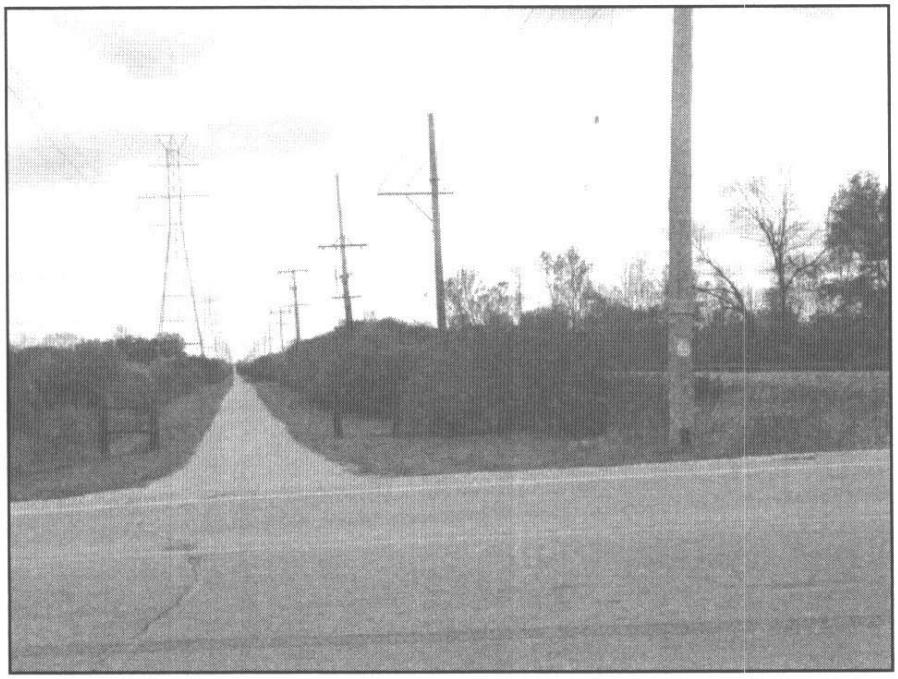


Figure 11-16 New residential area near existing transmission lines

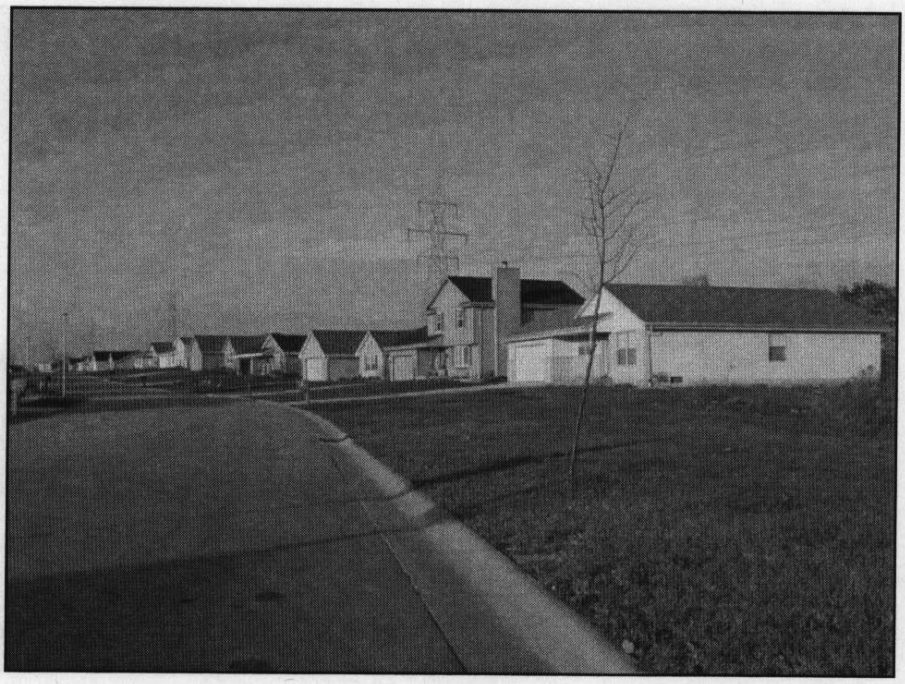


Figure 11-17 View of existing OCPP exhaust stacks from Elm Road

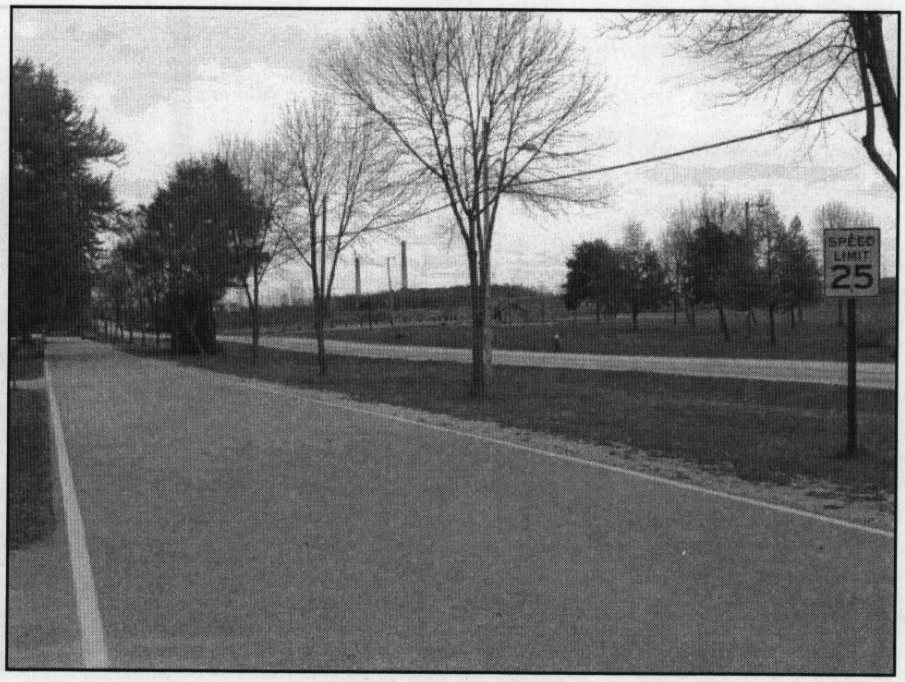
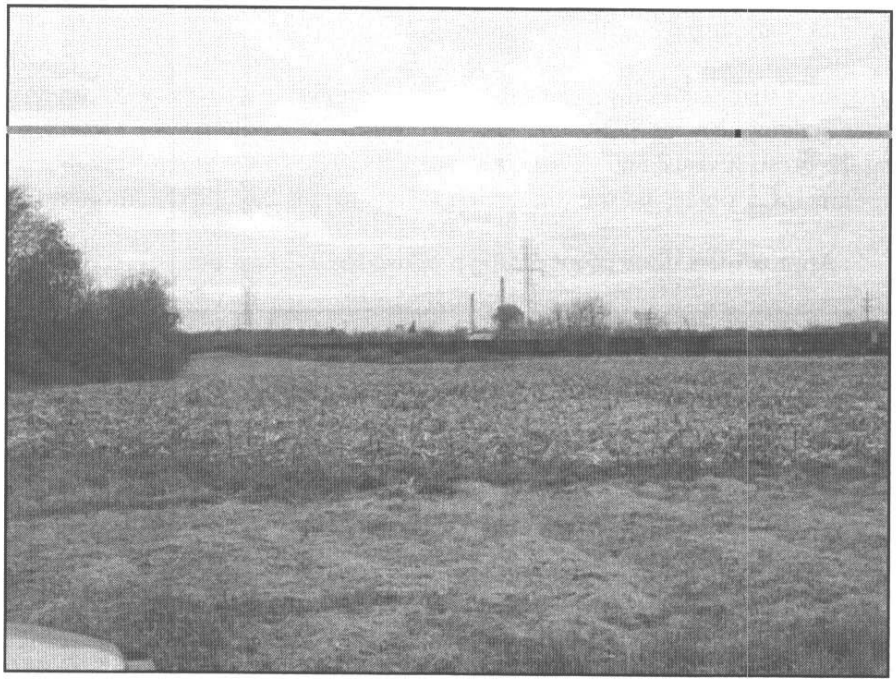


Figure 11-18 View of existing OCPP exhaust stacks from the south on Seven Mile Road



Existing light environment

Figure Vol. 2-30 shows a satellite image of Wisconsin during the night provided by the Defense Meteorological Satellite Program (DMSP), and available on the web at www.darksky.org, an organization that addresses light pollution. A similar image is in the UW-Extension publication on Sensible Shoreland Lighting, also available on the web at www.uwsp.edu/cnr/uwexlakes/publications/lighting.pdf. Both of these images show a continuous, broad band of light from the Chicago area through the Milwaukee area along the coast of Lake Michigan.

Expected visual impacts

Size of the proposed facilities

Table 11-27 shows the dimensions of the proposed plant facilities for the two SCPC units. From a visual perspective, height is the most important factor. Eight of the new buildings or plant components would be slightly over 100 feet tall; one would be 150 feet tall; one about 200 feet tall; and two almost 300 feet tall. The tallest features are the exhaust stacks which would be about 675 feet tall on the North Site. On the South Site, the stacks for the SCPC need to be shorter, at a final height of about 470 feet, to avoid interference with navigation related to the John H. Batten Airport in Racine County. Refer to the section on Site Lighting and the FAA review discussed below.

Table 11-28 shows the dimensions of the proposed plant facilities for the IGCC unit. There would be two structures about 100 feet tall; five structures about 150 feet tall; and one structure 275 feet tall. The tallest of the IGCC facilities is about the height of the main SCPC buildings.

The tallest structures that occupy a substantial space (as opposed to a tower or chimney) are the two 270-foot high boiler buildings for the SCPC units and the 180-foot coal silo for the proposed IGCC unit. The facility having the greatest visual impact would likely be the flare on the IGCC unit, because of its size and the absence of any other object like it in the site area. The flare is discussed in more detail below.

Table 11-27 Approximate dimensions for the proposed SCPC facilities

Building	Area (feet)	Height (feet)
Turbine generator building for units 1 & 2	134 x 540	105
Boiler building for unit #1	200 x 270	270
Boiler building for unit #2	200 x 270	270
Control building	160 x 100	72
Circulating water intake structure/ pump house	110 x 110	93
Make-up water treatment building	100 x120	24
Wastewater treatment building	35 x 100	24
Gypsum dewatering building	70 x 125	35
Fire pump house	30 x 60	20
Coal handling system: transfer tower TT-1	60 x 64	110
Transfer tower TT-2	60 x 76	80
Transfer tower TT-3	30 x 34	80
Transfer tower TT-4	40 x 60	210
Transfer tower TT-5	30 x 30	35
Transfer tower TT-6	50 x 50	40
Coal yard maintenance building	100 x 150	24
Rotary car dumper house	55 x 70	60
Coal yard crusher house	70 x 100	150
Two baghouse control buildings	32 x 50	24
Absorber pump & electrical building	110 x 110	50
Service building	100 x 150	60
Warehouse	90 x 90	40
Exhaust stack for unit #1		675 (470)*
Exhaust stack for unit #2		675 (470)*
Two fly ash vacuum blower buildings	100 x 130	20
Baghouse for unit #1	150 x 160	120
Baghouse for unit #2	150 x 160	120
Absorber for unit #1	60 diameter	110
Absorber for unit #2	60 diameter	110
Bottom ash bin for unit #1	35 diameter	51
Bottom ash bin for unit #2	35 diameter	51

Building	Area (feet)	Height (feet)
Fly ash silo for unit #1	42 diameter	107
Fly ash silo for unit #2	42 diameter	107
Limestone preparation building	75 x 100	30
Two limestone slurry tanks	50 diameter	30
Fuel oil storage tank (500,000 gallons) / pumphouse	50 diameter + dike	36?
Gypsum storage building	50 x 120	30
FGD wastewater building	50 x 120	30
Urea silo	27 diameter	52
Urea blower building	30 x 40	
Condensate storage tank (250,000 gallons)	40 diameter	29
Demineralized water storage tank (125,000 gallons)	32 diameter	23
Waste neutralization tank (95,000 gallons)	30 diameter	34
Fire protection tank (300,000 gallons)	42 diameter	31
Service water tank (350,000 gallons)	45 diameter	32

* (470) indicates the final height of the SCPC exhaust stacks on the South Site options.

Table 11-28 Approximate dimensions for the proposed IGCC facility

Building	Area (feet)	Height (feet)
Air separation unit	500 x 650	General structure is 20 feet Two columns of 180 feet each Two columns of 90 feet each
Combined cycle power plant	300 x 400	110
Gasification facility	550 x 550	General structure is 30 feet Open frame structures at 120 feet
Acid gas recovery unit	275 x 300	General structure is 30 feet Two vents at 75 feet each
Sulfur recovery unit	275 x 275	30
Water treatment building	60 x 120	30
Waste water treatment building	60 x 120	30
Coal slurry/preparation facility	120 x 160	General structure is 60 feet Coal silo would be 180 feet
Two HRSG exhaust stacks		275
Flare		150
Coal silo		180

IGCC flare

The flare would burn waste gases from the coal gasification process. It would operate during plant start-up, which takes about two days, and it would operate during certain types of equipment malfunction. The flare would not be in use during normal plant operation. Refer to Chapter 6 for further information.

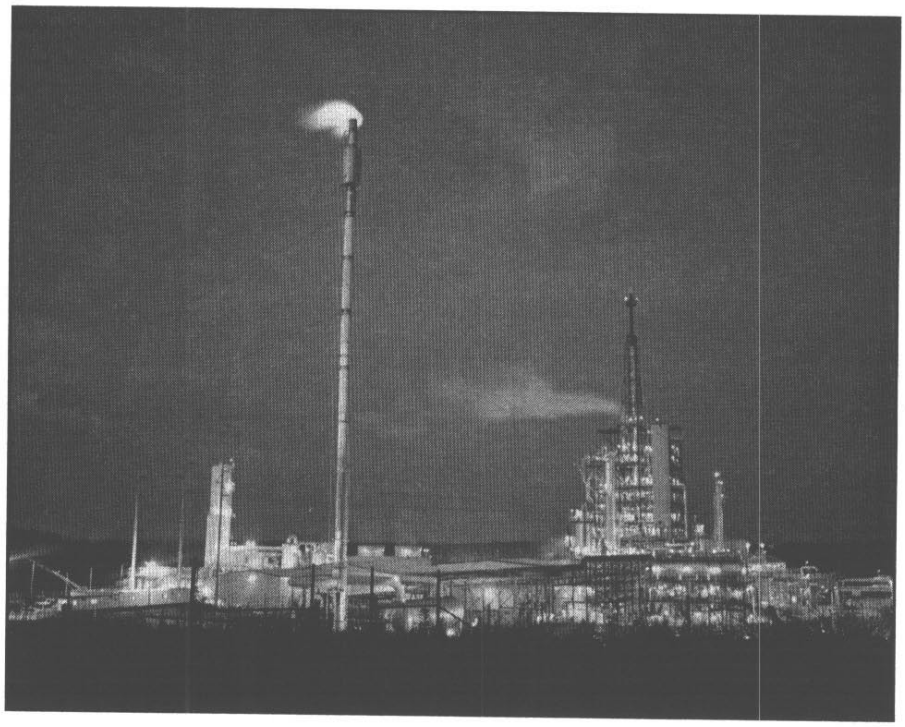
The applicants estimate that the flare would operate about 20 to 40 hours per year, but it would operate continuously for about two days when in use. According to Texaco, "The flare would not be visible during daylight hours. At night, the flame would be blue in color and similar to a hydrogen flame. With proper design, the flame would burn cleanly and with minimal noise."

The flame would burn from the top of a 150-foot structure. At its highest, the flame itself would be 80 feet tall, although this height would be reached shortly before the plant starts, and would only last for a few minutes. During these conditions, the top of the flame would be about 230 feet above ground level.

WE Power and WEPCO do not expect the flare to affect site lighting, since it is not in use during normal plant operation. The FAA would not require clearance or warning lights on the 150-foot structure. There would be a small natural gas pilot light for the flare. This pilot light would be kept burning whenever the plant is in service but WE Power and WEPCO do not expect it to be noticeable.

Figure 11-19 shows a flare at the Wabash IGCC plant, taken during a startup of the plant at night. The gas flow rate is not known.

Figure 11-19 Flare Operation at IGCC facility in Wabash, Indiana



Site lighting

Federal Aviation Administration (FAA) review

Because of the closeness of the proposed ERGS site to the General Mitchell International Airport in Milwaukee and the John H. Batten Airport in Racine County, the FAA reviewed the ERGS proposal to determine if any of the proposed structures would be considered navigational hazards and if lights would be required for the stacks or taller buildings. The FAA defines "tall" structures as those above 200 feet. For this project, there would be two buildings, one transfer tower and four exhaust stacks that are above 200 feet.

Table 11-29 Structures over 200 feet tall

Structure Type	Number of Structures	Proposed Height
Supercritical boiler buildings	2	270
Transfer tower for coal handling	1	210
Exhaust stacks for SCPC units	2	675
Exhaust stacks for IGCC facility	2	275

The FAA has reviewed the project, and determined that none of the buildings or structures on the North Site would be deemed a hazard to air navigation. However, the proposed 675-foot tall exhaust stacks for the SCPC units on the South Site (and the South Site-Exp option) constitute a presumed hazard to air navigation at their proposed height of 675 feet. The FAA would require that the proposed 675 feet stacks for the SCPC units be lowered to 474 feet and 469 feet for units 1 and 2, respectively. WEPCO conducted additional air modeling analysis to determine if the lowered stack height would adversely effect air emissions and the applicants' ability to secure an air construction permit. However, the modeling provided to the DNR does not include use of the most updated BACT parameters, rendering it incomplete for making such a determination.

WE Power proposed medium intensity lighting for the buildings and stacks over 200 feet in height. The FAA required that all marking/lighting meet the standards in FAA Advisory Circular 70/7460-1 K Chg 1. Accordingly, WE Power would light all four top corners of the boiler buildings. For the IGCC stacks, WE Power would likely use four 24-hour white medium intensity strobe lights spaced 90° apart and placed within the top 20 feet of the stack.

The SCPC stacks may require a dual system with white medium-intensity strobe lights operating during daylight hours with red lights in use at night. Lights would be spaced 90° apart within 20 feet of the top of the stacks and at about the mid-height elevation of the stacks.

Lighting during construction

During construction, WE Power would light parking and active work areas in accordance with OSHA Standard 1926 as well as the Wisconsin Administrative Code.

Both the city of Oak Creek and the town of Caledonia include lighting in the list of items that would be required for a zoning variance.

Building exterior and landscaping

Design details related to building exteriors and landscaping have not been completed and would remain flexible until WE Power and WEPCO consult with local officials. The only available information is general statements and architect's sketches. Figures Vol. 2-31 through Vol. 2-34 are conceptual sketches of views of the site from various locations around the site periphery. Refer to Appendix E for the design details contained in the city of Oak Creek's CUP conditions.

Fencing

WE Power plans to fence the entire site with a six-foot chain link fence. Where the fence is within view of the public, WE Power intends either to screen it with tree and shrub plantings, or use a decorative section of fencing.

The shooting range that would be moved if the South Site- Exp is selected, would also be fenced. The specifications for this fence are for a six-foot, chain-length fence with barbed wire on top, but it is not clear whether the fence would be inside or outside the berm that surrounds the rifle range.

Mitigation of visual impacts

Building locations

WE Power proposes to place the SCPC power plant facilities at the base of the bluff, thus significantly reducing the visual impact of the facilities. The entire plant would be visible only from the lake and from the air. The lake bluff would hide from landward view almost half the height of the facilities at the North Site, and almost one-third the height of the facilities at the South Sites.

Berms

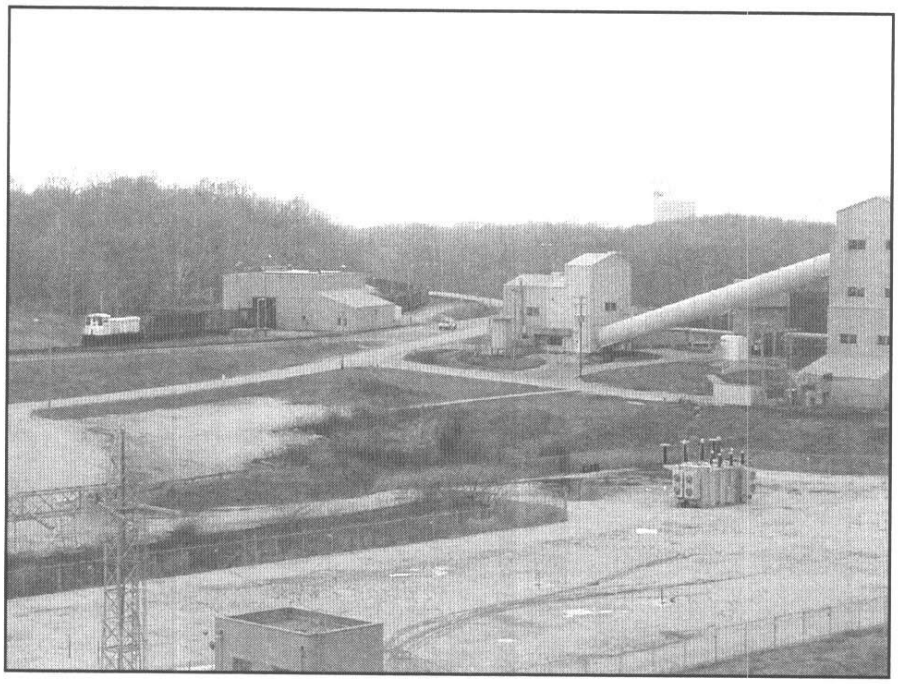
WE Power would create berms at strategic places on WEPCO's property to screen the proposed facilities from view. Figure 11-20 shows how berms and woods screen the existing plant facilities from the Barton Oaks neighborhood located in the background near the LNG tank. Refer to Figures Vol. 2-1 through 2-3 for the location of proposed berms. WE Power has indicated that the berms would be positioned as proposed to provide the maximum visual barrier to nearby residences. The height of a screening berm is dictated by the footprint available for its base.

The proposed berms locations include:

- Behind Haas Park to the south of the Barton Oaks Subdivision
- At both ends of Haas Park
- Running north and south along the rail tracks, to the east of the Barton Oaks Subdivision
- Along and to the south of Oakwood Road
- Inside the rail loop

Additional existing landscape features also provide screening. These include the raised railroad track to the east of Barton Oaks and wooded areas on-site.

Figure 11-20 Example of woods and berms screening plant activities from nearby residences



Distance and buffer land

There is about one-half mile distance between the North and South Sites, and neighbors to the west. The North Site is also located over a quarter mile from most of its southern neighbors. This distance allows plantings, either on WEPCO's land, or on neighboring properties to be more effective for screening. (See Figure 11-19). The distance also reduces the apparent size of plant chimneys.

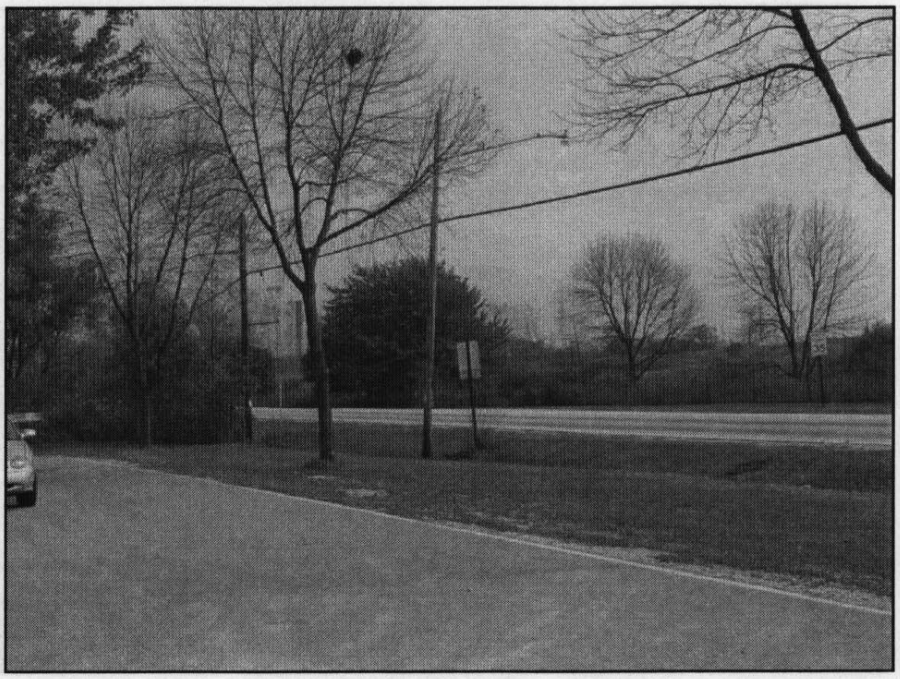
Building exterior and landscaping

Involving the surrounding community in selecting final design details for the appearance of the buildings and boundary landscaping is typical for new power plant construction. WE Power states that, "The overall approach to the re-vegetation of the site would be to create an aesthetically enhanced landscape while preserving woodlands, streams and other existing natural features if possible. Trees, shrubs, and grass areas will be planted."

The features viewed most frequently by the community are the gate houses. WE Power has indicated that it intends to construct attractive gate houses with landscaping at the Oakwood Road and Highway 32 entrances.

Various officials, including the Oak Creek City Administrator, visited power plants in Germany that use materials and design details to make them more attractive because they are located in urban and residential areas. It is expected that these desires and concerns would be taken into consideration in the final design.

Figure 11-21 Effectiveness of vegetation in screening plant views



Railroad Proposals and Impacts

Existing environment

Railroad lines

Canadian Pacific rail corridor, Amtrack, and MRRI

Three rail corridors (or rail lines) east of Interstate 94 connect Chicago to Milwaukee through Kenosha and Racine Counties. Canadian Pacific (CP) owns the westernmost rail line, which is CP's main route from Chicago to Minnesota and western Canada. This is also the rail line that Amtrak uses in eastern Wisconsin. Amtrak runs the Hiawatha train (between Chicago and Milwaukee), and the Empire Builder (Chicago to Milwaukee to Minnesota and west to the state of Washington). Amtrak will continue to develop its rail service along the CP rail corridor, and does not intend to switch to use of either of the other two rail corridors. The Midwest Regional Rail Initiative would also target improvements to this rail corridor, rather than the UP rail corridors. The CP rail line passing through Racine and Kenosha currently carries about 40 passenger and freight trains per day.

Union Pacific rail corridors (west and east), coal delivery, and commuter rail service

Union Pacific (UP) owns the two other rail corridors between Chicago and Milwaukee. A rail line that appears to be seldom used connects these two corridors in the city of Kenosha. The westernmost UP rail corridor is the UP's main freight line between Chicago, Milwaukee, and St. Paul. It serves WEPCO's Pleasant Prairie power plant. The easternmost UP rail corridor delivers freight to local customers, including

delivery of coal to the existing OCPP. Refer to Table 11-30. Potential commuter rail service between Chicago and Milwaukee would also use UP's eastern rail corridor.

Table 11-30 Current rail traffic on the UP line that delivers coal to the OCPP

	WEPCO's coal trains*	Other rail user #1* *	Other rail user #2* *
Number of trains per week	5 - 6	7 (one per day)	2
Number of cars per train	125	80 -100	20
Time of day	Any time	Between 1 a.m. and 4 a..m.	Between 10 a.m. and 2 p.m.

* Source: WEPCO
** Source: Union Pacific Railroad

Ownership of land and rail facililities

The rail corridor that serves the OCPP once contained two main tracks, but presently there is only one track. A second track (siding), for service to the OCPP site, begins just south of Five Mile Road. UP owns about a 100-foot wide right-of-way. Adjacent to the east side of the right-of-way are a gas pipeline and an overhead electric transmission line. In Racine County, there is an asphalt-paved bike path adjacent to the transmission line.

UP owns the railroad corridor, the tracks, and the train engines. WEPCO owns the rail track and other facilities on the Oak Creek site, and the rail cars that deliver coal. The UP would determine the route used by any rail traffic on its line.

Road crossings of the UP's easternmost rail corridor

Between the OCPP site and the Illinois state line, UP's easternmost rail corridor crosses about fifty roads in Racine County, and about thirty roads in Kenosha County. Most of these crossings are in the cities of Racine and Kenosha. At five of the Racine County road crossings and 12 of the Kenosha County road crossings the rail corridor is elevated above the road on a bridge. The road is elevated above the rail corridor at one Kenosha County crossing. The rest of the crossings are at grade level. In the town of Caledonia, the easternmost UP rail corridor crosses Seven Mile Road, Six Mile Road, Five Mile Road, STH 32, Four Mile Road, and Three Mile Road. All except Five Mile Road and STH 32 are at grade.

Existing coal delivery

Number of trains and timing of delivery

Coal delivery for the OCPP units 5-8 now account for about half of existing rail traffic on the UP Railroad through Caledonia and into Oak Creek (see Table 11-30). Table 11-31 shows estimated and actual coal train deliveries to the existing OCPP. The Site Manager for the OCPP keeps a log of train arrivals. In 2002, 233 trains delivered coal to OCPP, and in 2001, there were 258 train deliveries. For 2002, this averages about 4.5 trains a week. During June, the existing car dumper usually has a two-week outage. Excluding these two weeks, during which no trains deliver coal, the average number of existing coal trains arriving at the OCPP during 2002 is 4.7 trains per week. The similar averages for 2001 are 5.0 and 5.2 trains per week.

Table 11-31 Number of train deliveries to the existing OCPP*

Data source	Trains per year	Average per week	Average per week excluding 2 weeks in June w/ no rail traffic
2002 OCPP Site Log	233	4.5	4.7
2001 OCPP Site Log	258	5.0	5.2
WEPCO estimate	NA	5-6	NA

*The existing four units operate at about 80% capacity over time. The proposed units would operate at about 85% capacity. However, the existing units burn coal with a lower fuel content than the proposed units would burn and thus would require more coal per MWh than the proposed new units.

WEPCO states that it cannot predict the frequency or timing of coal deliveries. Three trains could arrive at one time and then none for several days. For a picture of the frequency and timing of current deliveries, Figure 11-21 shows the 2002 and 2001 coal deliveries by month, Figure 11-22 shows deliveries by day of week, and Figure 11-23 shows them by two-hour period.

Figure 11-21 2001 and 2002 coal train deliveries by month

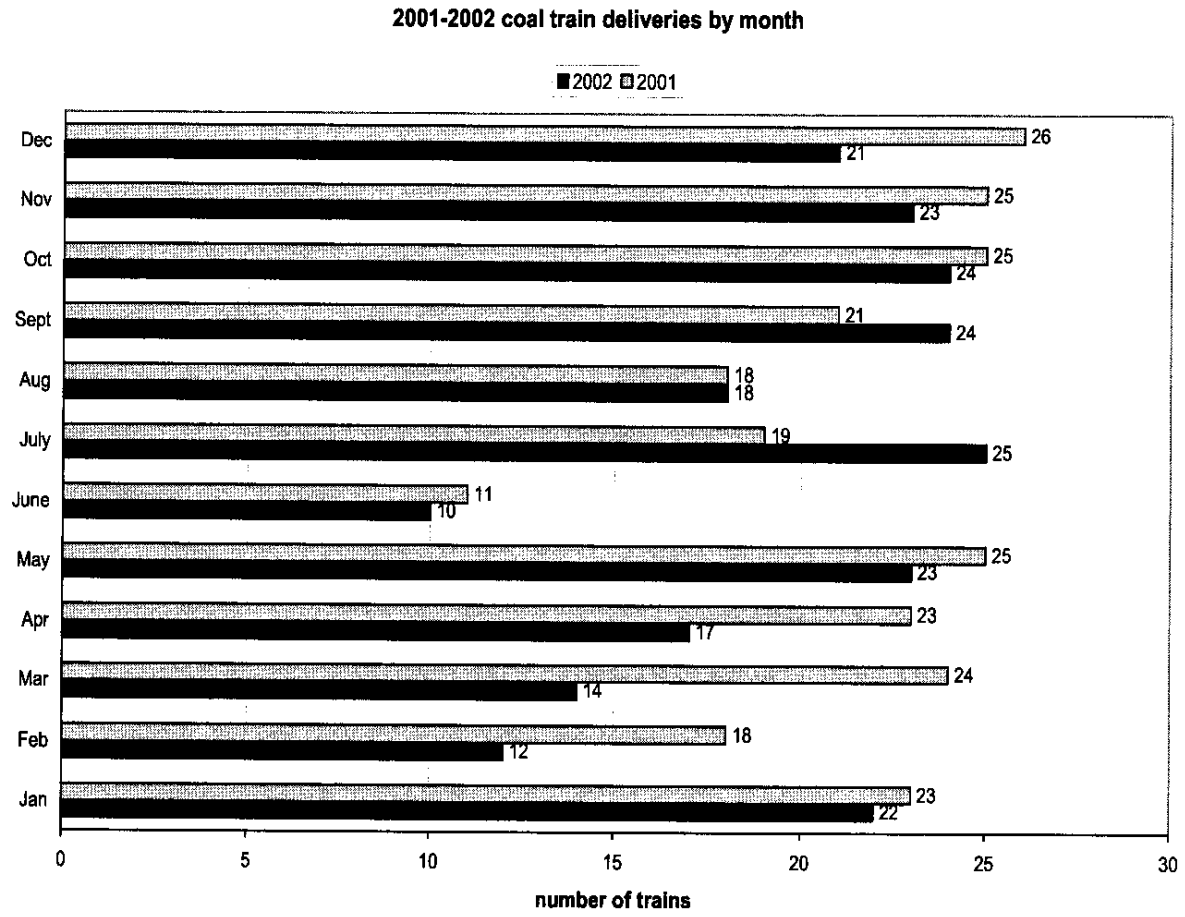


Figure 11-22 2001 and 2002 coal train delivers by day of week

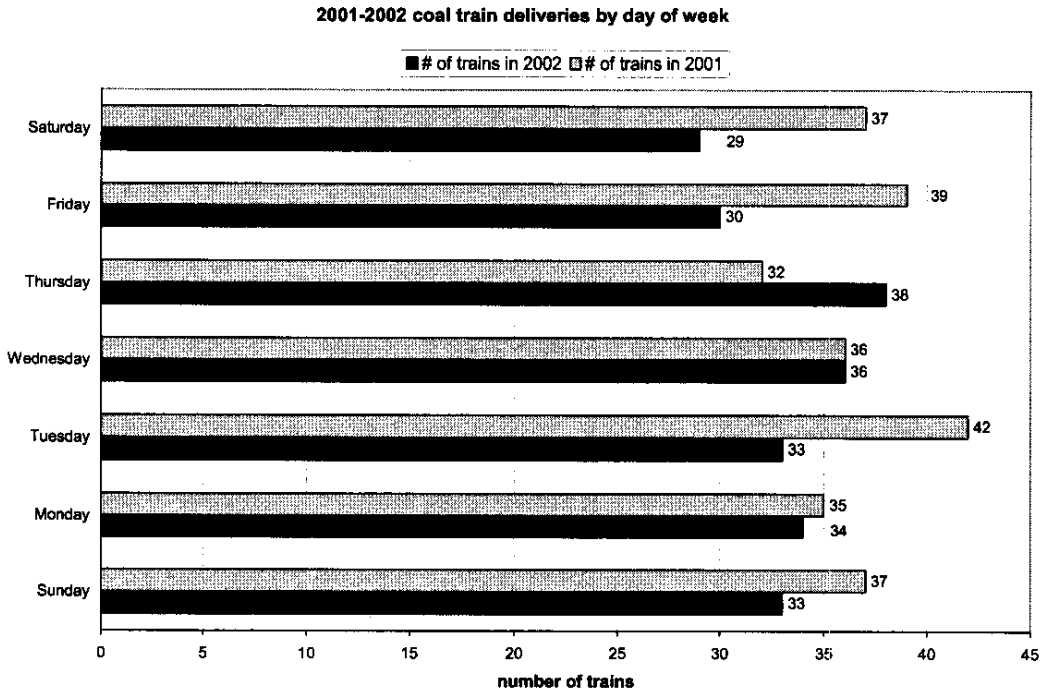
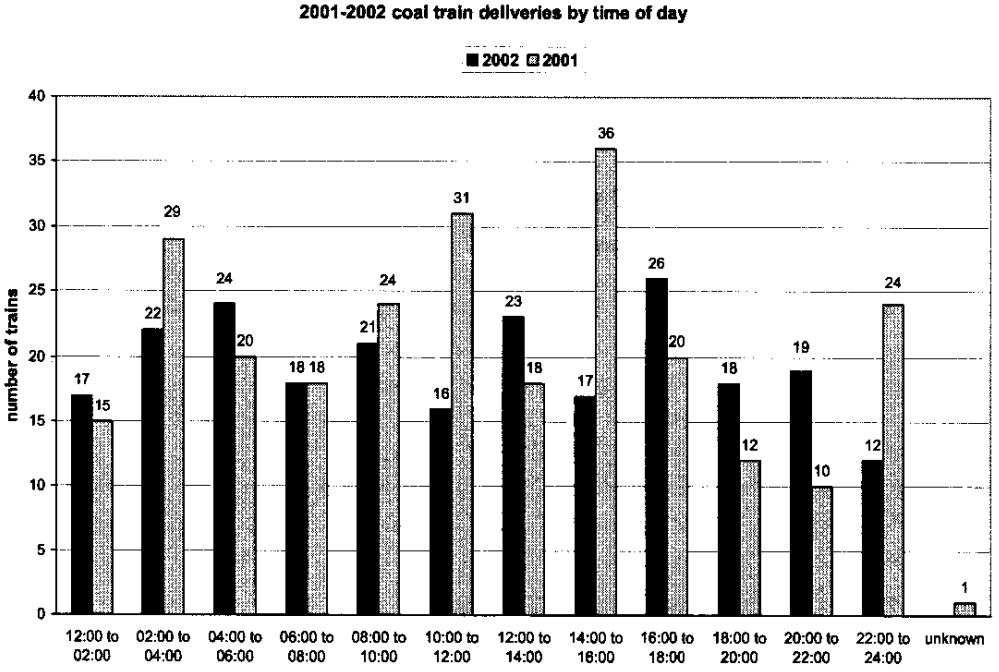


Figure 11-23 2001 and 2002 coal deliveries by two-hour period



Existing coal unloading procedures

Currently WEPCO breaks a 125-car train into three strings of about 42 cars per string. Strings/cars that are switched onto WEPCO's siding tracks located on-site are moved manually, which involves a great deal of stopping and starting of the train and results in significant noise. During the current coal unloading procedure, each individual car is manually lined up with the dumper, causing loud noises as the train strings stop and start. An average of about five cars per train require some kind of maintenance, which again involves moving the train backwards and forwards to de-couple those cars. This movement produces loud noises as cars bang together when the backward and forward movements begin. At present, it takes about 16 hours to unload a 125-car coal train.

Proposed coal delivery for ERGS

Delivery of coal by ship

In WEPCO's CPCN application, the possibility of transporting coal by water rather than rail was presented as an alternative. In the draft EIS improved docking facilities, as well as improved rail delivery facilities were shown on the same maps, leading many people to believe that both improvements would occur. However, the applicants have stated that it would not be economical to construct both types of facilities. At the present time, WEPCO would prefer to build only the railroad improvements and forego construction of the harbor facilities. However, it is still seeking DNR permits for both facilities.

In addition, whether water delivery is the primary or secondary mode of coal delivery to the new units, on-site coal storage would need to expanded and increased train deliveries would still be necessary due to freezing of the lake and the uncertainties of coal delivery by water. Thus, the increased use of water delivery would not decrease the overall impacts of land delivery, but would also entail significant impacts to the lake and increased costs.

Increases in rail traffic

Fuel source effect on train delivery estimates

When the applicants filed their CPCN application with the PSC, they had not yet decided on a western or eastern coal source. Western and eastern coals have significantly different properties. One difference is that eastern coal has higher energy (fuel) content. The amount of eastern coal that is required to fuel the proposed plant would be about 30 percent less than the amount of western coal. Because WEPCO did not know the coal source, it's estimates of increased rail traffic used in the CPCN application were for the worst-case condition, i.e. a western coal source. Since then, WEPCO has decided on the use of eastern coal (Pittsburgh #8 bituminous coal) for the new units. Therefore, current estimates for increased rail traffic are lower than the estimates in the CPCN application. The existing OCPP units would continue to burn western coal. All train traffic delivering coal to the OCPP would travel through Chicago, regardless of coal source.

Estimates of number of trains needed for ERGS proposal

Tables 11-32, 11-33, and 11-34 estimate total coal train traffic, assuming one, two, or three ERGS units. The first table uses WE Power's analysis. The second table is an independent PSC staff analysis. The third table

uses the largest numbers for existing train traffic (WEPCO's) and the largest numbers for proposed train traffic (PSC staff's). These estimates are lower than those in WEPCO's CPCN application, because WEPCO is now proposing to use eastern, rather than western coal for the new units, reducing needed train capacity by about 30 percent. The first two tables assume 135-car trains. The third table shows estimates for both 130-car trains and 135-car trains. Existing trains bringing coal to the site have 125 cars. WEPCO is proposing rail facilities capable of handling 150-car trains. There is some debate in the rail industry as to the number of cars and the capacity per car that will become the new industry standard. Actual weekly train traffic would be highly variable since coal deliveries cannot be scheduled.

Table 11-32 WEPCO estimate of future coal train deliveries

	Existing train deliveries	Deliveries with 1 SCPC unit	Deliveries with 2 SCPC units	Deliveries with 2 SCPC units and 1 IGCC unit
Total number of trains – weekly estimate*	5 to 6	7	9	11
Source of coal**	western coal	eastern coal	eastern coal	eastern coal
Number of cars per train***	125	135	135	135

*This estimate is the yearly total divided by 52
**Eastern coal requires 30% fewer deliveries due to its higher energy content. The percentage of time the proposed units would operate is similar to that for the existing units
***Number of cars per train and/or the capacity of train cars may increase in the future. WEPCO's proposed design for the rail unloading facilities would accommodate a 150-car train.

Table 11-33 PSC staff estimate of future coal train deliveries

	Existing train deliveries*	Deliveries with 1 SCPC unit	Deliveries with 2 SCPC units	Deliveries with 2 SCPC units and 1 IGCC unit
Total number of trains – weekly estimate**	4.7	7.08	9.42	11.75
Source of coal	western coal	eastern coal	eastern coal	eastern coal
Number of cars per train***	125	135	135	135

* Existing deliveries based on years 1998, 1999, and 2000
** This estimate is the yearly total estimate divided by 52
***Number of cars per train estimated to remain the same for the existing deliveries.

Table 11-34 Highest estimate for future coal train deliveries*

	Existing train deliveries	Existing deliveries with 1 SCPC unit		Existing deliveries with 2 SCPC units		Existing deliveries with 2 SCPC units and 1 IGCC unit	
Total number of trains – weekly estimate*	6.0	8.42	8.33	10.85	10.67	13.27	13.00
Number of cars per train**	125 cars per train	130 cars per train	135 cars per train	130 cars per train	135 cars per train	130 cars per train	135 cars per train

* This estimate is the yearly total estimate divided by 52
**Number of cars per train estimated to remain the same for the existing deliveries and varied for the proposed deliveries.

Effect of siting and number of units

The applicant's rail proposals do not differ depending on whether the North Site, South Site or South Site-Exp is used. Potential impacts would remain the same, regardless of site. However, the average number of train deliveries per week would increase by about two for each additional unit that is built and operated and the trains are expected to be about 10 cars longer than those used for current coal deliveries.

Proposed changes to the railroad corridor

To accommodate WEPCO's proposed changes in coal delivery, the UP would modify its easternmost rail corridor from the plant site to about 0.66 mile south of Five Mile Road (about 3,500 feet south as measured along the rail right-of-way). The UP would add no new main tracks, however, the location of the main track within the rail corridor would change for some or all of the area under reconstruction. The UP's new tracks, whether for main or siding purposes, would probably be built to higher standards (e.g. stronger ties, wider rails) than the track being replaced.

Currently, there is one siding track for WEPCO that begins about 800 feet north of Five Mile Road. Under the proposed reconstruction, train switching to WEPCO's sidings would begin about 1,500 feet south of Five Mile Road. The number of sidings servicing WEPCO's property would increase to two tracks from this point to a point about 1,700 feet south of Seven Mile Road. South of Seven Mile Road the sidings would increase to four tracks. Figures 11- 24 to 11-27 show proposed changes to the rail corridor immediately south of the OCPP site, and around Seven Mile Road, Six Mile Road, and Five Mile Road.

WEPCO's descriptions of the proposed changes in the rail corridor include the following information:

- All work would be done on existing UP railroad right-of-way and WEC right-of- way or property.
- There are currently two rail tracks on the UP right-of-way, a siding and a mainline. WEPCO's proposal would reverse the mainline and siding tracks so that the mainline would be the westernmost track and the siding would be the easternmost track.
- WEPCO's proposal adds two inbound tracks, which branch off the passing track south of Seven Mile Road. WEPCO's proposal adds two outbound tracks.
- Trains entering the site would stop at the entrance to the new indexer/car dumper on the inbound track.
- After the train has cleared the car dumper, it would be inspected and refueled.
- Refueling would be done by fuel truck at the head-end engine and at the tail-end engine. Refueling stations are locations where UP would re-fuel their engines by tanker truck. Drip pans would be fitted between the tracks in the refueling areas.
- While the train was in this outbound position, rail cars would be inspected. Cars requiring repair would be counted and marked.
- The proposed rail arrangement includes a bad order yard, where cars requiring repair, and repaired cars, would be stored. As the train left the site, repaired cars would be added to the train, and cars requiring repair would be removed from the train.
- After all the bad order cars were changed out, the brakes would be air tested as the train left on the mainline.

- Trains to the ERGS site would be a nominal 135 cars and 3 engines (7,500 feet in length). The maximum train length that the rail design would accommodate is 144 cars and 4 engines (8,100 feet in length).

Figure 11-24 Proposed rail facilities near the southern boundary of WEPCO's property

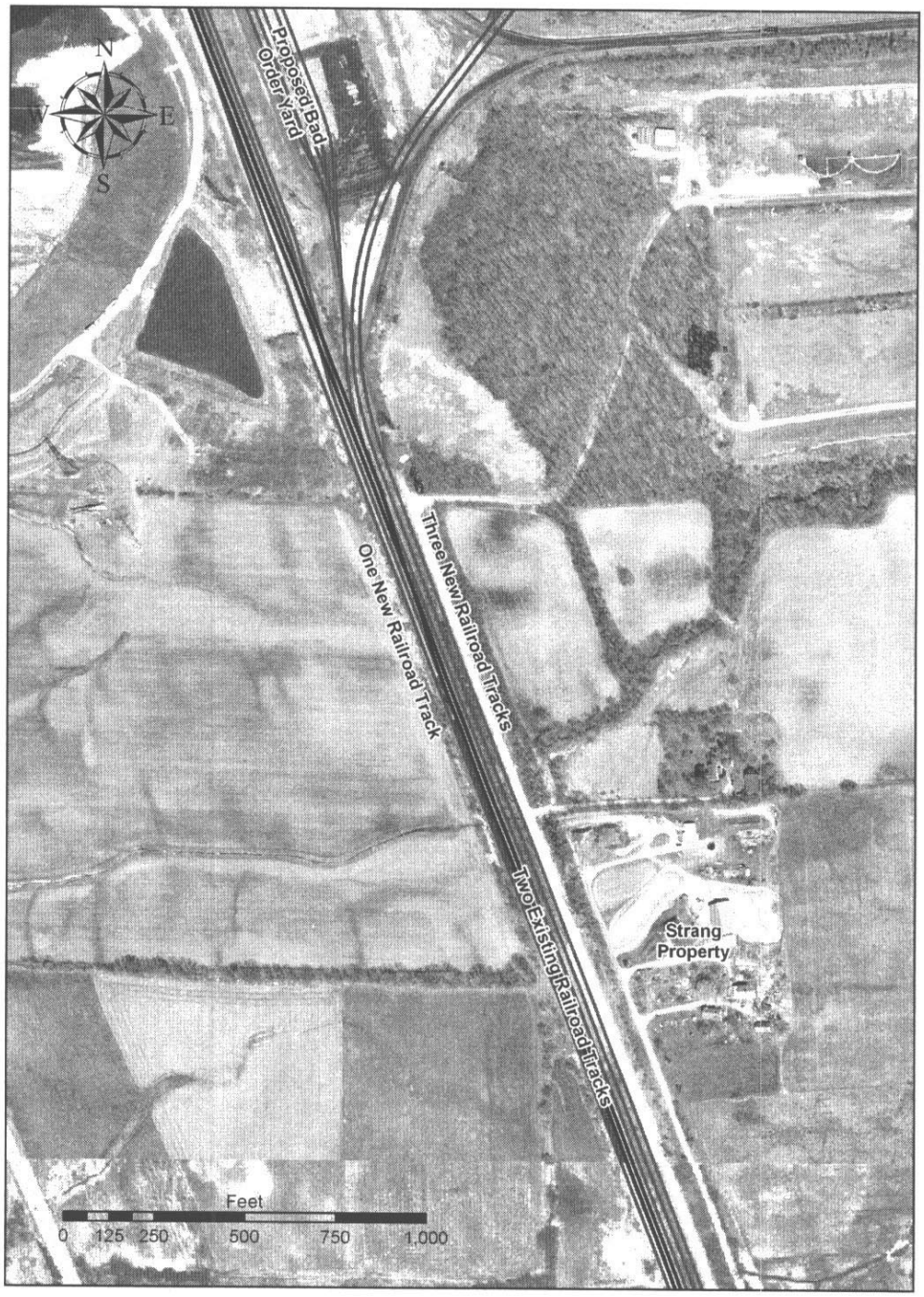


Figure 11-25 Proposed rail facilities near the Seven Mile Road crossing

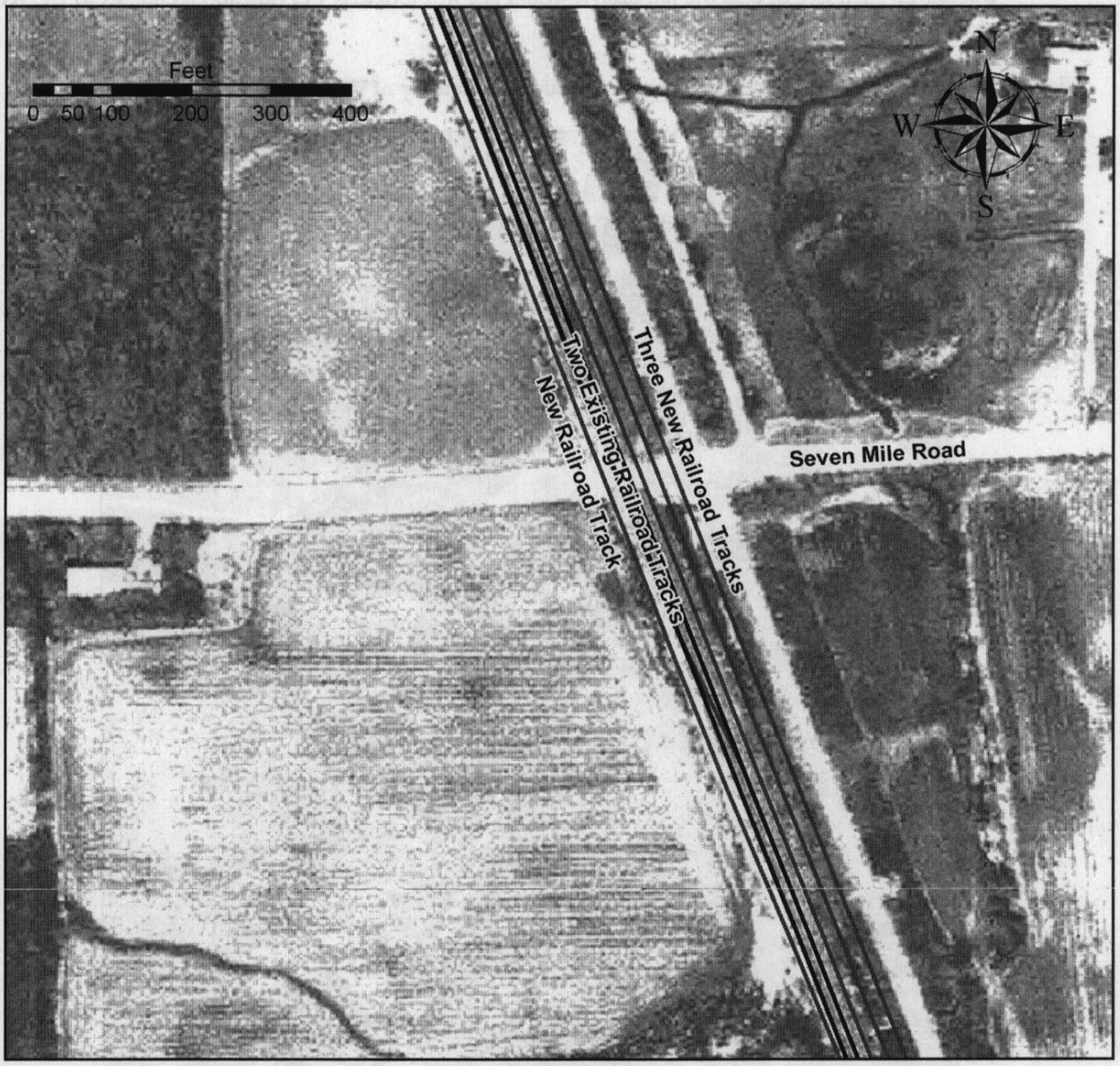
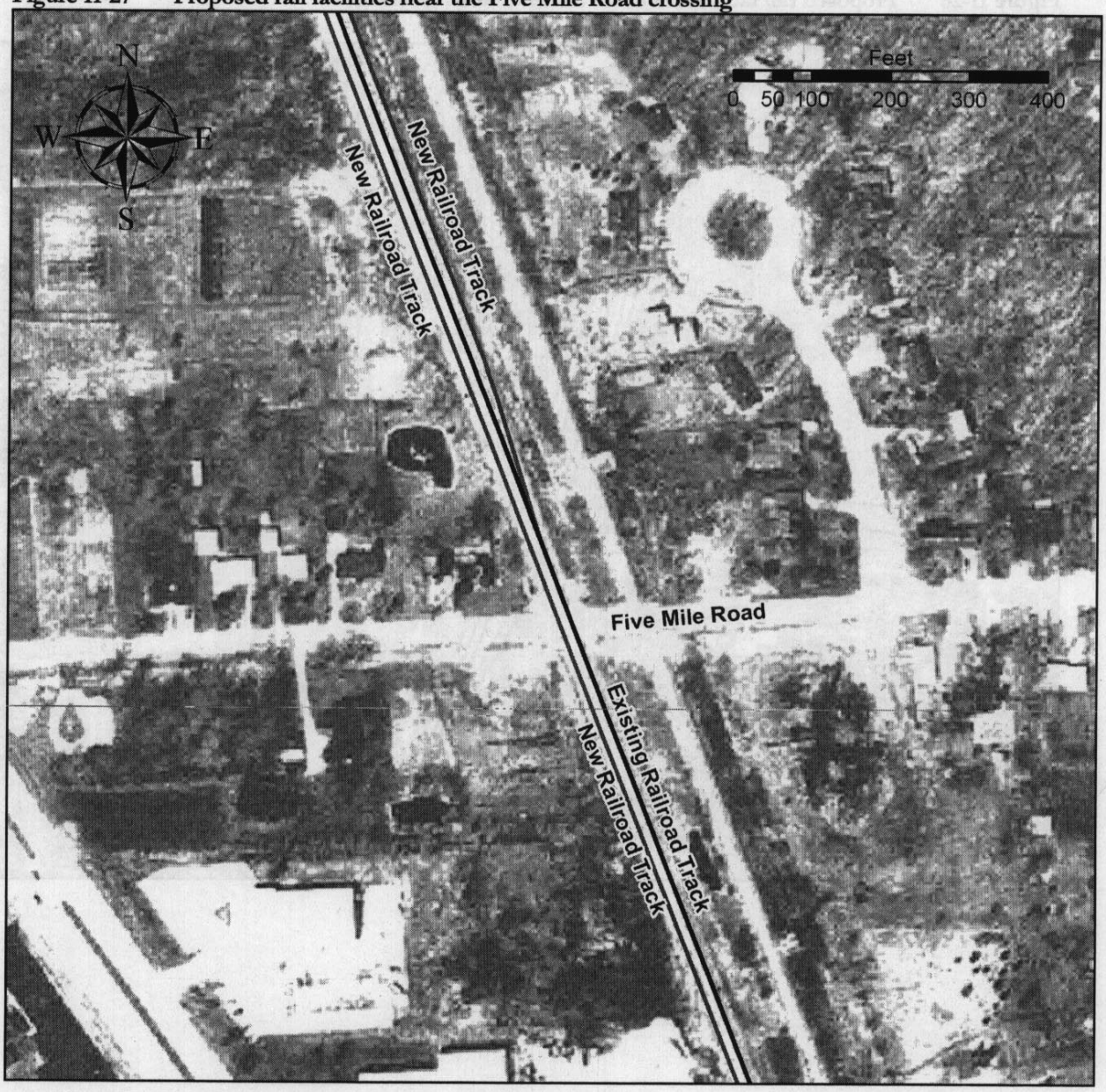


Figure 11-26 Proposed rail facilities near the Six Mile Road crossing

Figure 11-27 Proposed rail facilities near the Five Mile Road crossing



Potential air pollution from coal trains

Fugitive dust

RTP Environmental Associates, a consulting firm for WE Power, researched EPA wind erosion data. The two potential sources for fugitive dust from coal trains are the open coal cars, and the disturbance of the rail bed by train movement. RTP's analysis, reprinted below concludes that any particles of coal that would blow off or bounce out of an open coal car would be gone before the cars reached Wisconsin, and that the speed of coal trains in Wisconsin would not disturb materials on the rail bed. When the coal is unloaded at the

power plant site, it would be in an enclosed building incorporating dust suppression techniques. Empty rail cars would return over the same route that they came in on. Depending on weather conditions, the empty cars would give off coal dust. Damp or inclement weather would reduce dust.

Analysis of Potential for Fugitive Dust from Coal Train Deliveries by RTP Environmental Associates, November 2002

EPA has developed equations to estimate the dust generated from wind erosion of exposed areas, and these can be applied to estimate emissions from the train movement and open coal cars (wind erosion caused by air currents from the moving train are similar to wind emissions at stationary sources caused by wind). Wind erosion dust sources are typically characterized by non-homogeneous surfaces impregnated with "non-erodible elements" (particles larger than approximately one centimeter in diameter. "Field testing of exposed materials using a portable wind tunnel has shown that dust can be generated from undisturbed coal piles and road beds when wind speeds exceed approximately 50 miles per hour at seven meters above the surface and the particulate emission rates tend to decay rapidly (half-life of a few minutes) during an erosion event."

In other words, these undisturbed material surfaces have a finite availability of erodible dust, and once the available dust is emitted there is no additional material to generate additional dust (unless the material is disturbed, for example by bulldozers or other grinding processes that could generate fresh erodible material). Since the coal trains travel at speeds of less than 30 mph, and because the coal in the cars, and the railroad bed, are not "disturbed," the EPA wind erosion equations indicate that there will be no significant fugitive dust emissions from the coal train operations.

Diesel emissions from rail engines

Rail engines run on diesel and no entity regulates diesel emissions from rail engines. Dispersion and distance generally keep diesel fumes from being a problem for adjoining property owners around the OCPP. However, trains that stop and idle for hours or days can cause build-ups of diesel fumes. Residents of the house east of the railroad tracks, and north of Seven Mile Road, have reported experiencing problems with diesel fumes from engines idling for hours or days while parked adjacent to their property.

Train engines must idle in the winter to keep warm if they are not in a building or connected to a power source. If rail engines are not kept warm, and are turned off, they are difficult to restart. In addition, there might be other damage. One solution may be to house the engines, that might otherwise idle overnight or over a weekend, in one of the heated sheds used for coal unloading. Diesel fumes from rail engines idling do not occur in the summer months, because the engines can be turned off.

The UP is gradually replacing older locomotives with newer, more efficient ones that produce lower emissions, among other improvements. The UP ordered 1,000 new engines in 1999; the last of which will be delivered in 2003. The newer engines would decrease both emission and noise impacts.

Noise effects of proposed changes in coal unloading facilities

The noise section discusses potential noise from all sources, including trains. WE Power proposes to modify the on-site rail facilities in a number of ways that would reduce noise. Among the major changes it is proposing are a new indexer that would automatically position train cars in the precise position for coal

unloading and an expansion of the on-site tracks that would accommodate an entire train. See Table 11-35 below for a comparison of existing facilities and those proposed as part of the ERGS project.

Table 11-35 Proposed changes that would reduce noise during coal unloading

Subject	Now	Planned change
Train length on-site	WEPCO breaks a 125-car train into 3 strings of about 42 cars per string -- causing coupling and uncoupling noise	Expand the track to accommodate entire train (up to 150 cars) on property, thus eliminating noise
Switches to WEPCO siding	Manual; train stops and restarts causing car noise	Automatic; no stopping eliminates noise
Location of repair-in-place track (inspection pulls out an average of 5 cars per 120 car train for maintenance)	Requires uncoupling - backing up and moving forward which causes loud noise	Reduce on-site repairs; change location of repair-in-place (RIP) track to reduce movement and noise
Dumping coal from cars	Manual; line every car up with the dumper individually, causing noise due to trains starting and stopping. Takes about 16 hours to unload one train	Automatic indexer; only need to line up the first car; eliminates back and forward noise. Takes about 5 hours to unload one train.

In addition, the replacement of track in the rail corridor near the plant would reduce the noise associated with train movements, as the tracks would probably be built to carry heavier loads than the current tracks.

Potential safety issues associated with increased rail traffic

Table 11-36 summarizes 2001 accident and incident data for all UP trains. The length of a round trip from the Illinois border to the Oak Creek site is about 50 miles. Train speeds in Wisconsin are slower than in other states. The UP currently has 28 crossings between the Illinois border and the Oak Creek site. If two rail crossings are eliminated in Caledonia as proposed, this would lower the potential for accidents between rails and vehicles in Wisconsin.

Table 11-36 Accident statistics for the Union Pacific Railroad Company* (January - December 2001)

	# Accidents	Miles	# Accidents per million miles	Fatalities	Injuries
Highway/ rail accidents	629	172,712,098	3.64	72	227
Trespassing incidents	259	172,712,098	1.50	132	127

* Federal Railroad Administration Office of Safety Analysis (safetydata.fra.dor.gov/officeofsafety)

Coordination with potential commuter rail service

Existing commuter service runs from Chicago to Kenosha. There is wide support for expanding this service. Studies are progressing for extending service from Kenosha to Milwaukee. Currently, the alternative analysis phase of project development is ending. Followeing local review and approval, the next phase addresses preliminary engineering. During this stage, a draft and final EIS will be prepared.
The proposed increase in train deliveries would not conflict with future commuter trains. In the past, commuter trains and freight trains shared this rail corridor. Currently, there is only one track between Chicago and Milwaukee. There used to be two main tracks in the rail corridor. If commuter rail service

were implemented, there would be a need to reconstruct or reinstall passing sidings or a second main track to allow commuter trains to pass one another and to coordinate with freight trains. The need to engineer for coordination with an increased number of freight trains may increase costs (for example, requiring more communication facilities), but should not interfere with the establishment of commuter service. Other successful commuter services share rail lines with higher amounts of freight traffic. Coal trains are generally slower than commuter trains, and would be fewer in number.

Rail transportation planners envision from 8 to 15 diesel-powered commuter trains traveling in each direction during weekdays (concentrated around rush hour). The rail line would need track and signal improvements to enable commuter trains to operate at acceptable speeds, to allow for passes between commuter trains, and to accommodate the joint operation of freight train and commuter train traffic. At a minimum, several long passing sidings or segments of second track would need to be reinstalled. At a maximum, almost the entire route would be restored to a double track line. Train stations close to the OCPP/ERGS site would be in the town of Caledonia at or near Four Mile Road, and north in the city of Oak Creek.

Trains blocking crossroads due to proposed changes in the rail corridor and train length

Times and causes for blocking neighboring roads

Table 11-37 shows the expected range of times and the reasons for blockage of Seven Mile, and Six Mile Roads. The rail corridor is on a bridge over Five Mile Road (CTH G) and further south WEPCO maintains that all road crossings would occur at-speed. The first switch to a rail siding could occur about 0.25 mile south of Five Mile Road. Train speeds in Wisconsin are normally about 30 mph, but trains entering and leaving the OCPP site would slow or stop for a number of reasons.
Surprisingly, trains could block Six Mile Road for a longer time than Seven Mile Road, due to the proposed increase in siding track length. This would allow rail engineers to test their brakes before joining the main rail line as trains leave the OCPP/ERGS site. Assuming that bad order cars (cars removed for repair) are located near the end of a train, the worst-case scenario at the Six Mile Road crossing would result in a longer blockage than the worst-case scenario at Seven Mile Road. In reality, the time that most trains would block Six Mile Road is probably equal to or less than the time that most trains would block Seven Mile Road. The discussion following this table explains the causes for these blockage times.

Table 11-37 Time that a train could block Seven and Six Mile Roads

Trains entering site	Trains exiting site		Total time
Seven Mile Road	no bad order cars	5 bad order cars	
30 min	15 min	165 minutes (2 hrs 45 min)	45-195 minutes (45 min - 3 hrs 15 min)
Six Mile Road			
25 min	75 min (1 hr 15 min)	225 min (3 hrs 45 min)	100-250 min (1 hr 40 min-4 hrs 10 min)

Seven Mile Road

Trains coming into the Oak Creek site would block Seven Mile Road for approximately 30 minutes per train due to:

- road crossing time
- switching time (switching from the UP track to WEPCO's siding)
- dumping time for the first three rail cars (due to the length of the train, the tail of the train would still be blocking Seven Mile Road until the first three cars are unloaded)

Trains leaving the site would block Seven Mile Road for anywhere from 15 minutes to a maximum of 165 minutes per train. Crossing the road takes approximately 15 minutes. WEPCO inspects trains leaving the site for any needed repairs. Cars needing repair (bad order cars) are removed from the train and backed onto a special siding (RIP tracks) for later repair. Bad order cars average five per train. At 30 minutes for each bad order car, Seven Mile Road could be blocked for an additional 2.5 hours or 150 minutes. Blockage of Seven Mile Road by outgoing coal trains would be caused by:

- road crossing time (15 minutes)
- removal of bad order cars (0 to 150 minutes)

Six Mile Road

Trains coming into the Oak Creek site would block Six Mile Road for about 25 minutes per train due to:

- road crossing time
- switching time

Trains leaving the Oak Creek Site would block Six Mile Road for anywhere from 75 minutes to a maximum of 240 minutes. Crossing the road takes approximately 15 minutes per train. Engineers must test the train brakes before beginning operation on the main line. This usually requires an additional 60 minute per train. Removing bad order cars would take from 0 to 150 minutes per train. Blockage of Six Mile Road by outgoing coal trains would be caused by:

- road crossing time (15 minutes)
- air testing the brakes (60 minutes)
- removal of bad order cars (0 to 150 minutes)

Four Mile Road

WEPCO states that trains would delay traffic on Four Mile Road only for the time it takes the train to cross the road, approximately 3.5 to 4.5 minutes per train. Trains would cross this road at a higher speed than at the Seven Mile and Six Mile crossings, where engines have slowed down considerably to enter or leave the on-site rail unloading facilities.

In the past, some coal trains have blocked 4-Mile Road for a considerable time. WEPCO states that this occurred because these trains were pulling off the main track to stop on the siding, while waiting for another train to leave the OCPP site. As proposed, the new rail facility would have room for four trains on WEPCO's property. The new switch to WEPCO's siding is designed for 30 mph. Trains approaching the power plant site begin to slow down about two miles south of the plant, and this would not change under the current proposal.

To confirm the time that trains take to cross Four Mile Road, WE Power hired a consultant, Innovative Systems, to monitor train and vehicle traffic at Four Mile Road and the UP Railroad. The study period was between July 19 and August 12, 2002. Innovative Systems installed a video camera and recording equipment on a utility pole at the Northwest corner of the crossing. The camera had an infrared light source to provide day and night recording. The camera view included the crossing gates and roadway on both sides of the track. Innovative Systems provided WE Power with ten tapes and a summary. The summary included the following:

- 30 coal trains passed Four Mile Road traveling to and from the Oak Creek site
- The number of vehicles stopped at the crossing (for coal trains) averaged 24, with a maximum of over 50
- Coal train crossing times averaged 3 minutes 48 seconds
- The maximum coal train crossing time was 8 minutes 50 seconds
- The minimum coal train crossing time was 2 minutes 17 seconds
- There were 61 other (non-coal) trains or gate closings

Scheduling of rail deliveries

The time of day during which coal trains would block specific roads is difficult to predict because the trains are not scheduled. Figures 11-28 and 11-29 show the actual amount of time that Six Mile Road and Seven Mile Road would be blocked for one, two, three, or more train deliveries per day, assuming no train deliveries overlap.

Figure 11-28 Total time Seven Mile Road would be blocked by coal trains on a daily basis (depending on the number of trains per day)

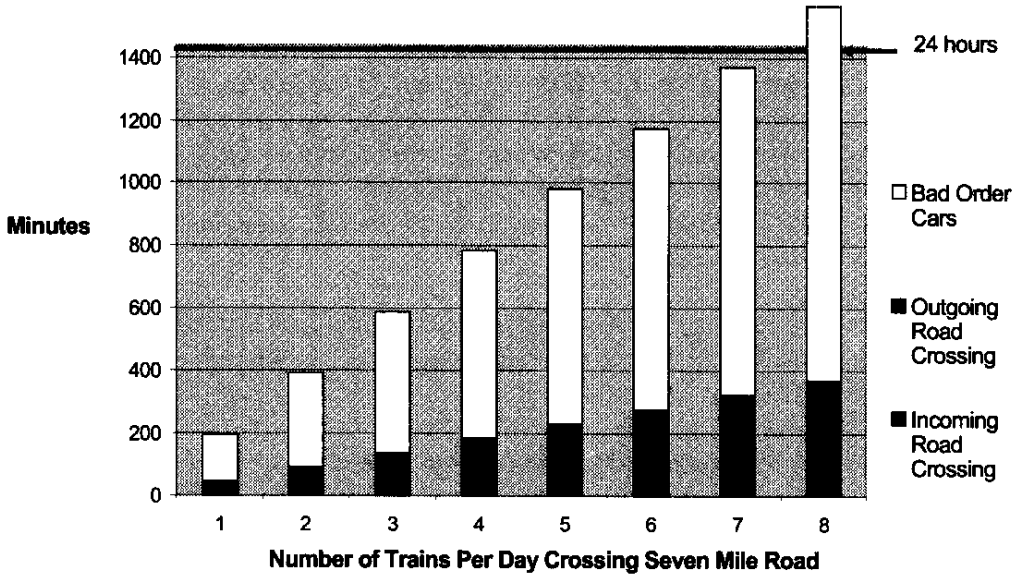
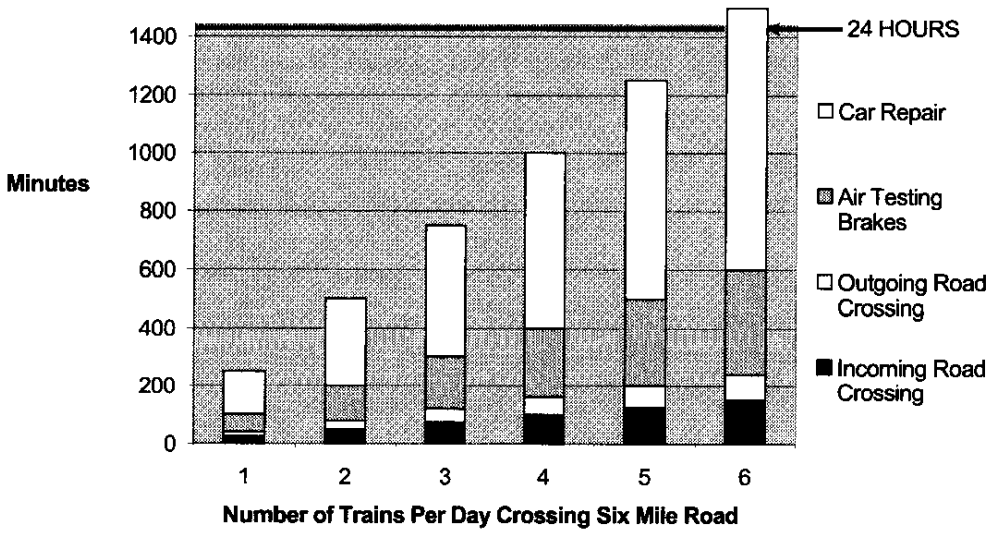


Figure 11-29 **Total time Six Mile Road would be blocked by coal trains on a daily basis (depending on the number of trains per day)**



Applicable federal laws

The U.S. Department of Transportation, Federal Railroad Administration addresses blocked crossings on its FAQ (frequently asked questions) internet site. The following paragraphs contain the information from that site verbatim.

> "The Federal Railroad Administration (FRA) takes the problem of blocked crossings very seriously, both because of their adverse safety effects and because of their adverse effects on the livability of our communities. While the federal government has not exercised regulatory authority in this matter, FRA rail safety regulations do address standing trains that unnecessarily activate grade-crossing warning systems. These regulations under Title 49 CFR, Section 234.209, prohibit standing trains, locomotives, or other rail equipment from activating the warning systems at grade crossings unless the operations are a part of normal train or switching movements. Each state has the authority to adopt its own requirements or leave such laws to the discretion of local governments.
>
> For guidance purposes, the 1987 Uniform Vehicle Code (UVC) 'a model set of motor vehicle laws' recommends that train operations should not block a highway-rail intersection for more than five minutes unless:
>
> - It is necessary to comply with signals affecting the safety of the movement of trains
> - It is necessary to avoid striking any object or person on the track
> - The train is disabled
> - There is no vehicular traffic waiting to use the crossing; or
> - It is necessary to comply with a governmental safety regulation

> The UVC is not binding, however. Each state has the prerogative of adopting its own version or leaving such laws to the discretion of local governments. The federal government has no authority in state matters, please contact the state attorney general's office for local or state laws that might be applicable to your situation, or for highway-rail grade crossing improvements, please contact the local and state highway authorities to determine if they might consider improvements at crossings that could resolve any such problems. Information on possible improvements, priorities, schedules, and the administration of funds is available through your state's Department of Transportation."

This site then suggests contacting the FRA Regional Manager for Highway-Rail Crossing and Trespass Prevention Programs for additional information and assistance.

Applicable state laws

Wis. Stat. 192.292 addresses the subject of trains obstructing highways. This statute is old, based on the assumption that in the countryside trains were just passing through, whereas in municipalities they were slowing down and stopping (for passengers and freight). This statute has seldom been used. Rail companies consider the $25 fine part of the cost of doing business.

The statute reads as follows: "It shall be unlawful to stop any railroad train, locomotive or car upon or across any highway or street crossing, outside of cities, or leave the same standing upon such crossing longer than 10 minutes, except in cases of accident; and any conductor, engineer, brakeman, or other person in charge thereof or responsible therefore who shall violate this section shall be liable to a fine of not more than $25 or to imprisonment of not more than 15 days."

The Office of the Commissioner of Railroads is charged with approving any physical change at railroad crossings of roads. The primary concern of this office is public safety.

Applicable Municipal laws

The Wisconsin statutes also allow municipalities to set their own standards for how long a train can block a track. Most such ordinances prescribe 10 minutes as the maximum interval; some use 15 minutes.

WEPCO's proposal to eliminate road crossing blockages

Train length, unloading operations, and increased numbers of trains would increase blockage time at the rail crossings of Seven Mile Road, and Six Mile Road in the town of Caledonia. WE Power hired engineering consultants Alfred Benesch & Company (Benesch) to investigate possible grade separations (putting the rail tracks over or under roads in the town of Caledonia).

Benesch held two workshops, inviting local officials, the Wisconsin Department of Transportation (DOT), the DNR, and the UP, to discuss the problem. Later, Benesch produced a report titled "Grade Separation Feasibility Studies." Copies of this report are in area libraries, as well as in the applicants' CPCN application. This report is conceptual in nature. It does not include the engineering studies needed to precisely locate, design, or estimate costs for possible changes at the two railroad/road crossings.

Proposal for Seven Mile Road

The Benesch report recommends closing Seven Mile Road east of the rail tracks by building cul-de-sacs on the east and west sides of the rail crossing. Benesch bases this recommendation on low traffic volume on Seven Mile Road east of the rail crossing (estimated at 200 vehicles per day), low population density east of the rail crossing, and the availability of Six Mile Road as an alternate route.

The traffic estimate for Seven Mile Road was based on data available on nearby roads and the estimates of local officials. Since then, the Town of Caledonia has used TimeMark Delta III traffic counting equipment to record an average daily traffic volume of 320 vehicles between October 22 and November 19, 2002. However, this would not change the Benesch recommendation, which was based on a safety-related "exposure factor", as defined in the Facilities Development Manual (FDM). The DOT and the Office of the Commissioner of Railroads use the FDM as a guideline for determining appropriate warning or safety improvements at road/railroad crossings. The exposure factor is the product of the average daily traffic and the number of trains crossing the road per day. The FDM guidelines list an exposure factor of above 100,000 as a justification for grade separation.

Proposal for Six Mile Road

The Benesch report recommends building an underpass beneath the railroad tracks at Six Mile Road. Six Mile Road would be relocated to the north of its present location and it would cross under the tracks.

For further discussion of the Benesch report, see the section below entitled, Potential impacts of a new rail underpass on Six Mile Road.

Process for altering railroads and ownership of new bridge/ road facilities

Any change to an existing rail crossing requires the approval of the Office of the Commissioner of Railroads (OCR), a five-person state agency that enforces section 195.29 Wis. Stats. (Chapter RR 1 of the Wisconsin Administrative codes). The local municipality must first pass a resolution supporting the project. Then the OCR must be petitioned. The OCR issues a notice of hearing and holds a hearing in the local area.

While WE Power would provide funds for the construction of any proposed underpass, it would not become the owner. The UP Railroad would own the rail bridge and the town of Caledonia would own the roadway and embankments of the underpass. WE Power would also pay for other specific changes to town or county roads due to the proposed power project.

Should the PSC and the OCR approve WE Power's plans for such an overpass, the town of Caledonia would need to be an active participant in order to acquire land for the relocated road. DNR permits would be required to discharge storm water (NR216) and possibly to relocate an intermittent waterway.

Potential impacts of WEPCO's proposal to eliminate road blockage problems on Seven-Mile Road

Loss of an access road for emergency vehicles

The Caledonia Fire Department has three stations that are sited west of the UP railroad tracks:

- one near Five Mile Road/Douglas Road (6040 Douglas)
- one near Nicholson Road/Six Mile Road (6900 Nicholson) – Station 1
- one near Nicholson Road/Highway K (9433 Northwestern Avenue)

The Department uses mostly east-west roads for response. Closing Seven Mile Road would remove one of its response access roads.

Although not in the applicants' current proposal, there is a means to allow both passage of emergency vehicles and direct access to STH 32 for those residents with driveways just east of the railroad crossing. A private access road could be constructed which would involve an arched tunnel under the railroad. This tunnel would need to be twelve feet high to accommodate fire trucks and would require the approval of the state OCR.

Loss of an access road for residents

Four homes have an access drive immediately east of the rail tracks. Closing Seven Mile Road would require those residents to access STH 32 by driving east on Seven Mile Road (about one-third mile), south on Michna Road (about one mile), and west on Six Mile Road (almost one-half mile). This is about one and one-half mile longer than a direct route traveling west on Seven Mile. There is also a residence at the intersection of Seven Mile Road and Michna Road, for which access from STH 32 would increase by about three-quarters of a mile. A private access road, such as the one described above, could eliminate the problem of access for residents on Seven Mile Road residing east of the proposed road closure.

Potential impacts of a new rail underpass on Six Mile Road

The applicants hired Benesch, as engineering consultants, to investigate possible grade separations (putting the rail tracks over or under Caledonian roads). Benesch produced a report titled "Grade Separation Feasibility Studies." Benesch recommends an underpass, with the road set north of its existing alignment. The design would include a dedicated bike path bridge (Alternative 3 in the Benesch report). While there is no detailed design for such an underpass, the general concept is shown in Figure 11-30, which shows the northern re-alignment of Six Mile Road and the proposed cul-de-sac on an airphoto of the area. The summary in Benesch' report, states that:

> "An underpass would be more aesthetically pleasing for the community, and constructing on an offset alignment would minimize the number of relocations and decrease the cost for traffic and railroad staging throughout construction."

Benesch held two workshops to develop ideas for solving the problems of traffic blocking Six Mile and Seven Mile roads. Benesch invited local officials, the DOT, the DNR, and the UP, to discuss the problem. The Benesch report presents the results of the two workshops. At the first workshop, a WE Power representative explained the problems and workshop participants brainstormed 14 possible solutions (total) for the two road crossings. From the 14 alternatives, Benesch picked nine to develop further. At the second workshop, Benesch handed out information related to each proposal, and workshop participants discussed the alternatives and listed advantages and disadvantages of each. Table 11-39 shows the advantages and disadvantages listed by participants for the two alternatives that Benesch ultimately recommended. The

Benesch report states that the recommendations were based on comments from the two workshops, additional investigation into ground water, costs, constructability, and engineering judgment.

Figure 11-30 Proposed Six Mile Road Realignment

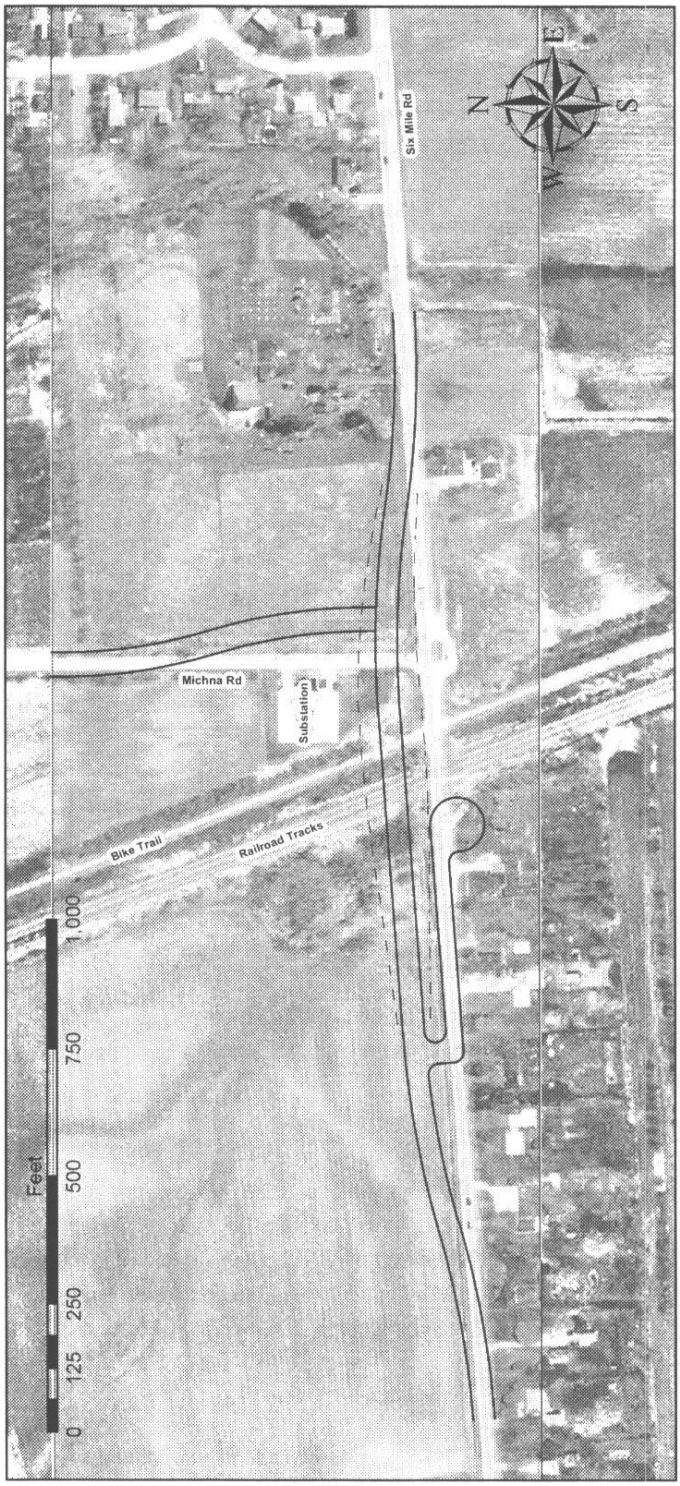


Table 11-38 Six Mile and Seven Mile Road alternatives selected by Benesch for further review*

Six Mile Road	
Alternative	**Name**
#1	At-grade crossing (no modification)
#2	Underpass on existing alignment
#3**	Underpass on offset alignment north**
#4	Overpass on existing alignment
#5	Overpass on offset alignment north
Seven Mile Road	
#1	At-grade crossing with advance signing
#2	Overpass on existing alignment
#3	Overpass on offset alignment north
#4**	Close 7-Mile Road**

* Benesch screened the 14 alternatives for the two crossings produced during the first workshop
** Recommended at end of study

DNR concerns with proposed railroad changes

DNR and DOT generally prefer projects to be on-alignment and within the existing right-of-way when possible, in order to avoid impact to new land. DNR concerns also focus on impact to wetlands, waterways and any endangered biota. DNR and DOT should remain involved in all discussions regarding preliminary and final design for any underpass project.

Drainage

Drainage flows from north to south under Six Mile Road through a culvert located west of the railroad tracks. It then crosses to the east side of the tracks through a culvert and flows north back under Six Mile Road. The footprint of the new underpass would interfere with the culvert on the west side of the railroad tracks. Engineers would most likely need to address the removal of this culvert by constructing a drainage ditch along the north side of any new underpass.

The closing of Seven Mile Road would not affect existing drainage. However, there is a stream located about 200 feet east of the crossing. If an overpass were built at Seven Mile Road, the stream would have to be enclosed for about 200 feet.

Wetlands

An overpass (rather than an underpass as proposed) at Six Mile Road, would have greater land disturbance and wetland impacts than other alternatives. It would also be more expensive than the Benesch recommendation. An overpass may be required if high groundwater exists at the crossing to an extent that pumping could not reasonably control it. However, this is not expected since soil boring data from a water main extension in the vicinity of Six Mile and Michna Road show no ground water present to a depth of approximately nine feet.

Table 11-39 Advantages and disadvantages of an underpass at Six Mile Road on an offset alignment to the north (with dedicated bike path bridge over Six Mile Road)

Advantages	Disadvantages
1. No relocations	1. Reverse curves
2. Provides property access	2. More land disturbance than Alt #2 (underpass on existing alignment with dedicated bike path bridge)
3. Easiest to construct	3. Shares these disadvantages with Alt #2: Pumping station – requires generator & maintenance More land disturbance than Alt. #1 (at-grade crossing) Bridge maintenance Possible high water table could make underpass drainage cost exceedingly high Possible unacceptable well drawdown for underpass drainage Additional cost for bike bridge
4. No sanitary sewer relocation	
5. Less land disturbance than overpass alternatives	
6. No impacts to transmission line	
7. Fewer impacts to Michna Road than overpass alternatives	
8. Can be widened to 4 lanes easier than overpass	
9. Shares these advantages with Alt #2 (underpass on existing alignment with dedicated bike path bridge): Less aesthetic impacts Positive consideration by OCR Easier E-W bike path access Eliminates rail vs. traffic/bike/pedestrian conflicts	

Electric Transmission Proposals and Impacts

Introduction

Figures Vol. 2-6, 2-7, and 2-8 and Tables 6-4 to 6-6 represent the best available information to date on the electric transmission needs for the ERGS proposed project. This representative list is the basis of the environmental impact analysis that follows. The discussion covers the impact associated with one short (four-mile) new transmission line, one long new transmission line, and many upgrades to existing lines.

Specific portions of the transmission improvements listed could change with further study by the ATC or the MISO, as the time for implementing the transmission changes nears. In addition, it is possible that new studies would show that the ERGS proposal does not create the need for a new, long transmission line in southern Wisconsin (although the line may still be needed for other reasons). However, without additional studies (which are not scheduled at this time), the following analysis assumes the need for a major, new transmission line in order to connect two or more of the proposed ERGS coal units to the electric system.

Process for electric transmission line/substation approval

The ATC has not yet applied to the PSC for approval of any of the listed transmission projects. The projects that require approval from the PSC, due to their size or cost, would receive further ATC study, PSC review, and public input.

Definitions of electric terms

Table 11-40 provides definitions for words that Tables 6-4 to 6-6 use to describe transmission line projects. The only word used to show the need for new right-of-way is "construct." All other words involve working with existing structures on existing rights-of-way. This could include simply replacing wires, to actually

replacing or raising the existing structures. Words used to describe proposed work at substations are more unclear. However, the ATC provided a description of proposed substation work, as shown in Table 11-41.

Table 11-40 Definition of term used to describe proposed electric transmission system improvements

Word used	Meaning	Level of environmental effects
Construct	Build a new set of transmission line structures on new or expanded[1] right-of-way.	Various, with a severity that depends on the location of the new right-of-way and the design of the structures.
Convert	Change the voltage of an existing transmission line by changing small equipment or electrical arrangements.	Usually little to no environmental effect.
Expand	Used for changes at an existing electric transmission substation[2]	Usually requires expansion of the existing fenced area; may require property expansion – environmental effects dependent on the surrounding environment.
Install	Used for changes at an existing electric transmission substation.[2]	Usually does not require any changes outside the substation fence; may require an expansion of the fenced area on utility property - environmental effects usually negligible.
Rebuild	Upgrade an existing transmission line in an existing right-of-way by replacing the old structures with new structures or raising the height of existing structures.	Environmental effects depend on the location of the existing right-of-way and the design of the structures – new structures are likely to be taller and may not be in exactly the same location as existing structures.
Reconductor	Replace existing wires on existing transmission structures with new wires capable of carrying more power. This may also require new insulators.	Effects would be caused by access to the existing– environmental effects would be dependent on the location of the poles.
String	Place new wires where there is an unused position ready for them.	Little to no environmental effect.

1 Right-of-way expansion would occur if a new transmission line is placed next to an existing transmission line so that their rights-of-ways could overlap, reducing the amount of new right-of-way required.

2 Refer to Table 11-41 in this section for information about substation changes proposed for this project.

Differences due to site selection or the number of units

Use of the North Site or the South Site would have no effect on electric transmission line requirements or impacts. The number of units may have an effect, but it's unclear without further study. There is some indication that constructing one SCPC unit would have a different effect on the electric transmission system than constructing more than one unit. However, there are many complicating factors, including the need for upgrading the existing transmission system just to serve customers in southeast Wisconsin. In addition, the effects on the electric transmission system caused by regulatory changes at the federal level continue to make planning for new transmission lines in Wisconsin uncertain. The only certainty is that many upgrades are needed, and probably at least one major, new extra-high voltage (345 kV) transmission line. Construction of three new coal units for the ERGS is most likely to contribute to or accelerate the need for these transmission line upgrades and new transmission construction.

Effect of proposed rebuilds of existing electric transmission lines

Using existing electric transmission line rights-of-way tends to minimize environmental effects, because land uses have adjusted to the barrier of the right-of-way and because the right-of-way is already disturbed to

some extent. The impacts of a rebuilt line tend to be incremental rather than wholly new. The exception is where an existing electric line is in a poor location, such as through a large, valuable natural area or the middle of potentially irrigable farm fields. There are no such lines included in the current transmission proposals.

The biggest impacts associated with rebuilding existing transmission lines are those associated with construction (e.g. noise or damage to a lawn or garden planted around a transmission structure) or construction access (e.g. compaction of soil on a farm field by construction equipment crossing the field). Construction impacts are usually temporary in nature.

Long-term effects of transmission construction include visual impacts and changes in electromagnetic fields (EMF). Taller transmission structures are more visible from a distance, but this may be an incremental visual effect. By raising the structures, or increasing the voltage or size of the conductor, the electromagnetic fields (EMF) below these transmission lines are likely to decrease. While there is no scientific consensus as to the effect (or lack of effect) of EMF on human health, some residents are concerned about issue. If existing structures are replaced by new structures, it's likely that the new structures would not be in the same location as the existing ones. This makes it possible for landowners to request minor changes to the location of structures to make them more compatible with surrounding land uses.

Effect of proposed substation work

The only proposed new substations would be at existing power plant sites (Oak Creek, Pleasant Prairie) or at an existing substation site (near an interstate interchange). Any environmental effects are likely to be minimal.

Table 11-41 Proposed construction work at electric substations[1]

Substation name	Property needs and potential environmental effects
Arcadian	Changes to this substation would likely fit within the existing substation fence.
Bain	Preliminary engineering indicates that the substation would have to be expanded to accommodate the new 345 kV ring bus. However, no facilities layout has been prepared from which to evaluate size or environmental impacts.
Bluemound	This 345 kV substation would likely be constructed immediately west of the existing substation's western fence on property currently being utilized by WEPCO's distribution training center.
Brookdale	Some expansion of the existing substation would be required although it is likely that there is enough land on the existing site for this expansion.[2]
Granville	Preliminary engineering indicates that no expansion is required.
Oak Creek	The existing 345 kV substation would be expanded to the west with dimensions of approximately 500 feet x 500 feet. This equates to approximately a 40% increase in overall size. ATC does not believe there to be any environmental concerns.[3]
Pleasant Prairie	No information was presented in the interconnection study reports for this substation.[4]
Racine	Preliminary engineering indicates that no expansion is required.
St. Martins	Preliminary engineering indicates no expansion is required.

1. Information provided by ATC in response to a PSC question concerning whether or not proposed substation work would require expanding the fenced area of the substation.
2. There is space on existing utility-owned property for this new substation. The property is located near the interchange of Highways 894 and I-43.
3. The location of this new substation on the site layout has changed since this answer. However, no environmental impact is expected.
4. Any changes to this substation would have minimal impact since the substation is located at an existing power plant.

Effect of a proposed new 4-mile transmission line

The proposed new transmission line is a 345 kV line that would extend from the substation on the OCPP/ERGS site to the Chicago and Northwest (C&NW) railroad track (It is listed as reinforcement 2a on Table 6-4). This new line would be one transmission circuit, (a set of three conductors) with three insulator strings. Some transmission structures carry two circuits (six conductors) on two sets of arms. At the C&NW railroad track, the circuit from this new line would continue on existing, two-circuit structures which are only carrying one operating circuit now.

Paralleling existing transmission lines

The most direct route from the Oak Street Substation to the rail track would parallel existing transmission line corridors. The first corridor contains two existing transmission lines (two sets of structures) and extends from the Oak Creek site to beyond Botting Road. The second corridor contains one existing line (one set of structures) and continues on to the railroad. Neither corridor has a right-of-way that is wide enough to accommodate a new transmission line.

On the first corridor, both transmission lines are already carrying two circuits each and there is not sufficient room on the existing right-of-way to locate a new set of structures. If ATC places the new line next to the existing right-of-way, the right-of-way would need to be expanded and ATC would need to remove two barns (located on the south side of the existing right-of-way). On the north side of the existing line are three houses that would probably need removal if a new power line were located on the north side of the existing corridor.

One alternative at this location is for ATC to change the design of the two transmission lines in order to provide room for one additional circuit on the existing right-of-way. Perhaps ATC could replace the existing structures with structures that would require less right-of-way, leaving room for a third structure or perhaps one of the transmission lines could be replaced with a new one that could carry three circuits. Until the ATC studies this problem, there is no definitive information about possible alternatives.

Route and potential environmental effects

Figure Vol. 2-4 shows the approximate, geographic, location of existing transmission lines in the project area. A series of photos, Figures 11-31 through 11-36 show features at various locations along the four-mile route. Although the right-of-way primarily passes through pastureland, cropped fields and old fields, there are several homes, and farmsteads with out-buildings located adjacent to the right-of-way. The two existing transmission lines leave WEPCO property and cross STH 32. Figure 11-31 shows that there is mostly open land on the south side of the existing right-of-way looking west from STH 32. A house is located near the north edge of the right-of-way near STH 32 (see Figure 11-32). Further west, there is a house and two barns on the south side, and one house on the north side of the right-of-way. As the lines approach Botting Road, another house and shed are located close to the north side (see Figure 11-33). After crossing Botting Road, there is another house close to the north edge of the right-of-way and an out-building adjacent to the south edge (see Figures 11-34 and 11-35). Between Botting Road and Foley Road, the two transmission lines separate; one of the lines turns due south, while the other continues to the west. This is shown in Figure 11-36. The proposed new line would follow the existing line that continues west. Near Foley Road, the existing line is routed around the edge of a small wetland, and crosses an old field. For the remainder of the route, the existing line crosses farm fields and the Root River.

In farmland, transmission lines can slow equipment that has to navigate around the structures and it can reduce the area of land in cultivation, especially if weeds grow around the base of the transmission pole and encroach further out into the field. Structures that are guyed can cause hazards for the safe operation of large farm equipment. Transmission lines can also produce noise during certain weather conditions. Loose hardware or loose connections between the conductors, insulators and the poles may cause a humming or buzzing sound under windy conditions. In fog and other damp weather conditions, a slight crackling sound may occur due to ionization of the moist air surrounding the wires. If the potential crossing of the Root River requires placement of structure(s) below the high water mark, ATC would need a permit from the DNR.

Effects of a new, long 345 kV transmission line

Information is available on two major transmission lines, each suggested as a possible solution for problems in the southeast area (and to enable the second SCPC unit of the proposed ERGS project to connect to the existing electric transmission system safely). One major line would connect the Pleasant Prairie power plant in Kenosha to the Libertyville substation in Illinois. This line would also connect with the Zion substation in Illinois on route to Libertyville. The second possible line would go from a new substation at Big Bend in Waukesha County to the Paddock substation in southern Rock County. Both of these lines are part of the ATC's 10-Year Transmission System Assessment, as reported in the Full Report dated August 2002. This document is available on the ATC's website at www.atcllc.com/Report.shtml Table 11-42 provides some information about resources located in routing study corridors for these two transmission line alternatives.

Figure 11-31 Open land on the south side of the transmission right-of-way looking west from STH 32

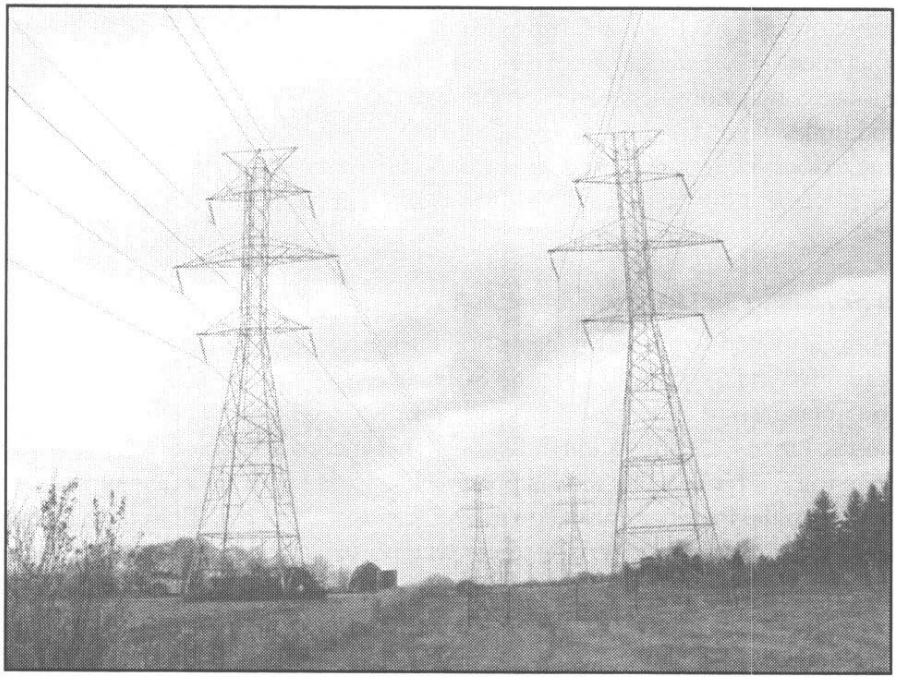


Figure 11-32 House located on the north side of the right-of-way looking west at STH 32

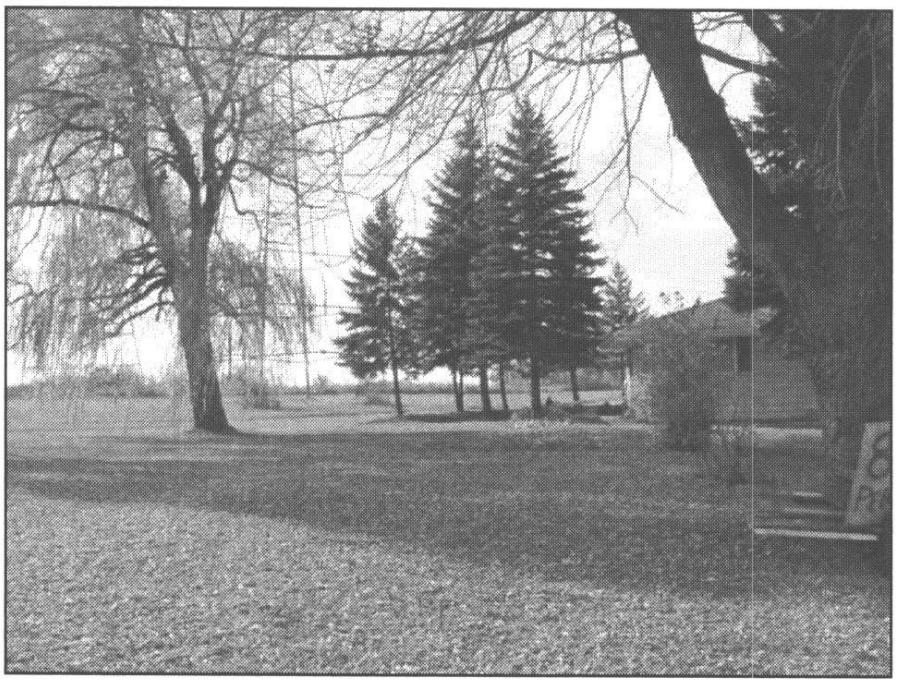


Figure 11-33 House and shed located on the north side of the right-of-way near Botting Road

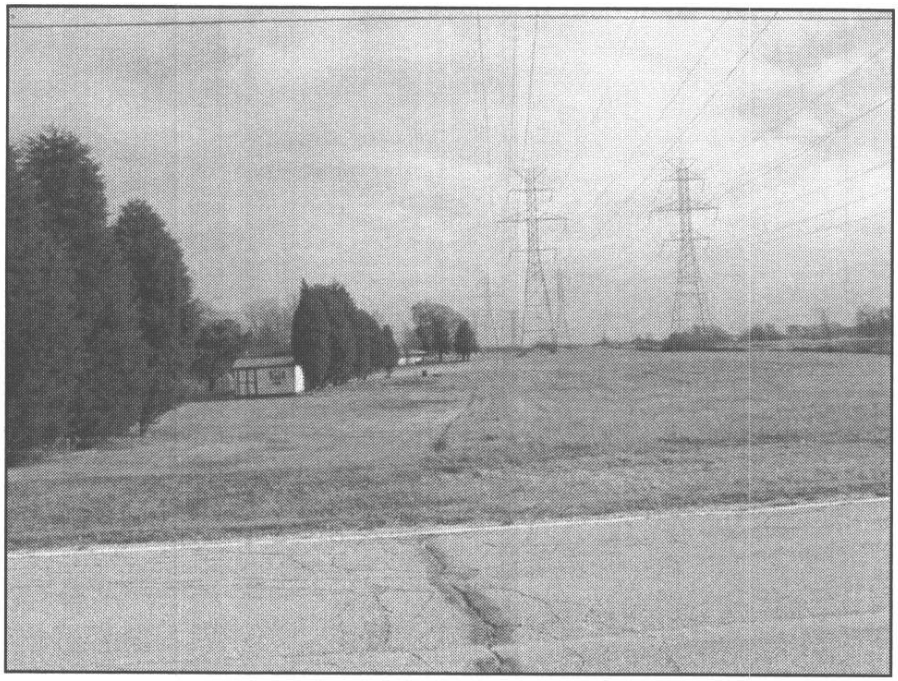


Figure 11-34 House on the west side of Botting Road near the north edge of the right-of-way

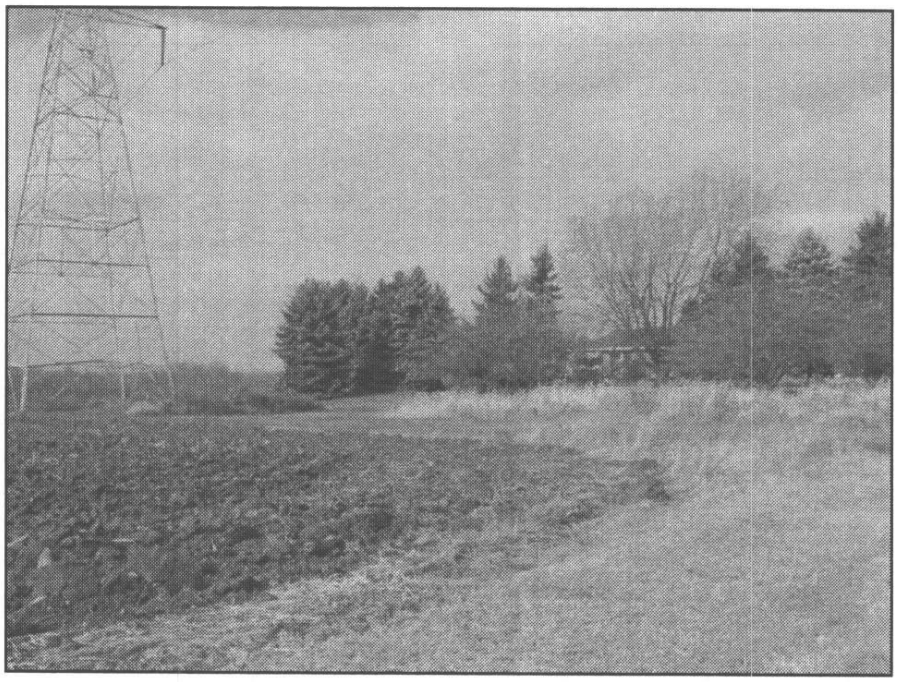


Table 11-42 Some information about resources affected by potential new 345 kV transmission lines in southeastern Wisconsin

Libertyville – Pleasant Prairie 345 kV	Big Bend – Paddock 345 kV
Length: about 30 miles	Length: about 55 miles
Potential conflicts with resources*	
Public lands: Numerous city, county, and state parks including Illinois Beach State Park, Chain O'Lakes State Park, Anderson Park, Red Arrow Park, Sunnyside Park, Beulah Park, Shiloh Park, and Prairie Springs Park.	Public lands: Numerous city, county, and state parks including Kettle Moraine State Forest, Big Foot Beach State Park, Muskego and Mukwonago County Parks, Carver-Roehl Park, Starin Park, LaMar Park, Memorial Park, Springs Park, Bong Recreation area, Ela Park, Phantom Glen Park, Denoon Park, and Heg Park. Numerous state wildlife areas and trails are located within the study area.
Sensitive resources: The Chiwaukee Prairie, Carol Beach Low Prairie, and Tobin Road Prairie state natural areas are found within the Wisconsin portions of the project area. The Van Patten Woods Forest Preserve, Wadsworth Savanna Forest Preserve, Waukegan Savanna Forest Preserve, Lyons Woods Forest Preserve, and Wedgewood Creek Forest Preserve, 15 natural areas within the Illinois Beach and Illinois Dunes area, and an additional 72 natural areas in the Chain O'Lakes-Fox River area in the portion of the project area in Illinois. The Des Plaines River watershed runs through much of the project area.	Sensitive resources: The Kettle Moraine State Forest, numerous state wildlife areas, and state natural areas including Beulah Bog, Lulu Lake, Bluff Creek Springs, Eagle Oak Openings, C.F Messinger Dry Prairie, Avon Bottoms, Scuppernong Prairie, Kettle Moraine Fens and Low Prairie, Muskego Park Hardwoods, Cherry Lake Sedge Meadow, and Karcher Springs among others are found within the project area.
Cultural Resources: The Third Avenue Historic District, Florence Parry Heide Home, Orson Welles Home, and the Library Park Historic District are among those cultural resources located in the Wisconsin portion of the project area.	Cultural resources: The Frances Wiggins Ford Farm, Old World Wisconsin, the General Atkinson Mound Group, Statesan Historic District, Governor Harvey Home, Clinton Village Hall, the Jefferson Prairie Norwegian Settlement, East Milwaukee Street Historic District, Prospect Hill Historic District, Conrad Cottages Historic District, the Grace and Pearl Historic District and many others, as well as numerous museums are located within the project area.
Corridor Sharing Opportunities**: State and County roads, railroad and existing transmission line corridors.	Corridor Sharing Opportunities**: State and County roads, railroad and existing transmission line corridors.

* Resources listed for the project's study area. The study area is defined as the length of the line multiplied by 30 percent of the line length for lines over 15 miles long.

** Corridor sharing means adjoining or overlapping the proposed transmission line right-of-way with the right-of-way of an existing linear corridor.

12

Chapter 12 - The Conditional Use Permit (CUP) Option

The origin of the proposed changes

This chapter provides a descriptive overview of a new ERGS facility layout on the North Site that was negotiated between WEPCO and the city of Oak Creek in May 2003. This new site layout, referred to as the Conditional Use Permit (CUP) Option was briefly described in WEPCO's direct testimony for the CPCN hearing which was received by the PSC and DNR in late May after the completion and issuance of the draft EIS. WEPCO testifies that this alternative was negotiated to satisfy community concerns regarding potential fugitive dust emissions from the coal storage and handling areas and aesthetic concerns surrounding the two proposed chimneys.

Based on WEPCO's testimony, PSC and DNR staff requested additional information and maps in order to evaluate the environmental and social effects of the new site layout. This information was provided in mid- to late-June, 2003. Agency staff, however, has not been able to perform a thorough environmental review of this site layout due to incomplete information, the lateness of the information submitted and continuing project design changes. The following sections of this chapter are based on the best information available at the time of review.

There is no "CUP" Option for either of the South Sites. Therefore, if the Commission approves one or more units of the ERGS and selects a South Site or if it selects the North Site with the original layout, the changes associated with the CUP Option would not occur.

Description of the proposed CUP Option layout - differences from the original North Site layout

The areas needed for construction of the ERGS using the CUP Option are located mostly on WEPCO's property, but would extend partially onto the federally-owned shooting range property, resulting in the need to relocate that facility. The proposed ERGS facility layout for the CUP Option is shown in Figure Vol. 2-4.

The CUP Option differs from the original North Site layout in the following ways:

- Two coal storage/handling areas, a coal pile runoff basin, a coal storage building, and a new road wrapping around the north side of the coal storage building would be constructed inside the train

loop. Under the original North site layout, these facilities were located north of Elm Road. The relocation of the coal storage and handling areas increases the distance between the coal piles and the nearest residence from about 1,200 feet to approximately 2,800 feet.

- Berms just south of Elm Road near Haas Park would be enlarged and reconfigured to some extent, with a resulting wavy edge effect. This would be intended to further shield the view of ERGS facilities from residents in the Barton Oaks subdivision. In addition, new berms would be built as a border around the new shooting range which would be moved to a former horse farm property on the north side of Seven Mile Road and adjacent to Lake Michigan (see discussion below).
- A different Main Access Road and a new Southern Access Road are proposed. The Main Access Road would enter the site from STH 32, north of Botting Road, travel easterly across the UP railroad and connect to the SCPC units, a visitor center, parking at the north ash disposal area, and a future ERGS employee parking lot. The Southern Access Road would also enter the property from STH 32, but at a point south of the Caledonia Ash Landfill. It would traverse the southern edge of the landfill to a bridge crossing the UP railroad tracks, and then follow an existing rail spur road to the east where it would split to provide access for employee parking and allow for deliveries and ash hauling.

  The original North Site layout was changed after the draft EIS. The layout as described in this final EIS includes building a new access road into the site from STH 32 across from Botting Road, with a second access road located about 500 feet further south. Following construction, the portion of Elm Road east of the UP rail tracks would be closed, and all construction and operational traffic would use the STH 32 access. Access to the site for fishing would be provided by extending Oakwood Road to the south along the lakeshore. Oakwood Road is currently a dead-end road. The proposed recreational trail would probably also access Bender Park from the end of Oakwood Road under any scenario.
- The existing 138/345 kV substation that connects the OCCP units to the electric transmission system is currently located inside the curved rail track directly south of the Oak Creek Power Plant Woods. Under the CUP Option, it would be split into two separate switchyards and relocated along with the existing transmission line connections. The 138 kV switchyard and related transmission lines would be moved to a location west of the UP rail tracks directly south of the closed South Oak Creek Ash Landfill. The 345 kV switchyard would be expanded substantially (it would increase in size by about 40 percent) and relocated to an area south of the proposed rail loop that is currently an Isolated Natural Resource Area on the western edge of the shooting range property. Connections from all of the new ERGS units would be routed through the 345 kV switchyard. Preliminary estimates of the cost to split the switchyards and relocate them are in the range of $20-$40 million. The original North Site layout proposes to slightly expand the 138/345 kV substation within the rail loop, but not to relocate these facilities.
- The number and height of chimney stacks associated with the SCPC units would be reduced from two stacks, each at 675 feet tall (the original North Site design), to one stack at 550 feet tall for the CUP Option.

In early July, agency environmental staff became aware of proposed new ash haul roads and an "ash reburn building" that had not been described in the CPCN application, WEPCO's testimony or any subsequent information filings. The ash haul roads are not shown on any map that was provided for environmental analyses purposes and the ash reburn building appears on several maps, but at different locations on different

maps. At the time of the final EIS preparation, it is unclear if these new haul roads and building are associated with the CUP Option or would be built to accommodate use of the North Site under either the CUP Option layout or the original site layout.

Shooting range

Use of the CUP Option on the North Site would result in the need to move and rebuild the shooting range which is currently located within WEPCO's property, south of the Oak Creek units 5-8. A new shooting range would be constructed further south on the north side of Seven Mile Road on a property that was previously a horse farm. The new shooting range has not yet been designed; however, any new shooting range would be designed to meet military safety standards in order to eliminate any danger from stray rounds. Noise would be somewhat reduced by the standard safety design features. The shooting range would be used only for small arms (pistols and rifles) target practice. The range is presently used by local gun enthusiasts, law enforcement agencies, military reserve units, and the National Guard.

Berms, trees and other landscape features may serve to reduce audible noise generated at the shooting range. However, some noise impact would likely be experienced at the closest residences which include the four houses directly east of the railroad corridor north of Seven Mile Road, the homes between STH 32 and the railroad on the south side of Seven Mile Road, and the home at the east end of Seven Mile Road.

Potential Environmental and Social Effects of the CUP Option

Topography and Soils

Chapter 10 includes a detailed description of the existing geology, topography, and soils on WEPCO's property. The topography of the existing landscape is shown in Figure Vol. 2-11.

The topographical changes related to the CUP Option would differ from those associated with the original North Site layout proposed in WEPCO's CPCN application. According to the applicants, the CUP Option would require somewhat less soil to be removed for the SCPC units. WEPCO has indicated that a total of about 7.4 million cubic yards would need to be excavated for the CUP Option as compared to about 9.9 million cubic yards for the original North Site layout. However, the information supplied for the CUP Option does not include about 1.0 million cubic yards of dredged soils that are included in the North Site totals and it states that less material would need to be excavated for the water intake tunnel. Also, the amount of soil excavated for building roads decreases dramatically for the CUP Option, even though WEPCO has proposed to build more miles of roads for site access and ash hauling under the CUP Option, than it proposed for the original North Site layout. These discrepancies have not been explained.

Large amounts of soil excavation, transport, and deposition would still occur. Soil from the excavated areas would be used to create new berms or be placed in soil deposition areas at various points around the site. Some of the berms would be located and shaped differently from those described for the North Site. (See Figure Vol. 2-20.) These changes include:

- The berms north of Elm Road would be shifted slightly south and westward toward the existing North Oak Creek landfill. They would have wavy edges and be a few feet higher.
- Near Elm Road, the berm would be limited to the South Oak Creek Landfill and the area east of the wetland and park. The highest point is still expected to be about 770 feet above msl, but the berm would be laid out in tiers increasing in elevation from the southeast corner of the landfill to the north and northwest.
- A bank of soil would be built up near the southern end of the rail loop for the purpose of (1) bringing a new road from the north up to grade with the existing truck road from OCPP Units 5 - 8 and (2) elevating the existing road to the south to create an overpass over the UP railroad line.
- An additional embankment would be built on the west side of the tracks to complete the bridge and connect the east side of the property with a road running along the south edge of the Caledonia Ash Landfill. Another small embankment would be created to bring the new road up to grade where it joins STH 32. The bridge embankments to enable spanning the railway would be at least 40 to 50 feet above the existing grade when the bridge was complete.

Excavation work would be required not only for the SCPC units but also for the relocated 345 kV switchyard that would be moved southeast of the existing WEPCO rail loop. The switchyard construction would require excavation of some of the western portion of the shooting range property berms. Excavation of this material would probably require remediation work for hazardous wastes as described in Chapter 9.

The locations and shapes of the soil repositories differ for the original North Site layout and the CUP Option. As discussed in Chapter 10 and shown in Figures Vol. 2-12 and Vol. 2-13, the North Site soil repositories would consist of: (1) berms to the north; (2) an addition to the height of the North Oak Creek and South Oak Creek Landfills; (3) an area on the west side of the property, south of the existing electric transmission corridor; (4) an area along the east side of the rail line inside the rail loop; and (5) a berm on the southwest corner of the property on existing agricultural land.

For the CUP Option, in addition to the newly-designed berms and North and South Oak Creek Landfill repositories and the embankment for the south side bridge, WEPCO would build berms around a large, irregularly shaped area in the southeastern corner of the property that would be developed as the new shooting range. The shooting range and berms would be placed on existing agricultural land south of the Power Plant Ravine Woods Natural Area, which is described in Chapter 10. WEPCO has not indicated the amount of soil that would be deposited in berms in this location, nor the expected height of the berms. It also does not yet appear to have designed the roadways needed to transfer the soil to this location.

In addition to the changes in excavation and stockpiling, the relocation of the inactive coal piles inside the rail loop would potentially affect a large EADA on the east side of the rail line (See Figure 9-3 for EADA locations). Adding the coal piles over the early ash deposits would require some remediation work to avoid adverse impacts to the local groundwater. See Chapter 9 for potential remediation work related to the EADAs.

As indicated in later sections of this chapter, new soil deposition areas associated with the CUP Option would affect some wetlands, woodlands, and SEWRPC-designated biological areas.

Air emissions

Pollution source descriptions

The sources of air pollutant emissions from the proposed ERGS are included in WEPCO's PSD construction permit application for the North Site and additional information submitted to the DNR on June 2, 2003 and June 27, 2003.

There are several differences between the pollution sources for the original ERGS layout at the North Site and using the CUP Option at the North Site. For the CUP Option, the coal storage and handling areas would be within the train rail loop. There would be one 550-foot tall chimney rather than two 675- foot chimneys for the SCPC boilers. There would also be minor changes to the material handling systems, including locations, stack heights, and flow rates for certain dust collection systems. The total fuel heat input for the proposed SCPC Auxiliary Boiler would be set not to exceed 498,000 MMBtu per year, of which no more than 122,500 MMBtu per year could be from the combustion of distillate fuel oil.

The actual emission sources included in the CUP Option permit application are the same as those listed for the North Site in Chapter 7:

- Two 615 megawatt (MW) supercritical pulverized coal (SCPC) electric generating units
- One 600 MW integrated gasification combined cycle (IGCC) unit
- Two auxiliary boilers
- Two emergency diesel generators each 1,500 kW
- Three diesel fire pumps
- Fuel storage tanks
- Coal handling and other material handling equipment

Ash haul routes and ash reburn building

WEPCO's June 2, 2003 submittal for its air permit application, for air pollution modeling purposes, indicated that new ash haul roads would be constructed to move ash by-products from the SCPC units built on the North Site to the Caledonia Landfill or off-site. It is uncertain if these new roads would serve the SCPC units for both the CUP Option and the original layout or only the CUP Option. No design details for the new ash haul roads or maps showing the location of these new roads and their relation to landscape features were provided.

The air permit information submitted on June 2, 2003 also indicates that there would be new roads from the ash landfills to an ash reburn building. No description of the location of the ash reburn building or the roads leading to it from the landfills, or the building dimensions or design were provided by the applicants.

The ash haul roads and the ash reburn building are facilities that could potentially impact additional wetlands on-site or biological areas of importance, such as PECs, INRAs, or CSH areas. In addition, there likely would be noise and fugitive dust associated with the new roads. Because these facilities were mentioned only in air permit application information submitted in June, PSC and DNR environmental staff were unable to assess the potential environmental effects of these facilities.

Expected project emissions

Potential emissions from the proposed project are estimated based on worst-case operating scenarios, taking into account control equipment and federally enforceable conditions expected to be in the power plant's permit. The potential annual emissions expected by WEPCO if the ERGS were built using the CUP configuration are identical to the emissions WEPCO projected for the original North Site layout, as shown in Table 7-8 in Chapter 7 of this EIS.[127]

Ammonia is included in Table 7-8. Ammonia is a pollutant regulated under NR 445. It is discussed along with other expected toxic pollutant emissions later in this chapter. The estimate of potential SCPC boiler ammonia emissions is based on a proposed SCR emission rate of 5 ppm dry volume (ppmdv).

The net changes in emissions compared to PSD significance levels are also identical with those projected by WEPCO for the North Site (see Table 7-9).

If any of a project's emission increases are greater than the PSD significance level, the project qualifies as a major pollutant source. Based on Table 7-9, the ERGS using the CUP configuration is classified as a major source under both the operation permits program in Wis. Adm. Code ch. NR 407, and the New Source Review programs under Wis. Adm. Code chs. NR 405 and NR 408 and is subject to PSD review.

If the project would result in an emission increase of any pollutant at a level that is greater than the PSD significance level, the project is subject to PSD review for that pollutant. CO, PM, PM_{10}, SO_2, sulfuric acid mist, NO_x, Pb, Hg, Be, and HF would all be emitted in quantities in excess of the PSD significant levels under Wis. Admin. Code § NR 405.02(27)(a), Table A. As a result, these pollutants are subject to PSD review, and thus also to the control technology review requirements of Wis. Admin. Code § NR 405.08.

Table 7-9 shows that VOC emissions would be subject to non-attainment New Source Review under Wis. Admin. Code ch. NR 408, and subject to the lowest achievable emission rate (LAER) control technology. NR 408 also requires WEPCO to obtain VOC emissions offsets for the potential VOC emissions from this project at a rate of 1.3 to 1.

Proposed BACT

The top down BACT approach to selecting control technologies was utilized by WEPCO for the numerous potential emission sources in the CUP Option. BACT is still being assessed by the DNR.

WEPCO's proposed BACT controls and projected emission limits for each potential project emissions sources are identical to those proposed for the North Site original layout and are summarized in the tables in Appendix D . The data in these BACT tables is also based on WEPCO's permit application and additional information submitted on June 27, 2003 and does not reflect DNR analysis, which is still in progress. It is subject to change pending DNR's further review and analyses. Table 7-12 summarizes WEPCO's proposed BACT and emission limits for the different pollution emission sources of the ERGS at the North Site and the CUP configuration. The emissions sources include boilers, engines, and materials handling systems.

[127] This data is subject to change pending DNR's further review and analysis.

The proposed BACT for ash trucks on haul roads to and from the Caledonia Landfill is also based on WEPCO's permit application materials and is subject to change pending DNR's further review and analysis.[128] BACT would involve the use of paved roads with new technology vacuum street sweepers as mitigative controls. The frequency of the vacuum street sweeping would be twice daily or whenever visible emissions from the haul roads are observed by trained personnel.

Air quality impacts - construction phase

Chapter 7 includes a brief discussion of expected air quality impacts during construction of the plant and the protections that would be put in place to control and regulate them. These impacts, controls, and regulations would be the same for each site and for the CUP Option.

Air quality impacts - plant operation

To assess pollutant-specific impacts, the maximum predicted impact for each air pollutant is added to the respective background ambient air concentrations to determine worst-case concentrations. These worst case concentrations are then compared to NAAQS. The last two lines in each table indicate the distances of the greatest air pollution impact from the sources.

Air modeling is being performed at the DNR to determine the maximum predicted impact relative to the NAAQS and to the allowable PSD increments. The resulting DNR Air Pollution Control permit would establish the PSD baseline for the area.

Comparisons with the NAAQS and to the PSD increment are shown in the tables in Appendix D. These tables include cumulative impacts and cumulative percentages of increment consumed. They differ from the tables for the North Site because of the change to a single, shorter SCPC exhaust stack and other equipment arrangements. The information in them is based on WEPCO's air pollution control permit application additional information submitted on June 2, 2003 and June 27, 2003. The data is subject to change pending DNR's further review and analysis.

A portion of the results shown in Appendix D are contained in Table 12-1.

Table 12-1 Air quality and PSD modeling results for the ERGS using the Cup Option at the North Site

Pollutant	PM_{10} 24-hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO_2 3-hour	SO_2 24- hour	SO_2 Annual	NO_2 Annual
Background concentration (ug/m3)	58	27	76	NA	208.10	57.80	9.30	31.00
Background plus ERGS concentration (ug/m3)	122.36	34.82	142.48	0.00	763.81	197.04	15.22	60.63

[128] In its June 2, 2003 air permit submittal, WEPCO changed the on-site haul road routes along with its other plant layout changes. The new routes would be different from those mapped in Figure 9-2 in Chapter 9.

Pollutant	PM_{10} 24-hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO_2 3-hour	SO_2 24- hour	SO_2 Annual	NO_2 Annual
NAAQS standard (ug/m3)	150	50	150	1.5	1,300	365	80	100
Percent of NAAQS	**81.6%**	**69.6%**	**94.99%**	-	**58.8%**	**53.9%**	**19.0%**	**60.63%**
PSD Class II Increment Concentration (ug/m3)	30	17	-	-	512	91	20	25
Maximum Elm Road Project Only Concentration (ug/m3)	25.03	5.40	-	-	228.56	69.34	5.20	1.30
Percent of Class II Increment	**83.4%**	**31.8%**	-	-	**44.6%**	**76.2%**	**26%**	**5.2%**

Table 12-1, containing WEPCO's modeling results, shows that the concentrations from the proposed ERGS using the CUP Option would be below the standard level of pollution allowed for the region, although the concentration of TSP would come very close to 100 percent of the standard. Most of the expected increment would be consumed by the ERGS for 24-hour PM_{10} and 24-hour SO_2 concentrations. Other pollutant concentrations would consume less of the increment.

Hazardous air pollutants

The primary fuel for the ERGS generation boilers would be a blend of 95 percent washed bituminous coal and 5 percent coal ash (on a weight basis). A variety of fuel ashes have been analyzed. The analyses demonstrate that the fuel ash meets the definition of lignite coal as found in Wis. Admin. Code § NR 400.02 (22e). For this reason, the fuel ash is exempt from review under the hazardous air pollutant rule, Wis. Admin. Code ch. NR 445.

The emissions of HAPs from the combustion of natural gas and fuel oil are also exempt from NR 445 requirements because these fuels are considered virgin fossil fuel.

However, as confirmed by Table 12-2 below, due to the emission levels of hydrogen chloride and the total projected HAPs emissions from the facility, the HAPs from the ERGS sources are subject to MACT. The case of mercury emissions applies as well, subject to the PSD program under Wis. Admin. Code ch. NR 405.

HAPs emissions estimates

HAPs emissions projections appear to be the same for the CUP Option as for the original North Site layout. Tables D-31 through D-37 in Appendix D summarize the HAPs emissions expected from the different emission sources. These emissions levels are based on WEPCO's calculations in its air permit application and additional information submitted on June 2, 2003 and June 27, 2003. This data is subject to change pending DNR's review and analysis. The SCPC units would be burning bituminous coal. The SCPC and IGCC auxiliary boilers would burn either natural gas or diesel fuel oil. WEPCO has elected to limit firing

natural gas to 1,500 hours per year and fuel oil to 500 hours per year. The IGCC unit would gasify bituminous coal and burn the syngas that is produced. The associated equipment that would produce sulfuric acid as a by-product of the IGCC operation is anticipated to emit the criteria pollutant emissions of nitrogen oxides, sulfur dioxide and sulfuric acid mist.

Table 12-2 provides a summary of the estimated potential emissions of hazardous air pollutants from major emissions sources. The summary table does not include consideration of fugitive coal dust and other dust.

Table 12-2 Hazardous air pollutants emissions from the major components of the ERGS in tons per year

Hazardous Air Pollutant	SCPC Unit 1	SCPC Unit 2	IGCC	SCPC Auxiliary Boiler	Diesel Generator	Fire Pump	IGCC Auxiliary Boiler
Antimony	0.091	0.091	0.021	Negligible	Negligible	Negligible	negligible
Arsenic	0.164	0.164	0.490	0.0000	0.00003	0.00001	0.0001
Beryllium	0.009	0.009	0.025	0.000	0.00000	0.00000	0.0001
Cadmium	0.030	0.030	0.018	0.0000	0.00001	0.00000	0.0000
Chromium	0.239	0.239	0.310	0.001	0.00004	0.00001	0.0002
Cobalt	0.038	0.038	0.119	0.002	0.00023	0.00008	0.0008
Lead	0.202	0.202	0.501	0.001	0.00006	0.00002	0.0002
Manganese	0.332	0.332	0.585	0.001	0.00010	0.00004	0.0004
Mercury	0.062	0.062	0.0329	0.0002	0.00000	0.00000	0.0001
Nickel	0.226	0.226	0.334	0.044	0.00504	0.00182	0.0178
Selenium	1.328	1.328	0.254	0.0010	0.00001	0.00001	0.0001
Hydrogen Chloride	69.360	69.360	2.946	0.145	0.01683	0.00608	0.0587
Hydrogen Fluoride	23.930	23.930	0.520	0.007	0.00078	0.00028	0.0027
Formaldehyde	0.130	0.130	2.886	0.015	0.00056	0.00303	0.0060
Organic HAPs	0.002	0.002	0.261	0.018	0.00100	0.00145	0.0073
Totals	96.1	96.1	9.30	0.23	0.0060	0.0045	0.094

Table 12-2 shows that the total potential emissions of HAPs from the ERGS are estimated at over 200 tpy. A major source would be a new process or production unit which in and of itself emits or has the potential to emit 10 tons per year of any individual HAP or 25 tons per year of any combination of any HAPs. Thus, the proposed ERGS project is subject to case-by-case MACT requirements for HAPs.

Case-by-case MACT for the CUP would be identical to the case-by-case MACT for the other three site options. Table 7-18 in Chapter 7 summarizes the case-by-case MACT proposed by WEPCO. The HAPs are aggregated into different types depending on their chemistry: inorganic solid HAPs, inorganic acid HAPs, organic HAPs, and mercury. The information in the table is based on WEPCO's air permit application information and additional information submitted on June 2, 2003 and June 27, 2003. The data is subject to change pending DNR's review and analysis.

Ammonia under NR 445

Ammonia emissions are expected from the use of SCR at the SCPC boilers, regardless of the power plant site. Ammonia is regulated under Table 1 of Wis. Admin. Code ch. NR 445. For ammonia, compliance with an acceptable ambient air concentration established by rule is required.

The SCPC boilers may emit ammonia in excess of the threshold value, so NR 445 requires that dispersion modeling be performed to demonstrate that the maximum ambient concentrations of ammonia do not exceed 2.4 percent of the threshold limit value (TLV) established by the American Conference of Governmental and Industrial Hygienists (ACGIH). The data in the WEPCO air permit application materials is subject to change depending on the DNR's review and analysis. Based on WEPCO's modeling results, the ERGS would meet the ambient air standards required under NR 445 for ammonia using the CUP Option as well as the other site layouts.

Modified On-shore Facilities and Potential Impacts on Wetlands and Streams

The changes to the North Site due to the CUP Option would not significantly change the type or amount of wetland impacts. The estimate provided in WEPCO's testimony, which has not been verified, indicates that 19.51 acres of wetland would be filled for the CUP option as opposed to 18.78 acres in the original North Site layout.

Table 12-3 Acres of wetland filled for proposed CUP and North Site alternative

	Estimated wetland acres filled	Percentage of wetland acres filled
North Site	18.78	22.5
North Site CUP	19.51	23.8

The CUP Option includes the relocation of the coal storage areas, switchyards, and access roads. The movement of the coal storage and handling areas to within the train rail loop would not significantly alter the project's impacts on wetlands. However, the construction of a switchyard south of the rail loop would affect a wetland that was not impacted by the original site layout and it would also completely destroy an INRA and an area designated as CSH that would not have been impacted previously. In addition, maps provided for the CUP Option show turning structures for two 345 kV lines placed with a wetland in another INRA.

The most significant wetland impacts related to the CUP Option layout would be due to the newly proposed Southern Access Road. The proposed road would enter WEPCO's property from STH 32, and run along the southern edge of the existing Caledonia Ash Landfill to a proposed bridge that would cross the UP railroad tracks south of the rail loop. The new road would then follow an existing rail spur road. The road would split to provide access to the new 345 kV switchyard and to the OCPP employee parking area, delivery route, and ash haul roads.

This new access road would require four additional wetlands to be partially filled. One of the impacted wetlands is a 38-acre shallow marsh comprised of 100 percent wetland or facultative wetland plant species and a low percentage (13 percent) of alien or non-native plants. A branch of the Rifle Range tributary flows through this wetland. A majority of this wetland, which is located within an INRA and adjacent to a CSH area, would be filled. The remainder of the wetland would experience secondary impacts as a result of the construction. Secondary impacts would include changes to the area hydrology, impacts to water quality, wildlife habitat, and the introduction or enhancement of non-native or invasive species. The footprint of

the new access road would interfere with the existing waterway flowing through the 38-acre wetland requiring either the placement of a culvert or the relocation of the waterway.

The applicants have been inconsistent with respect to the possibility of locating a future wallboard facility on its property. None of the maps provided for the CUP Option show a potential location for this plant, whereas all of the maps submitted for the original North Site layout and the two South Site layouts included the wallboard facility. Thus, the estimates for wetland impact provided in the draft and final EIS for the three original layouts may be high if the original sites and the CUP Option are evaluated on a consistent basis.

New and Modified On-shore Facilities and Potential Impacts to Biological Areas

As discussed in Chapter 10, two Primary Environmental Corridors, nine CSH areas, six INRAs, and the Ravine Woods Natural Area were identified by SWRPC in a recent survey of WEPCO's property.

Impacts on these designated biological areas would be different if the CUP Option were used rather than the original North Site layout. Potentially impacted biological areas are shown in Figure Vol. 2-20. for the CUP Option and Figure Vol. 2-14 for the original North Site layout.

The Power Plant Ravine Woods would not be directly affected by the CUP Option.[129]

PECs

The SCPC and IGCC buildings and construction area would still potentially eliminate a large portion of the north PEC along the lakeshore including bluff/beach, grasslands, old fields, wetlands, and woodland areas. The excavations for the buildings would account for the majority of PEC impacts. The disturbance to and loss of PEC areas on-site due to facility construction would fragment the existing PEC along the lakeshore which extends north beyond WEPCO's property boundaries

The new coal piles would be located inside the new rail loop, where they would not have a direct effect on PECs.

INRA/CSH areas

Because most of the identified INRAs contain CSH areas within their boundaries, these two types of special areas will be covered together in this discussion.

Two INRA/CSH areas at the south end of the rail loop, the Wood Duck Woods and the WEPCO Oak Woods, would be affected by the relocation of the 345 kV switchyard and building the new southern entrance road causeway. As described under the Wetlands section of this chapter, the Wood Duck Woods would be partially removed by creating a road causeway that parallels the rail loop and leads to the existing field road and the proposed bridge over the main UP rail tracks.

[129] It also would not be affected by the original North Site layout if the future wallboard facility were omitted as it has been from the CUP layout.

The new substation location would require a redesign of on-site transmission lines. A new set of lines would also be installed through these woods, with large turning structures located in the central portion of the CSH. The eastern half of the CSH would probably be removed. The WEPCO Oak Woods would be completely obliterated by construction of the switchyard and related transmission structures, and the fill needed to build the road bridge over the railway. The wildlife habitat discussion below describes potential impacts of the removal of this CSH.

The CSH inside the existing WEPCO rail loop, the Oak Creek Power Plant Woods, would remain in place, but the northernmost coal storage would be located directly south of it. Although the active coal pile would be enclosed, winds from the southeast could potentially blow coal dust from the piles or handling facilities into this CSH, with potential negative effects on the vegetation there. Runoff from the coal storage could adversely affect the area also. Design of the storm water system would be important to avoid coal pile runoff into this mature beech/maple woodland. As discussed in Chapter 10, the woodland includes large diameter trees and a state-endangered goldenrod species.

The WEPCO Woods INRA/CSH on the western side of the property could be affected by the installation of new north-south running transmission lines west of the Caledonia Landfill. The transmission lines would require clearing a swath of trees through the woods for rights-of-way. Another INRA located directly west of the rail loop has already been disturbed by existing transmission lines. Under the CUP Option it appears that each of the existing lines and rights-of-way would be expanded, thereby disturbing a greater area of this habitat resource.

Vegetation

Most of the major changes in vegetation are described earlier under the section titled Designated Biological Areas. However, other notable vegetation communities could also be adversely affected.
As described in Chapter 10, most if not all of the existing vegetation near the bluff and lake would be removed in the area of the North Site SCPC units (as shown in Figure Vol. 2-20) for the excavation of the bluff and other land clearing activities required to provide space for them. At least half of the upland meadow south of Elm Road would be removed.

Woodland

Railroad expansion and related construction would still affect the northern and eastern portions of the Oak Creek Power Plant Woods discussed above.

Old field

Existing old field habitat south of the Oak Creek Power Plant Woods would be covered by the relocated coal piles. South of the old field community, the land is more disturbed.

Grassland

Regardless of the site selected for the ERGS, the grassland areas on the North and South Oak Creek Ash Landfills would be disturbed during construction by using them as soil repositories. Thus, the CUP Option would also result in the removal of this grassland habitat either permanently or temporarily. As discussed in Chapter 10, vegetation similar to that now present on the closed landfills may eventually be established on the stockpiles, and re-established on top of the closed landfills after soil stock-piling is ended. However,

mining buried ash from these landfills for reburning in the new ERGS facilities, could prevent establishment of a grassland cover crop for many years.

At the southern end of WEPCO's property, the land north of Seven Mile Road that is currently in crops and pasture would be modified to accommodate the newly relocated shooting range. Tall berms would be built around the perimeter of the new shooting ranges using soils from the lake bluff excavations. Stockpiling soil to create these berms would take the land out of agricultural production and eventually replace it with an elevated grassland.

Impacts to Wildlife Habitat

Coal piles

Two coal separate piles, approximately 13.42 and 14.12-acres in size and both 55 feet high, would be relocated to the inside the existing railroad loop. The 13-acre pile would be on the north side of the loop in old field habitat, next to the Oak Creek Power Plant Woods. The northern coal pile would eliminate a sizeable portion of the old field habitat in the loop. This area provides habitat for a variety of wildlife (refer table 10-2). Species that use the area would be forced to relocate to other portions of WEPCO's property or off-site. The remaining old field habitat would be used sparingly by wildlife due to its smaller size and an increase in human activities in the area (e.g., trucks, heavy equipment, etc.).

Another potential impact from this coal pile would be contaminated runoff during rainfalls. Runoff from the piles could infiltrate into the old field and woodland areas affecting the land and water. Runoff impacts could include degradation of vegetation quality which wildlife rely on for food, cover or nesting/dens. Loss of one of these resources could force a particular individual/species to relocate to find that resource.

The northern coal pile would be located next to the Oak Creek Power Plant Woods. Dust from the coal pile has the potential to negatively affect the woodland vegetation and wildlife species using the area. Coal dust would cover leaves impairing plant development and growth, negatively affecting wildlife use of the vegetation (e.g., food, cover, etc.), potentially the woodland area.

The second coal pile would be located in the southern portion of the loop in a disturbed area, near a shallow marsh. From the general information known, the southern coal pile appears to be located in a disturbed area that does not provide quality habitat for wildlife. Placing the pile in this location would not create any direct significant loss of habitat.

Contaminated runoff from the pile has the potential to enter and impact a nearby shallow wetland. The runoff could impact the water quality of the wetland affecting several aspects of wetland life - aquatic plant growth, aquatic insects and wildlife development (e.g., frog eggs, etc.). Changes in any of these aspects would have the potential to force wildlife species to relocate, affect health of individual wildlife species,or cause a decrease reproductive success.

Coal dust has the potential to affect plant growth in the wetland. The dust would cover the plants impairing plant development and growth, negatively affecting its use by wildlife for food, cover or nesting/dens.

Archeology and historic properties

Wisconsin law -- protection of listed sites

As discussed in the corresponding section of Chapter 10, the eight archeological sites listed with the WHS on WEPCO's property were determined to be unlikely to be disturbed by constructing the ERGS facilities on the North Site, the South Site, or the South Site Exp. Three listed sites were surveyed in 2002 by a qualified archeologist, who determined, based on their condition and history, that it was unlikely that they would be disturbed. The other five were determined by staff to be out of the way of construction.

Figure Vol. 2-4 (plant equipment layout - CUP Option) shows that one of the five, a cemetery at the northwestern edge of the property, appears to be out of the way of ERGS construction for the CUP Option as well.

The four other sites are located in the southwest corner of the property to the west of the Caledonia Ash Landfill and just south of a SEWRPC-designated INRA. While no major power plant facilities are proposed for that area, according to Figure Vol. 2-4, a transmission line would run north-south along the west side of the rail line between the southernmost transmission corridor leaving the 345 kV switchyard and the existing east-west transmission corridor crossing the railroad. At least one transmission structure would be located in the vicinity of two listed archeological sites there. However, as discussed above and in Chapter 10, these two sites have been determined not to be a concern due to previous disturbance.

Another electric transmission line would run from the 345 kV electric transmission switchyard westward along the south side of the landfill and then northward across the INRA to join the lines in the 138 kV transmission corridor heading west from the plant. From Figure Vol. 2-4, it appears that at least two 345 kV transmission structures would be installed in the area of four archeological sites. However, archeological surveys were performed in 1985 as part of the approval process for the Caledonia Ash Landfill (See Chapter 9). The Wisconsin Historical Society determined that only one contained important information on prehistory or history. That one is a circa-1858 Euro-American cabin-homestead site that is currently being preserved by WEPCO as a result of WHS direction after reviewing the results of the 1985 archeological survey. It would be in the public interest for the protection of this site to continue.

Federal law - surveys to locate and evaluate historic properties

Because the US Army Corps of Engineers has shown an interest in the ERGS project as a whole, the historic properties review under state law will probably be superseded by the requirements of Section 106 of the National Historic Preservation Act. The implementation of Section 106 by the Army Corps could result in the need for more surveys and evaluations to locate, evaluate, and protect if necessary any other historic properties that might exist in the project area before construction on the project begins.

Fugitive Dust Impacts

As described in the draft and final EIS, the impacts related to fugitive coal dust from the coal piles in their original location north of Elm Road is expected to be minimal (see Fugitive Dust section in Chapter 11). Compaction and a chemical surfactant, which forms a hard crust on the surface, would be applied to the

inactive pile to prevent wind erosion. WEPCO proposes to place the active coal pile within an enclosure wherever it is located, in its original location north of Elm Road or within the rail loop. The coal handling system would also include a baghouse to control dust, regardless of location.

Moving the active and inactive coal piles and the associated coal handling equipment to a location inside of the proposed rail loop track under the CUP Option would increase the distance between that potential source of coal dust and the nearest residence from about 1,200 feet to 2,800 feet.

The potential for fugitive dust impacts, on the Barton Oaks residents, that would be caused by vehicle traffic would likely be reduced under the CUP Option due to creation of the new access road off of STH 32, closing Elm Road, and reducing the traffic volume on the new access road off of Oakwood Road.

Noise Impacts

The noise associated with coal handling equipment, bulldozing the coal piles and vehicle traffic would likely be reduced under the CUP Option for residents of the Barton Oaks subdivision as compared to the original North Site layout or the South Sites. Other noise sources and volumes, such as for the excavation and transport of soils to deposition sites, plant operational noise, and noise associated with trains would not change under the CUP Option.

The deposition of large amounts of soil around and on the South and North Oak Creek Ash Landfill areas would still result in substantial traffic and noise from trucks and bulldozing equipment in the general vicinity of the Barton Oaks neighborhood for the duration of the excavation and soil stockpiling activities. The proposed berm reconfiguration north and west of the SCPC units would entail more work closer to residences than the original layout.

Relocation of the shooting range from its present location, within WEPCO's property, to an area adjacent to Seven Mile Road and Lake Michigan, could increase noise levels for residents along that road and in subdivisions near Six Mile Road along the lake.

Traffic Impacts

Shifting the major construction traffic that would enter the site, as well as delivery and maintenance vehicles to a new road further to the south that would be accessed from STH 32, would reduce traffic noise for nearby residents and result in improved safety on Elm Road and better access to nearby Haas Park. Depending on the speed and volume of traffic moving on STH 32, a large number of vehicles entering and leaving the plant could create a safety hazard for cars traveling on STH 32.

As mentioned above, the soil excavation and stockpiling activities would cause the same amount or more traffic and noise as construction using the original North Site layout.

Visual Impacts

New and avoided impacts due to reduced stack height and number

Table 12-4 shows the difference in heights of the different SCPC proposals. The diameter of the proposed stacks would also increase over the existing stacks, by about 15 feet for each stack if there are two stacks and about 30 feet if there is one stack.

Table 12-4 Comparison of alternative stack heights

	Existing units 5 & 6*	Existing units 7 & 8*	Original SCPC units 9 & 10 at North Site	CUP SCPC units 9 & 10 at North Site	SCPC units at either South Site
Stack number & height	1 stack 454 feet	1 stack 557 feet	2 stacks 675 feet	1 stack 550 feet	2 stacks 470 feet
Stack diameter	44 feet – 7 in at the base	46 feet at the base	60 feet at the base of each	About 75 feet at the base	60 feet at the base of each

* These stacks would be present under all site layout options

The impact of any view of the stacks from off of WEPCO property is minimal, due to the distance of the view and the landscape features between the viewer and the stacks. The existing electric transmission lines throughout the area surrounding the plant, and the existing LNG tank on Elm Road are much more dominant and intrusive visual features. From the lake, the stacks are more visible, but still distant. Refer to Chapter 11 for photographs of the most prominent views of the existing stacks and for further discussion of aesthetic impacts.

The CUP Option would decrease the aesthetic impacts caused by the presence of the stacks. The difference in width between the existing stacks and the new SCPC stack would not be discernable at the distance involved.

Stack height was not a major aesthetic concern for residents at the public meetings on the draft EIS. However, residents are very concerned about increased air pollutants and how far these pollutants would disperse from the plant. If the DNR air modeling analyses show that the decreased stack height reduces dispersion of air pollutants, then residents near the plant would experience worsened air quality conditions than under the original SCPC proposal.

New and avoided impacts due to coal pile relocations

The relocation of the coal piles and coal handling facilities would probably not change the aesthetics of these features, as seen from residences surrounding WEPCO's property. Although the reserve and active coal piles would be moved to a location about 2,800 feet away from the nearest house in the Barton Oaks subdivision, some existing woods and line of trees along the eastern edge of the subdivision already partially blocks the view of facilities across the UP tracks. Also, the original North Site layout includes several berms that are intended to shield the view of the coal piles.

The change in location of the coal piles could increase visual impacts due to the resultant split in the switchyard. This split would create two switchyards, one of which would be placed in a new location that is

closer to WEPCO's western property boundary than the existing switchyard. This split would require a major expansion of facilities (40 percent greater than for the original proposal). The electric transmission lines that connect to these switching facilities would also be relocated.

Under the CUP alternative, a new 138 kV switchyard would be located west of the railroad tracks and could be visible to traffic along STH 32. A new 345 kV switchyard, located further south, might be visible from one or more of the four houses located closest to the south or from Seven Mile Road, especially when the sun reflects off the metal equipment and supporting structures of the switchyard. A switchyard is a very industrial looking facility. WEPCO's original North Site proposal includes a berm to screen the existing switchyard from the west, but the CUP alternative appears to include no screening berms for the two new switchyards.

Under the CUP Option, the rifle range would be moved south due to the location of the new 345 kV switchyard. This would increase the visual impact of this range on the residents closest to WEPCO's property on the south side.

New and avoided impacts due to access road changes

WEPCO has changed its proposed site access roads three times. The arrangement described in this final EIS would include two access roads from STH 32, one across from Botting Road and another about 500 feet to the south of the first. The northernmost access road is shown on maps. WEPCO's plans include a specially landscaped entrance for its access roads, and the possibility of some form of traffic control.

The CUP alternative appears to move the northernmost access road about 350 feet south of the Botting Road entrance on STH 32, and to reserve its use primarily for site visitors. The more southern access road appears to move over 1000 feet south of its originally proposed location, and its primary use would be for deliveries and ash hauling.

It would appear that the CUP alternative attempts to reduce the aesthetic impact of access to the site for the group of houses located along Botting Road west of STH 32. There would be no need for a stoplight at Botting and STH 32, and the greatest amount of traffic would turn off at the southern access road over 1000 feet further south.

New and avoided impacts due to berm changes

The CUP Option appears to reduce the number of berms proposed, and to better define their shape. However, the slopes would appear to be steeper than the slopes for those berms in the original North Site proposal. The CUP Option eliminates the berms proposed west of Haas Park, along WEPCO's northern property boundary, and west of the expanded distribution substation. It shortens the length of the berm along the railroad tracks north of Elm Road, and re-orients the remaining piece on a diagonal. A new berm would be located further east on a similar diagonal. As a result, there would be two buffers between the southeast corner of the Barton Oaks subdivision and the proposed excavation for the SCPC units.

Aesthetically, the CUP Option may improve screening for the Elm Road area while further alleviating the "close-in" feeling of living close to high hills, by eliminating the berm west of Haas Park and

pushing the berm east of Haas Park further to the east. The elimination of the berms along the rail track and the northern property line may make the plant more visible from the north, but the actual active plant facilities are further from Oakwood due to the change in location of the reserve and active coal piles.

However, the elimination of the berm that screens the expanded distribution substation in WEPCO's proposal is not compensated for in the CUP Option. There appear to be no new berms proposed to screen the two new distribution stations of the CUP proposal.

There are two fewer soil storage areas under the CUP Option. However, this may be offset by the increased amount of soil placed in other stockpile areas. This may be possible due to the apparent increased steepness of the slopes, which could be more difficult to maintain.

The CUP Option shows an on-site bridge for traffic to pass over the UP railroad, however, it's probable that such a bridge is needed under any alternative in order to allow for the continuous dirt hauling that WEPCO plans during the construction period. Without such a bridge, conflict with trains would be a major problem.

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Chapter 13 - Overview of the Required Decisions and Summary of Impacts

Approval, Denial, or Modification of Proposed Plan

The Commission has the obligation to approve, deny, or modify the applicants' proposal to build the ERGS, and to issue an order to that effect with appropriate conditions added.

Wis. Stat. § 196.491(3) requires the Commission to make the following determinations before approving construction of the ERGS project.

1. Under Wis. Stat. § 196.491(3)(d)2, the plant must satisfy the reasonable needs of the public for an adequate supply of electric energy.
2. Under Wis. Stat. § 196.491(3)(d)3, the plant must have a design and location that is in the public interest considering:
    a. Alternative sources of supply
    b. Alternative locations
    c. Individual hardships
    d. Engineering factors
    e. Economic factors
    f. Safety
    g. Reliability
    h. Environmental factors -- In its consideration of environmental factors, the Commission may not determine that the design or location is not in the public interest because of the impact of air pollution if the proposed plant meets the requirements of Wis. Stat. ch. 285.
3. Under Wis. Stat. § 196.491(3)(d)4, the plant must not have undue adverse impact on other environmental values such as, but not limited to:
    a. Ecological balance
    b. Public health and welfare
    c. Historic sites

d. Geological formations
e. Aesthetics of land and water
f. Recreational use

4. Under Wis. Stat. § 196.491(3)(d)6, the plant must not unreasonably interfere with the orderly land use and development plans for the area involved.
5. Under Wis. Stat. § 196.491(3)(d)7, the plant must not have a material adverse impact on competition in the relevant wholesale electric service market.

All of the above items have been considered and described at least to some extent for the proposed ERGS project.

Under Wis. Stat. § 196.491(3)(e), the Commission may not issue a CPCN until the DNR has issued all permits and approvals identified by the DNR that are required prior to construction.

Alternative power plant sites

Two power plant sites have been proposed for the ERGS facilities, the North Site and the South Site. The CPCN application also included a variation of the South Site layout that was slightly larger; this is called the South Site-Exp throughout this document.

An alternate site layout on the North Site, the CUP Option, was brought forward by WEPCO in its direct testimony filed in late May 2003. An environmental review of this alternate layout has been included in this final EIS, to the extent possible. However, incomplete or inconsistent information has hindered a detailed review of this option.

The North Site alternatives would locate the proposed generating facilities north of the existing South Oak Creek units, in the city of Oak Creek, Milwaukee County. The South Site alternatives would place the proposed generating units south of the existing South Oak Creek units, in the town of Caledonia, Racine County. The site alternatives address, to varying degrees, the public interest, environmental values, and consistency with orderly local development. However, the Commission must decide whether they do this adequately.

Alternative technologies or actions

As discussed in Chapter 4, Wis. Stat. §§ 1.12 and 196.025 require the Commission to give priority to specific methods of meeting energy demands, to the extent these methods are "cost-effective and technically feasible." The Commission must consider options based on the following priorities, in the order listed, for all energy-related decisions:

1. Energy conservation and efficiency.
2. Noncombustible renewable energy resources.
3. Combustible renewable energy resources.
4. Nonrenewable combustible energy resources, in the following order:
    a. Natural gas.
    b. Oil or coal with a sulfur content of less than 1 percent.

c. All other carbon-based fuels.

Options based on the above priorities have been analyzed and are discussed in Chapter 4 of this EIS. If the Commission identifies an alternative to all or a portion of the proposed ERGS project during this review that is cost-effective and technically feasible, it could reject or modify the ERGS power plant project as proposed.

Market power

Wis. Stat. § 196.491(3)(d)7 states that the Commission must find that the ERGS project "will not have a material adverse impact on competition in the relevant wholesale electric service market." As discussed in the section on Horizontal Market Power in Chapter 3, it is unlikely that the proposed project would have any adverse impacts on competition. This is because capacity and energy from the ERGS would be provided to WEPCO via a Facility Lease, at rates the PSC regulates through its review of the lease's economic terms and conditions.

Selection of the Site for the Plant

Project site selection

Two sites, one with an alternate variation, were proposed in the project application. In May 2003, the city of Oak Creek and the applicants agreed that the applicants should seek a Conditional Use Permit (CUP) from the city and that the permit should include some possible changes to the proposed project. These changes include the relocation of several of the planned facilities and other changes related to aesthetics. To the extent possible, the potential impacts related to these changes are reviewed and analyzed in this document and thus are available for consideration by the Commission.

If the Commission determines that the proposed sites are reasonable and viable, and if it approves the plant based on the legal findings listed above, it would select one of the plant sites and facility layouts as part of the approval of the plant.

The original proposed site alternatives are discussed in detail in Chapters 6 through 11 and the CUP Option is discussed in Chapter 12. These alternatives are briefly compared in terms of public interest and environmental values in Table 13-1.

Summary

The Commission has a CPCN application before it for three electric power generating units. With a 180-day time extension granted by the circuit court, it must issue an order by November 10, 2003 on whether to approve the proposed plants and under what conditions. If the plants are approved, the Commission must also approve a plant site. For whichever site is selected, the Commission must decide under what conditions the plants would be built and operated. The DNR must independently issue an air pollution control construction permit and several water-related permits before construction can begin. The Commission must determine that these DNR permits have been obtained or can be obtained before it decides whether to issue a CPCN.

Table 13-1 Comparisons between the proposed power plant sites for public interest and environmental values

Siting Factor	North Site – Original	North Site - CUP	South Site	South Site-Exp
Air	Concentrations of particulate matter, especially total suspended solids (TSP 24-hr), PM10 (24-hr), and SO2 (both 3- and 24-hr) would increase substantially, Several of these pollutant concentrations are nearly 100 % of the NAAQS for the region.	Concentrations of particulate matter, especially total suspended solids (TSP 24-hr), PM10 (24-hr), and SO2 (both 3- and 24-hr) would increase substantially, Several of these pollutant concentrations are nearly 100 % of the NAAQS for the region.	Concentrations of particulate matter, especially total suspended solids (TSP 24-hr), PM10 (24-hr), and SO2 (both 3- and 24-hr) would increase substantially, Several of these pollutant concentrations are nearly 100 % of the NAAQS for the region.	Concentrations of particulate matter, especially total suspended solids (TSP 24-hr), PM10 (24-hr), and SO2 (both 3- and 24-hr) would increase substantially, Several of these pollutant concentrations are nearly 100 % of the NAAQS for the region.
General location	The SCPC units and IGCC unit would be placed north of the existing OCPP. The coal storage area would be moved to inside the rail loop. A new 138 kV switchyard would be located west of the rail loop and a new 345 kV switchyard would be expanded and moved southeast of the loop, extending onto the shooting range.	The SCPC units and IGCC unit would be placed north of the existing OCPP. The coal storage area would be moved to inside the rail loop, replacing the substation. A new 138 kV switchyard would be located west of the rail loop and a new 345 kV switchyard would be expanded by 40% and moved southeast of the rail loop, extending onto the shooting range property.	The SCPC units and IGCC unit would be located south of existing OCPP and north the shooting range.	The SCPC units would be at the same location as the South Site, but the IGCC would extend onto the shooting range property.
Lake Michigan	Constructing and operating a new water intake system and a water discharge structure would require dredging and result in temporary water quality and habitat impacts as well as long-term effects on the bathymetry and lakebed composition and loss of aquatic habitat.* Ship delivery of coal would require extension of the coal dock, a new breakwater and a ship channel. Construction of these facilities would substantially alter the lakebed and destroy diverse nearshore habitat.	Constructing and operating a new water intake system and a water discharge structure would require dredging and result in temporary water quality and habitat impacts as well as long-term effects on the bathymetry and lakebed composition and loss of aquatic habitat.* Ship delivery of coal would require extension of the coal dock, a new breakwater and a ship channel. Construction of these facilities would substantially alter the lakebed and destroy diverse nearshore habitat.	Constructing and operating a new water intake system and a water discharge structure would require dredging and result in temporary water quality and habitat impacts as well as long-term effects on the bathymetry and lakebed composition and loss of aquatic habitat.* Ship delivery of coal would require extension of the coal dock, a new breakwater and a ship channel. Construction of these facilities would substantially alter the lakebed and destroy diverse nearshore habitat.	Constructing and operating a new water intake system and a water discharge structure would require dredging and result in temporary water quality and habitat impacts as well as long-term effects on the bathymetry and lakebed composition and loss of aquatic habitat.* Ship delivery of coal would require extension of the coal dock, a new breakwater and a ship channel. Construction of these facilities would substantially alter the lakebed and destroy diverse nearshore habitat.

Siting Factor	North Site – Original	North Site - CUP	South Site	South Site-Exp
Wetlands	Approximately 18.8 acres filled. Wetlands impacted include the larger high-quality wetlands located along the beach and bluff area.	Values provided in WEPCO's testimony indicate about 19.5 acres filled, comprising about 24 % of the total delineated wetlands. These figures may be low if the future wallboard facility is taken into account as it has been for the other sites.	About 15.8 acres filled, comprising about 19% of the total delineated wetlands.	About 15.2 acres filled. Impacts similar to wetland impacts of South Site. Would also fill in a high-quality hardwood swamp located in southernmost corner of property.
Vegetation - woodlands	About 1.65 acres removed inside the rail loop, incl. large beech, sugar maple, and basswood trees. About 2 acres removed for rail loop extension and wallboard plant. About 2.9 acres removed for soil stockpile west of railroad. Woods north of Elm Road reduced and divided by construction.	Several woodlands, all CSHs, severely affected: half of Wood Duck Woods for transmission ROW and roads; WEPCO Oak Woods completely removed for switchyard and road; portion of OCPP Woods removed for rail loop expansion; WEPCO Woods partially removed for transmission ROW east of Caledonia Landfill. Woods north of Elm Road fragmented by construction. Accurate acreage totals not available.	About 0.16 acres removed for rail track in rail loop. About 6.3 acres of woodland-wetland complex removed for rail loop extension and IGCC. Approx. 2.9 acres removed for soil stockpile west of railroad. Woods removed north of Elm Road if wallboard plant is built.	About 0.16 acres removed for rail track in rail loop. About 6 removed for construction laydown. Approx. 2.9 acres removed for soil stockpile west of railroad. Woods removed north of Elm Road if wallboard plant is built
Vegetation - grasslands	Grasslands on existing ash landfills to be buried under soil stockpiles and replanted as grasslands. Portions would be kept in place each year for bird nesting and other uses. New soil stockpiles at west side of property and near switchyard would eventually add grassland acres.	Grasslands on existing ash landfills would be buried and reestablished at some future date. Loss of old field habitat within the rail loop due to new coal storage location. New berms for the shooting range near Seven Mile Road could be planted to grassland, mitigating for some lost habitat.	Grasslands would be buried and reestablished on ash landfills as for plant at North Site. Fewer new grasslands as North Landfill is reduced in size and soil stockpile near switchyard is not needed.	Grasslands would be buried and reestablished on ash landfills as on the North Site. Soil stockpiles near west side and switchyard would create new grasslands. Cropland near Seven Mile Road would be covered by a soil stockpile, and established as grassland.
Vegetation- areas of special habitat	A large area of the northern PEC removed, including beach, bluff, and riparian habitat; 1.8 acres of CSH removed; 9.2 acres of INRA removed.	A large area of the northern PEC removed, including beach, bluff, and riparian habitat due to SCPCs. Three INRAs would be highly disturbed by the new transmission facilities and roads, the largest would be nearly eliminated. Accurate acreage totals not available.	About 75 acres of PEC removed; 1.8 acres of CSH removed; 10.0 acres of INRA removed.	About 87 acres of PEC removed; 1.8 acres of CSH removed; 21.4 acres of INRA removed.

Siting Factor	North Site – Original	North Site - CUP	South Site	South Site-Exp
Amount of soil requiring excavation*	Approx. 7.3 million cubic yards for the SCPCs; an additional 2.7 million cubic yards for the IGCC. Total 10.0 million cubic yards.	Accurate acreage totals not available. Would likely be very similar to the North Site – Original.	About 5.8 million cubic yards for SCPCs; 1.5 million cubic yards additional for the IGCC. Total of 7.3 million cubic yards.	About 5.8 million cubic yards for the SCPCs; an additional 4.1 million cubic yards for IGCC. Total of 9.9 million cubic yards.
Land use	Little to no difference across sites.	Use of this layout would permanently remove more land from agricultural use than other sites.	Little to no difference across sites.	Use of this site would permanently remove more land from agricultural use than other sites.
Noise potential	More residences located nearer to the sources of noise for construction of the plant buildings. Many noises related to operation of the plant (i.e. coal handling, train traffic) would not be different based on site.	When the plant is operational, noise may be somewhat less than at other sites because the coal handling facilities would be somewhat further from residences. Also traffic would be routed away from the Elm Road area to a greater extent. Relocation of the shooting range would increase noise levels further south near Six and Seven Mile Roads.	The impact of noise related to constructing the plant buildings would shift southward; however many noises related to operation of the plant (i.e. coal handling, train traffic) would not be different based on site.	The impact of noise related to constructing the plant buildings would shift southward; however many noises related to operation of the plant (i.e. coal handling, train traffic) would not be different based on site.
Visual impacts	The plant would appear larger to residents nearest to the site in Milwaukee County, especially residents of Barton Oaks subdivision.	The plant would appear larger to residents nearest to the site in Milwaukee County, especially residents of the Barton Oaks subdivision. One exhaust stack for the SCPC units (rather than two) at 550 feet tall. Berms for the shooting range would be closer to homes along Seven Mile Road.	Plant buildings would appear larger to the residents nearest to the site in Racine County; however, exhaust stacks would be shorter than those on North Site.	Plant buildings would apperar larger to the residents nearest to the site in Racine County; however, exhaust stacks would be shorter than those on North Site. The berm for the shooting range would be relocated closer to these homes.
Historic sites	Eight archeological sites on property, none expected be adversely affected.	Eight archeological sites on property. Most are out of the construction zone. Several are in the area where new transmission line structures would be located. However, due to previous disturbances, adverse effects on these resources are not expected.	Eight archeological sites on property, none expected be adversely affected.	Eight archeological sites on property, none expected be adversely affected.
Train traffic	No differences among sites.	No differences among sites.	No differences among sites.	No differences among sites.

Siting Factor	North Site – Original	North Site - CUP	South Site	South Site-Exp
Car traffic	Local and regional traffic would increase. On-site traffic could reach 4,180 vehicle trips per day during peak construction. New access roads could increase traffic on Oakwood Road and decrease it on Elm Road.	Local and regional traffic would increase. On-site traffic could reach 4,180 vehicle trips per day. Most traffic would enter and exit site from STH 32, decreasing dust and noise.	Local and regional traffic would increase. On-site traffic could reach 4,180 vehicle trips per day during peak construction. New site access road off of STH 32 would improve on-site traffic flow and reduce dust and noise.	Local and regional traffic would increase. On-site traffic could reach 4,180 vehicle trips per day during peak construction. New site access road off of STH 32 would improve on-site traffic flow and reduce dust and noise.
Economic effects	No substantial cost differences among sites. Additional excavation costs related to the North site could be negated by longer extensions for coal handling and intake water.	No substantial cost difference among sites. Expansion and relocation of the switchyards would add $20-$40 million..	No substantial cost differences among sites. Additional excavation costs related to the North site could be negated by longer extensions for coal handling and intake water.	No substantial cost differences among sites. Additional excavation costs related to the North site could be negated by longer extensions for coal handling and intake water.
Electric transmission	No differences among sites.	Relocation of the 138 and 345 kV switchyards and associated transmission line connections would result in increased costs and new environmental impacts.	No differences among sites	No differences among sites
Water supply	No differences among sites.	No differences among sites..	No differences among sites.	No differences among sites.
Sewer	No differences among sites	No differences among sites..	No differences among sites.	No differences among sites.

* These acreages include construction of the wallboard facility described in the CPCN application.

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Appendix A-1 – Executive Summary for the Calpine Fond du Lac Energy Center

Proposal

On June 18, 2001 Fond du Lac Energy Center, LLC (Calpine), a wholly owned subsidiary of Calpine Corporation, filed an application at the Commission for a Certificate of Public Convenience and Necessity (CPCN) under Wis. Stat. § 196.491(3) and Wis. Admin. Code ch. PSC 111, to construct and operate a large generating facility, associated high voltage transmission and water facilities in the town of Fond du Lac, Fond du Lac County. Amendments to the application were filed in December, 2001 and April, 2002. On May 9, 2002, the Commission determined that Calpine's application was complete.

Calpine is a fully integrated independent power producer. The new facility would be operated as a merchant plant as defined in Wisconsin Act 204, the Electric Reliability Act, which legalized the development of wholesale merchant plants in the state. Calpine would sell electric power generated by the plant at market-based rates to investor-owned utilities, cooperative utilities, power marketers, and other purchasers for resale in Wisconsin and throughout the Midwest region. At this time, Calpine has no pre-existing power purchase arrangements with public utilities for power generated at the proposed facility.

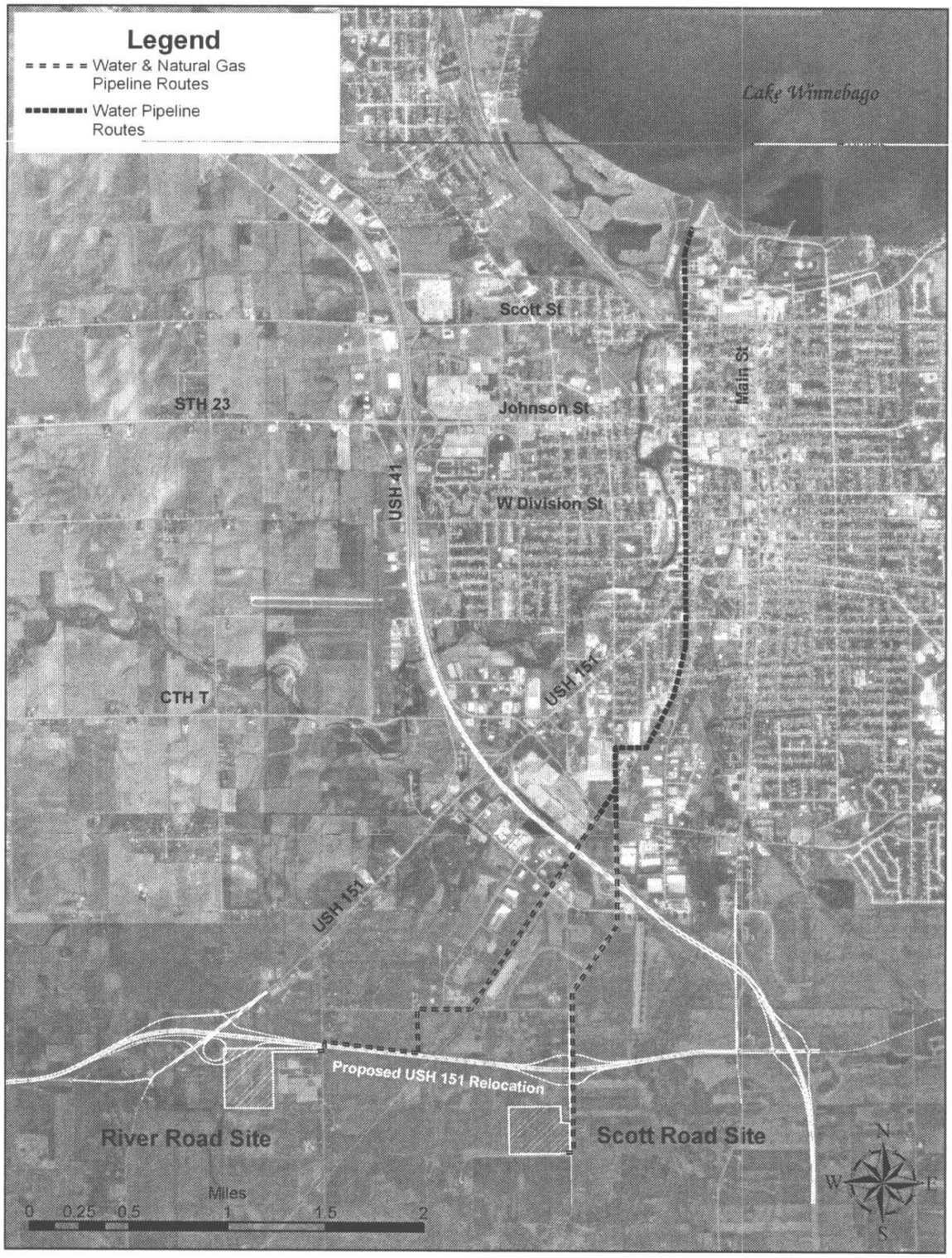
Project Location

Calpine has proposed that the power plant be located on one of two sites in the town of Fond du Lac. The Scott Road Site is a 47.5-acre parcel located along Hickory Road southwest of U.S. Highway (USH) 41. Surrounding land use is primarily industrial and agricultural in transition. The River Road Site is a 50-acre parcel south of USH 151 and directly west of the existing South Fond du Lac Generating Station on River Road. The two alternative sites are shown on Figure A-1.

Project Description

As proposed by Calpine, either site would contain two natural gas-fired combustion turbines with heat recovery steam generators and steam turbines capable of producing 523 MW of power. There would be two 150-foot exhaust stacks for the generating units and another of the same height for the auxiliary boiler.

Figure A-1 Project location map



Water from Lake Winnebago would be used for steam generation and cooling. Steam would be created from waste heat from exhaust gases from the combustion of natural gas at the turbines. Under peak load summer conditions, about 6.4 mgd would be withdrawn into a new intake structure and pipe and pumped through a new water supply line approximately 5.1 to 5.7 miles to the power plant site. About 1.0 mgd would be discharged back to the lake via a new discharge pipeline. The cooling tower blowdown water would be combined with treated effluent from the city of Fond du Lac and discharged into the lake through an existing outfall structure maintained and operated by the city of Fond du Lac.

At the Scott Road Site, all new transmission construction needed to interconnect the new plant to the transmission grid would be located on the plant site. The South Fond du Lac-Edgewater 345 kV line passes directly over the proposed site. A new double-circuit 345 kV transmission line, approximately 2,800 feet in length, would be needed to interconnect a plant built at the River Road Site to the South Fond du Lac-Edgewater transmission line.

Natural gas would be supplied to either plant site through a new 12-inch steel natural gas pipeline, approximately 1.6 to 2.3 miles in length (depending on the site). The new pipeline, which would be built by ANR or Calpine, would require construction authorization from the Federal Energy Regulatory Commission (FERC).

Environmental Issues

Air

Calpine applied for an air pollution control permit for the proposed plant. Modeling analyses predict that the power plant, with the Best Available Control Technologies (BACT) implemented, would remain in compliance with the National Ambient Air Quality Standards (NAAQS). The maximum predicted increases for nitrogen oxides (NO_x), sulfur dioxide (SO_2), particulate matter (PM/PM_{10}), and carbon monoxide (CO) would be less than the respective allowable Prevention of Significant Deterioration (PSD) increment and PSD monitoring *de minimus* concentrations.

Water

The surface water withdrawal system would include an intake structure and pipe, zebra mussel control, and a pump station. Calpine would construct the surface water withdrawal system and after construction is complete, the city of Fond du Lac would assume ownership and operation of the system.

Approximately 3.6 mgd (30-day average) would be used for cooling of the gas turbines, make-up water for the cooling tower, and make-up for the steam cycle. The projected maximum consumptive water use for the proposed power plant is about 0.1 percent of the total discharge from the Lake Winnebago watershed. Water withdrawal for the project would not be expected to have adverse effects on existing uses of the lake, such as recreational boating, fishing, public and private water supplies, navigation and scenic beauty.

Dredging activities necessary to install and maintain the water intake and pipe would disrupt the lake bottom and cause increased turbidity within the immediate area. This could disrupt the aquatic flora and

fauna (especially fish) habitat in the vicinity of the construction site. Surveys indicate that the lake bottom in the area that would be disturbed does not have an abundance of aquatic vascular plants or a large invertebrate population. The location of the intake structure is not known to contain unique habitat, spawning areas, or threatened or endangered species. Mitigation measures, such as the use of silt curtains and prohibition of dredging during fish spawning season would also help to minimize potential impacts to aquatic life.

The discharge to Lake Winnebago would be a combination of the cooling tower blowdown from the Fond du Lac Energy Center and the existing discharge from the city of Fond du Lac publicly-owned treatment works (POTW). During the warmest months the year, modeling indicates that the combined effluent, under expected conditions, would be cooler than the lake temperature. During the remainder of the year, the temperature of the blowdown water is expected to be cooler than the 87 degree Fahrenheit (°F) thermal limit calculated by the DNR.

Construction of the water supply and discharge lines through the urban area between the lake and USH 141 is not expected to cause major resource impacts because the proposed corridor is highly disturbed and Calpine would directionally bore the facilities under the East Branch of the Fond du Lac River. However, construction of the water lines and natural gas pipeline parallel to the Wild Goose State Trail (if the River Road Site were approved) would greatly disturb some remnants of mesic prairie that are present along the former railroad grade.

Vegetation and wildlife

Both sites are located on silty clay-loam soils that are planted in soybeans or corn in drier years. Common agricultural weeds are present across both sites. The Scott Road Site supports a line of trees along a portion of its northern boundary. Several low-growing brushy tree lines criss-cross the River Road Site. Drainage swales and seasonally wet basins are present on both sites, although they comprise about 2.6 acres on the River Road Site, compared to less than one acre on the Scott Road Site.

No rare or unusual plant or animal communities or species are present on or near either of the two alternative sites. Construction of both the water and natural gas facilities for the River Road Site would disrupt mesic prairie remnants along the Wild Goose State Trail.

Land use

The project appears to be consistent with local land use plans. Although both areas are currently farmed, they are located in areas where commercial and industrial development is expanding. Construction of the new USH 151 Fond du Lac bypass will begin within the next few years. The alignment for the new highway and interchange with the existing USH 151 roadway encroaches on the northwest corner of the River Road Site. When this highway is completed, farming will no longer be possible in several of the fields adjacent to the site.

There are several residences located quite close to the Scott Road Site. In fact the Hoehnen residence is within 65 feet of the site boundary. The closest residences to the River Road Site are located about 1,000 feet from the site along Willow Lawn Road and south on River Road.

Calpine and the town of Fond du Lac have been negotiating an agreement for use of the Scott Road Site that includes conditions regarding noise, landscaping, lighting, and several other topics. Although no agreement has been negotiated for the River Road Site, Calpine and the town are confident that a similar agreement could be reached for that location.

Local community services

The power plant facility is expected to be self-sufficient except for emergency services. Fire suppression water would be stored in tanks on-site as raw water. No additional police or fire protection beyond what the town of Fond du Lac currently provides would be necessary.

Fogging and icing

The cooling tower for the proposed plant at either site would consist of twelve cells located in structures oriented north-south at both sites. Based on modeling, fogging and icing from the cooling tower located at either site would be expected to affect primarily the areas southwest of the proposed plant. For the Scott Road Site, the areas most greatly affected would include Scott Road and the area around the East Branch of the Fond du Lac River and the Milton Scott residence. For the River Road Site, ground fog and possible icing would affect an area near CTH D. With the possible exception of CTH D, it is not anticipated that any major roadways in the area, such as USH 151, USH 41, Pioneer Road, or Hickory Road would be impacted by fogging or icing from cooling towers at either site.

Noise

Most of the noise caused by the construction equipment would be much greater than the ambient noise levels at the Scott Road or River Road Sites. However, these noise sources would be temporary. Operation of the plant at the Scott Road Site would result in a moderate to substantial increase in the perceptible dBA-weighted noise levels for most the residences within 0.25 mile of the site and little to no change in low-frequency sound levels. At the River Road Site, the noise produced by the existing South Fond du Lac power plant, when operating, would mask any incremental noise increase caused by operation of the proposed Calpine plant. When the existing South Fond du Lac plant is off-line, there would be a small increase in the perceptible dBA-weighted noise levels during the afternoon and early evening hours.

The applicant and the town of Fond du Lac have agreed on dBA noise limits at the site boundaries. Calpine intends to construct a building to enclose the major noise producing equipment. Thus, the sound level projections provided in the application and analyzed in this document would be further reduced.

Visual

Although the new plant would initially be a large new feature in the local visual landscape, over time it would blend in with other commercial and industrial developments that are expanding into the agricultural transition area bordering the southwest side of the city of Fond du Lac. The approved USH 151 bypass will substantially change the character of the area as it crosses through this area.

Historic properties

There are no known historic or archeological resources within the sites or the proposed corridors for the water supply and discharge lines, the natural gas pipeline, or the transmission facilities.

Appendix A-2 - Executive Summary for the Fox Energy Center

Proposals

In October 2000, Fox Energy applied to the Commission for a Certificate of Public Convenience and Necessity (CPCN) under Wis. Stat. § 196.491(3) and Wis. Admin. Code ch. PSC 111, to construct and operate a large electric power generating facility at one of two possible sites. In March 2001, Fox Energy and ATC amended the application to include ATC as a CPCN co-applicant responsible for building and operating the proposed electric transmission interconnection facilities to be owned by ATC. The applications were withdrawn in August 2001 as Fox Energy sought a different water source for the combined-cycle power plant. In April 2002, the applications were once again submitted for Commission review.

Fox Energy is a wholly owned subsidiary of MidAmerican Energy Holdings Company of Omaha, Nebraska. Fox Energy anticipates that it would enter into an operating, maintenance, and administrative services agreement with CalEnergy Generation Operating Company. CalEnergy is also a subsidiary of MidAmerican Energy Holdings Company.

The new facility would be operated as a wholesale merchant plant as defined in Wisconsin Act 204, the Electric Reliability Act, which legalized the development of wholesale merchant plants in the state. At this time, Fox Energy has signed no power purchase agreements with Wisconsin public utilities.

Project Location

Fox Energy has proposed that the power plant be located on one of the two sites in Outagamie County (see Figure 1). One site in the town of Kaukauna is located adjacent to the Wisconsin Central Limited Railroad (WCL) north of STH 96, southeast of USH 41 and west of County Line Road in the town of Kaukauna. The Kaukauna site is located in the western portion of Section 4, Township 21 North, Range 19 East. The other site is located south of the southwest corner of the intersection of County Trunk Highway (CTH) UU and State Trunk Highway (STH) 55 in the town of Freedom. The Freedom site is located in the northeast quarter of Section 27, Township 22 North, Range 19 East. The entire facility is expected to occupy approximately 30 acres regardless of site. Both sites are currently farmed.

Project Description

Power plant

The power plant, at either site, would consist of two Siemens-Westinghouse 501FD combustion turbines (CTs), two heat recovery steam generators (HRSGs), and a single steam turbine with a generating capacity of 530 megawatts (MW), plus gas duct-firing equipment to gain approximately 105 MW of additional peaking capacity. Selective catalytic reduction (SCR) equipment would reduce the nitrogen oxide (NO_x) emissions further. Each turbine would be connected to its own generation and main power transformer. Steam would be condensed into water before being pumped back to the HRSG. Heat removed by the condenser would be released into the atmosphere by evaporation in cooling towers.

The two CT units and the duct burners would have a maximum natural gas fuel flow of approximately 125,000 dekatherms (Dth) per day. Fox Energy has indicated that the full-load heat input for each CT would be 2,203 million British thermal units per hour (MMBTU/hr). The total plant full-load heat input with duct firing would be 5,228 MMBTU/hr. The overall heat conversion efficiency of the proposed Fox Energy facility would be 54 percent. The anticipated operational life span would be at least 30 years. Actual operations would depend on market conditions and the market price for natural gas.

Natural gas connection

The ANR Pipeline Company (ANR) would supply the natural gas via existing interstate natural gas transmission pipelines (see Figure 1), and a new metering station. From this metering station, Fox Energy would construct, own, and operate its own pipeline to the plant site and related facilities such as heating, odorizing, and overpressure protecting devices. Gas transportation service would be under one or a combination of firm, interruptible and market balancing rate schedules. Natural gas pipelines traverse the Freedom site and lie within 230 feet east of the Kaukauna site (see Figure 1).

Water supply and discharge

Consumptive water use at the proposed facility would be, on average, approximately 4.3 million gallons per day (MGD). Regardless of site, the Heart of the Valley Metropolitan Sewerage District (HOV) would provide the water supply via a Fox Energy-built, underground pipeline. The incoming water would be stored at either plant site in a 17-million gallon holding facility, covering 7.5 acres, that would be excavated to five feet below grade and bermed up to 13 feet above grade. The facility would be covered with a floating high-density polyethylene (HDPE) cover. The plant discharge would be piped to the Fox River and discharged just upstream from the Rapide Croche dam. The water supply and discharge systems would consist of 24-inch and 10-inch HDPE pipe, respectively. From the Freedom site, the discharge and supply pipelines would share the same right-of-way (ROW) for about six miles. Beyond this point, the discharge pipeline would continue northwestward toward the Fox River by one of two routes for three to six miles. From the Kaukauna site, a supply pipeline of about four miles and a discharge pipeline of about 0.5 mile would be needed.

Electric transmission interconnection

An interconnection study performed by the ATC determined that at least one 345 kV transmission line would be needed to connect the proposed plant to the transmission system.

There are two ways in which the power plant (located at either site) could be interconnected. One is a connection to the Forest Junction Substation via a tap into a currently de-energized line at a point north of the substation and a tap into the Point Beach-North Appleton (PBNA) 345 kilovolts (kV) line. This will be referred to as the Loop Solution. The second is a connection to the Forest Junction Substation via a tap to the de-energized line and a direct connection to the North Appleton Substation. This is the No-Loop Solution.

Each solution could utilize one of two routes:

- An Existing ROW Route that uses the existing PBNA 345 kV and Kaukauna Substation (KKSS) 138 kV right-of-way and results in a new double-circuit 345/138 kV line in place of the KKSS line next to the PBNA line.
- A New ROW Route that follows mostly a new path some distance from the existing PBNA-KKSS ROW.

ATC would construct the transmission lines using mostly H-frame structures for new single-circuit construction, but double-circuit structures could be used in the Existing ROW Route to support the existing 138 kV circuit and the new 345 kV circuit. The new double-circuit structures would be significantly taller than the existing structures for the 138 kV line. The costs are summarized in Table A-1.

Table A-1 Comparisons of transmission construction costs for each of the eight combinations of site, transmission solution, and route

Site	Freedom				Kaukauna			
Interconnection Approach	Loop		No-Loop		Loop		No-Loop	
Transmission line Route	Existing ROW	New ROW	Existing ROW	New ROW	Existing ROW	New ROW	Existing ROW	New ROW
Total cost	$17.3 M	$20.9 M	$19.6 M	$22.1 M	$13.8 M	$16.4 M	$19.6 M	$21.3 M

A detailed discussion of the proposed electric transmission construction and its potential impacts is found in Chapter 5.

Environmental Issues

Air

Fox Energy has submitted an air pollution control permit application for each power plant site. Both sites are currently in attainment of the primary and secondary National Ambient Air Quality Standards (NAAQS) for all criteria pollutants. The Wisconsin Department of Natural Resources (DNR) has completed its technical review of the application. The project would have to meet conditions, but appears permittable.

Water

Drainage ditches and other small wetlands occupy parts of the Freedom site. There are none on the Kaukauna site.

The estimated limit on water flow from HOV would be 5.43 MGD. The estimated maximum water usage from HOV would be approximately 4.9 MGD. Water piped to the plant from HOV would meet HOV's wastewater permit limits. This water would be used for evaporative cooling, demineralizer makeup, and fire protection. The maximum wastewater from the facility proposed for discharge into the Fox River would be 1.1 MGD, with an estimated average discharge of 0.9 MGD.

The effluent discharged from the plant would be assigned facility-specific DNR wastewater permit limits, separate from HOV's limits, for a variety of chemical and thermal characteristics. The discharge pipe would be installed in a 20-foot by 20-foot riprap pad placed on the riverbed. The proposed discharge structure would be about 9.5 feet below the water surface. Since both sites would discharge into the same point in the Fox River, the same impacts to the river are expected to occur regardless of which site is used. Scouring of the Fox River bed would be minimal. Biological surveys at the discharge site over time have indicated that it is not likely that the project would cause significant adverse environmental impact to the river's aquatic biota.

The water supply and discharge pipelines would primarily be trenched along road ROWs, and would be along different routes for each site. At the Freedom site, the plant would require more miles of water pipeline. The supply line from HOV would be about 5.8 miles long. The discharge line would be either 7.5 miles long or 8.6 miles long, depending on the option selected. The 8.6 mile option would include 5.4 miles shared with the supply line and 3.2 miles of new ROW. At the Kaukauna site, the supply line would run about 3.7 miles, and the discharge line would run about 0.4 mile.

If either the Freedom or the Kaukauna site were selected, Fox Energy would have to secure the necessary water-related permits from the DNR and the Army Corps of Engineers (ACOE). Chapter 30 permits, from the DNR, and Section 404 and Section 10 permits from the ACOE would be required for each site in order to construct raw water supply and waste water discharge structures from each site to the Fox River. No other water supply or discharge alternatives were proposed. If the permits could not be obtained, the project would not move forward.

Other plant site issues

The community surrounding each power plant site is an area that contains farms, farmsteads, and residences or small businesses not associated with farming. Land use on the sites and surrounding the sites is mainly agricultural, but there are residences close to each site. Visual changes in the landscape would be notable at either site because of the height, size, and materials proposed for the power plant facilities. Noise mitigation at each site would be needed if the audible sound levels are to be brought down near existing ambient levels at nearby homes. The greatest sound levels would come from the cooling towers. The cooling towers would also produce fog for about 2.5 to 4.5 total hours per year along STH 55 by the Freedom site and 2.5 to 10.5 total hours per year along STH 96 by the Kaukauna site. In winter, some of the fog may contribute to road icing. Appropriately placed caution signs should advise motorists of any possible icing hazard on nearby roads.

A short comparison of other environmental issues between the Freedom site and the Kaukauna site and the power plant impacts can be found in Table 2. Site differences are discussed in detail in Chapters 3 and 4.

Table A-2 Comparisons between the two proposed power plant sites for public interest and environmental values

Siting Factor	Freedom	Kaukauna
Land	Relatively flat farmland.	Relatively flat farmland.
Vegetation	Corn and soybeans plus hydrophytic plants.	Corn.
Land use	Farmland; surrounded by farmland and homes.	Farmland; surrounded by farmland, homes, and businesses.
Roads	Some congestion on CTH UU and CTH 55 during construction; impacts minimal during operation.	Some congestion on CTH U, USH 41 frontage road, Wrightstown Road, STH 96 during construction; impacts minimal during operation.
Fogging and icing potential	2.5 to 4.5 hours per year fogging along about 1,300 feet of STH 55; 15 minute to 5.5 hours per year icing along about 2,300 feet of STH 55.	2.5 to 10.5 hours per year fogging along about 2,000 feet of STH 96; 15 minutes to 3.5 hours per year icing along about 2,300 feet of STH 96.
Noise potential	More than 48 dBA at some of the closest receptors; would not comply with EPA guidelines without mitigation in addition to equipment upgrades. No low frequency vibration expected.	More than 48 dBA at closest receptors; would not comply with EPA guidelines without mitigation in addition to equipment upgrades. No low frequency vibration expected.
Distance to natural gas supply	On site.	230 feet east of site (2,500 feet total).

Potential environmental impacts of new transmission lines

It would appear that building a new transmission line would not cause a major conflict with current and future land use in this region where several transmission lines currently exist. However, there are some concerns about new lines passing through farmland and woodland, new crossings of streams, and the new

visual features on the landscape. Both proposed routes are essentially cross-country in character. Potential impacts are compared between the Existing ROW and New ROW routes in Table 3.

Table A-3 Environmental comparison among the four proposed electric transmission solutions for public interest and environmental values

Route Factor	Existing ROW	New ROW
Land use along ROW	Farmland, residential and roadways	Farmland, mostly
Length	Kaukauna , loop option- 4.55 miles; Freedom, loop option – 9.45 miles; Kaukauna and Freedom, non-loop option – 12.53 miles	Kaukauna, loop option – 5.95 miles; Freedom, loop option – 13.46 miles; Kaukauna, non—loop option – 16.46 miles; Freedom, non-loop option – 17.5 miles
Soils	Silty loam, silty clay loam, fine sandy loam	Silty loam, silty clay loam, fine sandy loam
Geology	No effect	No effect
Wetlands	About 2 acres of ROW is wetland: several stream crossings	2.5 acres of ROW is wetland; stream crossing
Vegetation and wildlife	No significant impact on species	Significant reduction in trees, forest crops
Existing contamination	None	None
Consistency with land use	Compatible	Compatible
Roads and utility lines	Some traffic disruption; some attention to other utilities needed	Some traffic disruption; some attention to other utilities and gas company
Visual landscape	Two existing lines present; one would be rebuilt taller	New transmission line feature in countryside
Historic properties	Nothing listed	Nothing listed
Noise	Open area – acceptable	Open area - acceptable
EMF	Moderate to high levels already exist with existing lines	New high EMF levels with new line
Aesthetics	Little impact	New impact – new feature on landscape

Required Decisions

The Commission, in reviewing Fox Energy's application for a CPCN, will decide, among other items, whether to authorize construction of the plant, whether the plant would have any effect on regional power plant competition, where to build the plant and its associated water supply and discharge pipelines if authorized, under what conditions the plant's natural gas line would be constructed, and where to build the associated electric transmission line. If it approves the plant and the transmission line CPCNs, it will also determine whether to impose any conditions on the construction of these facilities.

The DNR will decide whether to issue the air and water permits. Without those permits, the applicants will not be able to build the proposed facilities.

General Comparison of Natural Gas vs Coal-fired Generation

Many comments on the draft EIS indicated an interest in a general comparison of a natural gas-fired combined-cycle plant and a similarly sized coal-fired plant. Below is a comparison of several environmental resource impacts for these generation types. Some of the data is taken from projects that have previously been reviewed by the Commission while other information is more generic in nature.

Amount of land required

The footprint of the primary plant equipment is generally larger for a coal plant than for a similarly sized natural gas plant, although the SCPC power block is more compact than a conventional coal boiler. The auxiliary facilities and features needed to support a coal plant, such as the coal and limestone handling, unloading and storage areas, and ash disposal areas, also consume large areas of land.

For example, the proposed 1050 MW Badger Generating Plant, a natural gas-fired combined-cycle plant, proposed several years ago by Badger Generating LLC, a subsidiary of Pacific Gas and Electric, could have been constructed on about 35 acres of land. This would include the combustion equipment and turbines, cooling towers, and substation. In contrast, the power blocks for two SCPC units (1,230 MW) would consume about 20 acres of land with the substation would require about 10 more acres. However, the coal storage piles (active and inactive) for the ERGS project would take up about 55 to 60 acres of land and the ash landfills would use considerably more land.

These comparisons do not take into account the natural gas pipeline or the railroad facilities needed to bring coal to the plant site. Both types of plants would require a transmission interconnection and the length and cost of that facility would depend on the regional transmission system in the project area.

Air emissions

The expected project emissions from a natural gas-fired plant operating 100 percent of the time are much lower for most criteria pollutants than a similarly sized coal-fired power plant using the SCPC technology. The table below uses expected annual emissions from the Badger Generating Plant (1050 MW) and the two SCPC units proposed for the ERGS. The values do not include emissions from auxiliary equipment such as diesel generators (used for start-up), or other auxiliary equipment.

Table A-4 Potential annual emissions in tons per year

Technology	NOx	CO	PM_{10}	SO_2	Ammonia	VOC
Natural gas	471	899	530	76	466	49
Coal -SCPC	3,811	6,496	974	8,662	175	189

Information in Chapter 5 indicates that yearly CO_2 emissions from a 500 MW natural gas-fired combined-cycle plant would be about 450,000 tons per year compared to about 3,500,000 or more tons per year for a 600 MW coal plant.

Jobs and employment

During construction, WEPCO anticipates a need for about 900 workers per coal unit, with these jobs spanning a wide range of skilled and unskilled labor. About 100 employees would be needed to operate each of the SCPC units. A total of 500 workers would be needed to build a 1000 MW natural gas facility over the course of the project. The number of permanent employees that would operate the plant would be about 35.

Traffic

Expected traffic would be much greater for a coal-fired power plant than a natural gas facility. This is due to more construction workers and permanent employees, more deliveries and maintenance vehicles, and ash hauling. Following construction, a natural gas-fired power plant would not generate any more traffic than a small to medium size business.

B

Appendix B - EGEAS Modeled Expansion Plans for WEPCO 2005 to 2030

This Appendix contains the full results of the EGEAS modeled expansion plans for WEPCO. The tables in this Appendix contain a year-by-year description of the various power plants and necessary sizes that would need to be added to WEPCO's system to maintain system reliability in a cost effective fashion. The following tables examine WEPCO's supply needs from several perspectives using a wide range of input assumptions for capital costs, coal and natural gas fuel costs, wind farm potential, electricity demand and energy growth, and carbon dioxide monetization. The tables cover the proposed ERGS project and several supply alternatives to the ERGS project, including the 523 MW Calpine Fond du Lac Energy Center, up to 1,250 MW of Class 4 wind farm potential, as well as numerous generic 150 MW combustion turbines. Each of the modeled expansion plans assume commercial operation of one 545 MW combined-cycle power plant located in Port Washington for each year 2005 and 2008 respectively. These Port Washington plants were approved by the Commission in 2002. Refer to Chapter 4 for all appropriate definitions.

Figure B-1 410 MW Wind by 2030

Appendix B, Summary of EGEAS Expansion Plans

Proposal	Unit Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals
Staff Base																														
Optimal	150 MW CT				150				300		150	300	150	300	150					150				150	300					2100
	WEP 545 MW CC		545			545													545											1635
$19,073.3 MM	100 MW Biomass																												200	200
	WEP 515 MW Coal						515			515	515					515					515		515			515	515		515	4635
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**150**	**545**	**515**	**0**	**300**	**515**	**665**	**300**	**150**	**300**	**150**	**515**	**0**	**0**	**545**	**150**	**515**	**0**	**515**	**150**	**300**	**515**	**515**	**0**	**715**	**8570**
Calpine	150 MW CT						150			150	300	300	150	150			150	150		150				150	300					2100
	WEP 545 MW CC		545			545																	545							1635
$19,080.7 MM	100 MW Biomass																												200	200
	Calpine 523				523																									523
	WEP 515 MW Coal								515		515				515				515		515				515	515	515		515	4635
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**523**	**545**	**150**	**0**	**515**	**150**	**815**	**300**	**150**	**150**	**515**	**0**	**150**	**150**	**515**	**150**	**515**	**0**	**545**	**150**	**815**	**515**	**515**	**0**	**715**	**9093**
ERGS w/o IGCC	150 MW CT									300	300	300	150	300	150					150				150	300					2100
	WEP 545 MW CC		545		545														545											1635
$19,176.3 MM	100 MW Biomass																												200	200
	WEP 515 MW Coal					515	515				515					515					515		515			515	515		515	4635
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**545**	**515**	**515**	**0**	**0**	**300**	**815**	**300**	**150**	**300**	**150**	**515**	**0**	**0**	**545**	**150**	**515**	**0**	**515**	**150**	**300**	**515**	**515**	**0**	**715**	**8570**

Proposal	Unit Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals
DSM-EIA																														
Optimal	150 MW CT						150				300	150					150													750
	WEP 545 MW CC		545			545																								1090
$16,914.8 MM	100 MW Biomass																		100											100
	WEP 515 MW Coal									515	515		515							515			515		515	515			515	4120
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**0**	**545**	**150**	**0**	**0**	**515**	**815**	**150**	**515**	**0**	**0**	**0**	**150**	**0**	**100**	**515**	**0**	**0**	**515**	**0**	**515**	**515**	**0**	**0**	**515**	**6060**
Calpine	150 MW CT												150	150												150	150		150	750
	WEP 545 MW CC		545			545																								1090
$16,979.9 MM	100 MW Biomass																												100	100
	Calpine 523				523																									523
	WEP 515 MW Coal										1030				515				515				515		1030				515	4120
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**523**	**545**	**0**	**0**	**0**	**0**	**1030**	**0**	**150**	**150**	**515**	**0**	**0**	**0**	**515**	**0**	**0**	**0**	**515**	**0**	**1030**	**150**	**150**	**0**	**765**	**6583**
ERGS w/o IGCC	150 MW CT																													0
	WEP 545 MW CC		545			545							300		150	150	150													1840
$17,144.2 MM	100 MW Biomass																		100											100
	WEP 515 MW Coal					515	515				515									515			515		515	515			515	4120
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**0**	**1060**	**515**	**0**	**0**	**0**	**515**	**0**	**300**	**0**	**150**	**150**	**150**	**0**	**100**	**515**	**0**	**0**	**515**	**0**	**515**	**515**	**0**	**0**	**515**	**6060**

Figure B-2 410 MW Wind by 2030

Proposal	Unit Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals
High Gas																														
Optimal	150 MW CT				150				300		150	300	150			150	150	150		150				150						1800
	WEP 545 MW CC		545			545															545									1635
$19,233.0 MM	100 MW Biomass																													0
	WEP 515 MW Coal						515			515	515			515					515				515		515	515		515	515	5150
	WEP 500 MW IGCC																													0
	Totals	0	545	0	150	545	515	0	300	515	665	300	150	515	0	150	150	150	515	150	545	0	515	150	515	515	0	515	515	8585
Calpine	150 MW CT						150			150					150	150	300	150	300	300				150						1800
	WEP 545 MW CC		545			545																			545					1635
	100 MW Biomass																													0
$19,261.8 MM	Calpine 523				523																									523
	WEP 515 MW Coal								515		1030		515								515		515		515	515		515	515	5150
	WEP 500 MW IGCC																													0
	Totals	0	545	0	523	545	150	0	515	150	1030	0	515	0	150	150	300	150	300	300	515	0	515	150	1060	515	0	515	515	9108
ERGS w/o IGCC	150 MW CT									300	300	300	150			150	150	150		150				150						1800
	WEP 545 MW CC		545		545																545									1635
$19,334.9 MM	100 MW Biomass																													0
	WEP 515 MW Coal					515	515				515			515					515				515		515	515		515	515	5150
	WEP 500 MW IGCC																													0
	Totals	0	545	0	545	515	515	0	0	300	815	300	150	515	0	150	150	150	515	150	545	0	515	150	515	515	0	515	515	8585

Proposal	Unit Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals
Low Gas																														
Optimal	150 MW CT				150						450	150			150	150	300	150	300		150	150					150			2250
	WEP 545 MW CC		545			545	545																							1635
$18,690.1 MM	100 MW Biomass																												100	100
	WEP 515 MW Coal								515				515							515			515	515		515		515	515	4120
	WEP 500 MW IGCC																													0
	Totals	0	545	0	150	545	545	0	515	0	450	150	515	0	150	150	300	150	300	515	150	150	515	515	0	515	150	515	615	8105
Calpine	150 MW CT						150			150	300	300	150	150	300	150			150		150	150	150	150	150		300			2850
	WEP 545 MW CC		545			545														545										1635
	100 MW Biomass																													0
$18,666.8 MM	Calpine 523				523																									523
	WEP 515 MW Coal								515		515						515						515		515	515		515	515	4120
	WEP 500 MW IGCC																													0
	Totals	0	545	0	523	545	150	0	515	150	815	300	150	150	300	150	515	0	150	545	150	150	665	150	665	515	300	515	515	9128
ERGS w/o IGCC	150 MW CT									300	300	300	150	150	300	150			150		150	150					150			2250
	WEP 545 MW CC		545		545						545									545										2180
$18,821.1 MM	100 MW Biomass																													0
	WEP 515 MW Coal					515	515										515						515	515		515		515	515	4120
	WEP 500 MW IGCC																													0
	Totals	0	545	0	545	515	515	0	0	300	845	300	150	150	300	150	515	0	150	545	150	150	515	515	0	515	150	515	515	8550

Figure B-3 410 MW Wind by 2030

Appendix B, Summary of EGEAS Expansion Plans

Proposal	Unit Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals
Coal Capital Costs + 10%																														
Optimal	150 MW CT				150						450	300	150	150			150	150	300		150	150	150							2250
	WEP 545 MW CC		545			545	545																							1635
$19,485.6 MM	100 MW Biomass																							100						100
	WEP 515 MW Coal								515		515				515					515			515		515	515		515	515	4635
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**150**	**545**	**545**	**0**	**515**	**0**	**965**	**300**	**150**	**150**	**515**	**0**	**150**	**150**	**300**	**515**	**150**	**150**	**665**	**100**	**515**	**515**	**0**	**515**	**515**	**8620**
Calpine	150 MW CT						150			150	300	300	150	150			150	150		150				150	300					2100
	WEP 545 MW CC		545			545													545											1635
	100 MW Biomass																										200			200
$19,475.0 MM	Calpine 523				523																									523
	WEP 515 MW Coal								515		515				515						515		515		515	515		515	515	4635
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**523**	**545**	**150**	**0**	**515**	**150**	**815**	**300**	**150**	**150**	**515**	**0**	**150**	**150**	**545**	**150**	**515**	**0**	**515**	**150**	**815**	**515**	**200**	**515**	**515**	**9093**
ERGS w/o IGCC	150 MW CT									300	300	300	150	150			150	150	300		150	150	150							2250
	WEP 545 MW CC		545		545						545																			1635
$19,625.2 MM	100 MW Biomass																							100						100
	WEP 515 MW Coal					515	515								515					515			515		515	515		515	515	4635
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**545**	**515**	**515**	**0**	**0**	**300**	**845**	**300**	**150**	**150**	**515**	**0**	**150**	**150**	**300**	**515**	**150**	**150**	**665**	**100**	**515**	**515**	**0**	**515**	**515**	**8620**

Proposal	Unit Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals
CO2 Monetization																														
Optimal	150 MW CT				150		300				300			150	150	150	150	300	150		150	150	150	150	150					2550
	WEP 545 MW CC		545			545					545									545										2180
$27,009.9 MM	100 MW Biomass						200		300	300	100	200	200	100			100													1500
	WEP 515 MW Coal																						515			515	515		515	2060
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**150**	**545**	**500**	**0**	**300**	**300**	**945**	**200**	**200**	**250**	**150**	**150**	**250**	**300**	**150**	**545**	**150**	**150**	**665**	**150**	**150**	**515**	**515**	**0**	**515**	**8290**
Calpine	150 MW CT						150			150	300						300	150	300	300				150	300		300	150		2550
	WEP 545 MW CC		545			545					545										545									2180
	100 MW Biomass								200	200	100	200	300	100	300	100														1500
$27,017.2 MM	Calpine 523				523																									523
	WEP 515 MW Coal																						515		515	515			1030	2575
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**523**	**545**	**150**	**0**	**200**	**350**	**945**	**200**	**300**	**100**	**300**	**100**	**300**	**150**	**300**	**300**	**545**	**0**	**515**	**150**	**815**	**515**	**300**	**150**	**1030**	**9328**
ERGS w/o IGCC	150 MW CT									300	300				150	150	150					150		150	150				300	1800
	WEP 545 MW CC		545		545						545									545			545							2725
$27,356.6 MM	100 MW Biomass											200	200	200	100		100	200	200		100	100			100					1500
	WEP 515 MW Coal					515	515																			515	515		515	2575
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**545**	**515**	**515**	**0**	**0**	**300**	**845**	**200**	**200**	**200**	**250**	**150**	**250**	**200**	**200**	**545**	**100**	**250**	**545**	**150**	**250**	**515**	**515**	**0**	**815**	**8600**

Figure B-4 410 MW Wind by 2030

Appendix B, Summary of EGEAS Expansion Plans

Proposal	Unit Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals
Retire Coal at 60																														
Optimal	150 MW CT				150				300			300	150	150						450			150	150	300					2100
	WEP 545 MW CC		545			545											545													1635
$18,722.8 MM	100 MW Biomass																												200	200
	WEP 515 MW Coal						515			515					515				515		515		515			515	515		515	4635
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**150**	**545**	**515**	**0**	**300**	**515**	**0**	**300**	**150**	**150**	**515**	**0**	**545**	**0**	**515**	**450**	**515**	**0**	**665**	**150**	**300**	**515**	**515**	**0**	**715**	**8570**
Calpine	150 MW CT						150			150	150			150	150	300		150	450		300	150								2100
	WEP 545 MW CC		545			545																		545						1635
$18,736.3 MM	100 MW Biomass																												200	200
	Calpine 523				523																									523
	WEP 515 MW Coal								515			515					515			515			515		515	515	515		515	4635
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**523**	**545**	**150**	**0**	**515**	**150**	**150**	**515**	**0**	**150**	**150**	**300**	**515**	**150**	**450**	**515**	**300**	**150**	**515**	**545**	**515**	**515**	**515**	**0**	**715**	**9093**
ERGS w/o IGCC	150 MW CT									300	150	300	150	150						450			150	150	300					2100
	WEP 545 MW CC		545		545												545													1635
$18,825.2 MM	100 MW Biomass																												200	200
	WEP 515 MW Coal					515	515								515				515		515		515			515	515		515	4635
	WEP 500 MW IGCC																													0
	Totals	**0**	**545**	**0**	**545**	**515**	**515**	**0**	**0**	**300**	**150**	**300**	**150**	**150**	**515**	**0**	**545**	**0**	**515**	**450**	**515**	**0**	**665**	**150**	**300**	**515**	**515**	**0**	**715**	**8570**

Figure B-5 Other 410 MW Wind Runs

Appendix B, Summary of EGEAS Expansion Plans

Proposal	Unit Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals
Staff Base–Fox	150 MW CT						450				450			150	150	150			150		150	150	150	150						2100
	WEP 545 MW CC		545			545														545										1635
	100 MW Biomass																												200	200
$19,093.1 MM	Fox 260				260																									260
	WEP 515 MW Coal								515		515	515					515						515		515	515	515		515	4635
	WEP 500 MW IGCC																													0
	Totals	0	545	0	260	545	450	0	515	0	965	515	0	150	150	150	515	0	150	545	150	150	665	150	515	515	515	0	715	8830
Staff Base–ERGS	150 MW CT										150	150	300	150	300	150	150	150		150				150						1800
	WEP 545 MW CC		545		545						545																			1635
$19,423.4 MM	100 MW Biomass																													0
	WEP 515 MW Coal					515	515												515		515		515		515	515		515	515	4635
	WEP 500 MW IGCC								500																					500
	Totals	0	545	0	545	515	515	0	500	0	695	150	300	150	300	150	150	150	515	150	515	0	515	150	515	515	0	515	515	8570
No Nuke, No Coal	150 MW CT				150						450	150			150	150			150						150				150	1500
No Biomass	WEP 545 MW CC		545			545	545		545		545		545				545			545		545	545			545	545		545	7085
	100 MW Biomass																													0
$21,011.5 MM	WEP 515 MW Coal																													0
	WEP 500 MW IGCC																													0
	Totals	0	545	0	150	545	545	0	545	0	995	150	545	0	150	150	545	0	150	545	0	545	545	0	150	545	545	0	695	8585
No Nuke, No Coal	150 MW CT				150				300	300	300			150	150						150						150	300	300	2250
Biomass Limited	WEP 545 MW CC		545			545	545				545	545								545			545			545			545	4905
to 1,500 MW	100 MW Biomass															200	200	200	200			200	100	100	300					1500
	WEP 515 MW Coal																													0
$20,478.7 MM	WEP 500 MW IGCC																													0
	Totals	0	545	0	150	545	545	0	300	300	845	545	0	150	150	200	200	200	200	545	150	200	645	100	300	545	150	300	845	8655

Figure B-6 Unlimited Wind by 2030

Proposal	Unit Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals
With the Wind Tax Credit																														
Optimal	150 MW CT					150	450			300	900			150	150		150									300	300	150	150	3150
	WEP 545 MW CC		545			545																								1090
	100 MW Biomass																													0
$14,794.8 MM	Land Based Wind		400																		400	600	600	800	1400	200	1000		2200	7600
	Lake Michigan Wind								1000	500		1000	1000	500	500	500	500	1000	1000	3500	500	500	1000			500		500	1500	15500
	WEP 515 MW Coal																													0
	WEP 500 MW IGCC																													0
	Totals	0	945	0	0	695	450	0	1000	800	900	1000	1000	650	650	500	650	1000	1000	3500	900	1100	1600	800	1400	1000	1300	650	3850	27340
Calpine	150 MW CT						150			150	1050			150	300		150		150	300	150		150		150	300	300		300	3750
	WEP 545 MW CC		545			545																								1090
	100 MW Biomass																													0
$14,945.9 MM	Land Based Wind																								1200	600	200	600	1400	4000
	Lake Michigan Wind								1000	1000		1000	500	500		500	500	500	500	500	500	1000	4000		1000		500	500	1500	15500
	Calpine 523				523																									523
	WEP 515 MW Coal																													0
	WEP 500 MW IGCC																													0
	Totals	0	545	0	523	545	150	0	1000	1150	1050	1000	500	650	300	500	650	500	650	800	650	1000	4150	0	2350	900	1000	1100	3200	24863
ERGS w/o IGCC	150 MW CT									150	900	150	150			150	150	150	300	300	150		150					150	300	3150
	WEP 545 MW CC		545		545																									1090
	100 MW Biomass																													0
$15,547.1 MM	Land Based Wind																										400		1400	1800
	Lake Michigan Wind									500		500	500	500	1000	500	500				500	1000	2500	500	4000		500	1000	1500	15500
	WEP 515 MW Coal					515	515																							1030
	WEP 500 MW IGCC																													0
	Totals	0	545	0	545	515	515	0	0	650	900	650	650	500	1000	650	650	150	300	300	650	1000	2650	500	4000	0	900	1150	3200	22570

Proposal	Unit Description	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	Totals
NoWind Tax Credit																														
Optimal	150 MW CT				150				300		150	300	150	300		150	300	150	300	150	150	300	150	150		450	300	150		4050
	WEP 545 MW CC		545			545																								1090
	100 MW Biomass																													0
$18,028.8 MM	Land Based Wind														500					1500			1500	500	1000		500	500	4000	10000
	Lake Michigan Wind																													0
	WEP 515 MW Coal						515			515	515																			1545
	WEP 500 MW IGCC																													0
	Totals	0	545	0	150	545	515	0	300	515	665	300	150	300	500	150	300	150	300	1650	150	300	1650	650	1000	450	800	650	4000	16665
Calpine	150 MW CT						150			150	300	300	150	150	150	150	150	150	150	300	300		300	150	450	450	150			4050
	WEP 545 MW CC		545			545																								1090
	100 MW Biomass																													0
$17,699.7 MM	Land Based Wind																													0
	Lake Michigan Wind														500		500	500		500		1000	1500		1500		1500	1000	5000	13500
	Calpine 523				523																									523
	WEP 515 MW Coal								515		515																			1030
	WEP 500 MW IGCC																													0
	Totals	0	545	0	523	545	150	0	515	150	815	300	150	150	650	150	650	650	150	800	300	1000	1800	150	1950	450	1650	1000	5000	20193
ERGS w/o IGCC	150 MW CT									300	300	300	150	300		150	150	300		450	150	300	150	150		450	300	150	300	4350
	WEP 545 MW CC		545		545																									1090
	100 MW Biomass																													0
$18,128.6 MM	Land Based Wind																													0
	Lake Michigan Wind														500		500		500		500		1500	500	1000		500	500	2500	8500
	WEP 515 MW Coal					515	515				515																			1545
	WEP 500 MW IGCC																													0
	Totals	0	545	0	545	515	515	0	0	300	815	300	150	300	500	150	650	300	500	450	650	300	1650	650	1000	450	800	650	2800	15485

C

Appendix C – DNR 316(b) Determination for the OCER Station

**Determination of Applicability of
Cooling Water Intake Structure Regulations to the
WEPCO Facilities at Oak Creek and Elm Road
January 28, 2003**

Conslusion

Under the only currently applicable regulations, the additional Elm Road units do not meet all the conditions for a new facility as required by 40 CFR 125.83. As such, the "new facility" 316(b) regulatory requirements contained in 40 CFR 125.84 to 125.88 do not apply. For purposes of designing an intake structure modification of the Oak Creek-Elm Road (OCER) stations, the Department will refer to those standards given under the proposed 40 CFR 125, Subpart J in the April 9, 2002 Federal Register (pp. 17220-17225), and specifically those proposed at 40 CFR 125.94(b)(3) as guidance for establishing Best Technology Available (BTA) under s. 283.31(6), Stats. The WPDES permit for this facility will include requirements to assure that BTA is provided for this electrical generating station. Once the proposed federal regulation is finalized, a determination will be made to verify that the intake structure design meets BTA under the standards of the federal regulation and s. 283.31(6), Stats.

Introduction

On August 28, 2002, Wisconsin Energy Corporation (WE) requested that the U.S. Environmental Protection Agency (U.S. EPA) make a determination of applicability of s. 316(b) regulations (Clean Water Act) for the Oak Creek Power Plant and the proposed Elm Road Generating Station (see Attachment A). Section 316(b) requires that "the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." Prior to late 2001, neither U.S. EPA nor the State of Wisconsin had adopted rules further defining this standard.

The primary question in this WE request was whether the construction of additional generating capacity at Oak Creek Power Plant and the Elm Road Generating Station site requires application of the "new

facility" cooling water intake regulations published by U.S. EPA on December 18, 2001. If, as concluded by WE, the modification to this generating station is not a new facility in the context of this final regulation, then the best technology (BTA) standards and requirements in that regulation do not apply. EPA has proposed BTA regulations that will apply to "existing facilities" under s. 316(b) and a determination must be made regarding the applicability of those proposed rules to this facility including the modifications proposed by WE. EPA's schedule for promulgation of final rules for existing facilities is February 16, 2004.

On October 30, 2002, U.S. EPA responded to WE that this determination of applicability is part of the delegated permitting process under the National Pollutant Discharge Elimination System (see Attachment B). They stated that the Wisconsin DNR (in consultation with U.S. EPA-Region 5) should make this determination. This report contains the Department's review of the applicability of s. 316(b) regulations to the OCER facility.

Statutory Requirements

Section 316(b) of the Clean Water Act states:

> ***Cooling water intake structures.*** *Any standard established pursuant to section 1311 of this title or section 1316 of this title and applicable to a point source shall require that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. (33 U.S. Code Sec. 1326)*

Similarly, chapter 283 of the Wisconsin Statutes contain the following provision that implements the federal law under the authority of the Wisconsin Pollutant Discharge Elimination System program. Section 283.31(6) states:

> *Any permit issued by the department under this chapter which by its terms limits the discharge of one or more pollutants into the waters of the state may require that the location, design, construction and capacity of water intake structures reflect the best technology available for minimizing environmental impact.*

Application of s. 316(b) to the Oak Creek Power Plant

The Oak Creek Power plant is located on the Lake Michigan shoreline in the City of Oak Creek, just south of the City of Milwaukee. As noted in the WE letter, this facility operated as a 9 unit plant until the late 1980s. At that time, Units 1-4 were retired; Units 5-9 continue to operate. The cooling water intake at this location is at the shoreline and consists of a channel between the coal dock to the north and a breakwater structure on the south. Cooling water discharge is also at the shoreline south of the aforementioned breakwater.

In 1976, an investigation was conducted by Wisconsin Electric Power Company and a report submitted to the Department on the aquatic life impacts caused by the intake at the Oak Creek Power Plant. The report concluded (based on a one-year study of the power generation and aquatic life populations that existed at the time) that "it is apparent that entrapment of adult and juvenile fish, icthyoplankton, and benthic macroinvertebrates in the cooling water intake system of Oak Creek Power Plant causes at most

a very local reduction in abundance of these organisms. The impact on the environment must be considered to be minimal."[130] In an April 15, 1977 letter to Wisconsin Electric Power Company, the Department concurred with this conclusion. The Department has not reevaluated this conclusion since 1977.

Proposed Modifications to the Oak Creek Power Plant and Elm Road Generating Station

Wisconsin Energy Corporation's proposal for modifying the generating facilities at their Oak Creek site includes staged construction and operation as stated in their August 28, 2002, letter. Two additional coal-fired units and an integrated gasification combined cycle (IGCC) unit are proposed to be built on shoreline property contiguous or adjacent to the existing facility. One coal-fired unit would be constructed and be in operation in 2007, the second coal-fired unit would be operational in 2009 and the IGCC would come on line in about 2011. It is proposed that the additional units will share some of the existing (or relocated on the same property) coal handling facilities with expansions and modifications, as necessary. Tie-in to the existing power distribution system would also be shared on the site, again with necessary modifications and expansion of existing equipment.

With respect to the intakes, the first of the two new coal-fired units are proposed to share the existing intake structure with Units 5-9 while the new intake structure for the entire facility is being constructed. The proposal is to have both the existing and additional units use a single cooling water intake structure when in full operation.

S. 316(b) Regulations – New Facilities

Section 316(b) regulations for new facilities were published by U.S. EPA on December 18, 2001. Within that regulation, U.S. EPA defined a new facility as follows (see 40 CFR 125.83):

> *New facility means any building, structure, facility, or installation that meets the definition of a "new source" or "new discharger" in 40 CFR 122.2 and 122.29(b)(1), (2), and (4) and is a greenfield or stand-alone facility; commences construction after January 17, 2002; and uses either a newly constructed cooling water intake structure, or an existing cooling water intake structure whose design capacity is increased to accommodate the intake of additional cooling water. New facilities include only "greenfield" and "stand-alone" facilities. A greenfield facility is a facility that is constructed at a site at which no other source is located, or that totally replaces the process or production equipment at an existing facility (see 40 CFR 122.29(b)(1)(i) and (ii)). A stand-alone facility is a new, separate facility that is constructed on property where an existing facility is located and whose processes are substantially independent of the existing facility at the same site (see 40 CFR 122.29(b)(1)(iii)).* ***New facility does not include new units that are added to a facility for purposes of the same general industrial operation (for example, a new peaking unit at an electrical generating station).***
> *(1) Examples of "new facilities" include, but are not limited to: the following scenarios:*
> *(i) A new facility is constructed on a site that has never been used for industrial or commercial activity. It has a new cooling water intake structure for its own use.*

[130] "Oak Creek Power Plant Final Report on Intake Monitoring Studies Performed by Wisconsin Electric Power Company in Fulfillment of Conditions of WPDES Permit Number WI-0000914", June 1, 1976.

(ii) A facility is demolished and another facility is constructed in its place. The newly-constructed facility uses the original facility's cooling water intake structure, but modifies it to increase the design capacity to accommodate the intake of additional cooling water.
(iii) A facility is constructed on the same property as an existing facility, but is a separate and independent industrial operation. The cooling water intake structure used by the original facility is modified by constructing a new intake bay for the use of the newly constructed facility or is otherwise modified to increase the intake capacity for the new facility.
(2) Examples of facilities that would not be considered a "new facility" include, but are not limited to, the following scenarios:
(i) A facility in commercial or industrial operation is modified and either continues to use its original cooling water intake structure or uses a new or modified cooling water intake structure.
(ii) A facility has an existing intake structure. Another facility (a separate and independent industrial operation), is constructed on the same property and connects to the facility's cooling water intake structure behind the intake pumps, and the design capacity of the cooling water intake structure has not been increased. This facility would not be considered a "new facility" even if routine maintenance or repairs that do not increase the design capacity were performed on the intake structure. (emphasis added)

Elsewhere in the Federal Register preamble published when this regulation was made final, U.S. EPA includes the following explanatory discussion:

"Under 122.29(b), a source is a new source if it meets the definition of a new source in 122.2... and it meets any of three conditions... The first is that the source is constructed at a site at which no other source is located... The second is that the source totally replaces the process or production equipment that causes a discharge at an existing facility... The third is that the new source's processes are substantially independent of any existing source at the same site." (p. 65285)

"... the rule applies to greenfield and stand-alone facilities or those whose processes are substantially independent of an existing facility at the same site." (p. 65286)

"The definition of a new facility in the final rule applies to a facility that is repowered only if the existing facility has been demolished and another facility is constructed in its place, and modifies the existing cooling water intake structure to increase the design intake capacity." (p. 65286)

Section 316(b) Regulations – Existing Facilities

On April 9, 2002, U.S. EPA published proposed regulation to establish requirements for cooling water intake structures for existing (phase II) facilities under s. 316(b). Under a consent decree, U.S. EPA is required to publish a final regulation for existing facilities by February 16, 2004. These regulations, based on the volume of intake flow, would apply to the existing Oak Creek Power Plant, even without the proposed modifications.

In this proposal, U.S. EPA has defined existing facilities as follows:

"Existing facility means any facility that commenced construction before January 17, 2002; and
(1) Any modification of such a facility;
(2) Any addition of a unit at such a facility for purposes of the same industrial operation;

(3) *Any addition of a unit at such a facility for purposes of a different industrial operation, if the additional unit uses an existing cooling water intake structure and the design capacity of the intake structure is not increased; or*
(4) *Any facility constructed in place of such a facility, if the newly constructed facility uses an existing cooling water intake structure whose design intake flow is not increased to accommodate the intake of additional cooling water." (p. 17221)*

Within the preamble to this proposed regulation, they have included the following additional descriptions for existing facilities:

> *EPA has specified that any modification of a facility that commenced construction before January 17, 2002 remains an existing facility for purposes of this rule to clarify that significant changes to such a facility would not, absent other conditions, cause the facility to be a ``new facility" subject to the Phase I rule. In addition, the* ***proposed*** *definition specifies that any addition of a unit at a facility that commenced construction before January 17, 2002 for purposes of the same industrial operation as the existing facility would continue to be defined as an existing facility...Under this* ***proposed*** *rule certain forms of repowering could be undertaken by an existing power generating facility that uses a cooling water* ***intake*** *structure and it would remain subject to regulation as a Phase II existing facility. For example, the following scenarios would be existing facilities under the* ***proposed*** *rule: An existing power generating facility undergoes a modification of its process short of total replacement of the process and concurrently increases the design capacity of its existing cooling water* ***intake*** *structures; An existing power generating facility builds a new process for purposes of the same industrial operation and concurrently increases the design capacity of its existing cooling water* ***intake*** *structures... Thus, in most situations, repowering an existing power generating facility would be addressed under this* ***proposed*** *rule... (p. 17128)*

Discussion

The Department believes that the current intake at this facility may not meet currently acceptable standards for (BTA). Therefore, a new intake design or significant modifications to the existing intake operation may be necessary even if only the current units continue to operate. This review is based on the assumption that intake modifications will, as described previously, occur simultaneously with construction of the new Elm Road units.[131]

This determination of applicability is being made only to establish what specific performance standards will be used for the intake design at this facility, including the additional units. These performance standards will use the narrow definitions and application of 316(b), current federal regulations, and corresponding state law. In making this decision no determination has been made regarding the economic and environmental efficacy of this entire project or other aspects associated with the planned modifications at this facility. Any other factors associated with construction of this facility will be based on applicable regulatory standards.

The three additional coal-fueled units built at either the primary or alternate Elm Road sites will be within approximately 2,000 feet north or south of the existing units. WE plans to have the existing units and the new units, when the project is completed, share the intake with the existing units. The outfall location for

[131] For reasons of planning, design and construction and costs, modifications to the intake structure will be done simultaneously with the construction of the additional units.

the new units has been proposed north of the existing coal dock, directly to Lake Michigan. Some aspects associated with operation of the Elm Road units are not directly connected to or dependent on the existing facility.

Following is the Department's determination of the applicability of the "new facility" definition in 40 CFR 125.83 to the additional Elm Road units at this site:

1. This is a "new source" as defined in 40 CFR 122.2, because it will be constructed after promulgation of standards under section 306 of the Clean Water Act. It is not, however, a "new facility" for purposes of 316(b).
2. This is not a "greenfield" facility, because an existing power generating station is already on this site.[132]
3. This is not a stand-alone facility because, as defined in 40 CFR 125.83, the EPA regulation for a stand-alone facility "... does not include new units that are added to a facility for purposes of the same general industrial operation..." (i.e., the generation of electricity). Furthermore, there will be an integration of the existing and additional generating units. Common facilities shared between the existing and additional units will include the cooling water intake structure, coal delivery and handling systems and the electrical switchyard and substation. Most notably, the existing and additional units will share a common intake structure modified from its current configuration to meet operational needs and BTA.
4. Under current plans, the intake structure to supply water to existing units will be increased in capacity to accommodate the intake of additional water.

Therefore, under the only currently applicable regulations, the additional Elm Road units do not meet all the conditions for a new facility as required by 40 CFR 125.83. As such, the "new facility" 316(b) regulatory requirements contained in 40 CFR 125.84 to .88 do not apply.

If, as concluded above, the OCER proposal is not a new facility, then it must be an existing facility under the definition that states that an "Existing facility means any facility that commenced construction before January 17, 2002; and... (2) any addition of a unit at such a facility for purposes of the same industrial operation..." (40 CFR 125.93, proposed). In the preamble to this proposed regulation, it further explains, by example, that an existing facility is "an existing power generating facility [that] builds a new process for purposes of the same industrial operation and concurrently increases the design capacity of its existing cooling water intake structures" (p. 17128). The proposal to modify the intake structure to accommodate both the new and existing units further establishes the rationale for treating this permittee as an existing facility under 316(b) regulations.

In a prior instance, U.S. EPA determined that the addition of a unit at an existing power plant in San Francisco using the same intake structure was not a new facility. A memo dated January 11, 2003 from EPA's Engineering and Analysis Division to the Region 9 Water Division Director, states: "... addition of a new power generating unit or units at an electrical power generating station would not be a "new facility" under the CWA Section 316(b) rule for "new facilities."." The additional units at the OCER facility are, based on information available, similar to those for this power facility in California.

[132] Under 40 CFR 122.2: "Site" means the land or water area where any "facility or activity" is physically located or conducted, including adjacent land used in connection with the facility or activity.

Applicable requirements

No specific, final federal or state regulations are in place for facilities that are not defined as new facilities. Therefore, only the general statutory requirement for BTA contained in 316(b), CWA, and s. 283.31(6), Stats., apply to the intake at this site.
However, the Department believes that the existing intake for this permittee does not meet the statutory standard to "minimize environmental impact" (s. 283.31(6), Stats.) and changes are necessary to meet BTA. Regardless of the characterization of the additional units as new or existing under the 316(b) regulations, the intake structure must attain this BTA standard. Absent a specific federal regulatory standard, the Department must, therefore, establish the criteria or performance standard that will be used to design an intake structure that will meet this BTA statutory requirement. Accordingly, the Department believes that U.S. EPA's proposed performance standards for intakes at existing facilities contained in the Federal Register of April 9, 2002 are the most reasonable available criteria for BTA. No data currently available to the Department demonstrates that another performance standard better represents BTA for this type of intake system.

Therefore, for purposes of designing the intake structure for the OCER stations, the Department will require compliance with those standards given under the proposed 40 CFR 125, Subpart J in the April 9, 2002 Federal Register (pp. 17220-17225). These standards, once final regulations are promulgated, will be used to establish BTA under s. 283.31(6), Stats. A site-specific BTA determination for the OCER facility, using specifically the provision at proposed 40 CFR 125.94(b)(3), will be made as part of the WPDES permitting process using the proposed standards to assure environmental impacts caused by the intake are minimized.

Wisconsin Energy has proposed to attain the objectives of BTA by construction of an off-shore intake to replace the existing intake structure at the shoreline. The conclusions presented here are not a determination of whether such an intake will meet the applicable criteria for Best Technology Available. Specific design parameters will be established during the Department's review of this project to assure that any intake structure meets the statutory requirement for such facilities including any final state or federal regulations applicable at the time.

Other Related Issues

This determination of applicability is not intended to have any effect on the determination of whether this facility is a new source or new discharger for the purposes of regulating the discharge of pollutants in the WPDES permit. The discharge from the facility will be required, under their WPDES permit, to meet effluent limitations derived from state water quality standards including criteria for temperature. Temperature water quality standards revisions are currently under development and these new standards will, when formally adopted, apply to this facility.

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D

Appendix D – Air Emissions Data

Best Available Control Technology (BACT) for Pollutant Emission Sources and Proposed Emission Limits

This appendix includes tabulated lists of WEPCO's proposed BACT for each piece of equipment listed in Table 7-12 in Chapter 7. Tables D-1 through D-23 list proposed BACT and proposed emission limits for each pollutant in the DNR PSD review.[133]

The tables are presented first for the North Site, then for the South Sites. BACT for the South Sites is identical to that presented in the draft EIS and in WEPCO's June 27, 2003 submittal in support of its air pollution control permit application. The proposed emission limits for the South Sites' SCPC exhaust stacks were changed as part of WEPCO's compliance with FAA requests. BACT for the North Site has refinements that were provided by WEPCO in its June 2, 2003 submittal. The emission sources for the North and South Sites are described in Chapter 7.

The tables below are based on WEPCO's application materials and not DNR modeling.

North Site:

D-1	BACT and proposed emission limits for SCPC boiler emissions at the North Site
D-2	BACT and proposed emission limits for the auxiliary boiler for the SCPC boiler at the North Site
D-3	BACT and proposed emission limits for the auxiliary boiler for the IGCC boiler at the North Site
D-4	BACT and proposed emission limits for diesel generators at the North Site
D-5	BACT and proposed emission limits for diesel fire pumps at the North Site
D-6	BACT and proposed emission limits for the IGCC combined cycle plant at the North Site
D-7	BACT for inactive coal storage piles at the North Site
D-8	BACT for gypsum handling system at the North Site
D-9	BACT for limestone handling system at the North Site
D-10	BACT for coal material handling point sources at the North Site

[133] All information in the tables of this appendix is subject to review by the DNR. With the timing of the submittals, the DNR has not been able to complete its modeling work. In fact, WEPCO does not yet have complete applications before the DNR for the four site variations.

D-11 BACT for ash material handling point sources at the North Site
D-12 BACT and proposed limits for SCPC boiler emissions at the South Sites
D-13 BACT and proposed limits for the auxiliary boiler for the SCPC boiler at the South Sites
D-14 BACT and proposed limits for the auxiliary boiler for the IGCC boiler at the South Sites
D-15 BACT and proposed limits for diesel generators at the South Sites
D-16 BACT for diesel fire pump at the South Sites
D-17 BACT and proposed emission limits for the IGCC combined cycle plant at the South Sites
D-18 BACT for inactive coal storage piles at the South Sites
D-19 BACT for gypsum handling system at the South Sites
D-20 BACT for limestone handling system at the South Sites
D-21 BACT for urea material handling point sources at the South Sites
D-22 BACT for coal material handling point sources at the South Sites
D-23 BACT for ash material handling point sources at the South Sites

North Site and CUP

Tables D-1 through D11 in this section apply to the North Site.

Table D-1 BACT and proposed emission limits for SCPC boiler emissions at the North Site

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
CO	Low NO_x burners and good combustion practices	0.12 lb/mmBtu or 742 lbs/hr *See Note 1*
NO_x	Low NO_x burners selective catalytic reduction	0.07 lb/mmBtu < 5 ppmdv ammonia *See Note 2*
PM	Fabric filter baghouse and flue gas desulfurization	0.018 lb/mmBtu 20% opacity *See Note 3*
PM_{10}	Fabric filter baghouse and flue gas desulfurization	0.018 lb/mmBtu 20% opacity *See Note 3*
SO_2	Wet flue gas desulfurization	0.16 lb/mmBtu and 3,708 lbs/hr *See Notes 2 and 5*
VOC *See Note 4*	Low NOx burners and good combustion practices	0.0035 lb/mmBtu or 21.6 lbs/hr *See Notes 1 and 6*
Pb	Fabric filter baghouse and flue gas desulfurization	7.9 lb/trillion Btu *See Note 3*
Hg	Fabric filter baghouse and flue gas desulfurization	2.3 lb/trillion Btu *See Note 2*
Be	Fabric filter baghouse and flue gas desulfurization	0.35 lb/trillion Btu *See Note 2*
Fluorides	Fabric filter baghouse and flue gas desulfurization	0.00088 lb/mmBtu *See Note 2*
Sulfuric Acid Mist (H_2SO_4)	Flue gas desulfurization and wet electrostatic precipitator	Lb/mmBtu *See Note 2*

Note 1: Based on an 8-hour average
Note 2: Based on a 12 month rolling average limit
Note 3: Based on a 3 hour block average limit
Note 4: This limit is based on a 96 percent reduction in the emission rate of the design bituminous coal.
Note 5: Based on a 24 hour average.
Note 6: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table D-2 BACT and proposed emission limits for the auxiliary boiler for the SCPC boiler at the North Site

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
CO	Low NO_x burners and good combustion practices	0.075 lb/mmBtu *See Note 1*
NO_x	Low NO_x burners	0.0.036b/mmBtu when firing natural gas; 0.0.120lb/mmBtu when firing fuel oil *See Note 1*
PM	Good combustion practices and natural gas or fuel oil with <.0.003% sulfur	0.007lb/mmBtu when firing natural gas; 0.050 lb/mmBtu when firing fuel oil
PM_{10}	Good combustion practices and natural gas or fuel oil with <0.003% sulfur	0.007lb/mmBtu when firing natural gas; 0.0050 lb/mmBtu when firing fuel oil
SO_2	Natural gas or fuel oil with <0.0 03% sulfur	0.024lb/mmBtu when firing natural gas; 0.0.0032 lb/mmBtu when firing fuel oil
VOC *See Note 2*	Low NOx burners and good combustion practices	0.006lb/mmBtu when firing natural gas; 0.005 lb/mmBtu when firing fuel oil
Pb	Natural gas or fuel oil with <0.003% sulfur	2.4E-08 lb/mmBtu when firing natural; 0.000009 lb/mmBtu when firing fuel oil
Hg	Natural gas or fuel oil with <0.003% sulfur	2.6E-07 lb/mmbtu when firing natural gas; 0.000003 lb/mmBtu when firing fuel oil
H_2SO_4 mist	Natural gas or fuel oil with <0.0.003% sulfur	0.00024 lb/mmBtu when firing natural gas; 0.00064 lb/mmBtu when firing fuel oil *See Note 1*

Note 1: Based on an 30-day rolling average
Note 2: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.
Note 3: Total fuel heat input may exceed 498,000 mmBtu per year, of which no more than 122,500 mmBtu per year may be from the combustion of distillate fuel oil. This limit shall be based on a 12-month rolling average.

Table D-3 BACT and proposed emission limits for the auxiliary boiler for the IGCC boiler at the North Site

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
CO	Low NO_x burners and good combustion practices	0.045 lb/mmBtu when firing natural gas or fuel oil *(See Note 1)*
NO_x	Low NO_x burners	0.05lb/mmBtu when firing natural gas; 0.09 lb/mmBtu when firing fuel oil *(See Note 1)*
PM	Good combustion practices and natural gas or fuel oil with <0.003% sulfur	0.007lb/mmBtu when firing natural gas; 0.02 lb/mmBtu when firing fuel oil
PM_{10}	Good combustion practices and natural gas or fuel oil with <0.003% sulfur	0.007lb/mmBtu when firing natural gas; 0.02 lb/mmBtu when firing fuel oil
SO_2	Natural gas or fuel oil with <0.003% sulfur	0.0.0012lb/mmBtu when firing natural gas; 0.0.0032 lb/mmBtu when firing fuel oil
VOC *(See Note 2)*	Low NO_x burners and good combustion practices	0.006lb/mmBtu when firing natural gas; 0.002 lb/mmBtu when firing fuel oil
Pb	Natural gas or fuel oil with <0.003% sulfur	2.6E-08 lb/mmBtu when firing natural gas; 0.000009 lb/mmBtu when firing fuel oil
Hg	Natural gas or fuel oil with <0.003% sulfur	2.6E-07 lb/mmBtu when firing natural gas; 0.000003 lb/mmBtu when firing fuel oil
H_2SO_4	Natural gas or fuel oil with <0.003% sulfur	0.00024 lb/mmBtu when firing natural gas; 0.00064 lb/mmBtu when firing fuel oil *(See Note 1)*

Note 1: Based on an 30-day rolling average
Note 2: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table D-4 BACT and proposed emission limits for diesel generators at the North Site

Pollutant	Proposed Control Technology (BACT)	Proposed Limit
CO	New diesel engine design	41.2 lbs/hr *See Note 1*
NO_x	New diesel engine design	6.9 g/hp-hr 33.4 lbs/hr *See Note 1*
PM	Fuel oil with <0.003% sulfur	1.9 lbs/hr *See Note 1*
PM_{10}	Fuel oil with <0.003% sulfur	1.9lbs/hr *See Note 1*
SO_2	Fuel oil with <0.003% sulfur	0.2 lb/hr *See Note 1*
VOC *See Note 2*	Good combustion practices	4.8lbs/hr *See Note 2*
Pb	Fuel oil with <0.003% sulfur	*See Note 1*
Hg	Fuel oil with <0.003% sulfur	*See Note 1*
HF	Fuel oil with <0.003% sulfur	*See Note 1*
H_2SO_4	Fuel oil with <0.003% sulfur	*See Note 1*

Note 1: Operating limit of 500 hours per year
Note 2: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table D-5 BACT and proposed emission limits for diesel fire pumps at the North Site

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
CO	New diesel engine design	3.4/hr *See Note 1*
NO_x	New diesel engine design	14.0 lbs/hr *See Note 1*
PM	Fuel oil with <.0.003% sulfur	.0.21 lb/hr *See Note 1*
PM_{10}	Fuel oil with <.0.003% sulfur	0.21 lb/hr *See Note 1*
SO_2	Fuel oil with <.0.003% sulfur	0.0055 lb/hr *See Note 1*
VOC *See Note 2*	Good combustion practices	0.31 lb/hr *See Note 2*
Pb	Fuel oil with <0.003% sulfur	*See Note 1*
Hg	Fuel oil with <0.003% sulfur	*See Note 1*
HF	Fuel oil with <0.003% sulfur	*See Note 1*
H_2SO_4	Fuel oil with <0.003% sulfur	0.001 lb/hr *See Note 1*

Note 1: Operating limit of 500 hours per year
Note 2: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table D-6 BACT and proposed emission limits for the IGCC combined cycle plant at the North Site

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
CO	Good combustion practices	15 ppm; 0.030 lb/mmBtu
NO_x	Diluent injection	15 ppm; 0.030 lb/mmbtu

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
PM	Good combustion practices, syngas fuel	23 lbs/hr; 0.011 lb/mmbtu
PM_{10}	Good combustion practices, syngas fuel	23 lbs/hr; 0.011 lb./mmbtu
SO_2	IGCC process & gas cleanup	40 ppm sulfur in gasified fuel; 0.030 lb/mmBtu
VOC See Note 2	Good combustion practices	8.9 lbs/hr; 0.004 lb/mmBtu
Pb	Good combustion practices	26 lb/trillion Btu
Hg	IGCC & gas clean up	0.0005 lb/mmBtu

Note 1: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table D-7 BACT for inactive coal storage piles at the North Site

Source Description	Proposed Control Technology (BACT)
Inactive coal pile A reclaim/maintenance (S29)	Wet suppression
Inactive coal pile B reclaim/maintenance (S30)	Wet suppression
Inactive coal pile A wind erosion for pile A reclaim (S29B)	Compaction and wet suppression or cover
Inactive coal pile B s wind erosion for pile B reclaim (S30B)	Compaction and wet suppression or cover
Inactive coal pile A drop point (S34)	Covered conveyor, telescoping chute and wet suppressions
Inactive coal pile B drop point (S36)	Covered conveyor, telescoping chute and wet suppression

Table D-8 BACT for gypsum handling system at the North Site

Source Description	Proposed Control Technology (BACT)
Gypsum storage pile @barge dock -wind erosion (S121)	Tarp and wet suppression
Gypsum storage pile @barge dock - reclaim/maintenance (S121B)	Covered conveyor and telescoping chute
Gypsum stakeout conveyor drop at dock (S122)	Covered conveyor and telescoping chute
Gypsum loading into barge-drop (S125)	None
Gypsum pile and barge dock-pile reclaim to loading hopper (S123)	Supplemental wet suppression
Gypsum Xfr Twr No. 1 Dust Coll (S149)	Vent filter, 0.005 gr/acf
Gypsum Xfr Twr No. 2 Dust Collector (S150)	Vent filter 0.005 gr/acf,
Gypsum Hopper dust collector (S171)	Vent filter, 0.004 gr/acf
Gypsum building ventilator fan No. 1 (S104)	None
Gypsum building ventilator fan No. 2 (S105)	None

Table D-9 BACT for limestone handling system at the North Site

Source Description	Proposed Control Technology (BACT)
Lime barge unload (S37)	Enclosed clamshell
Limestone pile (S38)	Telescoping chute
Limestone storage pile (S33)	-
Limestone Pile (S33B)	-
Limestone prep building dust collector (S47) and limestone loading table insertable dust collector (S172)	Baghouse, 99% control efficiency, 0.004 gr/acf

Table D-10 BACT for coal material handling point sources at the North Site

Source Description	Proposed Control Technology (BACT)
Crusher house dust collector No. 1 (S23)	Baghouse, 99% control, 0.004 gr/acf
Crusher house dust collector No. 2 (S24)	Baghouse, 99% control, 0.004 gr/acf
Existing junction house 7/8 dust collector (S28)	Baghouse, 99% control, 0.004 gr/acf
Tripper room dust collector Unit No. 2 (S49)	Baghouse, 99% control, 0.004 gr/acf
Transfer tower No. 3 dust collector & tripper room unit 1 DC (S48)	Baghouse, 99% control, 0.004 gr/acf
Transfer house No. 5 dust collector (S58)	Baghouse, 99% control, 0.004 gr/acf
IGCC coal silos duct collector 1 (S59a)	Baghouse, 99% control, 0.004 gr/acf
IGCC coal silos dust collector 2 (S59b)	Baghouse, 99% control, 0.004 gr/acf
Transfer House #5 Dust Collector (S66)	Baghouse. 99% control, 0.004 gr/acf

Table D-11 BACT for ash material handling point sources

Number	Source Description	Proposed Control technology
S27	Fly ash silo 1 exhaust fan	Vent filter, 99% control, 0.01 gr/acf
S65	Fly ash silo 2 exhaust fan	Vent filter, 99% control, 0.01 gr/acf
S169a	Fly Ash Silo No. 1 Vacuum Exhauster a	Vent filter, 0.02 gr/acf
S169b	Fly Ash Silo No. 1 Vacuum Exhauster b	Vent filter, 0.02 gr/acf
S170a	Fly Ash Silo No. 2 Vacuum Exhauster a	Vent filter, 0.02 gr/acg
S170b	Fly Ash Silo No. 2 Vacuum Exhauster b	Vent filter, 0.02 gr/acf
S109	Ash reburn building exhaust fan	Vent filter, 99% control, 0.01 gr/acf

South Sites

Tables D-12 through D-21 in this section apply to the South Site and South Site-Exp. The information on the South Sites remains the same as that discussed in Chapter 7 of the draft EIS except for changes in stack heights and emission rates for SO_2.[134]

Table D-12 BACT and proposed limits for SCPC boiler emissions at the South Sites

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
CO	Low NO_x burners and good combustion practices	0.12 lb/mmBtu or 742 lbs/hr *See Note 1*
NO_x	Low NO_x burners selective catalytic reduction	0.07 lb/mmBtu < 5 ppmdv ammonia *See Note 2*
PM	Fabric filter baghouse and flue gas desulfurization	0.018 lb/mmBtu 20% opacity *See Note 3*
PM_{10}	Fabric filter baghouse and flue gas desulfurization	0.018 lb/mmBtu 20% opacity *See Note 3*
SO_2	Wet flue gas desulfurization	0.16 lb/mmBtu and 3,708 lbs/hr *See Notes 2 and 5*

[134] WEPCO, in its June 27, 2003 submittal in support of its air pollution control permit application, indicated that the should not include the "refinements" indicated for the North sites but that they should include the lowered stack heights to comply with the FAA and the lowered SO_2 emission rates.

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
VOC *See Note 4*	Low NOx burners and good combustion practices	0.0035 lb/mmBtu or 21.6 lbs/hr *See Notes 1 and 6*
Pb	Fabric filter baghouse and flue gas desulfurization	7.9 lb/trillion Btu *See Note 3*
Hg	Fabric filter baghouse and flue gas desulfurization	2.3 lb/trillion Btu *See Note 2*
Be	Fabric filter baghouse and flue gas desulfurization	0.35 lb/trillion Btu *See Note 2*
Fluorides	Fabric filter baghouse and flue gas desulfurization	0.00088 lb/mmBtu *See Note 2*
Sulfuric Acid Mist (H_2SO_4)	Flue gas desulfurization and wet electrostatic precipitator	Lb/mmBtu *See Note 2*

Note 1: Based on an 8-hour average
Note 2: Based on a 12 month rolling average limit
Note 3: Based on a 3 hour block average limit
Note 4: This limit is based on a 96 percent reduction in the emission rate of the design bituminous coal.
Note 5: Based on a 24 hour average.
Note 6: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table D-13 BACT and proposed limits for the auxiliary boiler for the SCPC boiler at the South Sites

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
CO	Low NO_x burners and good combustion practices	0.045 lb/mmBtu *See Note 1*
NO_x	Low NO_x burners	0.05lb/mmBtu when firing natural gas; 0.09 lb/mmBtu when firing fuel oil *See Note 1*
PM	Good combustion practices and natural gas or fuel oil with <0.05% sulfur	0.007lb/mmBtu when firing natural gas; 0.02 lb/mmBtu when firing fuel oil
PM_{10}	Good combustion practices and natural gas or fuel oil with <0.05% sulfur	0.007lb/mmBtu when firing natural gas; 0.02 lb/mmBtu when firing fuel oil
SO_2	Natural gas or fuel oil with <0.05% sulfur	0.024lb/mmBtu when firing natural gas; 0.056 lb/mmBtu when firing fuel oil
VOC *See Note 2*	Low NOx burners and good combustion practices	0.006lb/mmBtu when firing natural gas; 0.002 lb/mmBtu when firing fuel oil
Pb	Natural gas or fuel oil with <0.05% sulfur	-
Hg	Natural gas or fuel oil with <0.05% sulfur	-
HF	Natural gas or fuel oil with <0.05% sulfur	-
H_2SO_4 mist	Natural gas or fuel oil with <0.05% sulfur	0.00024 lb/mmBtu when firing natural gas; 0.0005 lb/mmBtu when firing fuel oil *See Note 1*

Note 1: Based on an 30-day rolling average
Note 2: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table D-14 BACT and proposed limits for the auxiliary boiler for the IGCC boiler at the South Sites

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
CO	Low NO_x burners and good combustion practices	0.045 lb/mmBtu *See Note 1*
NO_x	Low NO_x burners	0.05lb/mmBtu when firing natural gas; 0.09 lb/mmBtu when firing fuel oil

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
		See Note 1
PM	Good combustion practices and natural gas or fuel oil with <0.05% sulfur	0.007lb/mmBtu when firing natural gas; 0.02 lb/mmBtu when firing fuel oil
PM_{10}	Good combustion practices and natural gas or fuel oil with <0.05% sulfur	0.007lb/mmBtu when firing natural gas; 0.02 lb/mmBtu when firing fuel oil
SO_2	Natural gas or fuel oil with <0.05% sulfur	0.024lb/mmBtu when firing natural gas; 0.056 lb/mmBtu when firing fuel oil
VOC *See Note 2*	Low NO_x burners and good combustion practices	0.006lb/mmBtu when firing natural gas; 0.002 lb/mmBtu when firing fuel oil
Pb	Natural gas or fuel oil with <0.05% sulfur	-
Hg	Natural gas or fuel oil with <0.05% sulfur	-
HF	Natural gas or fuel oil with <0.05% sulfur	-
H_2SO_4	Natural gas or fuel oil with <0.05% sulfur	0.00024 lb/mmBtu when firing natural gas; 0.0005 lb/mmBtu when firing fuel oil *See Note 1*

Note 1: Based on an 30-day rolling average
Note 2: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table D-15 BACT and proposed limits for diesel generators at the South Sites

Pollutant	Proposed Control Technology (BACT)	Proposed Limit
CO	New diesel engine design	6.7 lbs/hr *See Note 1*
NO_x	New diesel engine design	6.9 g/hp-hr 29.0 lbs/hr *See Note 1*
PM	Fuel oil with <0.05% sulfur	1.2 lbs/hr *See Note 1*
PM_{10}	Fuel oil with <0.05% sulfur	1.2 lbs/hr *See Note 1*
SO_2	Fuel oil with <0.05% sulfur	0.7 lb/hr *See Note 1*
VOC See Note 2	Good combustion practices	3.6 lbs/hr *See Note 2*
Pb	Fuel oil with <0.05% sulfur	*See Note 1*
Hg	Fuel oil with <0.05% sulfur	*See Note 1*
HF	Fuel oil with <0.05% sulfur	*See Note 1*
H_2SO_4	Fuel oil with <0.05% sulfur	*See Note 1*

Note 1: Operating limit of 500 hours per year
Note 2: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table D-16 BACT for diesel fire pump at the South Sites

Pollutant	Proposed Control Technology (BACT)	Proposed Limits	
CO	New diesel engine design	3.5s/hr	See Note 1
NO_x	New diesel engine design	13 lbs/hr	See Note 1
PM	Fuel oil with <0.05% sulfur	0.41 lb/hr	See Note 1
PM_{10}	Fuel oil with <0.05% sulfur	0.41 lb/hr	See Note 1
SO_2	Fuel oil with <0.05% sulfur	0.11 lb/hr	See Note 1
VOC *See Note 2*	Good combustion practices	0.34 lbs/hr	See Note 2
Pb	Fuel oil with <0.05% sulfur	See Note 1	
Hg	Fuel oil with <0.05% sulfur	See Note 1	

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
HF	Fuel oil with <0.05% sulfur	See Note 1
H_2SO_4	Fuel oil with <0.05% sulfur	See Note 1

Note 1: Operating limit of 500 hours per year

Note 2: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table D-17 BACT and proposed emission limits for the IGCC combined cycle plant at the South Sites

Pollutant	Proposed Control Technology (BACT)	Proposed Limits
CO	Good combustion practices	15 ppm; 0.030 lb/mmBtu
NO_x	Diluent injection	15 ppm; 0.030 lb/mmbtu
PM	Good combustion practices, syngas fuel	23 lbs/hr; 0.011 lb/mmbtu
PM_{10}	Good combustion practices, syngas fuel	23 lbs/hr; 0.011 lb./mmbtu
SO_2	IGCC process & gas cleanup	40 ppm sulfur in gasified fuel; 0.030 lb/mmBtu
VOC See Note 2	Good combustion practices	8.9 lbs/hr; 0.004 lb/mmBtu
Pb	Good combustion practices	26 lb/trillion Btu
Hg	IGCC & gas clean up	0.0005 lb/mmBtu

Note 1: This limit represents the lowest achievable emission rate as required under s. NR 408, Wis. Adm. Code.

Table D-18 BACT for inactive coal storage piles at the South Sites

Source Description	Proposed Limits
Inactive coal pile A reclaim	Wet suppression
Inactive coal pile B reclaim	Wet suppression
Inactive coal pile A storage	Compaction and wet suppression or cover
Inactive coal pile B storage	Compaction and Wet suppression or cover
Inactive coal pile A drop point	Covered conveyor, telescoping chute and wet suppressions
Inactive coal pile B drop point	Covered conveyor, telescoping chute and wet suppression

Table D-19 BACT for gypsum handling system at the South Sites

Source Description	Proposed Limits
Gypsum dock-side storage pile	Tarp and water suppression
Gypsum dockside pile drop point	Covered conveyor and telescoping chute
Gypsum barge loading drop point	Covered conveyor and telescoping chute
Gypsum barge loading activities	Supplemental wet suppression
Gypsum wallboard plant drop point	Covered conveyor, telescoping chute
Gypsum wallboard plant reclaim	Supplemental wet suppression
Gypsum wallboard plant storage pile	Tarp and wet suppression
Gypsum building exhaust fan No. 1	Vent filter, 99% control, 0.01 gr/acf
Gypsum building exhaust fan No. 2	Vent filter, 99% control, 0.01 gr/acf
Gypsum building exhaust fan No. 3	Vent filter, 99% control, 0.01 gr/acf

Table D-20 BACT for limestone handling system at the South Sites

Source Description	Proposed Limits
Limestone transfer hopper drop point	Partially enclosed drop point
Limestone barge unloading	Enclosed hydraulic clamshell

Source Description	Proposed Limits
Limestone storage pile drop point	Covered conveyor and telescoping chute
Limestone storage pile and reclaim	Wet suppression
Limestone prep building dust collector	Baghouse, 99% control efficiency, 0.004 gr/acf

Table D-21 BACT for urea material handling point sources at the South Sites[135]

Source Description	Proposed Control Technology (BACT)
Urea silo exhaust fan	Vent filter, 99% control, 0.01 gr/acf
Urea storage bin No. 1 exhaust fan	Vent filter, 99% control, 0.01 gr/acf
Urea storage bin No. 2 exhaust fan	Vent filter, 99% control, 0.01 gr/acf
Urea storage bin No. 3 exhaust fan	Vent filter, 99% control, 0.01 gr/acf

Table D-22 BACT for coal material handling point sources at the South Sites

Source Description	Proposed Control Technology (BACT)
Crusher house dust collector No. 1	Baghouse, 99% control, 0.004 gr/acf
Crusher house dust collector No. 2	Baghouse, 99% control, 0.04 gr/acf
Existing junction house 7/8 dust collector	Baghouse, 99% control, 0.04 gr/acf
Transfer tower No. 4 and tripper room Unit No. 1 DC	Baghouse, 99% control, 0.04 gr/acf
Tripper room dust collector Unit No. 2	Baghouse, 99% control, 0.04 gr/acf
Transfer tower No. 3 dust collector	Baghouse, 99% control, 0.04 gr/acf
Transfer house No. 5 dust collector	Baghouse, 99% control, 0.04 gr/acf
IGCC coal Silos duct collector 1	Baghouse, 99% control, 0.04 gr/acf
IGCC coal silos dust collector 2	Baghouse, 99% control, 0.04 gr/acf
Coal ship unloading boom to hopper dust collector	Baghouse, 99% control, 0.04 gr/acf
Transfer house No. 6 dust collector	Baghouse, 99% control, 0.04 gr/acf
Transfer house No. 7 duct collector – alternate site only	Baghouse, 99% control, 0.04 gr/acf
Coal car dumper dust collector No. 1	Baghouse, 99% control, 0.04 gr/acf
Coal car dumper dust collector No. 2	Baghouse, 99% control, 0.04 gr/acf
Coal storage building dust collectors stack	Baghouse, 99% control, 0.04 gr/acf0.004

Table D-23 BACT for ash material handling point sources at the South Sites

Number	Source Description	Proposed Control technology
S27	Fly ash silo 1 exhaust fan	Vent filter, 99% control, 0.01 gr/acf
S65	Fly ash silo 2 exhaust fan	Vent filter, 99% control, 0.01 gr/acf
S114	Fly ash storage building	Baghouse, 99% control, 0.04 gr/acf
S109	Ash reburn building exhaust fan	Vent filter, 99% control, 0.01 gr/acf

[135] WEPCO indicated in its June 2, 2003 submittal for the air permit that the urea handling point sources are not under consideration at the North Site. It indicated in its June 27, 2003 submittal for the air permit that BACT for the South Sites would not change.

WEPCO's Air Quality Modeling Results[136]

Tables D-24 through D32 show the results of WEPCO's air quality modeling as of June 27, 2003. The DNR is reviewing the information and will complete its own modeling. The tables in this appendix are of two types: air quality modeling compared with the NAAQS, and PSD increment modeling compared with the Class II PSD increments. Each type of table is included for each proposed ERGS site. The last two lines in each table indicate the direction and distances of the greatest air pollution impact from the sources.

Table D-24 Air quality modeling results for the ERGS at the North Site (original site layout)*

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO_2 3 – hour	SO_2 24 - hour	SO_2 Annual	NO_2 Annual
Maximum concentration (ug/m3)	65.99	7.98	72.26	0.00157	649.78	165.31	5.71	30.35
Background concentration (ug/m3)	58	27	76	NA	208.10	57.80	9.30	31.00
Total concentration (ug/m3)	123.99	34.98	148.26	0.00157	857.88	223.11	15.01	61.35
NAAQS standard (ug/m3)	150	50	150	1.5	1,300	365	80	100
Percent (%) of NAAQS	82.7%	69.9%	98.8%	-	65.9%	61.1%	18.8%	61.35%
Impact UTM easting (m)	432,,542	432,542	432.542	429,092	429,692	429,192	429,092	432,395
Impact UTM northing (m)	4,743,400	4,743,550	4,743,400	4,743,400	4,747,400	4,747,200	4,746,800	4,743,650

*** Based on WEPCO information supplied to the DNR in December 2002, and on June 2, 2003.**

Table D-25 PSD increment modeling results for the ERGS at the North Site (original site layout)*

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	NO_2 Annual	SO_2 3 - hour	SO_2 24 - hour	SO_2 Annual
PSD Class II Increment Concentration (ug/m3)	30	17	25	512	91	20
Maximum Elm Road Project Only Concentration (ug/m3)	27.45	5.03	1.14	239.09	76.86	4.30
Percent (%) of Class II Increment	91.5%	29.6%	5.0%	46.7%	84.5%	21.5%
Maximum Cumulative Concentration (ug/m3)	27.45	5.03	1.14	239.09	76.86	4.30

[136] The information in WEPCO's December 2002 air pollution control permit applications for the North Site, South Site, and South Site-Exp was supplemented or replaced in subsequent submittals dated: April 16, 2003 for the, June 2, 2003 for the North Site, and June 27, 2003 to differentiate the North and South Sites. A WEPCO submittal on July 2, 2003 requests that the BACT and emission limits for the be made the same as the corresponding BACT and emission limits for the North Site. The DNR is reviewing the information, and has determined that the applications are still incomplete. The DNR is currently reviewing this information and will provide an update on its review at the CPCN Hearing proceedings.

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	NO_2 Annual	SO_2 3 - hour	SO_2 24 - hour	SO_2 Annual
Percent (%) of Class II Increment	91.5%	29.6%	5.0%	46.7%	84.5%	21.5%
Cumulative Impact UTM Easting (m)	43,083.59	431,452.69	432,278	430,292	429,792	431,792
Cumulative Impact UTM Northing (m)	4,744,085.5 0	4,743,201	4,744,273	4,742,950	4,746,800	4,742,900

*** Based on WEPCO information supplied to the DNR in December 2002, and on June 2, 2003.**

Table D-26 Air quality modeling results for the ERGS at the North Site (with the CUP Option layout)

Pollutant	PM_{10} 24-hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO_2 3- hour	SO_2 24- hour	SO_2 Annual	NO_2 Annual
Maximum concentration (ug/m3)	64.36	7.82	66.48	0.00	555.71	139.24	5.92	29.63
Background concentration (ug/m3)	58	27	76	NA	208.10	57.80	9.30	31.00
Total concentration (ug/m3)	122.36	34.82	142.48	0.00	763.81	197.04	15.22	60.63
NAAQS standard (ug/m3)	150	50	150	1.5	1,300	365	80	100
Percent of NAAQS	81.6%	69.6%	94.99%	-	58.8%	53.9%	19.0%	60.63%
Impact UTM easting (m)	432,542	431,542	432,542	429,092	429,692	429,192	429,192	432,543
Impact UTM northing (m)	4,743,400	4,743,550	4,743,400	4,746,800	4,747,400	4,747,200	4,746,800	4,743,550

Table D-27 PSD increment modeling results for the ERGS at the North Site (with the CUP Option layout)

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	NO_2 Annual	SO_2 3 - hour	SO_2 24 - hour	SO_2 Annual
PSD Class II Increment Concentration (ug/m3)	30	17	25	512	91	20
Maximum Elm Road Project Only Concentration (ug/m3)	25.03	5.40	1.30	228.56	69.34	5.20
Percent of Class II Increment	83.4%	31.8%	5.2%	44.6%	76.2%	26%
Maximum Cumulative Concentration (ug/m3)	25.03	5.40	1.30	228.56	69.34	5.20
Percent of Class II Increment	83.4%	31.8%	5..2%	44.6%	76.2%	26%
Cumulative Impact UTM Easting (m)	431,425.69	431,425.69	432,792	431,046.03	431,281.09	431,098.69
Cumulative Impact UTM Northing (m)	4,743,201	4,743,201	4,744,750	4,744,299.5	4,743,574	4,744,173.5

Table D-28 Air quality modeling results for the ERGS at the South Site*

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO_2 3 - hour	SO_2 24 - hour	SO_2 Annual	NO_2 Annual
Maximum Concentration (ug/m3)	61.96	8.06	73.71	0.0030	730.11	178.48	12.80	28.52
Background Concentration (ug/m3)	58	27	76	NA	208.10	57.80	9.30	31.00
Total Concentration(ug/m3)	119.96	35.06	149.71	0.0030	9938.21	236.28	22.10	59.52
NAAQS Standard (ug/m3)	150	50	150	1.5	1,300	365	80	100
Percent (%) of NAAQS	79.9%	77.0%	99.8%	-	72.2%	64.7%	27.6%	59.52%
Impact UTM Easting (m)	432,494	432,494	431,191	432,342	432,342	432,292	432,292	432,494
Impact UTM Northing (m)	4,743,421	4,743,421	4,743,807	4,744,450	4,747,450	4,744,450	4,744,450	4,743,421

*** Based on WEPCO information supplied to the DNR in December 2002, and on April 16 and June 27, 2003.**
Assumptions: SCPC units stack heights – 470 feet; SCPC units short-term SO_2 emission rate at 1,150 lbs/hr

Table D-29 PSD increment modeling results for the ERGS at the South Site*

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	NO_2 Annual	SO_2 3 - hour	SO_2 24 - hour	SO_2 Annual
PSD Class II Increment Concentration (ug/m3)	30	17	25	512	91	20
Maximum Elm Road Project Only Concentration (ug/m3)	29.61	5.67	2.72	185.20	85.21	6.09
Percent (%) of Class II Increment	98.7%	33.4%	10.9%	36.2%	93.6%	30.5%
Maximum Cumulative Concentration (ug/m3)	29.61	5.67	2.72	185.20	85.21	6.09
Percent (%) of Class II Increment	98.7%	33.4%	10.9%	36.2%	93.6%	30.5%
Cumulative Impact UTM Easting (m)	431,173	431,425	432,842	431,041	431,980	433,192
Cumulative Impact UTM Northing (m)	4,742,590	4,743,201	4,742,900	4,742,594	4,742,925	4,743,750

*** Based on WEPCO information supplied to the DNR in December 2002, and on April 16 and June 27, 2003.**

Table D-30 Air quality modeling results for the ERGS at the South Site-Exp*

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO_2 3 - hour	SO_2 24 - hour	SO_2 Annual	NO_2 Annual
Maximum Concentration (ug/m3)	61.97	7.98	73.77	0.0030	732.00	180.98	12.93	28.47
Background	58	27	76	NA	208.10	57.80	9.30	31.00

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	TSP 24-hour	Pb Calendar Quarter	SO_2 3 - hour	SO_2 24 - hour	SO_2 Annual	NO_2 Annual
Concentration (ug/m3)								
Total Concentration(ug/m3)	119.97	34.98	149.77	0.0030	940.10	238.78	22.23	59.47
NAAQS Standard (ug/m3)	150	50	150	1.5	1,300	365	80	100
Percent (%) of NAAQS	79.9%	69.9%	99.8%	-	72.3%	65.4%	27.8%	59.47%
Impact UTM Easting (m)	432,494	432,494	431,191	432,342	432,292	432,342	432,292	432,292
Impact UTM Northing (m)	4,743,421	4,743,421	4,743,807	4,744,450	4,747,550	4,744,450	4,744,450	4,743,450

*** Based on WEPCO information supplied to the DNR in December 2002, and on April 16 and June 27, 2003.**
Assumptions: SCPC units stack heights at 470 feet; SCPC short-term SO_2 emission rate at 1,650 lbs/hr

Table D-31 PSD increment modeling results for the ERGS at the South Site-Exp*

Pollutant	PM_{10} 24 - hour	PM_{10} Annual	NO_2 Annual	SO_2 3 - hour	SO_2 24 - hour	SO_2 Annual
PSD Class II Increment Concentration (ug/m3)	30	17	25	512	91	20
Maximum Elm Road Project Only Concentration (ug/m3)	29.73	5.66	2.91	276.76	89.92	2.91
Percent (%) of Class II Increment	99.1%	33.3%	11.6%	54.1%	98.8%	14.6%
Maximum Cumulative Concentration (ug/m3)	29.73	5.66	2.91	276.76	89.92	2.91
Percent (%) of Class II Increment	99.1%	32.3%	11.6%	54.1%	98.8%	14.6%
Cumulative Impact UTM Easting (m)	431,173	431,425	432,842	430,992	431,192	433,192
Cumulative Impact UTM Northing (m)	4,742,590	4,743,201	4,742,900	4,741,100	4,742,100	4,743,750

*** Based on WEPCO information supplied to the DNR in December 2002, and on April 16 and June 27, 2003.**

WEPCO's Projected Hazardous Air Pollutant Emissions

The six tables below summarize the hazardous air pollutant (HAP) emissions expected from the ERGS's main pollutant emission sources, as described in the last section of Chapter 7.

These emissions levels are based on WEPCO's calculations in its air permit application and additional information submitted on June 2, 2003 and June 27, 2003. This data is subject to change pending DNR's review and analysis.

Table D-32 Hazardous air pollutants emissions expected from each SCPC coal-fired boiler

Pollutant	Lbs/hr	TPY
Antimony	0.021	0.091
Arsenic	0.037	0.16

Pollutant	Lbs/hr	TPY
Beryllium	0.0020	0.0087
Cadmium	0.0068	0.03
Chlorine (as HCL)	15.8	69.4
Chromium	0.055	0.24
Cobalt	0.0087	0.038
Fluorine	5.46	23.9
Lead	0.046	0.20
Manganese	0.076	0.33
Mercury	0.014	0.062
Nickel	0.052	0.23
Selenium	0.30	1.33
Formaldehyde	0.297	0.130
Other organic HAPs	0.0004	0.002

Table D-33 Hazardous air pollutants emissions expected from the SCPC boiler island auxiliary boiler

Pollutant	Lbs/hr	TPY
Lead	0.0022	0.0006
Mercury	0.0007	0.0002
Beryllium	0.0007	0.0002
Hydrogen fluoride	- 0.0270	- 0.0067
Sulfuric acid mist	0.16	0.08
Formaldehyde	0.02	0.02
Other organic HAPs	0.06	0.01

Table D-34 Hazardous air pollutants emissions expected from the IGCC boiler island auxiliary boiler

Pollutant	Lbs/hr	TPY
Lead	0.0009	0.0002
Mercury	0.0003	0.0001
Beryllium	0.0003	0.0001
Hydrogen fluoride	0.0109	0.0027
Sulfuric Acid Mist	0.06	0.03
Formaldehyde	0.01	0.01
Other organic HAPs	0.03	0.01

Table D-35 Hazardous air pollutants emissions expected from the IGCC unit

Pollutant	Lbs/hr	TPY
Antimony	0.005	0.02
Arsenic	0.01	0.49
Beryllium	0.006	0.03
Cadmium	0.005	0.02
Chlorine (as HCL)	0.67	2.95
Chromium	0.07	0.31
Cobalt	0.03	0.12
Fluorine	0.12	0.52
Lead	0.11	0.50

Pollutant	Lbs/hr	TPY
Manganese	0.13	0.59
Mercury	0.007	0.03
Nickel	0.08	0.33
Selenium	0.06	0.25
Formaldehyde	0.33	1.40
Organic HAPs	0.06	0.26

Table D-36 **Hazardous air pollutant emissions expected from each of two 1,500 kW diesel engine/electric generators sets in lbs/hr and tons per year***

Pollutant	Lbs/hr	TPY
Antimony	negligible	Negligible
Arsenic	0.00006	0.00001
Beryllium	0.000002	0.0000005
Cadmium	0.00001	0.000004
Chlorine (as HCL)	0.034	0.0084
Chromium	0.000074	0.000019
Cobalt	0.00046	0.00011
Fluorine as hydrogen fluoride	0.0016	0.00039
Lead	0.00011	0.000028
Manganese	0.00019	0.000049
Mercury	0.0000068	0.0000017
Nickel	0.010	0.0025
Selenium	0.000029	0.0000075
Formaldehyde	0.0011	0.00028
Other organic HAPs	0.02414	0.00604

* For the North Site and the CUP Option, as described in WEPCO's June 2, 2003 submittal in support of its air permit applications; not for the South Sites, as indicated in the June 27, 2003 submittal.

Table D-37 **Hazardous air pollutants emissions expected from each of three fire pumps in lbs/hour and tons per year***

Pollutant	Lbs/hr	TPY
Antimony	Negligible	Negligible
Arsenic	0.000015	0.0000037
Beryllium	0.00000051	0.00000013
Cadmium	0.000004	0.0000010
Chlorine (as HCL)	0.0081	0.0020
Chromium	0.000018	0.0000045
Cobalt	0.00011	0.000027
Fluorine as hydrogen fluoride	0.00038	0.000094
Lead	0.000027	0.0000068
Manganese	0.000048	0.000012
Mercury	0.0000016	0.00000041
Nickel	0.0024	0.00061
Selenium	0.0000072	0.0000018
Formaldehyde	0.00040	0.0010
Other organic HAPs	0.0058	0.0015

* For the North Site and CUP Option, as described in WEPCO's June 2, 2003 submittal in support of its air permit applications; not for the South Sites, as indicated in the June 27, 2003 submittal.

E

Appendix E – Agreement Between WEPCO and the City of Oak Creek, and the Conditional Use Permit

Oak Creek

CITY ADMINISTRATOR

WISCONSIN PUBLIC SERVICE COMMISSION

2003 JUN -5 P 1:37

RECEIVED

June 4, 2003

Ms. Linda L. Dorr
Secretary to the Commission
Public Service Commission of Wisconsin
610 North Whitney Way
P.O.B. 7854
Madison, WI 53707-7854

Dear Ms. Dorr:

On March 31, 2003, the City of Oak Creek and We Energies entered into a development agreement regarding the construction of the Elm Road Generating Station Docket No. 05-CE-130. The Public Service Commission had previously received a copy and referenced the agreement in the Draft Environmental Impact Statement on page 28 and 29, which was released on April 21, 2003. On page xxii of the DEIS the staff explained that the agreement had been approved and discussed the community mitigation payments including a footnote reference.

A copy of the agreement is again attached for inclusion as part of the application process. We are filing 30 copies with this letter.

Sincerely,

Robert L. Kufrin.
City Administrator

8640 S. HOWELL AVE.
OAK CREEK, WI 53154
TEL (414) 768-6701
FAX (414) 768-9587

WISCONSIN PUBLIC SERVICE COMMISSION

AGREEMENT

THIS AGREEMENT is made and effective as of the 2 day of April 5, 2003, by and between the **City of Oak Creek** (the "City") and **Wisconsin Energy Corporation**, ("WEC"), on behalf of its subsidiaries, Wisconsin Electric Power Company ("Wisconsin Electric"), W.E. Power, LLC ("We Power"), WISPARK LLC ("WISPARK"), and Wisconsin Gas Company ("Wisconsin Gas") (collectively referred to as the "Subsidiaries").

WITNESSETH:

WHEREAS, WEC or one of the Subsidiaries is the current owner and operator of coal-based electric generating facilities located in the City.

WHEREAS, WEC desires, as a part of its "Power the Future" project for increasing electric generating facilities, to create three coal burning new electric generating facilities at the site of existing facilities in the City.

WHEREAS, it is anticipated that the construction and operation of the new facilities may have certain effects on the City.

WHEREAS, in order to mitigate any such effects on the City, WEC and the City desire to enter into this Agreement.

NOW, THEREFORE, for good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, WEC, for itself and the Subsidiaries, and the City agree as follows:

1. AGREEMENT CONCERNING AIR QUALITY ISSUES.

   A. Purpose. The purpose of this paragraph 1 is to ensure that effective upon the date of this Agreement, the total actual annual air emissions from Oak Creek Units 5-8 ("Existing Facilities") and Elm Road Units 1-3 ("New Facilities") will not result in a net increase of the total actual annual air emissions as compared with the baseline condition. The parties recognize that the air pollution requirements established and implemented by the Wisconsin Department of Natural Resources "DNR" are designed to protect public health and welfare and that this Agreement is in furtherance of and not in conflict with those state requirements.

   B. Baseline Emission Level. For the purpose of establishing that there will be no net increase in total actual annual air emissions, WEC has used calendar year 2000 as the baseline condition, and determined that the baseline emission level from the facility is 38,400 tons per year ("Baseline Emission Level"). The Baseline Emission Level includes the actual annual air emissions in calendar year 2000 of sulfur dioxide ("SO_2"), nitrogen oxides ("NO_X"), particulate matter ("PM"), mercury ("Hg"), volatile organic compounds ("VOC"), hydrochloric acid ("HCl"), hydrofluoric acid ("HF"), and sulfuric acid ("H_2SO_4")

C. Measure of Compliance. WEC agrees that the total actual annual air emissions from the stacks of the Existing Facilities and New Facilities will not exceed the Baseline Emission Level. Compliance with the Baseline Emission Level will be measured on a rolling 12-month basis so that in each 12-month period the emissions shall not exceed the Baseline Emission Level.

D. Implementation and Enforcement.

1. WEC agrees that it will use all reasonable efforts to obtain enforceable limitations in the construction and operation air pollution control permit or equivalent order (state or federal) which includes emission limitations that will ensure that the total actual annual emissions from the Existing Facilities and New Facilities will not exceed the Baseline Emission Level ("Enforceable Permit Condition").

2. In the event for any reason the Department of Natural Resources or the U.S. Environmental Protection Agency does not include in the construction and operation air pollution control permit or equivalent order (state or federal) emission limitations that will ensure that the total actual emissions from the Existing Facilities and New Facilities will not exceed the Baseline Emission Level, the parties to this Agreement shall meet and agree to a local enforcement mechanism the validity and enforceability of which WEC agrees not to contest in any way.

E. Air Monitoring.

1. Elm Road Monitoring Site. WEC or its contractor agrees to install, maintain and operate an air monitoring station at a location to be mutually agreed upon between WEC and the City within 1200 feet of the intersection of Elm Road and the Chicago and Northwestern Railroad line to monitor for particulate matter measured as Total Suspended Particulates ("TSP"), PM_{10} and $PM_{2.5}$ consistent with appropriate state and/or federal ambient air quality monitoring requirements except that the monitoring shall occur on a daily basis. Meteorological data including wind speed, wind direction and temperature shall also be collected at this location. The air monitors at this location shall be operational as soon as practicable, but no later than 150 days after the date of this Agreement and shall continue for a period of no less than two years after commencement of construction of the first of any of the New Facilities approved by the PSC. If after two years following

commencement of construction of the first of any of the New Facilities no exceedences of state or national ambient air quality standards attributable to any WEC operations are detected, the frequency of the monitoring can be reduced to a sampling frequency of once every three days for each of the above air pollutants. Monitoring shall continue thereafter unless the provisions of Paragraph E.4 apply.

2. Carrollton Monitoring Site. WEC or its contractor agrees to install, maintain and operate air monitoring station at Carrollton Elementary School (8965 South Carrollton Drive) to monitor for SO_2 and NO_X consistent with appropriate state and/or federal ambient air quality monitoring requirements. Meteorological data including wind speed, wind direction and temperature shall also be collected at this location. The monitoring shall occur on a frequency consistent with state and/or federal ambient air quality monitoring requirements. The monitoring at this location shall be operational within 150 days of the granting of the CPCN for any of the New Facilities. Monitoring shall continue thereafter unless the provisions of Paragraph E.4 apply.

3. Data Reporting. The air emission and meteorological data from both of the monitoring sites under this paragraph shall be reported to the City after completion of QA/QC checks and shall be summarized in a quarterly report submitted to the City and DNR within 45 days after the end of the quarter. In addition to the Quarterly Report, the data shall also be available at the new Education and Visitors Center and City Hall as soon as practicable after the completion of QA/QC checks. It is anticipated that normal reporting time for PM_{10}, $PM_{2.5}$, SO_2, and NO_x will be the first business day within 24 hours after completion of the QA/QC checks, but, in any event, no later than 4 days after the sample date. TSP results will be furnished within 30 days after completion of QA/QC checks.

4. Exceptions to Monitoring Requirements. The monitors shall continue to be operated and maintained until (a) all of the New Facilities authorized by PSC Docket No. 05-CE-130 have been built and have been in operation for a period of not less than five years, (b) the emission data indicates that the emissions and ambient air quality are within state and/or national ambient air quality standards, all applicable permit limits and the Baseline Emission Level of this Agreement for three consecutive years, and (c) the concentration of air pollutants are at or less than the maximum concentrations modeled as part of WEC air modeling calculations submitted with the air pollution control permit

applications for the New Facilities for three consecutive years. If the requirements of this sub-paragraph are satisfied, paragraph E will no longer apply. If none of the New Facilities sought in PSC Docket No. 05-CE-130 has been approved by the PSC for construction in Oak Creek, or if WEC does not proceed with construction of the New Facilities, then the requirements of paragraph E will no longer apply.

2. REDEVELOPMENT OF PROPERTY.

A. Upon the signing of this Agreement and irrespective of whether WEC receives a CPCN from the PSC in docket #05-CE-130 for construction of any New Facilities, pursuant to Sec 196.491(3), Wis. Stats., WEC shall at its sole cost and expense: (a) complete a Market Study; (b) complete an Environmental Site Conditions Analysis; and (c) develop a Land Use Plan for certain parcels within the City of Oak Creek, which parcels shall be selected by mutual Agreement of the Director of Community Development and WEC. The Environmental Analysis, Market Study and Land Use Plan shall be completed within twelve months of the signing of this Agreement, and shared with the Director of Community Development as soon as they are completed. In the event WEC does not proceed to develop, under paragraph 2B, the parcels studied, then thirty copies of the Environmental Analysis, Market Study and Land Use Plan together with all supporting documents shall be provided to the City of Oak Creek. Notwithstanding anything to the contrary contained herein, WEC's obligations to provide the analysis, study, and plan under this paragraph 2A are contingent upon WEC obtaining all necessary consents and/or access from the owner(s) of the proposed property.

B. For each of the first two New Facilities for which WEC receives a CPCN from the PSC in docket #05-CE-130, WEC shall be required to invest 10 million dollars, within ten years of the date of the granting of the CPCN by the PSC for each unit, to construct improvements of a type WEC deems appropriate on parcels within the City of Oak Creek, which WEC selects. WEC shall use its best efforts to invest such funds in as expeditious a manner as is reasonably prudent. For purposes of this Agreement, improvements include the following:

1. Demolition of existing structures.
2. Environmental remediation to the level necessary to construct and occupy the planned building(s), facility(s) and/or uses, in accordance with Wisconsin environmental statutes and Wisconsin Administrative Code Chapters NR 700 – NR 754 requirements and any federal environmental laws, regulations and guidance.
3. Construction of improvements, including buildings and structures.

4. Installation of public improvements, including, but not limited to sanitary sewer, water main, storm water facilities, streets, including curb and gutter, street lights, landscaping and other amenities all of which shall be as defined under the Oak Creek Municipal Code.
5. Marketing of properties until initial occupancy.
6. Other improvements proposed by WEC and agreeable to the City.
7. Acquiring all parcels necessary to undertake the aforementioned improvements.

3. PAYMENT OF MITIGATION COSTS. During the term (including any applicable extensions) of that certain Facility Lease (the "Facility Lease") between Elm Road Generating Station LLC and Wisconsin Electric for each unit of the New Facility (the "Lease Term"), We Power shall support, and shall use its best efforts to have approved, an annual mitigation payment to the City in the amount of $1.5 million for the first unit (Elm Road Unit 1), $750,000 for the second unit (Elm Road Unit 2), and $250,000 for the third unit (Elm Road Unit 3), respectively (a "Mitigation Payment"). If, and to the extent, approved by the PSCW, Mitigation Payments will be made on a calendar year basis. The first Mitigation Payment for each unit shall be made thirty days after commencement of construction (commencement of construction shall mean the start of earth moving or excavation at the site) of a unit. Thereafter, Mitigation Payments shall be paid in one annual payment on June 30th each year during the Lease Term. Mitigation Payments for partial calendar years during the Lease Term (including the year of the first Mitigation Payment) shall be prorated on a per-diem basis. The obligation to pay Mitigation Payments is independent of the receipt of shared revenue funds from the State of Wisconsin and of any future changes in state law pertaining to utility taxation. Notwithstanding anything to the contrary contained herein, in no event will WEC or any of the Subsidiaries have any obligation under this paragraph 3 in the event that (i) the PSCW determines that the payments described in this Section 3 may not be properly included in the rent payments under the Facility Lease, or (ii) a unit of the New Facility permanently ceases operation after start-up and is decommissioned

4. NO THIRD PARTY BENEFICIARIES. None of the provisions of this Agreement is intended for the benefit of any person except the parties hereto and their respective successors and permitted assigns. No interest on behalf of any third-party beneficiary is created by this Agreement.

5. REIMBURSEMENT OF CITY EXPENSES. WEC agrees to reimburse the City for its reasonable out-of-pocket expenses incurred by the City in participating in all matters relating to the application for and approval of the New Facilities by the PSCW. The expenses to be reimbursed include the City's out-of-pocket expenses for attorneys and technical consultants. The expenses to be reimbursed will be

determined based on a budget to be prepared by the City, with a cap established above which WEC and the City will share expenses on an equal basis.

6. CITY APPROVALS. WEC, through the Subsidiaries, and the City agree to cooperate in good faith on all matters involving review and approval of the New Facilities by the City and any agencies or instrumentalities thereof. Without limitation, WEC's Subsidiaries will continue to work through the City's Planning and Conditional Use Permit processes to resolve issues raised by the City pertaining to the New Facility. The parties intend that the resolution of all such issues shall be presented to the PSCW as part of its certification process and included as a condition of the Certificate of Public Convenience and Necessity ("CPCN").

7. CITY SUPPORT. Upon execution of this Agreement, the City agrees to use its best efforts to support the construction of the New Facilities before the PSCW and other applicable regulatory or governmental bodies. Subject to the requirements of this paragraph 7, nothing in this Agreement shall be construed as an agreement by the City to grant City approvals, which shall remain subject to the Planning and Conditional Use Permit processes noted above.

8. COMPROMISE OF CITY CLAIMS. WEC and the City acknowledge and agree that the construction and operation of the New Facility, and other activities related thereto as described in the applications before the PSCW for CPCN approval, are anticipated to have a substantial effect on the City (the "Effects"). Without limitation, the Effects might include safety concerns, noise, or the need for additional fire, police and emergency medical service. WEC and the City agree that the obligations undertaken by WEC in this Agreement are designed to mitigate the Effects, and the City agrees not to sue WEC nor any of its Subsidiaries for the Effects except as set forth herein. Nothing in this Agreement shall be construed to preclude the City from taking any action, including the filing of legal actions, to enforce provisions of its ordinances, permits or approvals, or the provisions of this Agreement related to the New Facility; provided, however, that such actions shall not prevent the continued use or operation of the New Facility in accordance with paragraph 1 and all other state permits.

9. DEFAULT PROVISIONS. A party shall be in default under this Agreement if it fails to perform any of its obligations as set forth herein, and such failure continues for a period of sixty (60) days after the defaulting party's receipt of written notice of such failure from the non-defaulting party. In the event of such default, the non-defaulting party shall be entitled to exercise any or all available rights and remedies at law or in equity.

10. ASSIGNMENT. Neither party may assign its interest under this Agreement without the prior written consent of the other party hereto, which consent will not be unreasonably withheld or delayed.

11. NOTICES. All notices permitted or required by this Agreement shall be given in writing and shall be considered given upon receipt if hand delivered to the party or person intended, or upon facsimile transmission to the fax numbers set forth herein, or one business day after deposit with a nationally recognized overnight commercial courier service, air bill prepaid, or forty-eight (48) hours after deposit in the United States mail, postage prepaid, by certified mail, return receipt requested, addressed by name and address to the party or person intended as follows:

To WEC:	Wisconsin Energy Corporation 231 West Michigan Street Milwaukee, WI 53203 Attn: Larry Salustro, Esq. Fax No.: (414) 221-2140
To the City:	City of Oak Creek 8640 S. Howell Avenue Oak Creek, WI 53154 Attn: Robert Kufrin Fax: 414-768-6516

12. GOVERNING LAW. This Agreement concerns real property located in the State of Wisconsin, and shall be interpreted and construed according to the laws of the State of Wisconsin.

13. SEVERABILITY OF PROVISIONS. If any of the terms or conditions contained herein shall be declared to be invalid or unenforceable by the PSC in a court of competent jurisdiction, then the remaining provisions and conditions of this Agreement, or the application of such to persons or circumstances other than those to which it is declared invalid or unenforceable, shall not be affected thereby and shall remain in full force and effect and shall be valid and enforceable to the full extent permitted by law, except that as to any such provisions or conditions declared invalid or unenforceable, the parties agree to negotiate a comparable substitute provision.

14. CAPTIONS. The captions in this Agreement are inserted only as matters of convenience and for reference and in no way define or limit the scope or intent of the various provisions, terms or conditions hereof.

15. BINDING EFFECT. The terms and conditions of this Agreement shall be binding upon and benefit the parties hereto and their respective successors and assigns.

16. ENTIRE AGREEMENT. This Agreement may be modified, amended or terminated only by written instrument signed by both parties.

17. COUNTERPARTS. This Agreement may be executed in one or more counterparts, each of which will be deemed an original.

18. ATTORNEYS' AND CONSULTANTS' FEES. In the event of litigation arising out of this Agreement, the prevailing party shall be entitled to court costs, out-of-pocket expenses and reasonable attorneys' and consultants' fees from the unsuccessful party.

19. REPRESENTATIONS AS TO AUTHORITY. Each party to this Agreement represents and warrants as follows:

    (a) It is duly organized, validly existing and in good standing under the laws of the state of its incorporation and has the power and authority to consummate the transactions contemplated by this Agreement.

    (b) All proceedings necessary for it to consummate the transactions contemplated by this Agreement have been duly taken in accordance with law.

    (c) The persons executing this Agreement on behalf of it have been duly authorized to execute this Agreement.

20. FAX SIGNATURES. The parties agree that fax signatures shall be binding on the parties hereto.

21. EFFECTIVENESS OF PROVISIONS. Except as specified in this paragraph 21, this Agreement is not effective until, and only so long as, the PSCW issues the CPCN for the New Facilities in the City, except that paragraphs 5, 18, and 21 are effective even if the New Facilities are not approved and survive this Agreement. Paragraphs 1E, 6, and 7 are effective immediately upon approval of the Agreement by WEC and the City, but continue in effect only if one or more New Facilities are approved by the PSCW within Oak Creek and WEC proceeds with the project.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the date first above written.

WISCONSIN ENERGY CORPORATION

By: _____
Print Name: LARRY SALUSTRO
Title: General Counsel, WEC

CITY OF OAK CREEK

By: _____
Print Name: DAVE J. RICHARDS
Title: MAYOR

By: _____
Print Name: BEVERLY A. BURETTA
Title: CITY CLERK

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OFFICE OF THE CITY CLERK

Oak Creek, Wisconsin

June 10, 2003

I hereby certify that the attached is a true and correct copy of Ordinance 2250 passed and adopted by the Common Council of the City of Oak Creek at a regular meeting held on the 3rd day of June, 2003.

CORPORATE SEAL
CITY OF OAK CREEK
MILWAUKEE COUNTY
WISCONSIN
WISCONSIN

City Clerk

ORDINANCE NO. 2250

By: ALD. Charles Koehler

AN ORDINANCE TO APPROVE A REZONING OF THE PROPERTIES AT 4420, 4500, 4650, 4750 AND 4800 E. ELM ROAD AS WELL AS 4285, 4299, 4431, 4451R, 4503, 4513, 4541, AND 4541R E. OAKWOOD ROAD FROM A-1, AGRICULTURAL, P-1, PARK, M-1, MANUFACTURING AND RS-4, SINGLE FAMILY RESIDENTIAL TO M-1, MANUFACTURING.

(4th Aldermanic District)

WHEREAS, the Wisconsin Energy Corporation has requested that the properties at 4420, 4500, 4650, 4750 and 4800 E. Elm Road as well as 4285, 4299, 4431, 4451R, 4503, 4513, 4541, and 4541R E. Oakwood Road be rezoned from A-1, Agricultural, P-1, Park, M-1, Manufacturing and Rs-4, Single Family Residential to M-1, Manufacturing, and

WHEREAS, these properties are more precisely described as follows: Being part of the Northwest 1/4 and the Northeast Fractional 1/4 of Section 36, Town 5 North, Range 22 East and the Northwest Fractional 1/4 of Section 31, Town 5 North, Range 23 East, City of Oak Creek, Milwaukee County, Wisconsin, bounded and describes as follows:

Commencing at the Northwest corner of the aforesaid Northeast Fractional 1/4 of Section 36; thence N89°49'27'E along the North line of said Northeast Fractional 1/4 of Section 36, 2199.57 feet to a point on the East line of East Oakwood Road as delineated by the aforesaid City of Oak Creek, said point also being a meander corner on said North line and the point of beginning; thence N89°49'27"E along the North line of the aforesaid Northeast Fractional 1/4 of Section 36, 255.1 feet more or less to the Ordinary High Water Mark (OHWM) of the Westerly boundary of Lake Michigan as delineated by the Wisconsin Department of natural Resources in March of 2002; thence Southeasterly along said OHWM, 3213.1 feet more or less to the South line of the aforesaid Northwest Fractional 1/4 of Section 31; thence S89°11'23"W along said South line, 857.7 feet more or less to a point on the East line of East Elm Road as delineated by the aforesaid City of Oak Creek, said point also being a meander corner on the South line of the aforesaid Northwest Fraction 1/4 of Section 31; thence S89°11'23"W along said South line, 702.85 feet to the Southeast corner of the aforesaid Northeast Fractional 1/4 of Section 36; thence S89°44'16"W along the South line of the said Northeast Fractional 1/4 Section 36, 2389.50 feet to a point on the Easterly line of the Chicago and North Western Transportation Company right-of-way; thence N21°17'33"W along said Easterly line, 2803.75 feet to an iron pipe found and a point on the South line of the aforesaid East Oakwood Road; thence N89°49'19"E along said South line, 194.06 feet to the Westerly line of Lot 1, Certified Survey Map (C.S.M.) No. 5261; thence S21°17'33"E along said Westerly line, 911.31 feet to an iron rod found; thence N89°46'47"E along the South line of said Lot 1, 366.42 feet to a iron rod found; thence N00°40'16"W along the East line of said Lot 1 and the West line of Lot 2, C.S.M. No. 88, 822.89 feet to a point on the South line of the aforesaid East Oakwood Road, said point also being the Northwest corner of Lot 2, Certified Survey Map No. 88; thence N89°49'27"E along said South line, 528.00 feet to an iron pipe found; thence N00°40'16"W along said South line, 27.00 feet; thence N89°49'27"E along said South line, 1539.27 feet to a point on the aforesaid East line of East Oakwood Road; thence N00°10'33"W along said East line, 33.00 feet to the point of beginning, expecting the Southerly 33 feet West of the meander corner dedicated for road purposes, together with that part of the aforesaid Northeast Fractional 1/4 Section 36 and that part of the aforesaid Northwest Fractional 1/4 of Section 31 lying East of the aforesaid meander

lines and West of the Westerly boundary of Lake Michigan. Containing 193.8592 acres (8,444,507 Sq. Ft.) more or less of land. Subject to riparian rights, covenants, conditions, restrictions and easements of record.; and

WHEREAS, the Plan Commission reviewed the application and recommended that the rezoning be approved; and

WHEREAS, the Common Council held a public hearing on said application on June 3, 2003, at which time all interested parties appeared and were heard; and

WHEREAS, following said public hearing and with the favorable recommendation of the Plan Commission, the Common Council is of the opinion that the best interests of the City would be served if the rezoning was approved; and

NOW, THEREFORE, the Common Council of the City of Oak Creek does hereby ordain as follows:

SECTION 1: To promote the general welfare, public safety and general planning within the City of Oak Creek, the lands hereinabove described are hereby rezoned and the Zoning Map of Chapter 17 of the Municipal Code is hereby amended to reflect the rezoning.

SECTION 2: All ordinances or parts of ordinances and zoning district maps made a part of Chapter 17 of the Municipal Code of the City of Oak Creek in conflict herewith are hereby repealed.

SECTION 3: The several sections of this ordinance are declared to be severable. If any section shall be declared, by a decision of a court of competent jurisdiction, to be invalid, such decision shall not affect the validity of other provisions of this ordinance.

SECTION 4: The rezoning shall take place contemporaneously with the enactment of this ordinance and shall take effect immediately upon its passage and publication.

Passed and adopted this 3 day of June, 2003.

/s/ Elizabeth J. Kopplin
President, Common Council

Approved this 4 day of June, 2003

/s/ Richard R. Bolender
Mayor

ATTEST:

/s/ Beverly A. Buretta
City Clerk

VOTE: Ayes 6 Noes 0

OFFICE OF THE CITY CLERK

Oak Creek, Wisconsin

June 10, 2003

I hereby certify that the attached is a true and correct copy of Ordinance 2251 passed and adopted by the Common Council of the City of Oak Creek at a regular meeting held on the 3rd day of June, 2003.

CORPORATE SEAL
CITY OF OAK CREEK
MILWAUKEE COUNTY
WISCONSIN
WISCONSIN

Beverly A Burnett
City Clerk

Orig.
Map = Ex A

ORDINANCE NO. 2251

By: Ald. Charles Koehler

AN ORDINANCE TO APPROVE AND AUTHORIZE THE ISSUANCE OF A CONDITIONAL USE PERMIT FOR POWER GENERATION, TRANSMISSSION AND DISTRIBUTION FOR THE PROPERTIES AT 4801 E. ELM ROAD ET. AL.

(4th Aldermanic District)

WHEREAS, the Wisconsin Energy Corporation has applied for a Conditional Use Permit for power generation, transmission and distribution for the properties at 4401, 4415, 4420, 4500, 4501, 4650, 4750, 4800 and 4801 E. Elm Road; 4285, 4299, 4431, 4451, 4503, 4513, 4541 and 4541R E. Oakwood Road; 10700, 10760, 10920, 11002, 11050 and 11050R S. Chicago Road.; and

WHEREAS, this portion of the property is more precisely described as follows:

"AREA A" - Being part of the Northwest 1/4 and the Northeast Fractional 1/4 of Section 36, Town 5 North, Range 22 East and the Northwest Fractional 1/4 of Section 31, Town 5 North, Range 23 East, City of Oak Creek, Milwaukee County, Wisconsin, bounded and describes as follows:

Commencing at the Northwest corner of the aforesaid Northeast Fractional 1/4 of Section 36; thence N89°49'27'E along the North line of said Northeast Fractional 1/4 of Section 36, 2199.57 feet to a point on the East line of East Oakwood Road as delineated by the aforesaid City of Oak Creek, said point also being a meander corner on said North line and the point of beginning; thence N89°49'27"E along the North line of the aforesaid Northeast Fractional 1/4 of Section 36, 255.1 feet more or less to the Ordinary High Water Mark (OHWM) of the Westerly boundary of Lake Michigan as delineated by the Wisconsin Department of natural Resources in March of 2002; thence Southeasterly along said OHWM, 3213.1 feet more or less to the South line of the aforesaid Northwest Fractional 1/4 of Section 31; thence S89°11'23"W along said South line, 857.7 feet more or less to a point on the East line of East Elm Road as delineated by the aforesaid City of Oak Creek, said point also being a meander corner on the South line of the aforesaid Northwest Fraction 1/4 of Section 31; thence S89°11'23"W along said South line, 702.85 feet to the Southeast corner of the aforesaid Northeast Fractional 1/4 of Section 36; thence S89°44'16"W along the South line of the said Northeast Fractional 1/4 Section 36, 2389.50 feet to a point on the Easterly line of the Chicago and North Western Transportation Company right-of-way; thence N21°17'33"W along said Easterly line, 2803.75 feet to an iron pipe found and a point on the South line of the aforesaid East Oakwood Road; thence N89°49'19"E along said South line, 194.06 feet to the Westerly line of Lot 1, Certified Survey Map (C.S.M.) No. 5261; thence S21°17'33"E along said Westerly line, 911.31 feet to an iron rod found; thence N89°46'47"E along the South line of said Lot 1, 366.42 feet to a iron rod found; thence N00°40'16"W along the East line of said Lot 1 and the West line of Lot 2, C.S.M. No. 88, 822.89 feet to a point on the South line of the aforesaid East Oakwood Road, said point also being the Northwest corner of Lot 2, Certified Survey Map No. 88; thence N89°49'27"E along said South line, 528.00 feet to an iron pipe found; thence N00°40'16"W along said South line, 27.00 feet; thence N89°49'27"E along said South line, 1539.27 feet to a point on the aforesaid East line of East Oakwood Road; thence N00°10'33"W along said East line, 33.00 feet to the point of beginning, expecting the Southerly 33 feet West of the meander corner dedicated for road

purposes, together with that part of the aforesaid Northeast Fractional 1/4 Section 36 and that part of the aforesaid Northwest Fractional 1/4 of Section 31 lying East of the aforesaid meander lines and West of the Westerly boundary of Lake Michigan. Containing 193.8592 acres (8,444,507 Sq. Ft.) more or less of land. Subject to riparian rights, covenants, conditions, restrictions and easements of record.

"AREA B" - Being part of the Southeast 1/4 Section 36, Town 5, Range 22 East and the Southwest Fractional 1/4 of Section 31, Town 5 North, Range 23 East, City of Oak Creek, Milwaukee County, Wisconsin, bounded and described as follows:

Beginning at the Northeast corner of the aforesaid Southeast 1/4 of Section 36; thence N89°11'23"E along the North line of the aforesaid Southwest Fractional 1/4 of Section 31, 702.85 feet to a meander corner on said North line; thence N89°11'23"E along the North line of the aforesaid Southwest Fractional 1/4 of Section 31, 857.7 feet more or less to the Ordinary High Water Mark (OHWM) of the Westerly boundary of Lake Michigan as delineated by the Wisconsin Department of Natural Resources in March of 2002; thence Southeasterly along said OHWM, 4539.9 feet more or less to the South line of the aforesaid Southwest Fractional 1/4 of Section 31; thence S89°12'43"W along said South line, 679.7 feet more or less to a meaner corner on the South line of the aforesaid Southeast Fractional 1/4 of Section 31; thence S89°12'43"W along said South line, 1655.56 feet to the Southeast corner of the aforesaid Southeast 1/4 of Section 36; thence S89°13'29"W along the South line of said Southeast 1/4, 1346.79 feet to the Easterly line of the Chicago and North Western Transportation Company right-of-way; thence N21°17'33"W along said Easterly line, 750.00 feet; thence continuing along said Easterly line, N51°17'33"W, 100 feet; thence continuing along said Easterly line, N51°17'33"W, 2009.95 feet to a point on the North line of the aforesaid Southeast 1/4 of Section 36; thence N89°44'16"E along said North line, 2389.50 feet to the point of beginning, excepting the Northerly 33 feet West of the meander corner dedicated for road purposes, together with that part of the aforesaid Southwest Fractional 1/4 of Section 31 lying East of the aforesaid meander line and West of the Westerly boundary of Lake Michigan. Containing 241.3945 acres (10,515,143 Sq. Ft.) more or less of land. Subject to riparian rights, covenants, conditions, restrictions and easements of record.

"AREA K" – Being part of the Southeast 1/4 and the Southwest 1/4 of Section 36, Town 5 North, Range 22 East, City of Oak Creek, Milwaukee County, Wisconsin, bounded and described as follows:

Commencing at the Northwest corner of the aforesaid Southeast 1/4 of Section 36; thence S00°42'13"E along the West line of said Southeast 1/4 of Section 36, 24.75 feet to a point on the North line of East Elm Road, said point also being the point of beginning; thence continuing on said West line of the Southeast 1/4 of Section 36 and said North line of East Elm Road, S00°42'13"E, 8.25 feet; thence continuing on said North line, N89°44'16"E, 143.35 feet to a point on the Westerly line of the Chicago and North Western Transportation Company right-of-way; thence S21°17'33"E along said Westerly line, 2793.51 feet to a point on the South line of said Southeast 1/4 of Section 36; thence S89°13'29"W along said South line, 1125.71 feet to the Southwest corner of said Southeast 1/4 of Section 36; thence S89°39'50"W along the South line of the aforesaid Southwest 1/4 of Section 36, 22.27 feet to the Northwest corner of the Northeast 1/4 of Section 1, Town 4 North, Range 22 East, Town of Caledonia, Racine County, Wisconsin; thence continuing S89°39'50"W along said South line, 2049.83 feet to a point on the Easterly line of South Chicago Road (S.T.H. "32"), said Easterly line is 33.0 feet Easterly of (as measured at right angles to) the reference line described in Document No. 6669080; thence N44°36'55"W

along said Easterly line, 25.21 feet; thence continuing along said Easterly line and the arc of a curve to the right, 529.07 feet, radius of 1730.06 feet and a chord bearing N35°51'16"W, 527.01 feet; thence N89°39'50"E along South line of lands conveyed by Deed recorded on Reel 4709 of Deeds at Image 0663, 322.71 feet; thence N00°42'13"W along the East line of said Deed, 356.82 feet; thence S89°39'50"W along the North line of said Deed, 295.10 feet; thence N00°20'10"W along the East line of Certified Survey Map (C.S.M.) No. 1173, 134.00 feet; thence S89°39'50"W along the North line of said C.S.M. No 1173, 116.77 feet; thence N00°20'10"W, 25.00 feet; thence S89°39'50"W, 20.00 feet; thence S00°20'10"E, 25.00 feet; thence S89°39'50"W along the North line of said C.S.M. No. 1173, 49.65 feet to a point on the aforesaid Easterly line of South Chicago Road (S.T.H. "32"); thence Northwesterly along said Easterly line and the arc of a curve to the right, 289.09 feet, radius of 1730.06 feet and a chord bearing N05°08'04" W, 288.75 feet; thence N89°40'13"E along the South line of lands conveyed by Deed recorded on Reel 3975 of Deeds, at Image 1278, 403.69 feet; thence N01°27'03"E along the East line of said Deed, 100.05 feet; thence S89°40'13"W along the North line of said Deed, 189.75 feet; thence N06°26'53"E along the East line of lands conveyed by Deed recorded in Volume 118 of Deeds at page 607, 204.93 feet; thence S89°40'13"W along the North line of said Deed, 214.50 feet to a point on the aforesaid Easterly line of South Chicago Road; thence Northeasterly along said easterly line and the arc of a curve to the right, 142.66 feet, radius of 1730.06 feet and a chord bearing N12°07'05"E, 142.62 feet; thence continuing along said Easterly line, N14°28'49"E, 367.90 feet; thence continuing along said Easterly line and the arc of a curve to the left, 611.60 feet, radius of 3307.05 feet and a chord bearing N09°10'56"E, 610.73 feet to a point on the South line of East Elm Road; thence N89°40'36"E along said South line, 726.76 feet; thence S00°42'24"E along the West line of lands conveyed by Deed in Reel 630 of Deeds at image 1338-1339, 363.00 feet; thence N89°40'36"E along the South line of said Deed, 900.00 feet; thence N00°42'24"W along the East line of said Deed, 363.00 feet to a point on the aforesaid South line of East Elm Road; thence N89°40'36"E along said South line, 684.93 feet to the point of beginning. Containing 171.5600 acres (7,473,155 Sq. Ft.) more or less of land. Subject to covenants, conditions, restrictions and easements of record.

WHEREAS, the Plan Commission reviewed the application and recommended that the Conditional Use Permit be authorized and issued; and

WHEREAS, the Common Council held a public hearing on said application on June 3, 2003, at which time all interested parties appeared and were heard; and

WHEREAS, the Plan Commission had recommended that the application for issuance of the Conditional Use Permit be approved and authorized subject, however, to the imposition of certain conditions and restrictions upon the construction, location and operation of this Conditional Use and which conditions and restrictions are incorporated by reference into the Conditional Use Permit; and

WHEREAS, following said public hearing and with a recommendation from the Plan Commission, the Common Council is of the opinion that the best interests of the City would be served if the Conditional Use Permit was approved and authorized for the lands hereinabove described, subject, however, to the imposition of certain conditions and restrictions on the design, construction, location and operation of the Conditional Use.

NOW, THEREFORE, the Common Council of the City of Oak Creek does hereby ordain as follows:

SECTION 1: To promote the general welfare, public safety and general planning within the City of Oak Creek, the Building Commissioner is hereby authorized to a issue a Conditional Use Permit for power generation, transmission and distribution facilities in the M-1 Manufacturing District, which shall include the aforementioned conditions and restrictions.

SECTION 2: The Conditional Use is subject to the aforementioned conditions and restrictions on the design, location, construction and operation of the M-1 Conditional Use for power generation, transmission and distribution.

SECTION 3: All ordinances or parts of ordinances and Zoning District Maps made a part of Chapter 17 of the Municipal Code of the City of Oak Creek in conflict herewith are hereby repealed.

SECTION 4: The several sections of this ordinance are declared to be severable. If any section shall be declared, by a decision of a court of competent jurisdiction, to be invalid, such decision shall not affect the validity of other provisions of this ordinance.

SECTION 5: The approval and authorization of the issuance of a Conditional Use Permit for power generation, transmission and distribution shall take place contemporaneously with the enactment of this ordinance and shall take effect immediately upon its passage and publication.

Passed and adopted this 3 day of June, 2003.

/s/ Elizabeth J. Kopplin
President, Common Council

Approved this 4 day of June, 2003

/s/ Richard R. Bolender
Mayor

ATTEST:

/s/ Beverly A. Buretta
City Clerk

VOTE: Ayes 6 Noes 0

City of Oak Creek - Conditional Use Permit ("CUP")

Conditions and Restrictions

Owner: Wisconsin Energy Corporation
Property Address: 4801 Elm Road
Tax Key Number: 965-9999 et al.
Approved by Plan Commission: May 13, 2003
Approved by Common Council: June 3, 2003[1]
Conditional Use: Power generation, transmission, distribution, and usual and customary accessory uses

1. **OWNER AND LEGAL DESCRIPTION OF PROPERTY**

A. The Owner of the property and applicant for this conditional use permit is Wisconsin Energy Corporation or its subsidiaries (the "Owner").

B. The legal description of the property subject to this conditional use permit is as follows (the "Property")

Area "A"

Being part of the Northwest 1/4 and the Northeast Fractional 1/4 of Section 36, Town 5 North, Range 22 East and the Northwest Fractional 1/4 of Section 31, Town 5 North, Range 23 East, City of Oak Creek, Milwaukee County, Wisconsin, bounded and describes as follows:

Commencing at the Northwest corner of the aforesaid Northeast Fractional 1/4 of Section 36; thence N89°49'27'E along the North line of said Northeast Fractional 1/4 of Section 36, 2199.57 feet to a point on the East line of East Oakwood Road as delineated by the aforesaid City of Oak Creek, said point also being a meander corner on said North line and the point of beginning; thence N89°49'27"E along the North line of the aforesaid Northeast Fractional 1/4 of Section 36, 255.1 feet more or less to the Ordinary High Water Mark (OHWM) of the Westerly boundary of Lake Michigan as delineated by the Wisconsin Department of natural Resources in March of 2002; thence Southeasterly along said OHWM, 3213.1 feet more or less to the South line of the aforesaid Northwest Fractional 1/4 of Section 31; thence S89°11'23"W along said South line, 857.7 feet more or less to a point on the East line of East Elm Road as delineated by the aforesaid City of Oak Creek, said point also being a meander corner on the South line of the aforesaid Northwest Fraction 1/4 of Section 31; thence S89°11'23"W along said South line, 702.85 feet to the Southeast corner of the aforesaid Northeast Fractional 1/4 of Section 36; thence S89°44'16"W along the South line of the said Northeast Fractional 1/4 Section 36, 2389.50 feet to a point on the Easterly line of the Chicago and North Western Transportation Company right-of-way; thence N21°17'33"W along said Easterly line, 2803.75 feet to an iron pipe found and a point on the South line of the aforesaid East Oakwood Road; thence N89°49'19"E along said South line, 194.06 feet to the Westerly line of Lot 1, Certified Survey Map (C.S.M.) No. 5261; thence S21°17'33"E along said Westerly line, 911.31 feet to an iron rod found; thence N89°46'47"E along the South line of said Lot 1, 366.42 feet to a iron rod found; thence N00°40'16"W along the East line of said Lot 1 and the West line of Lot 2, C.S.M. No. 88, 822.89 feet to a point on the South line of the aforesaid East Oakwood Road, said point also being the Northwest corner of Lot 2, Certified Survey Map No. 88; thence N89°49'27"E along said South line, 528.00 feet to an iron pipe found; thence N00°40'16"W along said South line, 27.00 feet; thence N89°49'27"E along said South line, 1539.27 feet to a point on the aforesaid East line of East Oakwood Road; thence N00°10'33"W along said East line, 33.00 feet to the point of beginning, expecting the Southerly 33 feet West of the meander corner dedicated for road purposes, together with that part of the aforesaid Northeast Fractional 1/4 Section 36 and that part of the aforesaid Northwest

[1] City of Oak Creek, Ordinance No. 2251

Fractional 1/4 of Section 31 lying East of the aforesaid meander lines and West of the Westerly boundary of Lake Michigan. Containing 193.8592 acres (8,444,507 Sq. Ft.) more or less of land. Subject to riparian rights, covenants, conditions, restrictions and easements of record.

Area "B"

Being part of the Southeast 1/4 Section 36, Town 5, Range 22 East and the Southwest Fractional 1/4 of Section 31, Town 5 North, Range 23 East, City of Oak Creek, Milwaukee County, Wisconsin, bounded and described as follows:

Beginning at the Northeast corner of the aforesaid Southeast 1/4 of Section 36; thence N89°11'23"E along the North line of the aforesaid Southwest Fractional 1/4 of Section 31, 702.85 feet to a meander corner on said North line; thence N89°11'23"E along the North line of the aforesaid Southwest Fractional 1/4 of Section 31, 857.7 feet more or less to the Ordinary High Water Mark (OHWM) of the Westerly boundary of Lake Michigan as delineated by the Wisconsin Department of Natural Resources in March of 2002; thence Southeasterly along said OHWM, 4539.9 feet more or less to the South line of the aforesaid Southwest Fractional 1/4 of Section 31; thence S89°12'43"W along said South line, 679.7 feet more or less to a meaner corner on the South line of the aforesaid Southeast Fractional 1/4 of Section 31; thence S89°12'43"W along said South line, 1655.56 feet to the Southeast corner of the aforesaid Southeast 1/4 of Section 36; thence S89°13'29"W along the South line of said Southeast 1/4, 1346.79 feet to the Easterly line of the Chicago and North Western Transportation Company right-of-way; thence N21°17'33"W along said Easterly line, 750.00 feet; thence continuing along said Easterly line, N21°17'33"W, 100 feet; thence continuing along said Easterly line, N21°17'33"W, 2009.95 feet to a point on the North line of the aforesaid Southeast 1/4 of Section 36; thence N89°44'16"E along said North line, 2389.50 feet to the point of beginning, excepting the Northerly 33 feet West of the meander corner dedicated for road purposes, together with that part of the aforesaid Southwest Fractional 1/4 of Section 31 lying East of the aforesaid meander line and West of the Westerly boundary of Lake Michigan. Containing 241.3945 acres (10,515,143 Sq. Ft.) more or less of land. Subject to riparian rights, covenants, conditions, restrictions and easements of record.

Area "K"

Being part of the Southeast 1/4 and the Southwest 1/4 of Section 36, Town 5 North, Range 22 East, City of Oak Creek, Milwaukee County, Wisconsin, bounded and described as follows:

Commencing at the Northwest corner of the aforesaid Southeast 1/4 of Section 36; thence S00°42'13"E along the West line of said Southeast 1/4 of Section 36, 24.75 feet to a point on the North line of East Elm Road, said point also being the point of beginning; thence continuing on said West line of the Southeast 1/4 of Section 36 and said North line of East Elm Road, S00°42'13"E, 8.25 feet; thence continuing on said North line, N89°44'16"E, 143.35 feet to a point on the Westerly line of the Chicago and North Western Transportation Company right-of-way; thence S21°17'33"E along said Westerly line, 2793.51 feet to a point on the South line of said Southeast 1/4 of Section 36; thence S89°13'29"W along said South line, 1125.71 feet to the Southwest corner of said Southeast 1/4 of Section 36; thence S89°39'50"W along the South line of the aforesaid Southwest 1/4 of Section 36, 22.27 feet to the Northwest corner of the Northeast 1/4 of Section 1, Town 4 North, Range 22 East, Town of Caledonia, Racine County, Wisconsin; thence continuing S89°39'50"W along said South line, 2049.83 feet to a point on the Easterly line of South Chicago Road (S.T.H. "32"), said Easterly line is 33.0 feet Easterly of (as measured at right angles to) the reference line described in Document No. 6669080; thence N44°36'55"W along said Easterly line, 25.21 feet; thence continuing along said Easterly line and the arc of a curve to the right, 529.07 feet, radius of 1730.06 feet and a chord bearing N35°51'16"W, 527.01 feet; thence N89°39'50"E along South line of lands conveyed by Deed recorded on Reel 4709 of Deeds

at Image 0663, 322.71 feet; thence N00°42'13"W along the East line of said Deed, 356.82 feet; thence S89°39'50"W along the North line of said Deed, 295.10 feet; thence N00°20'10"W along the East line of Certified Survey Map (C.S.M.) No. 1173, 134.00 feet; thence S89°39'50"W along the North line of said C.S.M. No 1173, 116.77 feet; thence N00°20'10"W, 25.00 feet; thence S89°39'50"W, 20.00 feet; thence S00°20'10"E, 25.00 feet; thence S89°39'50"W along the North line of said C.S.M. No. 1173, 49.65 feet to a point on the aforesaid Easterly line of South Chicago Road (S.T.H. "32"); thence Northwesterly along said Easterly line and the arc of a curve to the right, 289.09 feet, radius of 1730.06 feet and a chord bearing N05°08'04" W, 288.75 feet; thence N89°40'13"E along the South line of lands conveyed by Deed recorded on Reel 3975 of Deeds, at Image 1278, 403.69 feet; thence N01°27'03"E along the East line of said Deed, 100.05 feet; thence S89°40'13"W along the North line of said Deed, 189.75 feet; thence N06°26'53"E along the East line of lands conveyed by Deed recorded in Volume 118 of Deeds at page 607, 204.93 feet; thence S89°40'13"W along the North line of said Deed, 214.50 feet to a point on the aforesaid Easterly line of South Chicago Road; thence Northeasterly along said easterly line and the arc of a curve to the right, 142.66 feet, radius of 1730.06 feet and a chord bearing N12°07'05"E, 142.62 feet; thence continuing along said Easterly line, N14°28'49"E, 367.90 feet; thence continuing along said Easterly line and the arc of a curve to the left, 611.60 feet, radius of 3307.05 feet and a chord bearing N09°10'56"E, 610.73 feet to a point on the South line of East Elm Road; thence N89°40'36"E along said South line, 726.76 feet; thence S00°42'24"E along the West line of lands conveyed by Deed in Reel 630 of Deeds at image 1338-1339, 363.00 feet; thence N89°40'36"E along the South line of said Deed, 900.00 feet; thence N00°42'24"W along the East line of said Deed, 363.00 feet to a point on the aforesaid South line of East Elm Road; thence N89°40'36"E along said South line, 684.93 feet to the point of beginning. Containing 171.5600 acres (7,473,155 Sq. Ft.) more or less of land. Subject to covenants, conditions, restrictions and easements of record.

C. A Property survey, sealed by a professional surveyor registered in the state of Wisconsin, shall be provided to the City by the Owner by January 1, 2004.

2. DEFINITIONS

A. "Commencement of Construction (COC)" is defined in Wis. Stats. s. 196.49(1)(b).
B. "Commercial Operation Date (COD)" is defined as the day that an electric generating unit begins commercial operation as defined by the Public Service Commission.
C. "Elm Road Generating Station (ERGS)" is defined as the two (2) supercritical pulverized coal electric generating units and one (1) integrated gasification combined-cycle electric generating unit proposed in the Owner's application to the Public Service Commission assigned Docket No. 05-CE-130.
D. "Oak Creek Power Plant (OCPP)" is defined as the five (5) existing (as of May 2003) electric generating units owned by Owner affiliate Wisconsin Electric Power Company, located in the City of Oak Creek.

3. GENERAL PLANS AND EASEMENTS

A. The following plans for the area affected by the conditional use shall be submitted to or approved by the City as outlined below. The plans and their contents are as follows:

1) An Initial Property Development and Construction Laydown Plan Sheet shall be submitted to the City for ERGS Units 1 and 2 at least 2 months prior to COC of ERGS Units 1 and 2 and for EGRS Unit 3 at least 2 months prior to COC of ERGS Unit 3. The plan shall include at least the following:
   a) scale of 1 inch = 200 feet covering the entire Property
   b) toe of slope positions and heights of screening berms
   c) property lines, setbacks, and easements
   d) electric, water, sewer, telephone, and other utility line easements and corridors

e) footprints, heights, and square footage of structures
f) material storage areas
g) construction trailers
h) driveways with traffic flow arrows
i) parking areas
j) vegetative cover areas
k) paved areas
l) fencing heights and type
m) lighting positions and directions in accordance with Section 17.0808 of the Municipal Code at:
   i) roadways
   ii) construction storage/laydown areas
   iii) Property entrance points
n) note requiring that all lighting be directed away from the Oakview #3 and Barton Oaks Subdivisions
o) security facilities
p) fire water supply line and hydrant locations
q) land and water loading and unloading berths

2) A Final Property Development Plan Sheet shall be submitted to the City for ERGS Units 1 and 2 at least 6 months prior to COD of either ERGS Units 1 or 2, and at least 6 months prior to COD of ERGS Unit 3. The plan shall include at least the following:
   a) scale of 1 inch = 200 feet covering the entire Property
   b) 5-foot topographic contours showing final grading
   c) property lines, setbacks, and easements
   d) electric, water, sewer, telephone, and other utility line easements and corridors
   e) footprints, heights, and square footage of structures
   f) material storage areas
   g) driveways with traffic flow arrows
   h) parking areas
   i) vegetative cover areas
   j) drainage ditches, retention basins, detention basins, wetlands, and surface water flow arrows
   k) paved areas
   l) fencing heights and type
   m) lighting positions and directions in accordance with Section 17.0808 of the Municipal Code at:
      i) roadways
      ii) entrance points
   n) a note requiring that all lighting be directed away from the Oakview #3 and Barton Oaks Subdivisions
   o) security facilities
   p) fire water supply line and hydrant locations
   q) land and water loading and unloading berths
   r) location of signage fronting Oakwood Road, Elm Road, and Highway 32

3) An Initial Landscaping Plan covering the area between the Construction Setback Line A and the boundary of the Property nearest to the Oakview #3 or Barton Oaks Subdivisions depicted on Exhibit A attached hereto shall be submitted to the City prior to COC of ERGS Units 1 and 2 for approval by the Plan Commission. Failure of the Plan Commission to approve this plan shall not prohibit or otherwise inhibit construction on the Property. A Final Landscaping Plan, covering the same area shall be submitted to the City within 30 months after COC of ERGS Units 1 and 2 for approval by the Plan Commission. The plans of any portion of the Oak Creek South Ash Landfill or the Oak Creek North Ash Landfill may also be subject to approval of the Department of Natural Resources and shall include at least the following:
   a) plan sheet that includes the following:
      i) scale of 1 inch = 200 feet covering the entire Property

ii) 5-foot topographic contours showing grading
iii) property lines
iv) driveways with traffic flow arrows
v) parking areas
vi) vegetative cover areas
vii) drainage ditches, retention basins, detention basins, wetlands, and surface water flow arrows
viii) paved areas
ix) fencing heights and type
x) wetlands and greenspace
xi) groundcover
xii) berms
xiii) storage areas

b) number, initial size, mature size and types of plantings and seeding
c) landscape maintenance plan
d) signage, driveway, and planting details
e) schedule of landscaping activities which shall include plans to complete the screening vegetation along the following areas within 18 months of COC.
   i) north-facing slope of the Oak Creek South Ash Landfill along Elm Road from Hwy 32 east to the railroad tracks
   ii) west-facing slope of the Oak Creek South Ash Landfill along Hwy 32 from Elm Road south to County Line Road
   iii) any berm(s) to be located from the northeast corner of the Oak Creek South Ash Landfill to Elm Road near the Elm Road/railroad track intersection
   iv) any berm(s) to be located east of the railroad tracks and north of the Proposed Main Access Road as labeled on Exhibit A

4) A Plan for the Visitor's Center building and surrounding grounds shall be submitted to the City at least 3 months prior to start of construction of the Visitor Center, for approval by the Plan Commission. The plan shall include at least the following:
   a) architectural elevations
   b) building floor plans and elevations
   c) materials of construction
   d) public access plan to the Lake Michigan water front in compliance with Section 17.0328 of the Municipal Code including:
      i) lakefront access
      ii) preservation areas
      iii) recreational trails
      iv) fishing pier
   e) parking requirements in accordance with Section 17.0403 of the Municipal Code
   f) driveway approaches in compliance with all the standards set forth in Chapter 6 of the Oak Creek Municipal Code
   g) parking areas shall be lighted in accordance with Section 17.0808 of the Municipal Code
   h) landscaping in accordance with Sections 17.1010 of the Municipal Code

5) An Initial Grading, Drainage and Stormwater Management Plan shall be submitted to the City at least 2 months prior to the COC. The drainage and stormwater portion of the plan shall meet the intent of Sec.s 13.100 through 13.114 of the Municipal Code, except as authorized by the City Engineer. The Plan Commission shall approve the initial grading portion of the plan. Failure of the Plan Commission to approve this portion of the plan shall not prohibit or otherwise inhibit construction on the Property. A Final Grading, Drainage and Stormwater Management Plan shall be submitted to the City within 6 months of COD. The drainage and stormwater portion of the plan shall meet the intent of Sec.s 13.100 through 13.114 of the Municipal Code, except as authorized by the City Engineer. The Plan Commission shall approve the final grading portion of the plan. Nothing herein shall be construed to require the Owner to do anything inconsistent with any state or federal regulation. The plans shall

include at least the following:

a) plan sheet that includes the following:
   i) scale of 1 inch = 200 feet covering the entire Property
   ii) 5-foot topographic contours showing final grading
   iii) property lines, setbacks, and easements
   iv) electric, water, sewer, telephone, and other utility line easements and corridors
   v) footprints, heights, and square footage of structures
   vi) material storage areas
   vii) driveways with traffic flow arrows
   viii) parking areas
   ix) vegetative cover areas
   x) drainage ditches, retention basins, detention basins, wetlands, and surface water flow arrows
   xi) paved areas
   xii) wetlands and greenspace
   xiii) storm sewers
   xiv) detention/retention basins, if needed
b) grading schedule
c) plan for slope texturing along the following areas:
   i) north-facing slope of the Oak Creek South Ash Landfill along Elm Road from Hwy 32 east to the railroad tracks
   ii) west-facing slope of the Oak Creek South Ash Landfill along Hwy 32 from Elm Road south to County Line Road
   v) any berm(s) to be located from the northeast corner of the Oak Creek South Ash Landfill to Elm Road near the Elm Road/railroad track intersection
   vi) any berm(s) to be located east of the railroad tracks and north of the Proposed Main Access Road as labeled on Exhibit A
d) a Lakefront Shoreline and Bluff Stabilization Plan in compliance with Section 17.0328 of the Municipal Code shall be submitted to the City at least 2 months prior to COC for Plan Commission approval.
e) proper drainage shall be maintained with no standing water except at retention/detention basins and wetlands.

6) A Fire Protection and Emergency Management Plan for the Property for the Construction Period shall be submitted to the City for ERGS Units 1 and 2 at least 2 months prior to COC of ERGS Unit 1 and for ERGS Unit 3 at least 2 months prior to COC of ERGS Unit 3.

7) A Fire Protection and Emergency Management Plan for the Property for the Operations Period shall be submitted to the City for ERGS Units 1 and 2 at least 6 months prior to the COD for ERGS Units 1 and 2 and for ERGS Unit 3 at least 6 months prior to the COD for ERGS Unit 3.

B. If required by the City, public easements for telephone, sanitary sewer, storm sewer and watermain shall be granted by the Owner. Said easements shall be maintained free and clear of any buildings, structures, trees or accessory outdoor appurtenances. Shrubbery type plantings shall be permitted provided there is access to each of the aforementioned systems and their appurtenances.

4. CONSTRUCTION

A. Until all of the berms in this area have been constructed, construction excavation, earthmoving, grading, and landscaping activities north and west of the Construction Setback Line A depicted on Exhibit A, between the Construction Setback Line A and the boundary of the Property nearest to the Oakview #3 or Barton Oaks Subdivisions, shall be permitted on Saturday from September 1 through May 31 from 6:30 a.m. to 5:00 p.m., and throughout the year Monday through Friday from 6:30 a.m. to 7:00 p.m.. Until all of the berms in this area have been constructed, construction activities to the east and south of Construction Setback Line A shall be permitted anytime except from 3:30 a.m. on Sunday to 6:30 a.m.

on Monday. .

B. After the berms identified in Condition 4.A. are constructed, no construction excavation, earthmoving, grading, or equipment laydown activities shall occur north and west of the Construction Setback Line B depicted on Exhibit A, between Construction Setback Line B and the boundary of the Property nearest to the Oakview #3 or Barton Oaks Subdivisions. Construction activities to the east and south of Construction Setback Line B shall be permitted anytime.

C. Construction shifts for ERGS shall not begin between 7:01 a.m. and 8:30 a.m. and 3:31 p.m. and 5:00 p.m.

D. No idling of earth-moving equipment shall be allowed for periods of more than 15 minutes north and west of the Construction Setback Line A depicted on Exhibit A, between the Construction Setback Line A and the boundary of the Property nearest to the Oakview #3 or Barton Oaks Subdivisions.

E. All construction related parking shall be located on the Property.

F. The Owner or Owner's representative and the Owner's construction contractors shall meet with the Police Chief prior to COC to discuss construction security plans and procedures.

G. During construction activities, dust management shall be conducted in accordance with the applicable state law and regulations.

H. In addition to the construction mitigation measures listed above, the following additional measures shall be undertaken:
   1) In order to minimize construction dust, construction roads will be paved where practical. Wet dust suppression will be used on roads when weather conditions permit. A wheel cleaning method will be provided for construction vehicles. Vehicle material covers will be used where practical and appropriate vehicle speeds will be established.
   2) Construction noise mitigation measures will be accomplished through a muffler inspection program for all heavy construction vehicles. If there is a non-compliance with the noise requirements, a supplemental muffler program will be used if feasible to further reduce noise levels from some construction vehicles.

5. <u>GRADING, BUILDING, AND SETBACKS</u>

A. Except for general maintenance, landscaping, wetland mitigation, or construction of access roads, transmission lines, underground utilities, and utility tie-ins, no construction activities shall occur in the following areas also depicted on Exhibit A attached hereto:

   1) from the south Elm Road right-of-way, 400 feet south beginning at Highway 32 on the west and ending at the railroad tracks on the east, except for grading of the soil berm to be located from the northeast corner of the Oak Creek South Ash Landfill to a point near the Elm Road/railroad track intersection,

   2) from the east Highway 32 right-of-way, 300 feet east beginning at Elm Road on the north and ending at County Line Road on the south, and

   3) from the south Oakwood Road right-of-way, 500 feet south beginning at the railroad tracks on the west and ending at Lake Michigan on the east.

B. Any soil berm along Highway 32 between County Line Road and Elm Road shall have a final elevation no higher that 775 feet mean sea level. During the ERGS construction period, the height of this berm may extend to no greater than 790 feet mean sea level. If the berm is extended higher than elevation 775

feet mean sea level, the Owner will be allowed one year following written notice by the City, to lower the berm to the final elevation of 775 feet mean sea level. The general location of this berm is depicted on Exhibit A attached herein. Construction of any berm in this area shall begin at COC and be completed no later than 12 months after the COC.

C. Any soil berm along Elm Road between Highway 32 and the railroad tracks shall have a final elevation no higher than 775 feet mean sea level. During the ERGS construction period, the height of this berm may extend to no greater than 790 feet mean sea level. If the berm is extended higher than elevation 775 feet mean sea level, the Owner will be allowed one year following written notice by the City, to lower the berm to the final elevation of 775 feet mean sea level. The general location of this berm is depicted on Exhibit A attached herein. Construction of any berm in this area shall begin at COC and be completed no later than 12 months after the COC.

D. Unless disallowed by the Public Service Commission, the Department of Natural Resources or Office of Commissioner of the Railroad, a screening berm(s) shall be placed east of the railroad tracks and north of the Proposed Main Access Road, as depicted on Exhibit A, such that they form a horizontally continuous barrier between the ERGS plant construction area and the Oakview #3 or Barton Oaks subdivisions. The berm(s) shall have a final elevation of at least 730 feet mean sea level but no greater than 740 feet mean sea level. During the ERGS construction period, the height of this berm may extend to no greater than 750 feet mean sea level. If the berm is extended higher than elevation 740 feet mean sea level, the Owner will be allowed one year following written notice by the City, to lower the berm to the final elevation of 740 feet mean sea level. Construction of this berm(s) shall begin at COC and be completed no later than 12 months after the COC.

E. A soil berm shall be placed from the northeast corner of the Oak Creek South Ash Landfill to a point near the Elm Road/railroad track intersection, as depicted on Exhibit A. The berm shall have a final elevation of at least elevation 730 feet mean level but no greater than 740 feet mean sea level. During the ERGS construction period, the height of this berm may extend to no greater than 750 feet mean sea level. If the berm is extended higher than elevation 740 feet mean sea level, the Owner will be allowed one year following written notice by the City, to lower the berm to the final elevation of 740 feet mean sea level. along its entire length. Construction of this berm shall begin at COC and be completed no later than 12 months after the COC.

F. Sideslopes of perimeter soil berms facing Elm Road, Highway 32, Oakwood Road, and the Oakwood #3/Barton Oaks subdivisions shall be contoured showing variable elevations and vegetated with a slope no steeper than 3 horizontal to 1 vertical.

G. No excavated soils that are contaminated, other than those approved by the Department of Natural Resources, shall be placed between the Construction Setback Line A (depicted on Exhibit A) and the Property lines nearest to the Oakview #3 or Barton Oaks subdivisions.

6. <u>MAINTENANCE AND OPERATION</u>

A. Solid waste collection and recycling shall be the responsibility of the Owner.

B. Outdoor storage shall not be within the setbacks outlined in the Grading, Building, and Setbacks Section.

C. During operations, dust management shall be conducted in accordance with the Department of Natural Resources Construction and Operations air permit requirements.

7. <u>SIGNS</u>

A. All signs visible from public roads shall conform to the provisions of Sec. 17.0706 of the Municipal Code.

B. No signage shall be allowed on the stacks.

8. **WATER SUPPLY**

A. For City water supply requirements up to 1,000 gpm nominal for the Property, the owner will connect to the Owner's existing 12-inch water main on the Property.

B. For City water supply requirements in excess of 1,000 gpm nominal, the Owner shall be responsible for the cost to provide water main service to the Property, as mutually determined and agreed upon by the Owner, City Engineer, and Water and Sewer Utility, in accordance with the City's "Master Plan for Water Supply Service."

9. **SANITARY SEWER**

A. For up to 200 gpm nominal of wastewater discharge to the City sanitary sewer mains from the Property, the Owner will connect to the Owner's existing 12-inch sanitary sewer discharge main on the Property.

B. For wastewater discharge in excess of 200 gpm nominal, the Owner shall be responsible for the cost to provide the sanitary sewer service to the Property, as mutually determined and agreed upon by the Owner, City Engineer, and Water and Sewer Utility, in accordance with the City's "Master Plan for Water Sanitary Sewer Service."

C. The Owner agrees that any wastewater or surface waters discharged from the Property shall not have a deleterious effect on the City's sanitary sewer system or surface waters.

10. **TRAFFIC, ROADWAYS, AND ACCESS**

A. The Owner shall repave Oakwood Road from Highway 32 to a terminating cul de sac, consistent with the City Design Manual. After a portion of Oakwood Road is vacated by the City, the Owner shall be responsible for the physical removal of the vacated portion of Oakwood Road , or its reconstruction as a private road. The Owner will not object to such vacation. The Owner shall dedicate any additional right-of-way needed for the cul de sac. All work shall be completed prior to the opening of the Visitor's Center.

B. The City shall design and construct a connector road from the new terminus of Elm Road to its closest frontage road, consistent with the City Design Manual. The Owner shall dedicate any additional right-of-way needed for the connector road.

C. The Owner shall construct a secondary access road off of Oakwood Road which shall connect to an existing roadway within the Property which ultimately connects to Highway 32. The Owner agrees to complete construction of this access road within 24 months of COC, or the opening of the Visitor's Center, whichever is first. Thereafter, the City shall commence vacation proceedings for a portion of Elm Road. Upon vacation of a portion of Elm Road the Owner shall be responsible for physical removal of any vacated portion of Elm Road. All physical removal of any vacated portion of Elm Road shall be completed within 2 months of commencement of its removal. The Owner will not object to such vacation. Unless disallowed by the Public Service Commission, the Department of Natural Resources or Office of Commissioner of the Railroad, the Owner will complete construction of the proposed main access road railroad crossing as shown on Exhibit A within 12 months of vacating Elm Road.

D. All construction worker and delivery vehicle access to the Property shall be directly off of Highway 32 on to the Property.

E. Within 12 months of the COC, the primary access point to the Property for operations personnel shall be directly from Highway 32.

F. In the event of an emergency that prohibits access from Highway 32, all traffic essential to the operations shall have the capability to access the Property from Oakwood Road.

G. Visitor Center access shall be from Oakwood Road. Access to the Property for the construction of the Visitor Center and its access road may be from Oakwood Road.

H. The Owner shall conduct a traffic study for Highway 32 from County Line Road to Highway 100 and be responsible for the installation of traffic control signals and turning lanes if recommended by the study, subject to approval by Department of Transportation provided that the applicable governmental entity acquires any land required for such turning lanes. The Owner shall reimburse the City for any and all costs incurred in acquiring any land required for such turning lanes.

11. NOISE DURING OPERATIONS

A. During operations, when no construction activities occur, noise levels shall be determined at specified locations using specified protocols as defined below. The monitoring locations, limits, monitoring and compliance protocols, reporting protocols, and non-compliance penalty are as follows.

1) Noise monitoring stations consisting of continuous noise monitoring devices and recorders shall be installed by the Owner by the COD of the last approved ERGS Unit and maintained by the Owner during the operational life of the ERGS to monitor noise emissions from the Property. The monitoring stations shall be installed at the locations described below and depicted on Exhibit A hereto attached and as agreed to by the City and the Owner. The monitoring stations shall be accessible to the Owner and City for purposes of data recording, quality assurance, quality control, and verification of results. The data collected shall include the 10 minute L_{eq}, and the 1 hour L_{eq}, L_{max}, L_1, L_{10}, L_{50}, and L_{90} for dbA and dbC, plus a full system calibration signal. All data shall be transmitted electronically to the Owner at the end of each day in a format agreed to by the City and the Owner. The Owner shall provide the City electronic access to the data on a real-time basis, in a format agreed to by the City and Owner. All costs to procure, install, and maintain the monitoring station shall be paid by the Owner. The continuous noise monitoring devices are not for assessing compliance.

Station Location	Description
1	East of Haas Park and north of Elm Road
2	Approximately half way between ERGS Unit 1 and 2 and monitoring location No. 1.

2) The noise emissions associated with operations activity on the Property, measured at monitoring location No. 1, must be less than or equal to the following dBA and dBC values.

dBA Limit (10 min.L_{eq})	dBC Limit (10 min.L_{eq})
50	60

3) Noise measurements shall be made in accordance with the methodology in the latest version of the American National Standards Institute (ANSI) S12.9/Part 1 and Part 3. The measurements shall be a 10 minute time-weighted average of dBA and dBC readings, exclusive of intrusive events, and shall be verified by both the City and Owner. The Owner shall be in compliance with the CUP if the measurements at location No. 1 do not exceed the limits designated above. The Owner shall be considered out of compliance with the CUP if the Owner or City records an exceedance of any limit (manual measurement required) and the Owner has been notified of an exceedance of any limit by the City and fails to restore the condition to a level below the compliance limit within 5 days thereafter. The 5 days is considered a grace period for the Owner to restore the condition to a level below the compliance limit. Noise emissions from safety/relief valves and during start-up shall be excluded from the noise compliance requirements.

4) Noise levels are to be measured by an engineer, technician, or acoustical consultant qualified by experience or training.

5) The noise measuring instrumentation shall comply with ANSI S1.4, ANSI S1.43, and ANSI S1.40. The noise level meter shall be a "Type 1 Precision" model.

6) If the Owner is considered out of compliance with the CUP, a fine of $1,000 per day shall be imposed against the Owner. The penalty shall begin on the first day after the City notifies the Owner that the compliance limit was not met.

12. NOISE DURING CONSTRUCTION

A. Noise levels during the construction of ERGS will be determined at a specified location using specified protocols as defined below. Noise limits are set for all ERGS construction activities on the Property. The monitoring location, limits, monitoring and compliance protocols, reporting protocols, and non-compliance penalties are as follows.

1) A noise monitoring station consisting of continuous noise monitoring device and recorder shall be installed by the Owner by the COC and maintained by the Owner during the period of construction of ERGS to monitor noise emissions from the Property. The monitoring station shall be installed at the location described below and depicted on Exhibit A hereto attached and as agreed to by the City and the Owner. The monitoring station shall be accessible to the City for purposes of data recording, quality assurance, quality control, and verification of results. The data collected shall include the 1 hour L_{eq}, L_{max}, L_1, L_{10}, L_{50}, and L_{90} for dbA, plus a full system calibration signal. All data shall be transmitted electronically to the Owner at the end of each day in a format agreed to by the City and the Owner. The Owner shall provide the City electronic access to the data on a real-time basis, in a format agreed to by the City and Owner. For the first 12 months after COC, the Owner shall submit monthly reports interpreting the noise monitoring data to the City. Thereafter, the Owner shall submit quarterly reports interpreting the noise monitoring data to the City. All costs to procure, install, and maintain the monitoring station shall be paid by the Owner.

Station Location	Description
1	East of Haas Park and north of Elm Road

2) To be in compliance with the CUP, the noise emissions associated with construction activity on the Property, measured at monitoring station No. 1, must be less than or equal to the following dBA value at the specified times.

a) Until completion of construction of the berms between the Construction Setback Line A and the boundary of the Property nearest to the Oakview #3 or Barton Oaks Subdivisions:

Monday – Friday

Hours	dBA Limit (1 Hour L_{50})
6:30 AM to 7:00 PM	None
7:00 PM to Midnight	63
Midnight to 6:30 AM	63

Saturday (September 1 through May 31)

Hours	dBA Limit (1 Hour L_{50})
6:30 AM to 5:00 PM	None
5:00 PM to Midnight	63
Midnight to 6:30 AM	63

Saturday (June 1 through August 31)

Hours	dBA Limit (1 Hour L_{50})
Anytime	63

Sunday

Hours	dBA Limit (1 Hour L_{50})
Anytime	63

b) After completion of construction of the berms between the Construction Setback Line A and the boundary of the Property nearest to the Oakview #3 or Barton Oaks Subdivisions, but prior to substantial completion of the excavation, earthmoving, and grading activities:

Monday – Friday

Hours	dBA Limit (1 Hour L_{50})
6:30 AM to 7:00 PM	75
7:00 PM to Midnight	63
Midnight to 6:30 AM	63

Saturday

Hours	dBA Limit (1 Hour L_{50})
6:30 AM to 5:00 PM	75
5:00 PM to Midnight	63
Midnight to 6:30 AM	63

Sunday

Hours	dBA Limit (1 Hour L_{50})
Anytime	63

c) After substantial completion of the excavation, earthmoving, and grading activities:

Monday – Friday

Hours	dBA Limit (1 Hour L_{50})
6:30 AM to 7:00 PM	75
7:00 PM to Midnight	55
Midnight to 6:30 AM	55

Saturday

Hours	dBA Limit (1 Hour L_{50})
6:30 AM to 5:00 PM	63
5:00 PM to Midnight	55
Midnight to 6:30 AM	55

Sunday

Hours	dBA Limit (1 Hour L_{50})
6:30 AM to 5:00 PM	63
5:00 PM to Midnight	55
Midnight to 6:30 AM	55

3) Noise measurements shall be made in accordance with the methodology in the latest version of the American National Standards Institute (ANSI) S12.9/Part 1 and Part 3. The measurements shall be a 1 hour L_{50} dBA readings, exclusive of intrusive events. The Owner shall be in compliance with the CUP if the measurements at location No. 1 do not exceed the limits designated above. The Owner shall be considered out of compliance with the CUP if the Owner or City records an exceedance of noise emissions from construction activity on the Property of any limit outlined above which has been substantiated by the City or a citizen complaint related to the exceedance, and the Owner fails to restore the condition to a level below the compliance limit, within 5 days thereafter. The 5 days is considered a grace period for the Owner to restore the condition to a level below the compliance limit. Noise emissions from pile-driving, blasting, and other similar activities shall be excluded from the noise compliance requirements provided the Owner notifies the City and residents of the Barton Oaks and Oakview #3 subdivisions in writing at least 7 days prior to such activity.

4) Noise levels are to be measured automatically at the monitoring station. The monitoring station is to be maintained by an engineer, technician, or acoustical consultant qualified by experience or training.

5) The noise measuring instrumentation shall comply with ANSI S1.4, ANSI S1.43, and ANSI S1.40. The noise level meter shall be a "Type 1 Precision" model.

6) If the Owner is considered out of compliance with the CUP, a fine of $1,000 per day shall be imposed against the Owner. The penalty shall begin on the first day after the City notifies the Owner that the compliance limit was not met.

13. MISCELLANEOUS

A. The approval and execution of this permit shall confirm acceptance of the terms and conditions hereof by the Owner, and this permit, when recorded, shall run with said Property until revoked by the City, or terminated by mutual agreement of the City and the Owner, and their subsidiaries, related entities, successors and assigns.

B. As to ERGS, the Owner shall be responsible for, and indemnify the City against all claims, damages and costs associated with toxic, hazardous, flammable or combustible materials stored, kept upon or coming to or from the Property, and for the removal, confinement, neutralizing clean-up or remediation of such materials by persons, firms, agencies, departments, or companies specializing in such materials.

C. The Owner shall provide the City with a written report from a qualified expert of the impact of barge traffic on recreational uses of Lake Michigan. The Owner agrees to cooperate with the governing agency to mitigate any impact caused by such barge traffic.

D. Except as required by the Federal Aviation Administration, all lighting on the site during construction and operations activities shall be directed away from the Oakview #3 and Barton Oaks subdivisions.

E. The Owner shall be responsible for implementation of any plans included herein according to schedules that may be approved by the City.

14. INSPECTIONS AND PERMIT FEES

A. City inspections will be conducted in accordance with state and local law. The Owner will reimburse the City for any out-of-pocket expenses related to any required and authorized inspections to the extent that the City has jurisdiction to conduct such inspections. The City will consider utilizing the Owner's inspection reports in lieu of hiring an independent inspector.

15. PERMITTED USES

A. Power generation, transmission, and distribution

B. Usual and customary accessory uses to the above listed permitted uses including, the Visitor's Center, coal ash disposal facilities, and air and noise monitoring equipment and facilities.

16. TIME OF COMPLIANCE

A. The Owner shall begin installing or constructing the elements required in these conditions and restrictions for the conditional uses, upon receipt of the Certificate of Public Convenience and Necessity required by the Public Service Commission, the air and Chapter 30 Permits required by the Department of Natural Resources, and approvals required by the Owner for ERGS. This conditional use approval shall expire within 6 months after decommissioning of the last operating power generating unit on the Property.

17. COAL STORAGE AND HANDLING FACILITIES

A. If approved by the Public Service Commission and permitted by the Department of Natural Resources, all coal storage and handling facilities shall be located within the rail spur loop, approximately 2,000 feet southeast of the intersection of Elm Road and the railroad tracks in order to mitigate potential impacts to the residents of the Oakview #3 and Barton Oaks subdivisions.

18. OTHER REGULATIONS

A. Compliance with all other applicable State and Federal regulations not heretofore stated or referenced, is mandatory.

B. City and Owner agree that this CUP shall be, to the extent applicable under Wisconsin law, subject to the superintending authority of the State. Nothing herein shall preclude the City from challenging the State's authority.

19. CHANGES

A. Any substantial change to a condition or requirement outlined in this Conditional Use Permit, including but not limited to noise limits, must be presented to the Director of Community Development and the City Engineer for review. If the Director of Community Development or the City Engineer considers the change significant to the health and welfare of the City, the change must be approved by the Plan Commission. If the Director of Community Development and the City Engineer consider a change to be insignificant to the health and welfare of the City, they may approve the change.

B. The City and Owner reserve their rights to modify this agreement if any changes are made to the ERGS development plan by the Owner or a regulatory agency.

20. NOTIFICATIONS

A. Any notifications or notices related to this CUP by the City shall be directed to the Owner's local affairs representative, ERGS plant manager, and OCPP plant manager, or their designees. Any notifications or notices related to this CUP by the Owner shall be directed to the City's Director of Community Development.

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Created: June 3, 2003
Revision Number: 1

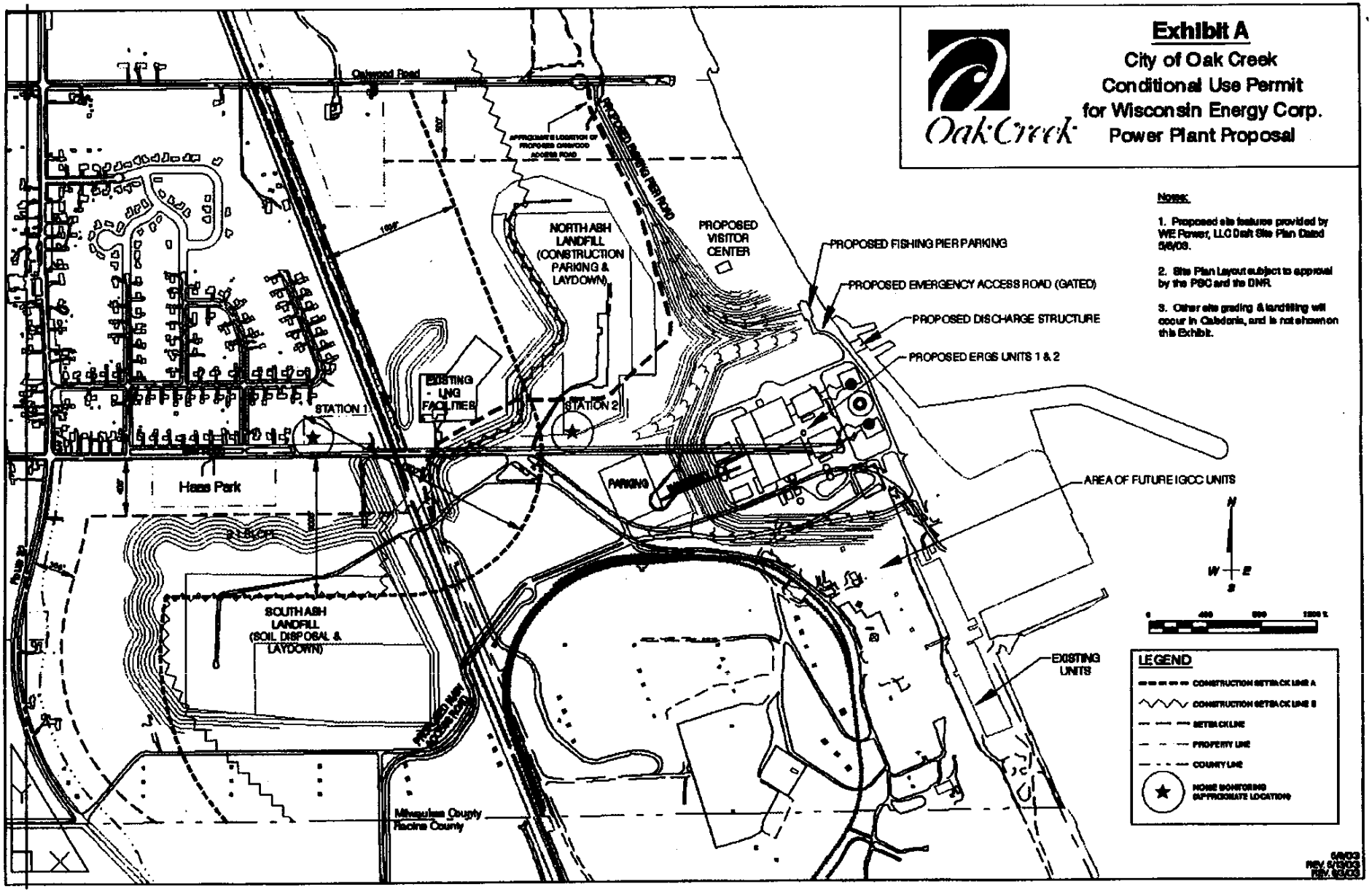


Exhibit A
City of Oak Creek
Conditional Use Permit
for Wisconsin Energy Corp.
Power Plant Proposal
Oak Creek
Notes:
1. Proposed site features provided by WE Power, LLC Draft Site Plan Dated 5/6/03.
2. Site Plan Layout subject to approval by the PSC and the DNR.
3. Other site grading & landfilling will occur in Caledonia, and is not shown on this Exhibit.
Oakwood Road
NORTH ASH LANDFILL (CONSTRUCTION PARKING & LAYDOWN)
PROPOSED VISITOR CENTER
PROPOSED FISHING PIER PARKING
PROPOSED EMERGENCY ACCESS ROAD (GATED)
PROPOSED DISCHARGE STRUCTURE
PROPOSED ERGS UNITS 1 & 2
EXISTING LNG FACILITIES
STATION 1
STATION 2
Hass Park
PARKING
AREA OF FUTURE IGCC UNITS
SOUTH ASH LANDFILL (SOIL DISPOSAL & LAYDOWN)
EXISTING UNITS
Milwaukee County
Racine County
N
W
E
S
LEGEND
CONSTRUCTION SETBACK LINE A
CONSTRUCTION SETBACK LINE B
SETBACK LINE
PROPERTY LINE
COUNTY LINE
NOISE MONITORING (APPROXIMATE LOCATION)

Acronyms

Abbreviation or Acronym	Definition
AADT	Annual average daily traffic
ACGIH	American Council of Governmental and Industrial Hygienists
AGR	Acid gas removal
AP-8	Advance Plan 8
ASU	Air separation unit
ATC	American Transmission Company
BACT	Best Available Control Technologies
BMP	Best Management Practices
BTA	Best technology available
BTU	British thermal unit
C_aO	Calcium oxided
C&I	Commercial and Industrial
C&NW	Chicago and Northwestern Railroad
CC	Combined cycle
CCP	Coal combustion production
CH_4	Methane
CLSM	Controlled low strength material
CO	Carbon monoxide
CO_2	Carbon dioxide
Commission or PSC	Public Service Commission of Wisconsin
CORMIX	Cornell Mixing Zone Expert System
CPCN	Certificate of Public Convenience and Necessity
CSH	Critical species habitat
CT	Combustion turbine
CUB	Citizens' Utility Board
CUP	Conditional Use Permit
dB	Decibels
dBA	Decibels A-weighted
dBC	Decibels C-weighted
DMA	Department of Military Affairs
DNR	Department of Natural Resources
DOA	Department of Administration
DOE	Department of Energy
DSM	Demand-side management
EADA	Early ash disposal area

Abbreviation or Acronym	Definition
EGEAS	Electric Generation Expansion Analysis System
EHV	Extra high voltage
EIA	Energy Information Administration
EIS	Environmental impact statement
EMF	Electromagnetic fields
EPA	Environmental Protection Agency
EPC	Engineer, procure, construct
EPRI	Electric Power Research Institute
ERGS	Elm Road Generating Station
ESP	Electrostatic precipitators
EWU	Eastern Wisconsin Utilities
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FG-hr	Flowgate hours
GLARC	Great Lakes Archaeological Research Center, Inc.
GPM	Gallons per minute
Gr/acf	Grains per actual cubic foot
Gr/dscf	Grains per dry standard cubic foot
GWh	Gigawatt hours (billionwatt hours)
H_2S	Hydrogen sulfide
HAP	Hazardous air pollutants
H_g	Mercury
HRSG	Heat recovery steam generator
Hz	Hertz
INRA	Isolated natural resource areas
IP	Intermediate pressure
IGCC	Integrated-coal gasification combined-cycle
IPP	Independent Power Producer
kV	Kilovolt – 1,000 volts
kW	Kilowatt
kWh	Kilowatt-hour
LAER	Lowest achievable emission rate
LDC	Local distribution company
LNG	Liquified natural gas
LTGC	Low temperature gas cooling
m/s	Meters per second
MACT	Maximum Achievable Control Technologies
MAIN	Mid-American Interconnected Network
MAPP	Mid-Content Area Power Pool

Abbreviation or Acronym	Definition
mG	Milligauss
Mgd	Million gallons per day
MGE	Madison Gas and Electric Company
MISO	Midwest Independent System Operator
mmBtu	Million British thermal units
MMSD	Milwaukee Metropolitan Sewerage District
MP	Measurement protocol
Msl	Mean sea level
MSDS	Material safety data sheets
MW	Megawatt
MWh	Megawatt hour
MWH	Montgomery Watson Harza and Associates
NAAQS	National Ambient Air Quality Standards
N_2O	Nitrous oxide
NERC	North American Electric Reliability Council
NOAA	National Oceanic and Atmospheric Administration
NPDES	National Pollution Discharge Elimination System
NRC	Nuclear Regulatory Commission
NRT	Natural Resource Technology
NSPS	New Source Performance Standard
NO_2	Nitrogen dioxide
NOx	Nitrogen oxides
NSR	New Source Review
O_2	Ozone
O&M	Operation and Maintenance
OCER	Oak Creek Elm Road
OCN	Oak Creek North
OCPP	Oak Creek Power Plant
OCR	Office of the Commissioner of Railroads
OCS	Oak Creek South
PAH	Polycyclic aromatic hydrocarbons
Pb	Lead
PCB	Polychlorinated biphenyls
PEC	Primary environmental corridor
PM	Particulate matter
PM_{10}	Particulate matter less than 10 microns in diameter
PM_{25}	Particulate matter less than 25 microns in diameter
POTW	Publicly owned treatment works
PPM	Parts per million
PPMDV	Parts per million dry volume

Abbreviation or Acronym	Definition
PPA	Power Purchase Agreement
PRB	Powder River Basic coal
PSC or Commission	Public Service Commission
PSD	Prevention of significant deterioration
PSIA	Per square inch absolute
PSIG	Pounds per square inch gauge
PTC	Production tax credit
PV	Photovoltaic
PWGS	Port Washington Generating Station
PWPP	Port Washington Power Plant
RACT	Reasonably available control technology
ROW	Right-of-way
RTP	RTP Environmental Associates (consultant)
SCPC	Super-critical pulverized coal
SCR	Selective Catalytic Reduction
SEA	Strategic Energy Assessment
SEWRPC	Southeastern Wisconsin Regional Planning Commission
SHPO	State Historic Preservation Officer
SIP	State Implementation Plan
SO_2	Sulfur dioxide
SquiRTS	Screening Quick Reference Tables
SRU	Sulfur recovery unit
SSO	Structural setback overlay
STEP	Statewide Technical and Economic Potential
STG	Steam turbine generator
STS	STS Consultants, Ltd.
SWPPP	Storm water pollution prevention plan
Syngas	Synthetic gas
TCF	Trillion cubic feet
TGU	Tailgas treating unit
THPO	Tribal Historic Preservation Officer
TLR	Transmission loading relief
TLV	Threshold limit value
Tpy	Total suspended particulates
μ/m^3	Micrograms per cubic meter
UP	Union Pacific Railroad
US ACOE	United States Army Corps of Engineers
US EPA	United States Environmental Protection Agency
USH	United States Highway
VOC	Volatile organic compounds

Abbreviation or Acronym	Definition
WEC	Wisconsin Electric Company
WEPA	Wisconsin Environmental Policy Act
WEPCO	Wisconsin Electric Power Company
WHS	Wisconsin Historical Society
WPDES	Wisconsin Pollution Discharge Elimination System
WPPI	Wisconsin Public Power Incorporated
WQC	Water quality criterion
WUMS	Wisconsin Upper Michigan System

APPENDIX

(Supplemental appendix, *Final Environmental Impact Statement: Elm Road Generating Station – Volume 2*, accepted per court order dated 2/24/05)
WI Elec. Power Co., W.E. Power, LLC and WI Energy Corp

July
2003

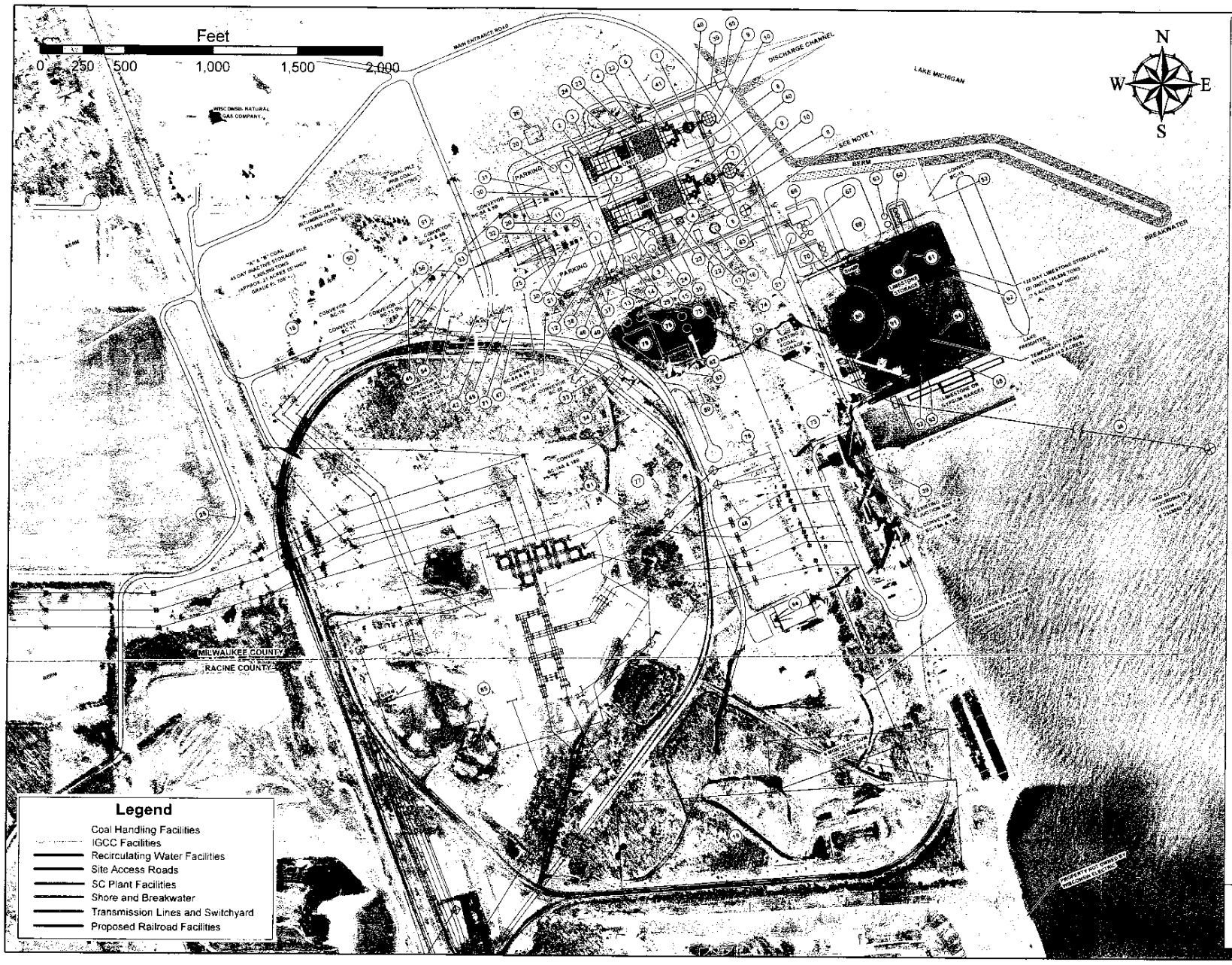
PUBLIC SERVICE COMMISSION OF WISCONSIN
DEPARTMENT OF NATURAL RESOURCES

Final Environmental Impact Statement

Elm Road Generating Station – Volume 2

Docket 05-CE-130

Date Issued, July 2003



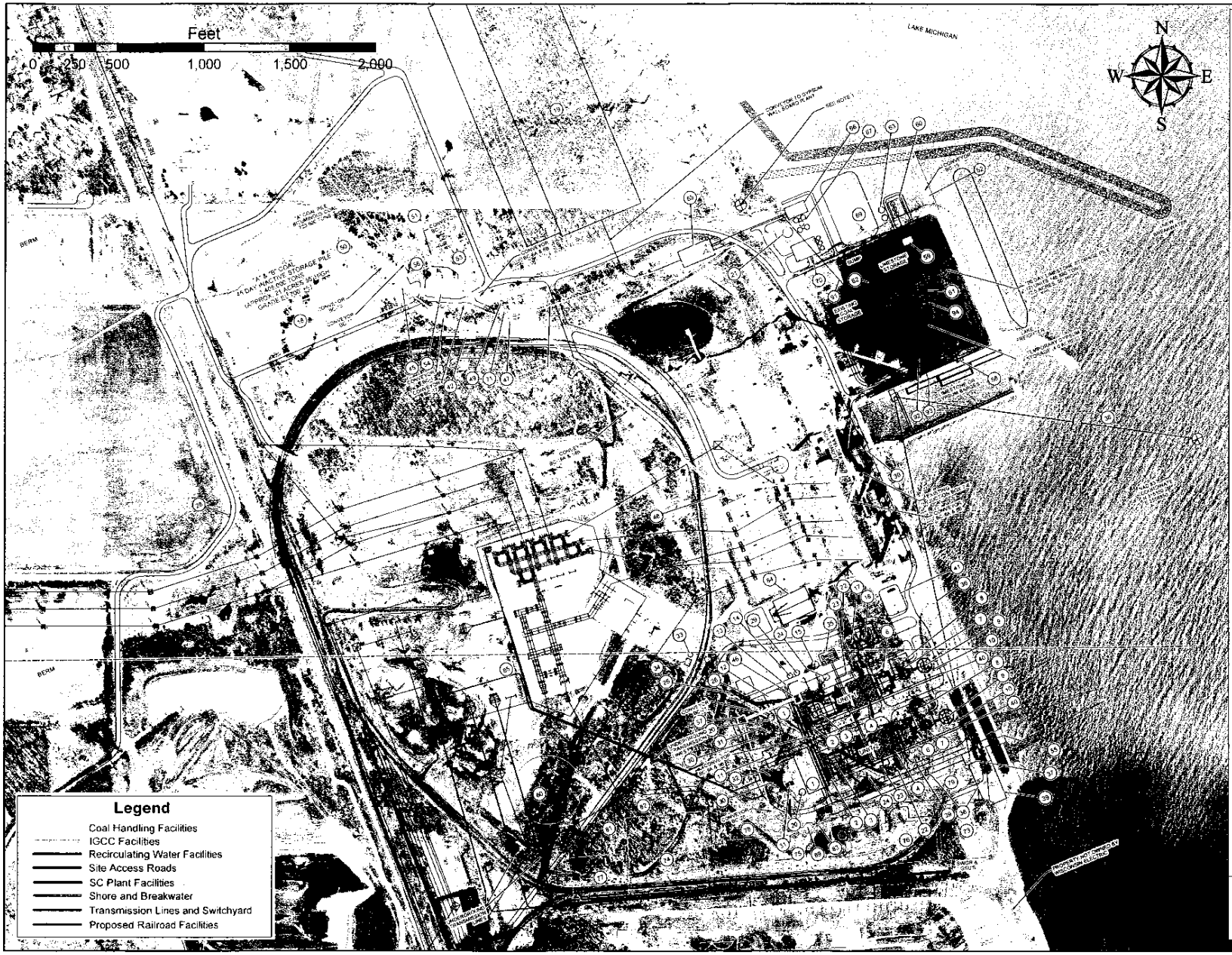
EQUIPMENT & FACILITIES ITEM DESCRIPTION

1	TURBINE BUILDING UNIT 1 & 2
2	COAL HANDLING BAY
3	BOILER BUILDING
4	BAGHOUSE
5	UNUSED
6	ID FANS
7	ABSORBER
8	ABSORBER PUMP & ELECTRICAL BUILDING
9	CHIMNEY
10	CEMS BUILDINGS
11	CONTROL BUILDING (WITH DIESEL GENERATORS & AIR COMPRESSORS)
12	SERVICE BUILDING & AUX. BOILER 1ST FLOOR MAINTENANCE FACILITIES 2ND F. COAL ADMINISTRATION FACILITIES
13	WATER TREATMENT BUILDING & BULK ACID/CAUSTIC STORAGE TANKS
14	DEMINERALIZED WATER TANK
15	SERVICE WATER TANK
16	FUEL OIL STORAGE TANK
17	FUEL OIL PUMP HOUSE
18	3 DAY ACTIVE COAL STORAGE & RECLAIM FACILITY
19	PROPOSED GYPSUM WALL BOARD PLANT
20	CONDENSATE STORAGE TANK
21	ABSORBER HOLDING TANK
22	FLY ASH SILO (72HRS)
23	FLY ASH VACUUM BLOWER & ELECTRICAL BUILDING
24	BOTTOM ASH BINS
25	HYDROGEN & CARBON DIOXIDE AREA
26	WAREHOUSE
27	UNUSED
28	GUARDHOUSE
29	WASTE NEUTRALIZATION TANK
30	MAIN POWER TRANSFORMER
31	UNIT AUX TRANSFORMER
32	STATION AUXILIARY TRANSFORMER
33	UREA SYSTEM STORAGE SILO
34	UREA SYSTEM BLOWER BLDG
35	UREA/AMMONIA ENCLOSURE
36	CIRCULATING WATER INTAKE PIPE
37	CIRCULATING WATER INTAKE PUMP HOUSE
38	CIRCULATING WATER SUPPLY PIPE
39	CIRCULATING WATER DISCHARGE PIPE
40	PIPE RACK
41	STORM WATER BASIN
42	COAL CAR DUMPER & TRAIN POSITIONER
43	UNUSED
44	UNUSED
45	COAL TRANSFER TOWER 3
46	COAL TRANSFER TOWER 4
47	COAL TRANSFER TOWER 5
48	COAL TRANSFER TOWER 6
49	COAL CRUSHER HOUSE
50	COAL RECLAIM HOPPER - PILE A
51	COAL RECLAIM HOPPER - PILE B
52	COAL SHIP UNLOADER & HOPPERS
53	COAL PILE SEDIMENTATION BASIN
54	ASH REBURN HOPPER BLDG
55	SEAL WELL STRUCTURE
56	COAL YARD MAINTENANCE BUILDING
57	UNUSED
58	LIMESTONE BARGE UNLOADING PAD W/BARGE UNLOADER AND HOPPER/FEEDER
59	LIMESTONE RECLAIM HOPPER ENCLOSURE
60	LIMESTONE SILOS, MILL & PREPARATION BUILDING
61	LIMESTONE CONVEYORS
62	LIMESTONE PILE PERIMETER DRAINAGE AREA
63	LIMESTONE SLURRY STORAGE TANKS
64	UNUSED
65	GYPSUM STORAGE BUILDING (30 DAY STORAGE)
66	GYPSUM DEWATERING BUILDING
67	PRIMARY GYPSUM DEWATERING TANKS
68	UNUSED
69	WASTE WATER COLLECTION & EQUALIZATION BASIN
70	WASTE WATER TREATMENT BLDG.
71	COAL HANDLING CONTROL/SWITCHGEAR BLDG
72	UNUSED
73	IGCC POWER BLOCK
74	IGCC AIR SEPARATION UNIT
75	IGCC GASIFICATION FACILITY
76	IGCC ACID GAS REMOVAL UNIT (SELEXOL FROM)
77	IGCC SULFUR RECOVERY UNIT
78	IGCC COAL PREPARATION
79	IGCC STORM WATER BASIN
80	IGCC FLARE
81	IGCC SULFURIC ACID STORAGE TANKS
82	IGCC WASTE WATER TREATMENT
83	IGCC SLAG STORAGE SILO
84	FLY ASH STORAGE BUILDING
85	SWITCHYARD EXPANSION FOR SCPC & IGCC UNITS
86	EXISTING UNITS 5 TO 8 TURBINE ROOMS (NOT SHOWN)
87	EXISTING UNITS 5 TO 8 BOILER ROOMS (NOT SHOWN)
88	UNIT NO. 9 BUILDING
89	IGCC FUEL OIL TANK
90	UNUSED
91	GYPSUM CONVEYOR
92	GYPSUM HOPPER FOR BARGE LOADING CONVEYOR
93	GYPSUM BARGE LOADING CONVEYOR
94	GYPSUM PILE PERIMETER DRAINAGE AREA

NOTES

1. THE COORDINATES USED ARE BASED ON N 10000 & E 10000 BEING EQUAL TO THE PLANT 8 DOCK BASE LINE OF N 6014.1 & E 10 BE MOVED TO NORTH 313 38' 42" EAST 2581.661 IN WISCONSIN STATE PLANE SYSTEM GRID (REF RUPKER/MILKE EXISTING BASELINE)
2. ELEVATIONS SHOWN ARE ABOVE MEAN SEA LEVEL FOR CALCULATION ELEVATIONS SUBTRACT 581.2 (PLANT ELEVATION EQUAL 0000 - 581.2 MSL)
3. SCPC PLANT GRADE = 584.0' (PLANT ELEVATION = 10.8') COAL HANDLING GRADE IS 590.0' (PLANT ELEVATION = 16.8')

Figure Vol. 2-1
Plant Equipment Layout - North Site



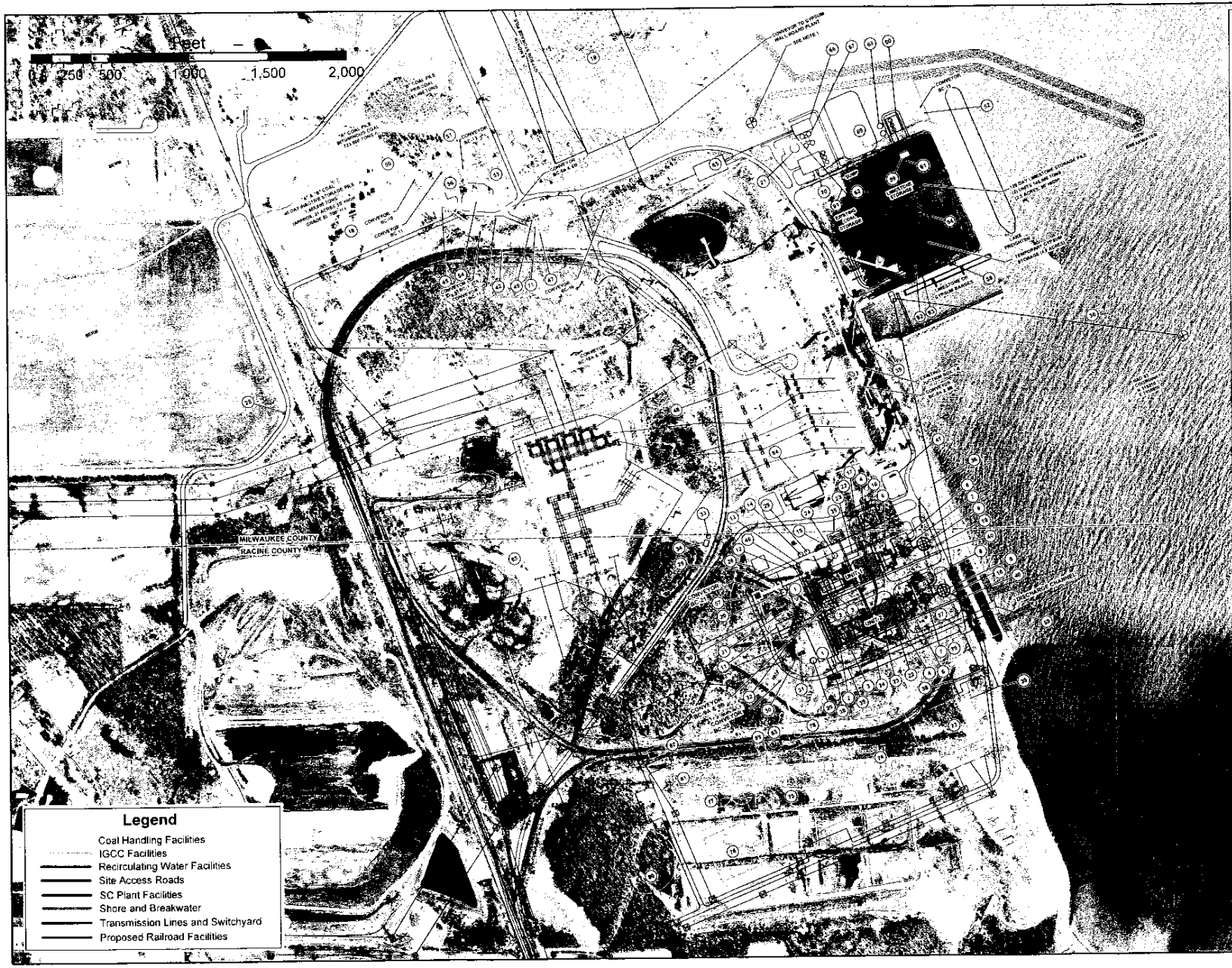
EQUIPMENT & FACILITIES ITEM DESCRIPTION

1 TURBINE BUILDING UNIT 1 & 2
2 COAL HANDLING BAY
3 BOILER BUILDING
4 BAGHOUSE
5 UNUSED
6 I.D. FANS
7 ABSORBER
8 ABSORBER PUMP & ELECTRICAL BUILDING
9 CHIMNEY
10 CEMS BUILDINGS
11 CONTROL BUILDING (WITH DIESEL GENERATORS, AIR COMPRESSORS)
12 SERVICE BUILDING & AREA OF BUILDING
1ST FLOOR MAINTENANCE FACILITIES
2ND FLOOR ADMINISTRATION FACILITIES
13 WATER TREATMENT BUILDING & BULK HYDROXIDE STORAGE TANKS
14 DEMINERALIZED WATER TANK
15 SERVICE WATER TANK
16 FUEL OIL STORAGE TANK
17 FUEL OIL PUMP HOUSE
18 3 DAY ACTIVE COAL STORAGE & RECLAIM FACILITY
19 PROPOSED GYPSUM WALL BOARD PLANT
20 CONDENSATE STORAGE TANK
21 ABSORBER HOLDING TANK
22 FLY ASH SILO (12HRS)
23 FLY ASH VACUUM BLOWER & ELECTRICAL BUILDING
24 BOTTOM ASH BINS
25 HYDROGEN & CARBON DIOXIDE AREA
26 WAREHOUSE
27 UNUSED
28 DEWATERING
29 WASTE NEUTRALIZATION TANK
30 MAIN POWER TRANSFORMER
31 UNIT AUX. TRANSFORMER
32 STATION AUXILIARY TRANSFORMER
33 UREA SYSTEM STORAGE SILO
34 UREA SYSTEM BLOWER BLDG
35 UREA/AMMONIA DISTILLERIES
36 CIRCULATING WATER INTAKE PIPE
37 CIRCULATING WATER INTAKE PUMP HOUSE
38 CIRCULATING WATER SUPPLY PIPE
39 CIRCULATING WATER DISCHARGE PIPE
40 PIPE RACK
41 STORM WATER BASIN
42 COAL CAR DUMPER & TRAIN POSITIONER
43 UNUSED
44 UNUSED
45 COAL TRANSFER TOWER 3
46 COAL TRANSFER TOWER 4
47 COAL TRANSFER TOWER 5
48 COAL TRANSFER TOWER 6
49 COAL CRUSHER HOUSE
50 COAL RECLAIM HOPPER / PILE A
51 COAL RECLAIM HOPPER / PILE B
52 COAL SHIP UNLOADER & HOPPERS
53 COAL PILE SEDIMENTATION BASIN
54 ASH RECLAIM HOPPER BLDG
55 SEAL WELL STRUCTURE
56 COAL YARD MAINTENANCE BUILDING
57 COAL TRANSFER TOWER 7
58 LIMESTONE BARGE UNLOADING PAD (WITH HOPPER UNLOADER AND HOPPER FEEDER)
59 LIMESTONE RECLAIM HOPPER (PILE C SUPPLY)
60 LIMESTONE SILOS, MILLS & PREPARATION BUILDING
61 LIMESTONE CONVEYORS
62 LIMESTONE PILE RAINWATER DRAINAGE AREA
63 LIMESTONE SLURRY STORAGE TANKS
64 UNUSED
65 GYPSUM STORAGE BUILDING - 7 DAY STORAGE
66 GYPSUM DEWATERING BUILDING
67 PRIMARY GYPSUM DEWATERING TANKS
68 UNUSED
69 WASTE WATER COLLECTION & EQUALIZATION BASIN
70 WASTE WATER TREATMENT BLDG
71 COAL HANDLING CONTROL (WITH CHECK BUILD)
72 UNUSED
73 IGCC POWER BLOCK
74 IGCC AIR SEPARATION UNIT
75 IGCC GASIFICATION FACILITY
76 IGCC ACID GAS REMOVAL UNIT
77 IGCC SULFUR RECOVERY UNIT
78 IGCC COAL PREPARATION
79 IGCC STORM WATER BASIN
80 IGCC FLARE
81 IGCC SULFURIC ACID STORAGE TANKS
82 IGCC WASTE WATER TREATMENT
83 IGCC SLAG STORAGE SILO
84 FLY ASH STORAGE BUILDING
85 SWITCHYARD (WITH MAIN POWER TRANSFORMERS & IGCC UNITS)
86 EXISTING UNITS 3 TO 5 TURBINE ROOMS (NOT SHOWN)
87 EXISTING UNITS 3 TO 5 BOILER ROOMS (NOT SHOWN)
88 UNIT NO. 6 BUILDING (NOT SHOWN)
89 IGCC FUEL OIL TANK
90 UNUSED
91 GYPSUM CONVEYOR
92 GYPSUM HOPPER FOR BARGE LOADING CONVEYOR
93 GYPSUM BARGE LOADING CONVEYOR
94 GYPSUM PILE PERIMETER DRAINAGE AREA

NOTES

1 THE COORDINATES USED ARE BASED ON N 10000 & E 10000 BEING EQUAL TO THE PLANT & DOCK BASE LINE OF N 0.0 & E 0.0 BEARING EQUAL TO NORTH 31° 58' 41" EAST 2,981,681.93 WISCONSIN STATE PLANE SYSTEM GRID, PER WISDOT, OF FRISTMS BASELINE
2 ELEVATIONS SHOWN ARE ABOVE MEAN SEA LEVEL FOR OAK CREEK PLANT DATUM ELEVATIONS SUBTRACT 581.2 (PLANT ELEVATION = 581.2 MSL)
3 SCPC PLANT GRADE IS 592.0' - PLANT ELEVATION = 10.8'; COAL HANDLING GRADE IS 708.0' - PLANT ELEVATION = 116.8'

Figure Vol. 2-2
Plant Equipment Layout - South Site



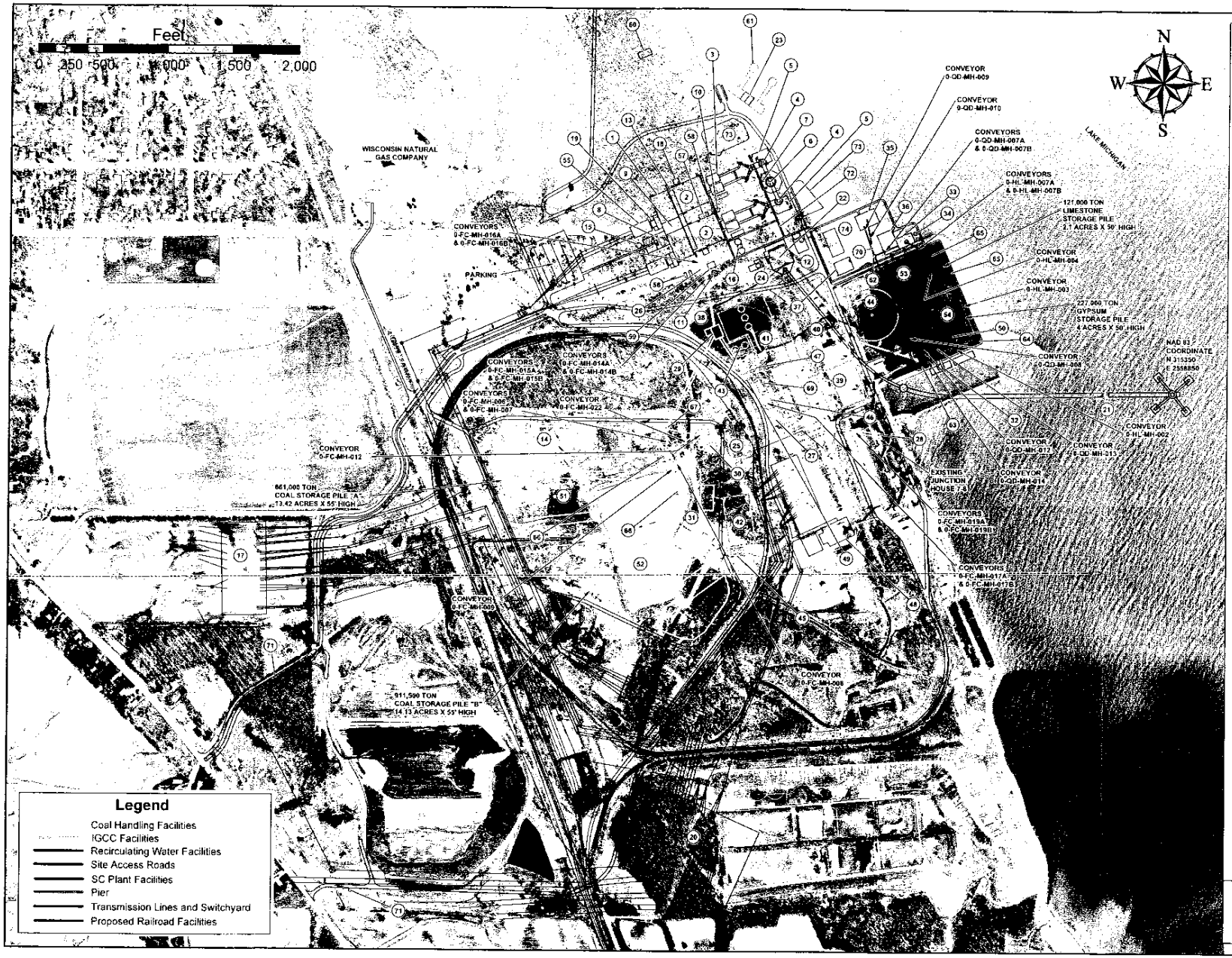
EQUIPMENT & FACILITIES ITEM DESCRIPTION

1 TURBINE BUILDING UNIT 1 & 2
2 COAL HANDLING BFI
3 BOILER BUILDING
4 BAGHOUSE
5 UNUSED
6 ID FANS
7 ABSORBER
8 ABSORBER PUMP & ELECTRICAL BUILDING
9 CHIMNEY
10 CEMS BUILDING
11 CENTRAL BUILDING (WITH DIESEL GENERATORS AIR COMPRESSORS)
12 SERVICE BUILDING & A.V.R. BOILER 1ST FLOOR MAINTENANCE FACILITIES 2ND FLOOR ADMINISTRATION FACILITIES
13 WATER TREATMENT BUILDING & BULK ACID/CAUSTIC STORAGE TANKS
14 DEMINERALIZED WATER TANK
15 SEWAGE WATER TANK
16 FUEL OIL STORAGE TANK
17 FUEL OIL PUMP HOUSE
18 SEMI-ACTIVE COAL STORAGE & RECLAIM FACILITY
19 PROPOSED GYPSUM WALL BOARD PLANT
20 CONDENSATE STORAGE TANK
21 ABSORBER HOLDING TANK
22 FLY ASH SILO (TYPES)
23 FLY ASH VACUUM BLOWER & ELECTRICAL BUILDING
24 BOTTOM ASH BINS
25 HYDROGEN & CARBON DIOXIDE AREA
26 WAREHOUSE
27 UNUSED
28 SUMP HOUSE
29 WASTE NEUTRALIZATION TANK
30 MAIN POWER TRANSFORMER
31 UNIT AUX TRANSFORMER
32 STATION AUXILIARY TRANSFORMER
33 NHRA SYSTEM STORAGE SILO
34 NHRA SYSTEM BLOWER BLDG
35 LIME/AMMONIA ENCLOSURE
36 CIRCULATING WATER INTAKE PIPE
37 CIRCULATING WATER INTAKE PUMP HOUSE
38 CIRCULATING WATER SUPPLY PIPE
39 CIRCULATING WATER DISCHARGE PIPE
40 PIPE RACK
41 STORM WATER BASIN
42 COAL CAR DUMPER & TRAIN MOVITIONER
43 UNUSED
44 UNUSED
45 COAL TRANSFER TOWER 3
46 COAL TRANSFER TOWER 4
47 COAL TRANSFER TOWER 5
48 COAL TRANSFER TOWER 6
49 COAL CRUSHER HOUSE
50 COAL RECLAIM HOPPER - PILE 4
51 COAL RECLAIM HOPPER - PILE 5
52 COAL SHIP UNLOADER & HOPPERS
53 COAL PILE SEDIMENTATION BASIN
54 ASH REBURN HOPPER BLDG
55 SEAL WELL STRUCTURE
56 COAL YARD MAINTENANCE BUILDING
57 COAL TRANSFER TOWER 7
58 LIMESTONE BARGE UNLOADING PAD (WHARFSIDE UNLOADER AND HOPPER FEEDER)
59 LIMESTONE RECLAIM HOPPER ENCLOSURE
60 LIMESTONE BALL MILL & PREPARATION BUILDING
61 LIMESTONE CONVEYORS
62 LIMESTONE PILE PERIMETER DRAINAGE AREA
63 LIMESTONE SLURRY STORAGE TANKS
64 UNUSED
65 GYPSUM STORAGE BUILDING (3 DAY STORAGE)
66 GYPSUM DEWATERING BUILDING
67 PRIMARY GYPSUM DEWATERING TANKS
68 UNUSED
69 WASTE WATER COLLECTION & EQUALIZATION BASIN
70 WASTE WATER TREATMENT BLDG
71 COAL HANDLING CONTROL/SWITCHGEAR BLDG
72 UNUSED
73 IGCC POWER BLOCK
74 IGCC AIR SEPARATION UNIT
75 IGCC GASIFICATION FACILITY
76 IGCC ACID GAS REMOVAL UNIT
77 IGCC SULFUR RECOVERY UNIT
78 IGCC COAL PREPARATION
79 IGCC STORM WATER BASIN
80 IGCC FLARE
81 IGCC SULFURIC ACID STORAGE TANKS
82 IGCC WASTE WATER TREATMENT
83 IGCC SLAG STORAGE SILO
84 FLY ASH STORAGE BUILDING
85 SWITCHYARD EXPANSION FOR SCPC & IGCC UNITS
86 EXISTING UNITS 5 TO 8 TURBINE ROOMS (NOT SHOWN)
87 EXISTING UNITS 5 TO 8 BOILER ROOMS (NOT SHOWN)
88 UNIT NO. 6 BUILDING (NOT SHOWN)
89 IGCC PLOT TANK
90 UNUSED
91 GYPSUM CONVEYOR
92 GYPSUM HOPPER FOR BARGE LOADING CONVEYOR
93 GYPSUM BARGE LOADING CONVEYOR
94 GYPSUM PILE PERIMETER DRAINAGE AREA

NOTES

1 THE COORDINATES USED ARE BASED ON N 1000 & E 1000 BEING EQUAL TO THE PLANT SOUTH BASELINE OF BLDG 8 & 9 BEING EQUAL TO NORTH 1172.36' AND EAST 2,361.491 IN WISCONSIN STATE PLANE SYSTEM GRID (REFERENCE EXISTING BASELINE)
2 ELEVATIONS SHOWN ARE ABOVE MEAN SEA LEVEL FOR SAK CREEK PLANT DATUM ELEVATIONS SUBTRACT 581.0' (PLANT ELEVATION 7-6-K 9630 = 581.2 MSL)
3 SCPC PLANT GRADE IS 662.0' (PLANT ELEVATION = 10 ft) COAL HANDLING GRADE IS 704.0' (PLANT ELEVATION = 118 ft)

Figure Vol. 2-3
Plant Equipment Layout - South Site-Exp



EQUIPMENT & FACILITIES ITEM DESCRIPTION

1 TURBINE GENERATOR BUILDING (2)
2 BOILER BUILDING
3 BAGHOUSE (4)
4 ABSORBER/WET ESP'S (2)
5 ABSORBER PUMP/CONTROL BUILDING
6 CHIMNEY
7 CEMS BUILDING (2)
8 MAINTENANCE/WAREHOUSE/
ADMINISTRATION/CONTROL BUILDING
MAINTENANCE BUILDING/WAREHOUSE - 1ST FLOOR
ADMINISTRATION BUILDING - 2ND FLOOR
CONTROL BUILDING - 3RD FLOOR
9 WATER TREATMENT AREA
BULK ACID/CAUSTIC STORAGE TANKS
10 DEMINERALIZED WATER STORAGE TANK
11 SERVICE/FIRE WATER TANK
12 FUEL OIL PUMP HOUSE & FUEL OIL STORAGE TANK
13 SILO FAN (2)
14 XDAY ACTIVE COAL STORAGE FACILITY
15 CONDENSATE STORAGE TANK (2)
16 FLY ASH SILO (2) & FLY ASH VACUUM BLOWER BUILDING
17 138KV SWITCHYARD
18 BOTTOM ASH BIN (2)
19 MAIN POWER TRANSFORMER (2)
& UNIT AUXILIARY TRANSFORMER (4)
20 345 KV SWITCHYARD
21 CIRCULATING WATER INTAKE TUNNEL
22 CIRCULATING WATER INTAKE PUMP HOUSE
23 CIRCULATING WATER DISCHARGE STRUCTURE
24 AMMONIA UNLOADING TANKS & AMMONIA PUMPS
25 PRIMARY CRUSHER HOUSE
26 COAL TRANSFER TOWER NO. 3
27 COAL TRANSFER TOWER NO. 4
28 COAL TRANSFER TOWER NO. 5
29 COAL CRUSHER HOUSE
30 ASH REBURN BUILDING
31 COAL YARD MAINTENANCE BUILDING
32 GYPSUM LOADER/LIMESTONE BARGE UNLOADER
33 LIMESTONE PREP BUILDING
34 LIMESTONE SLURRY STORAGE TANK (2)
35 GYPSUM STORAGE BUILDING
36 GYPSUM DEWATERING BUILDING
37 RAW WATER/WASTE WATER TREATMENT BUILDING
38 COAL HANDLING CONTROL/SWITCHYARD BUILDING
39 IGCC POWER BLOCK
40 IGCC AIR SEPARATION UNIT
41 IGCC GASIFICATION FACILITY
42 IGCC ACID GAS REMOVAL UNIT (2ND FLOOR)
43 IGCC SULFUR RECOVERY UNIT
44 IGCC COAL PREPARATION
45 IGCC FLARE
46 IGCC SULFURIC ACID STORAGE TANK (2)
47 IGCC WASTE WATER TREATMENT
48 IGCC SLAG STORAGE SILO
49 IGCC FLY ASH STORAGE BUILDING/HOPPER
50 IGCC FUEL OIL STORAGE TANK
51 TEMPORARY GYPSUM LOADING HOPPER
52 COAL STORAGE PILE "A"
53 COAL STORAGE PILE "B"
54 LIMESTONE STORAGE PILE
55 TEMPORARY GYPSUM STORAGE
56 345 KV TRANSMISSION AREA (2)
57 DIESEL GENERATOR (2)
58 AUXILIARY BOILER
59 OIL/WATER SEPARATOR
60 FIRE WATER PUMP HOUSE
61 ENERGY INFORMATION CENTER
62 FISHING PIER
63 GYPSUM TRANSFER TOWER NO. 1
64 GYPSUM TRANSFER TOWER NO. 2
65 LIMESTONE TRANSFER TOWER NO. 1
66 LIMESTONE TRANSFER TOWER NO. 2
67 COAL TRANSFER TOWER NO. 1
68 COAL TRANSFER TOWER NO. 2
69 COAL RECLAIM HOPPER
70 IGCC WATER TREATMENT
71 LIMESTONE AREA ELECTRICAL BUILDING
72 GUARD HOUSE (2)
73 PIER RAMP
74 STORM WATER BASIN (2)
75 WASTE WATER BASIN

Figure Vol. 2-4
Plant Equipment Layout - North Site-CUP Option

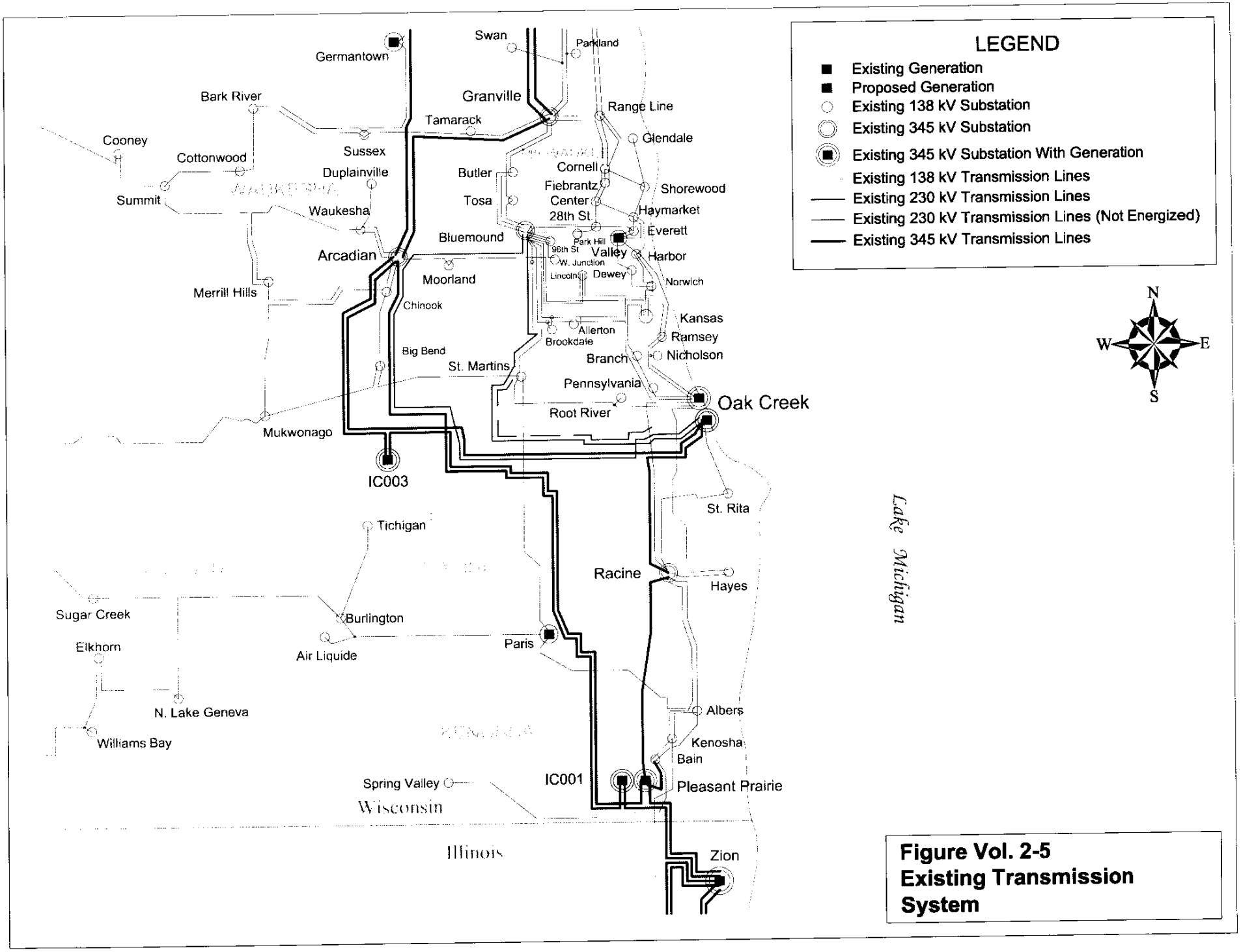


Figure Vol. 2-5
Existing Transmission System

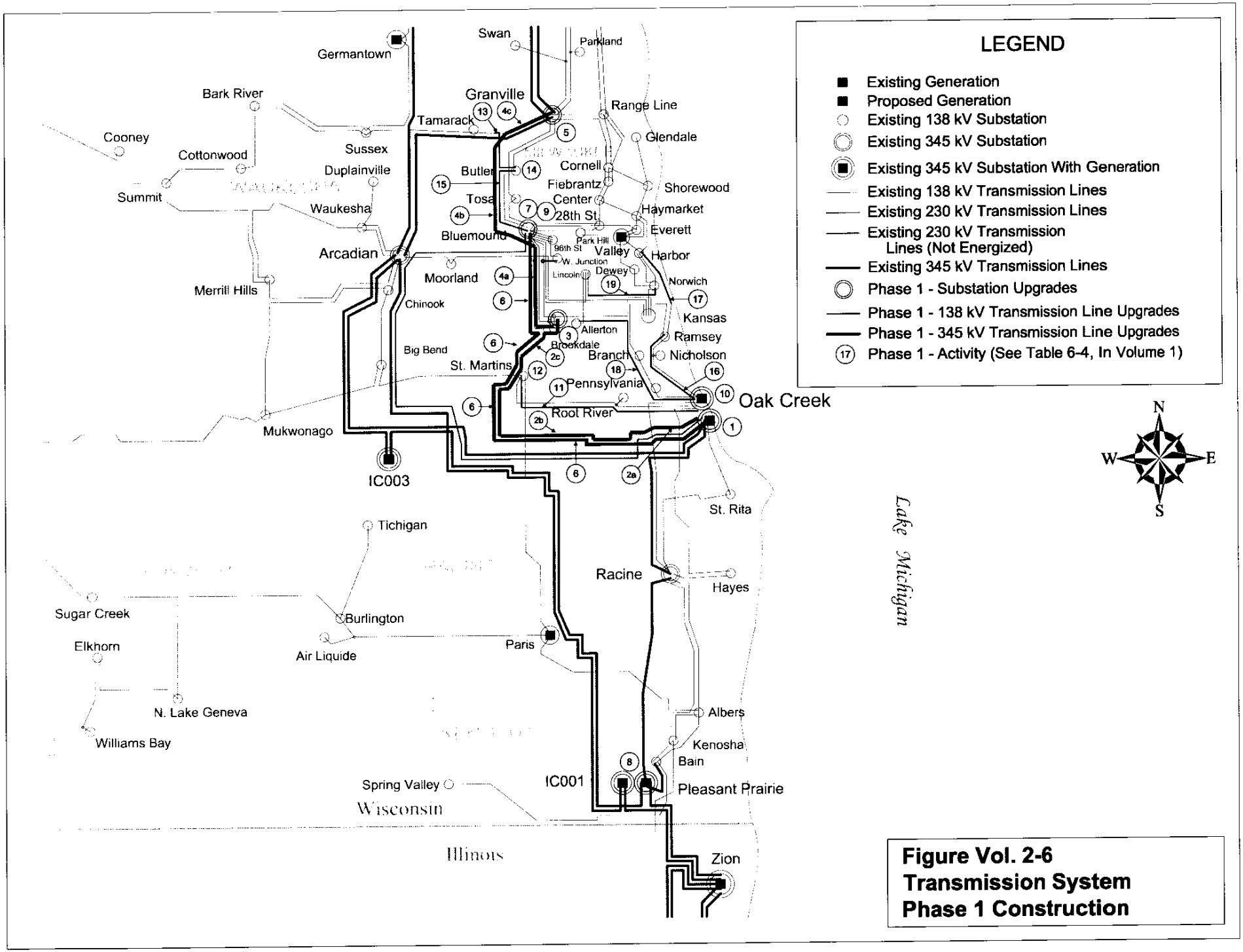


Figure Vol. 2-6
Transmission System
Phase 1 Construction

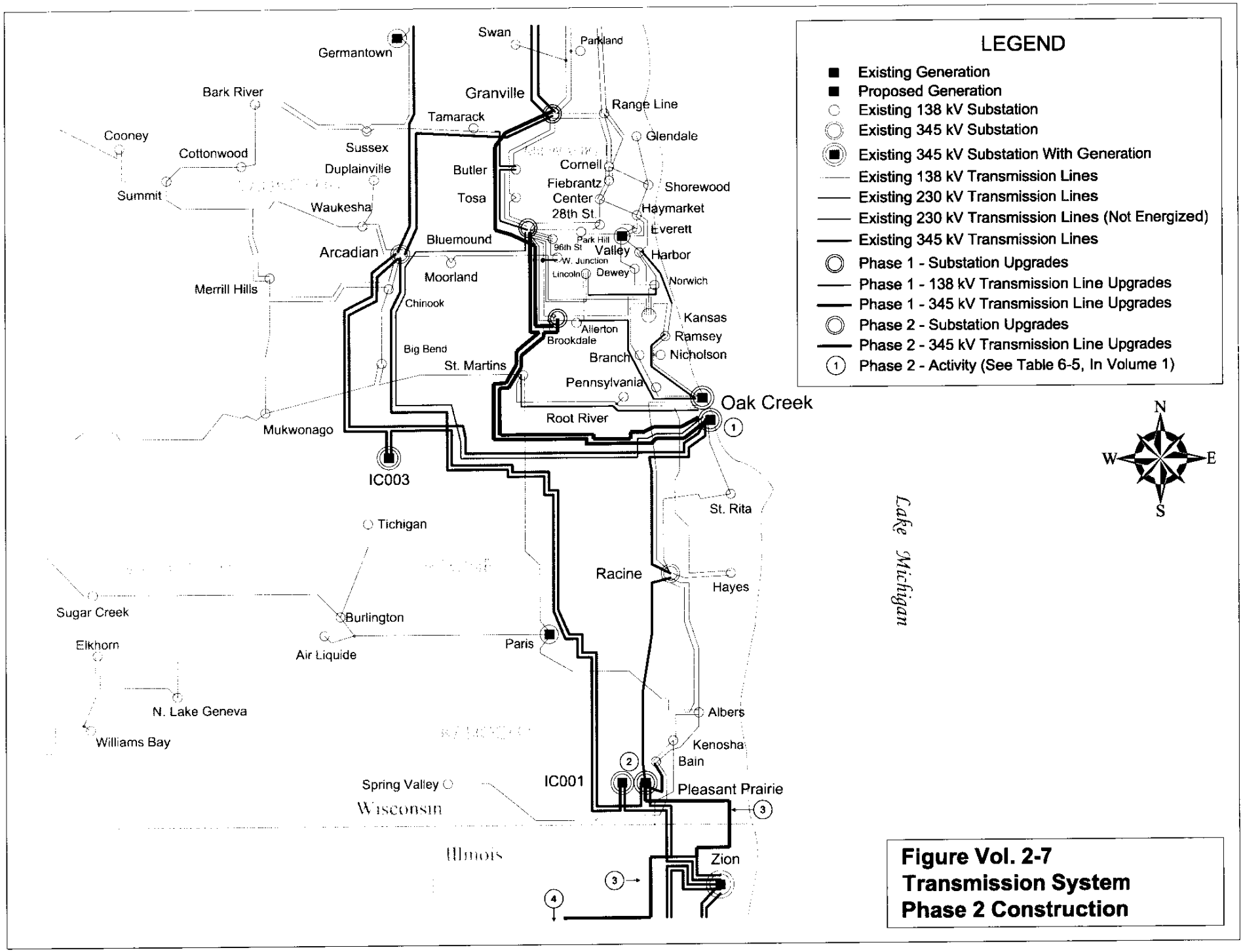


Figure Vol. 2-7
Transmission System
Phase 2 Construction

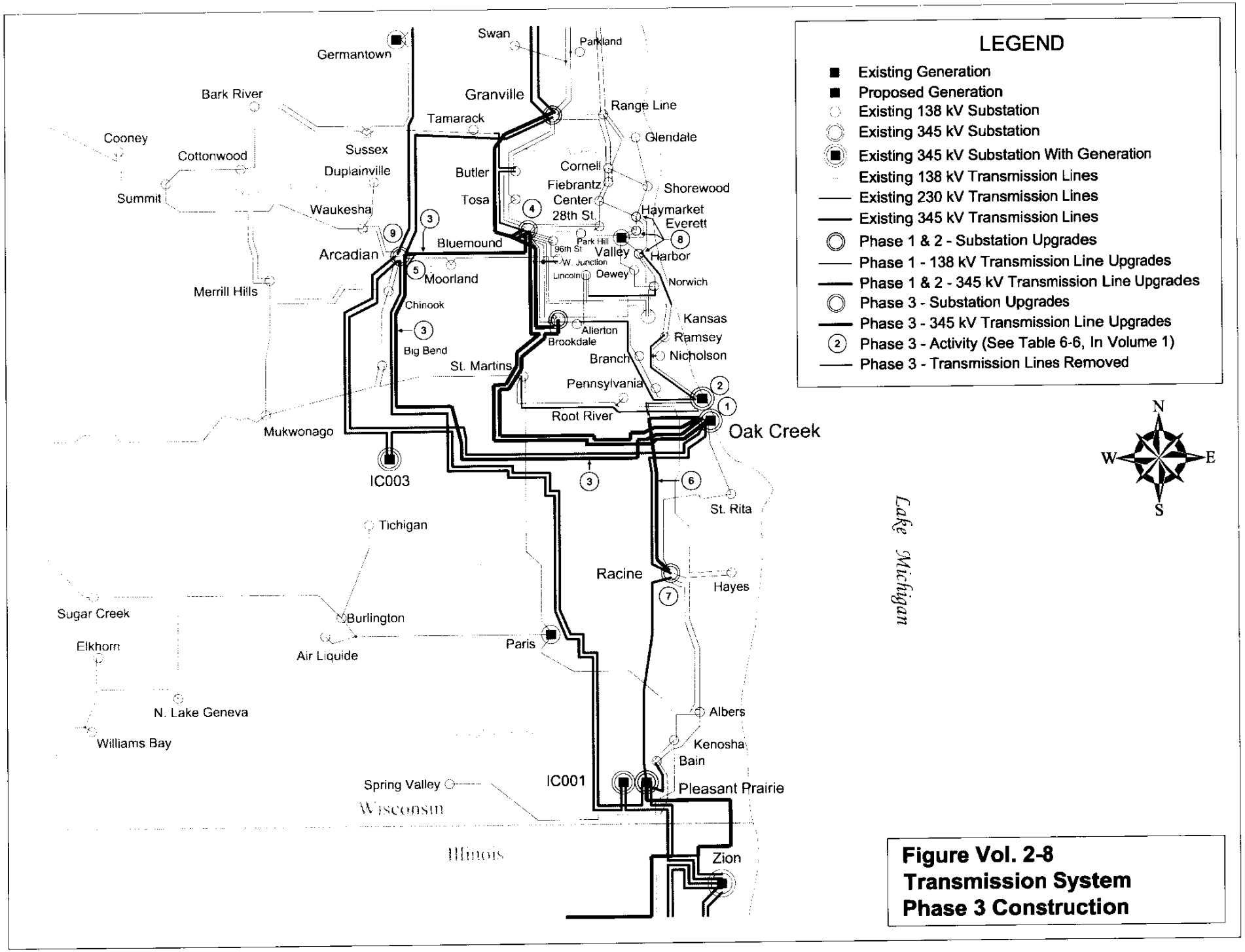


Figure Vol. 2-8
Transmission System
Phase 3 Construction

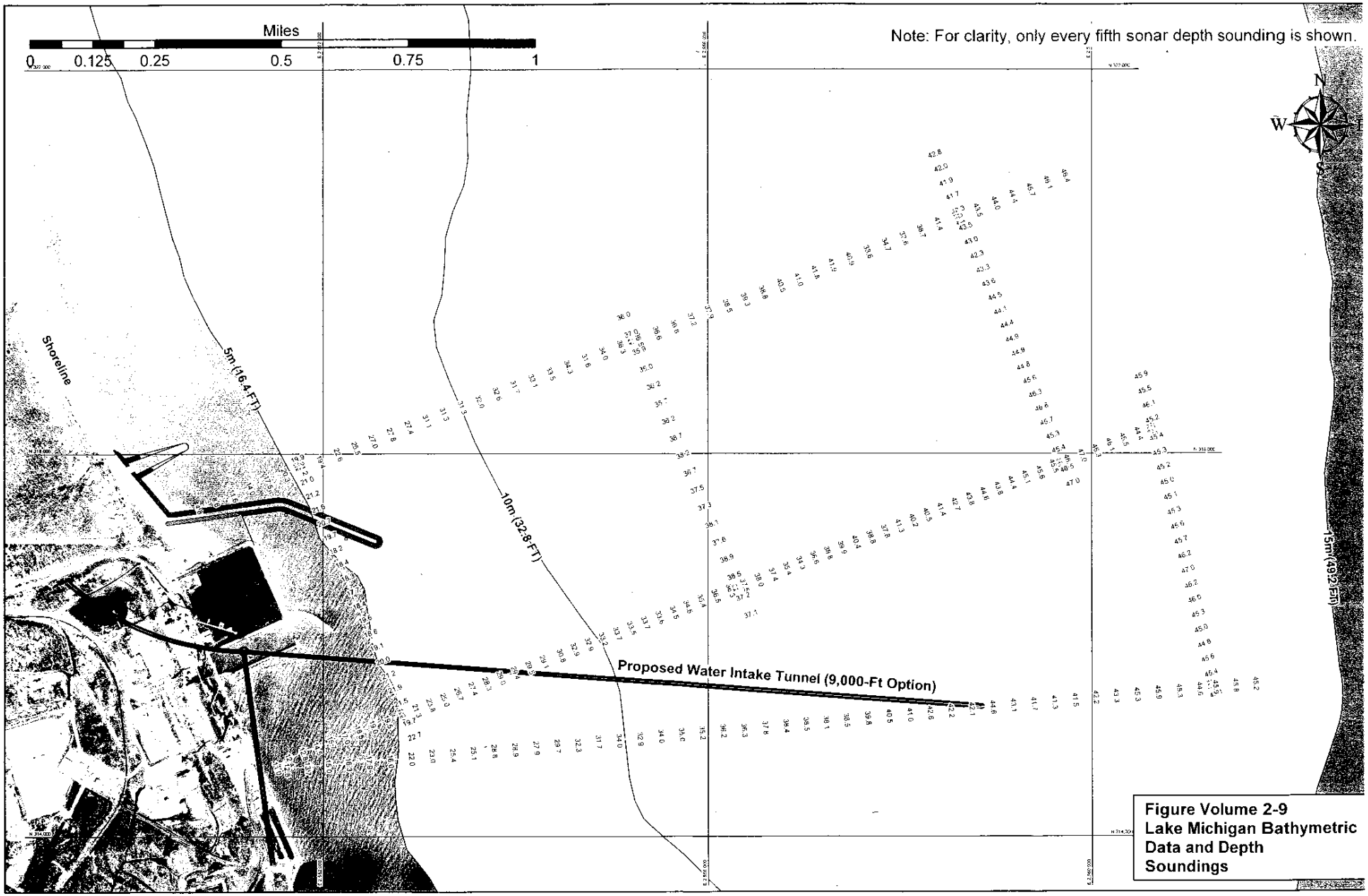


Figure Volume 2-9
Lake Michigan Bathymetric Data and Depth Soundings

Figure Vol. 2-10
Lake Michigan Bottom Conditions

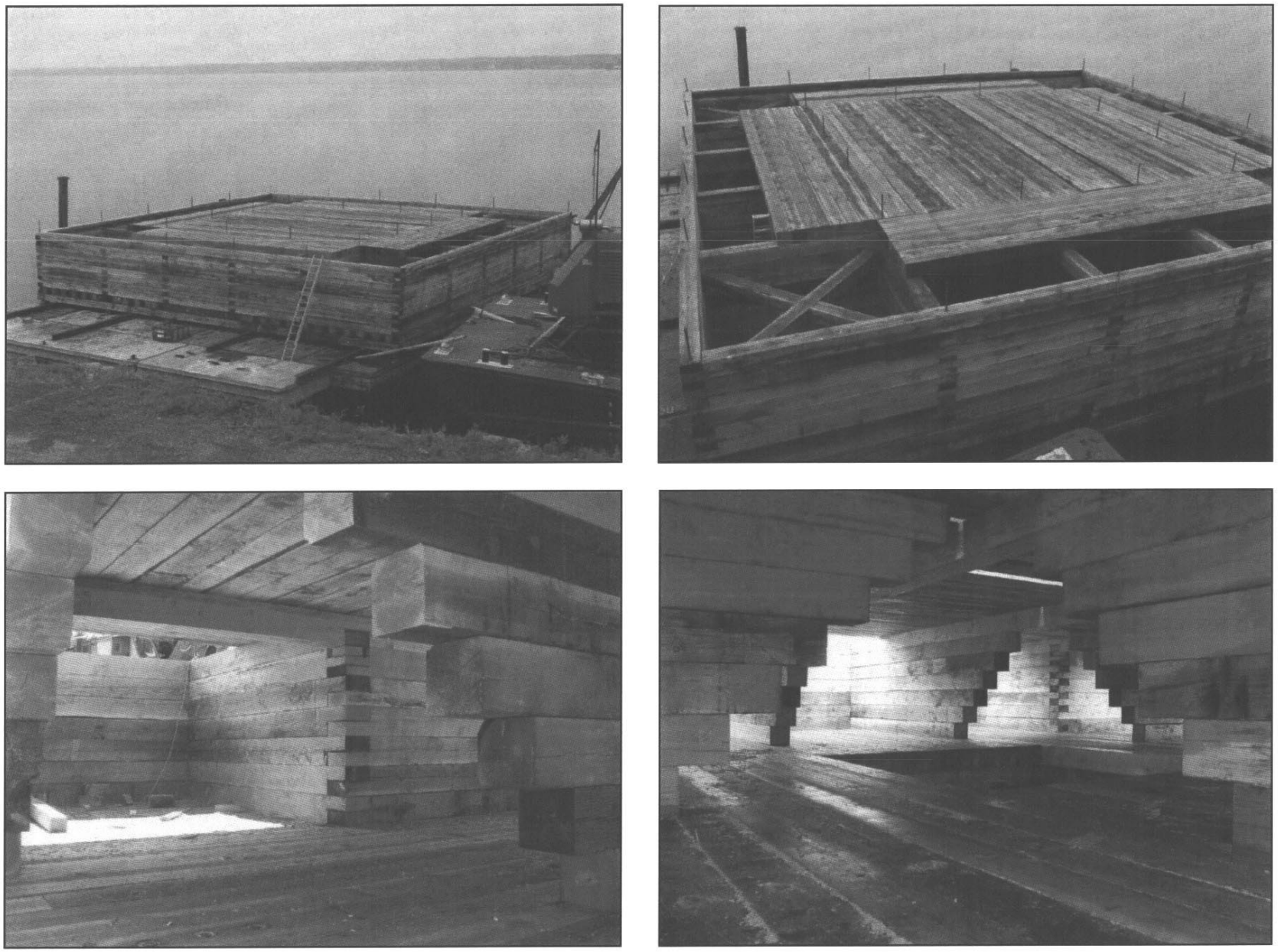


Figure Vol. 2-11
Conceptual Design of a Timber Intake Crib For ERGS

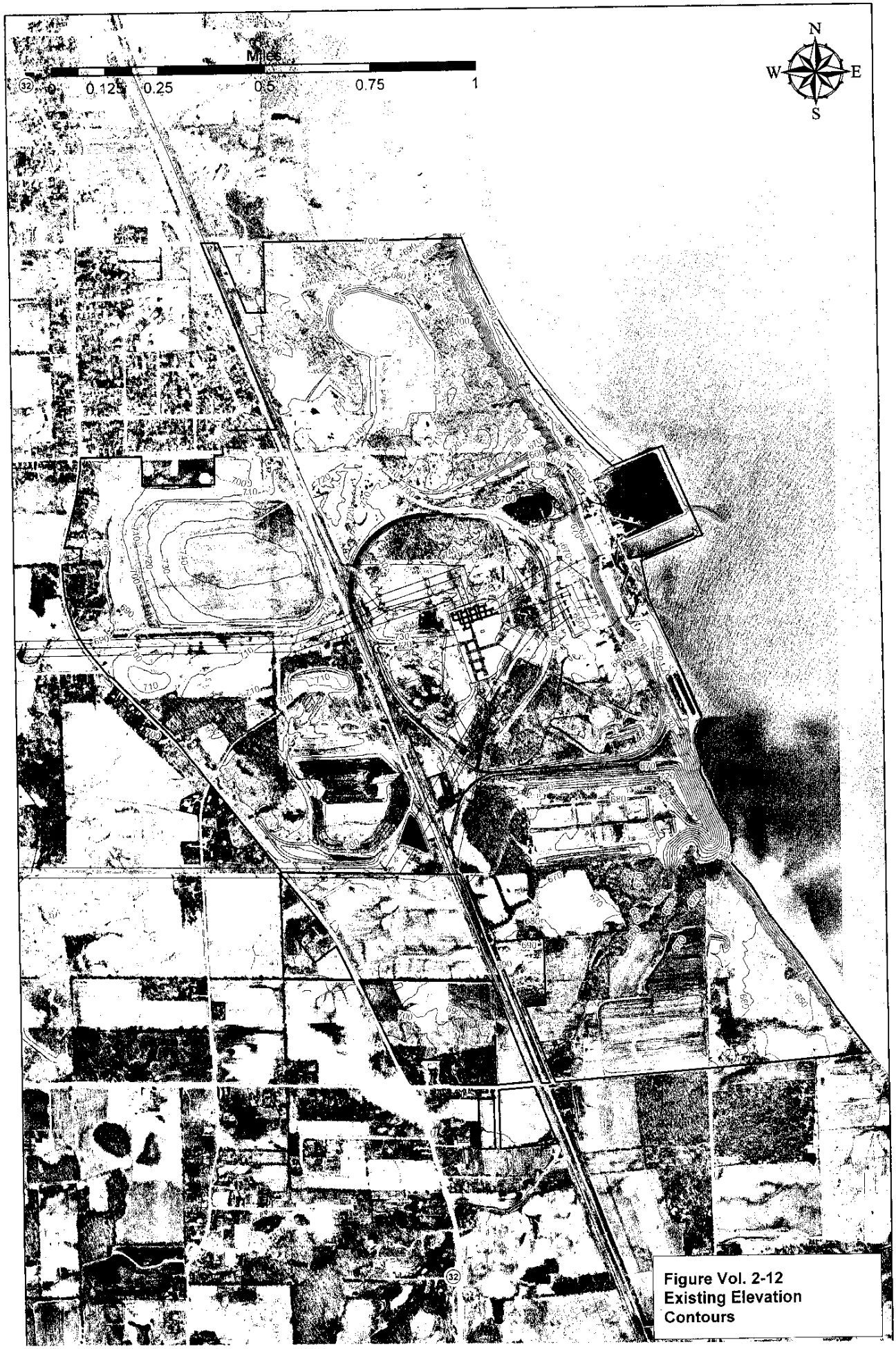


Figure Vol. 2-12
Existing Elevation Contours

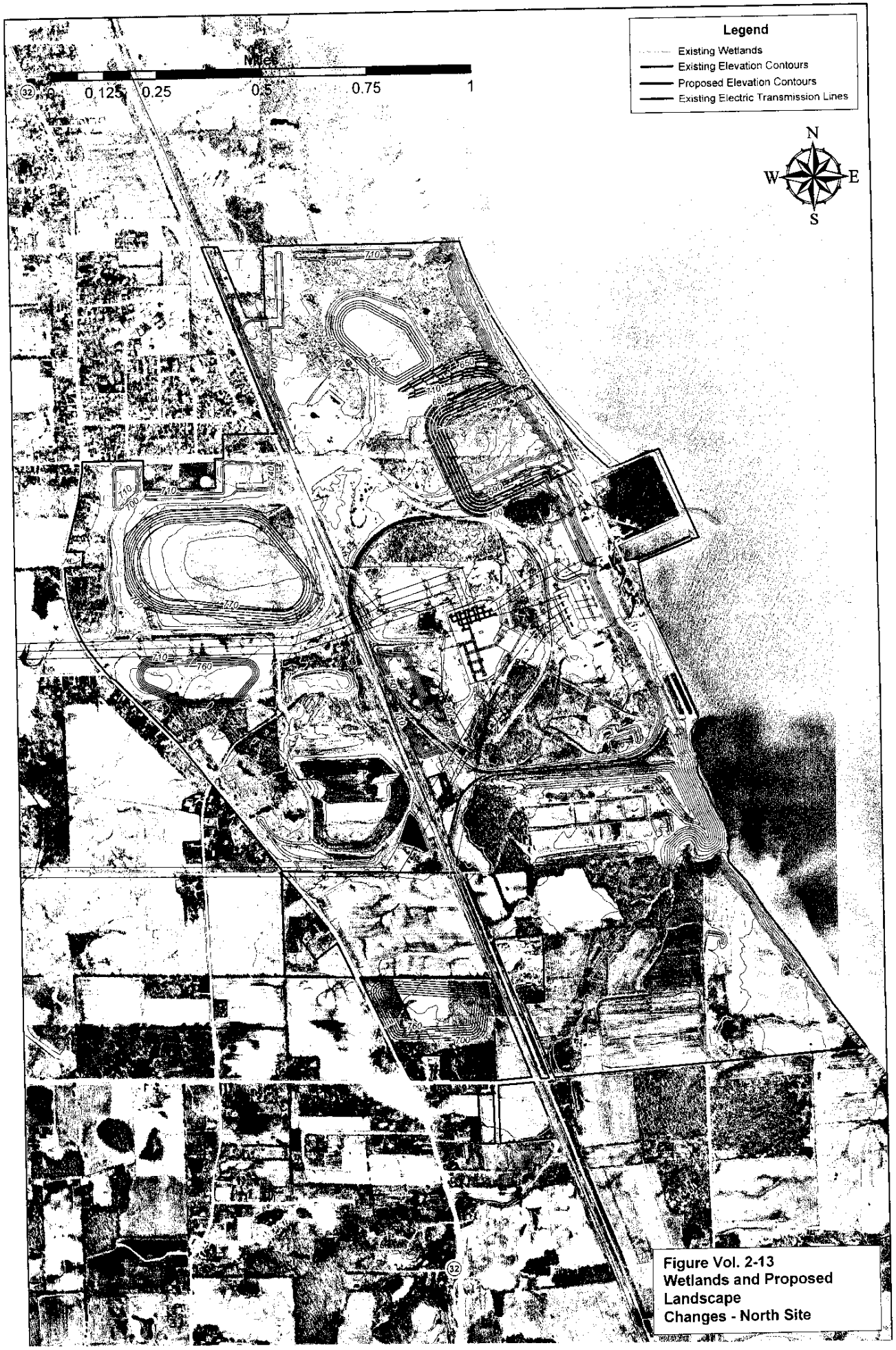


Figure Vol. 2-13
Wetlands and Proposed Landscape Changes - North Site

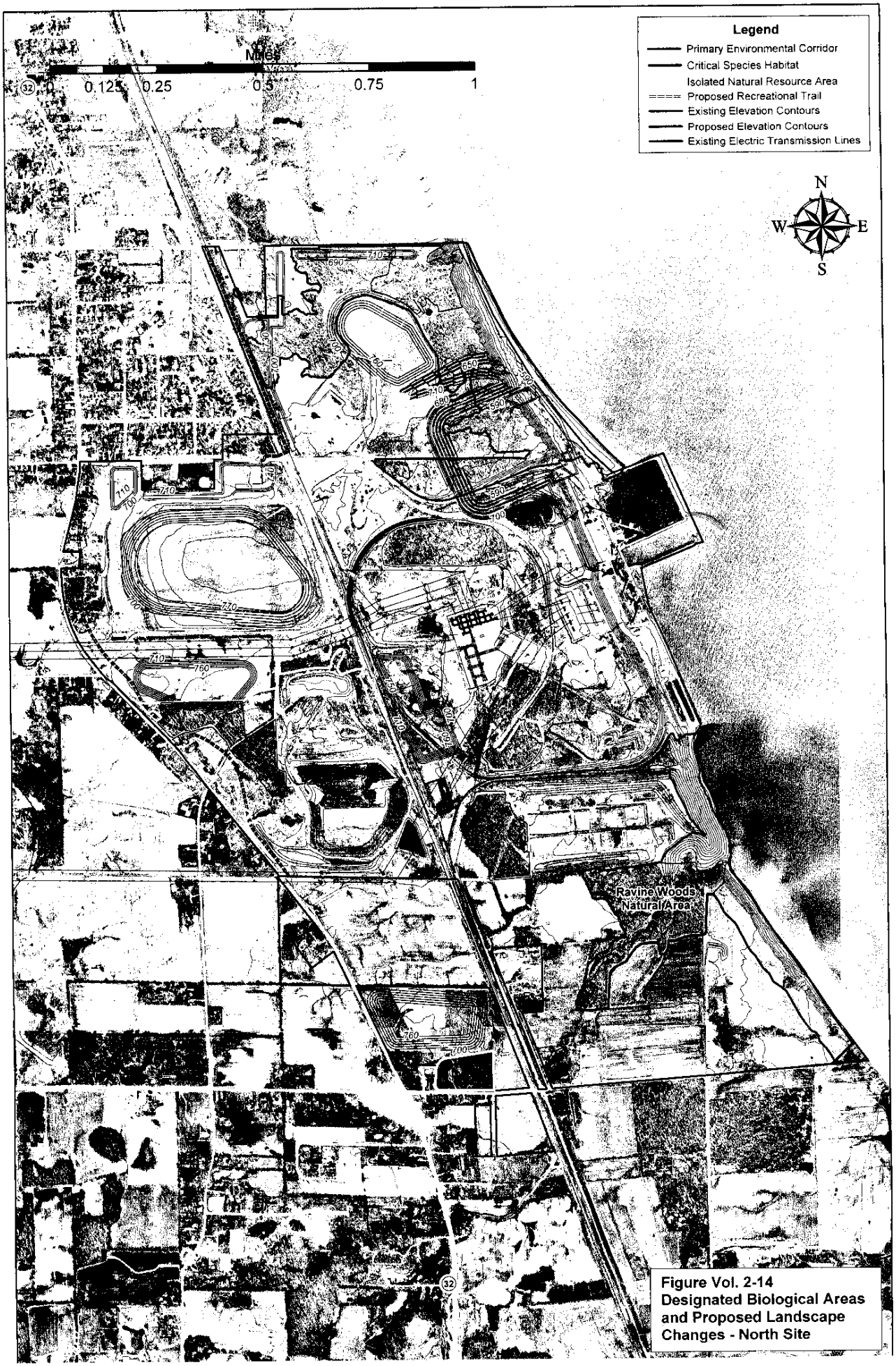


Figure Vol. 2-14
Designated Biological Areas and Proposed Landscape Changes - North Site

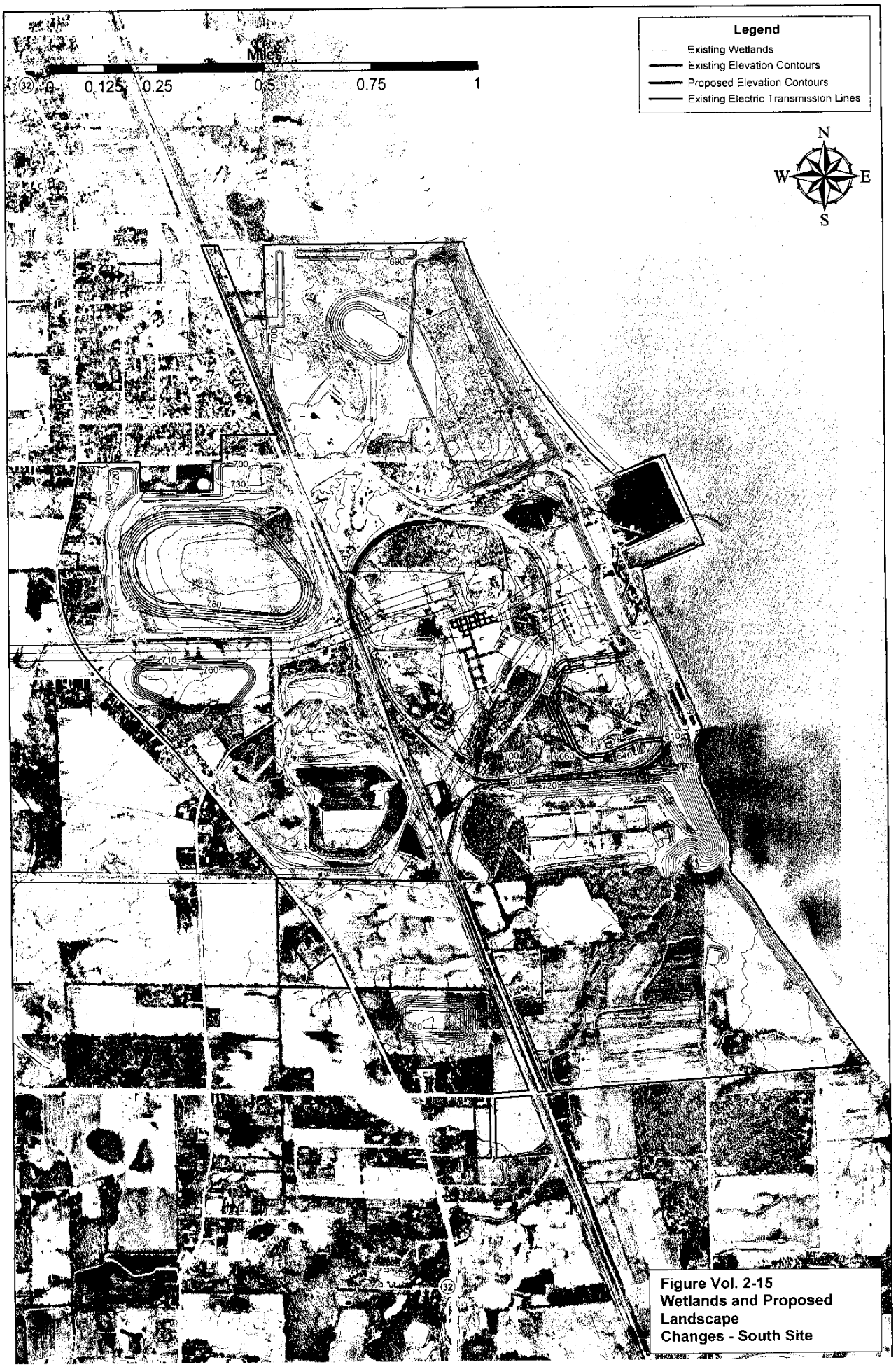


Figure Vol. 2-15
Wetlands and Proposed Landscape Changes - South Site

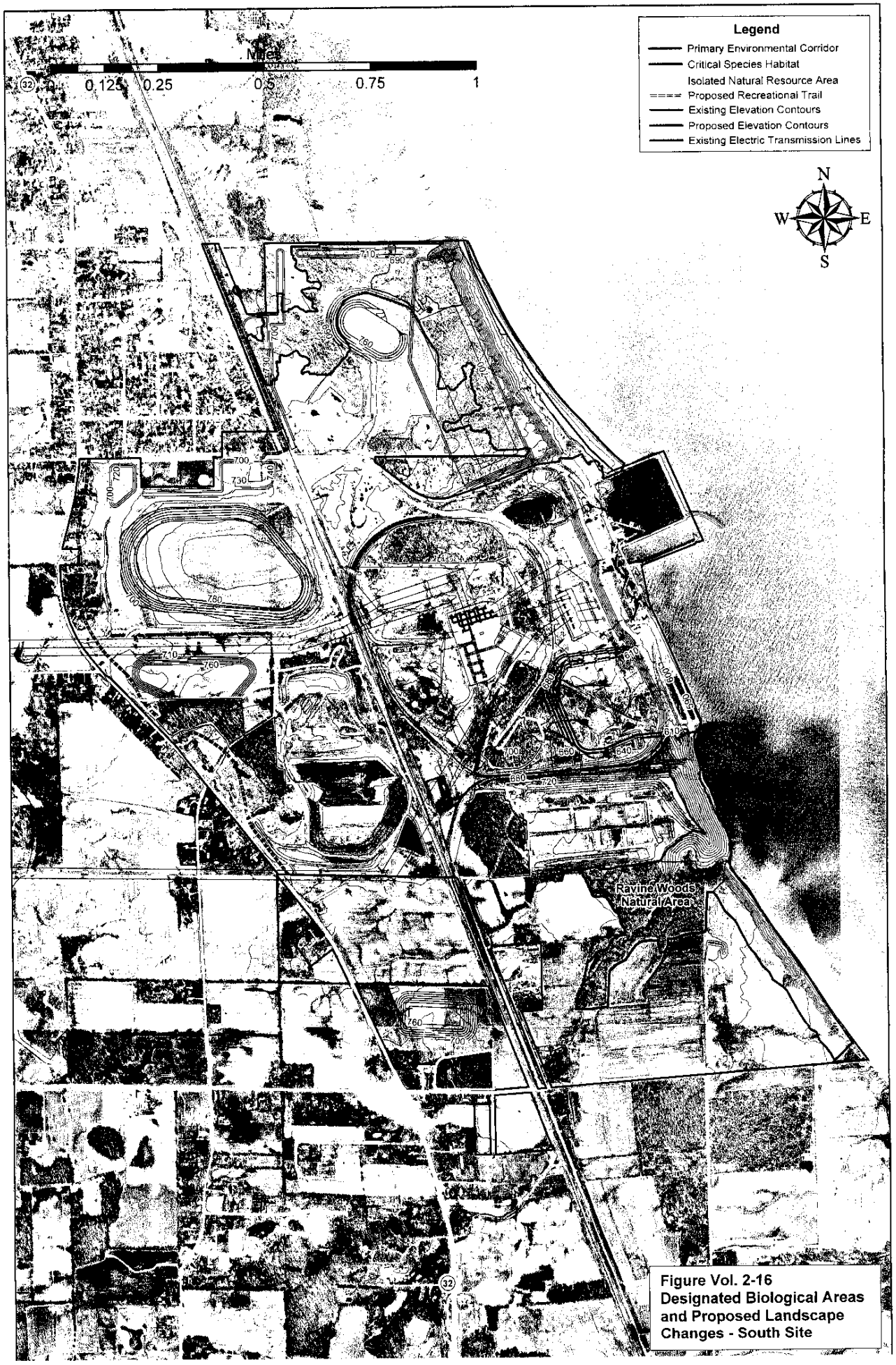


Figure Vol. 2-16
Designated Biological Areas and Proposed Landscape Changes - South Site

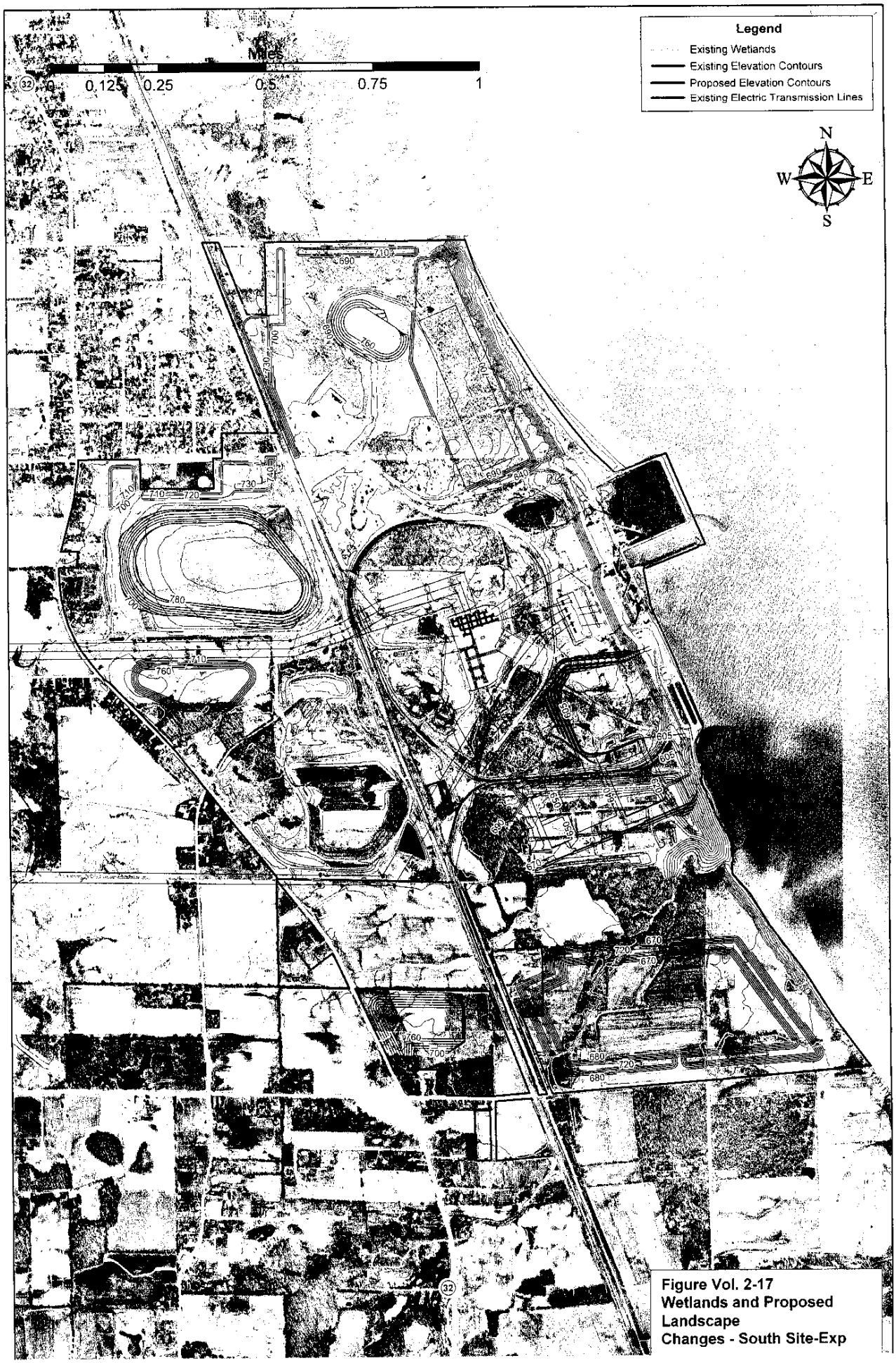


Figure Vol. 2-17
Wetlands and Proposed Landscape Changes - South Site-Exp

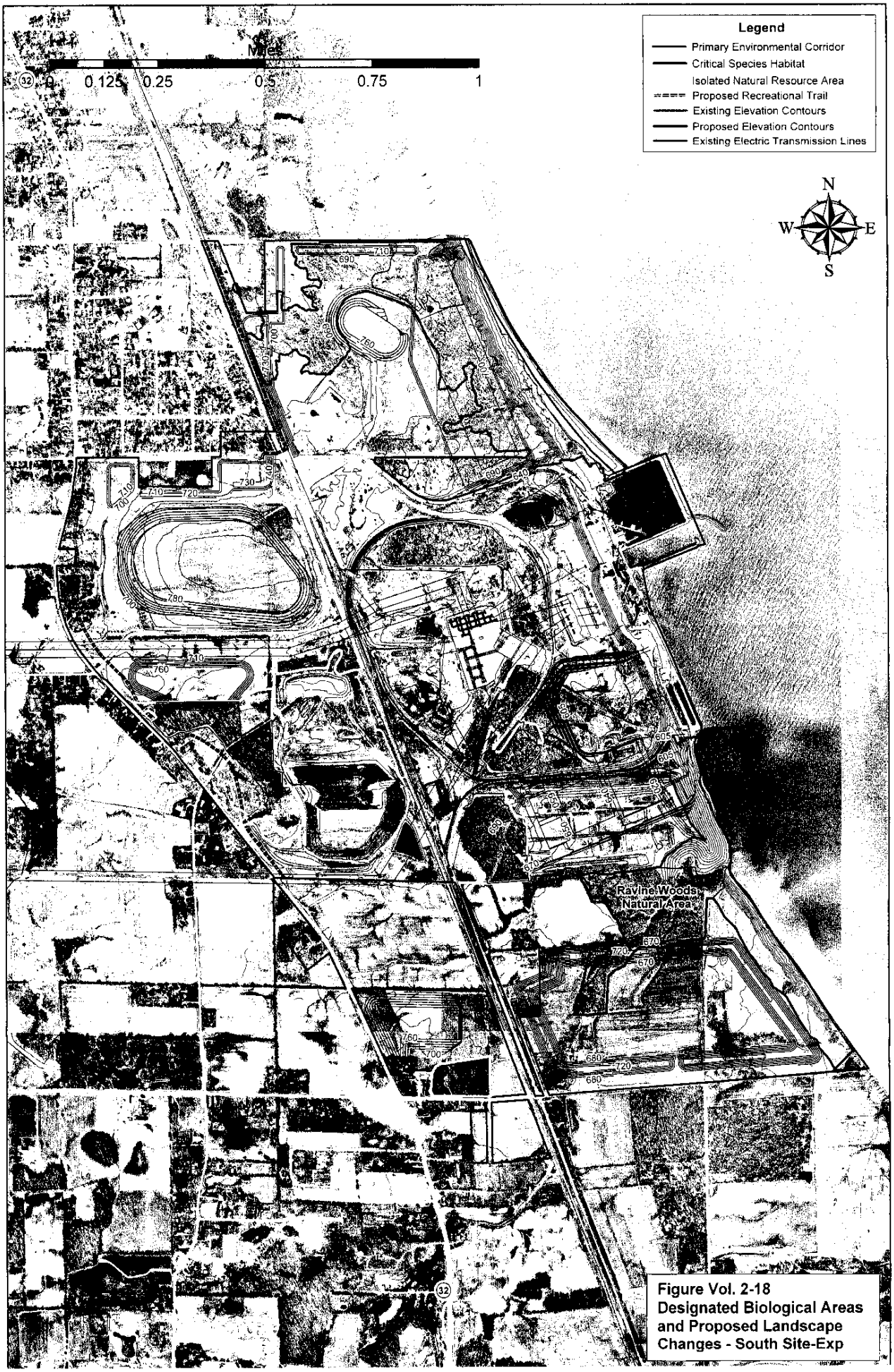


Figure Vol. 2-18
Designated Biological Areas and Proposed Landscape Changes - South Site-Exp

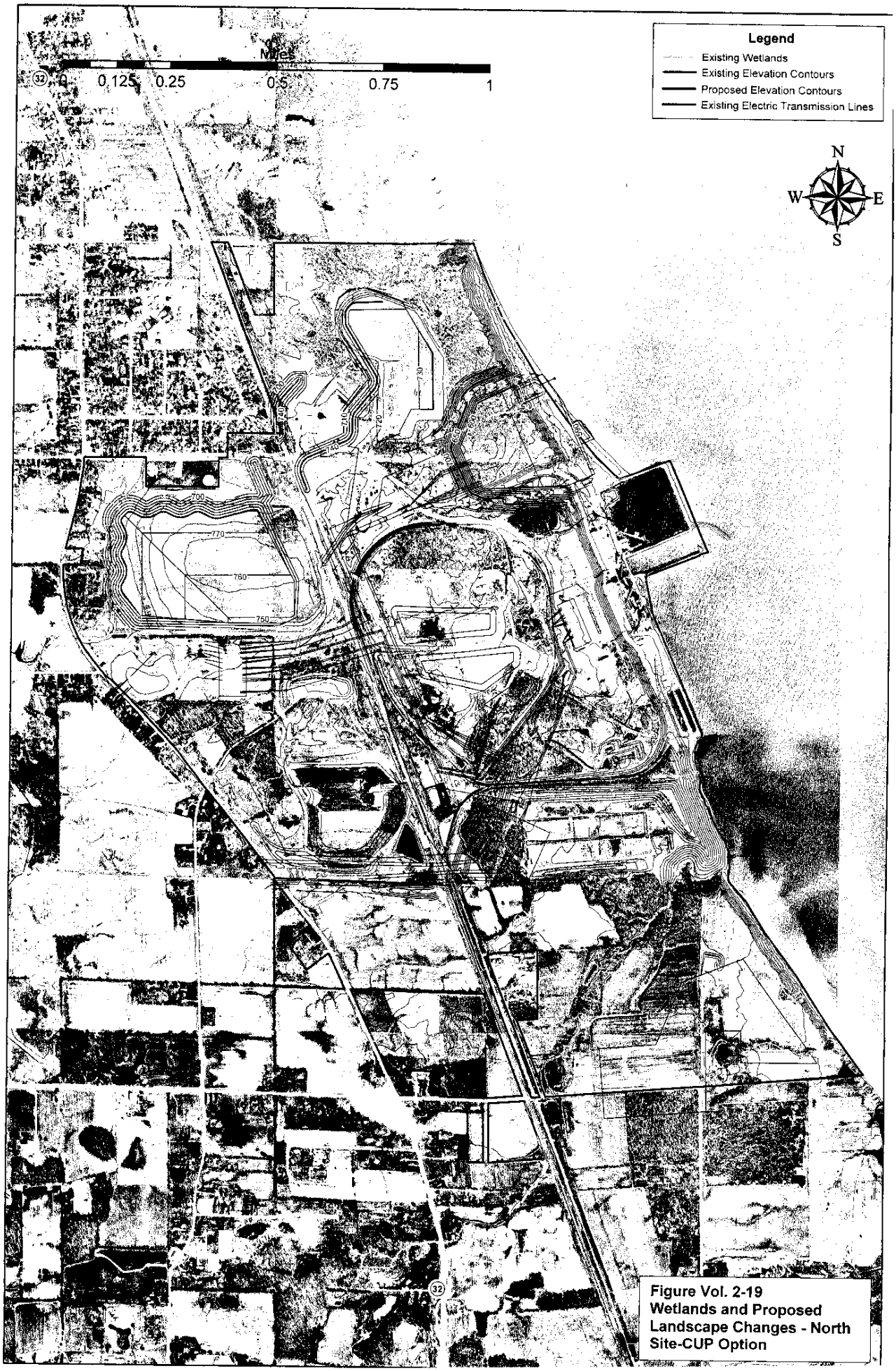


Figure Vol. 2-19
Wetlands and Proposed Landscape Changes - North Site-CUP Option

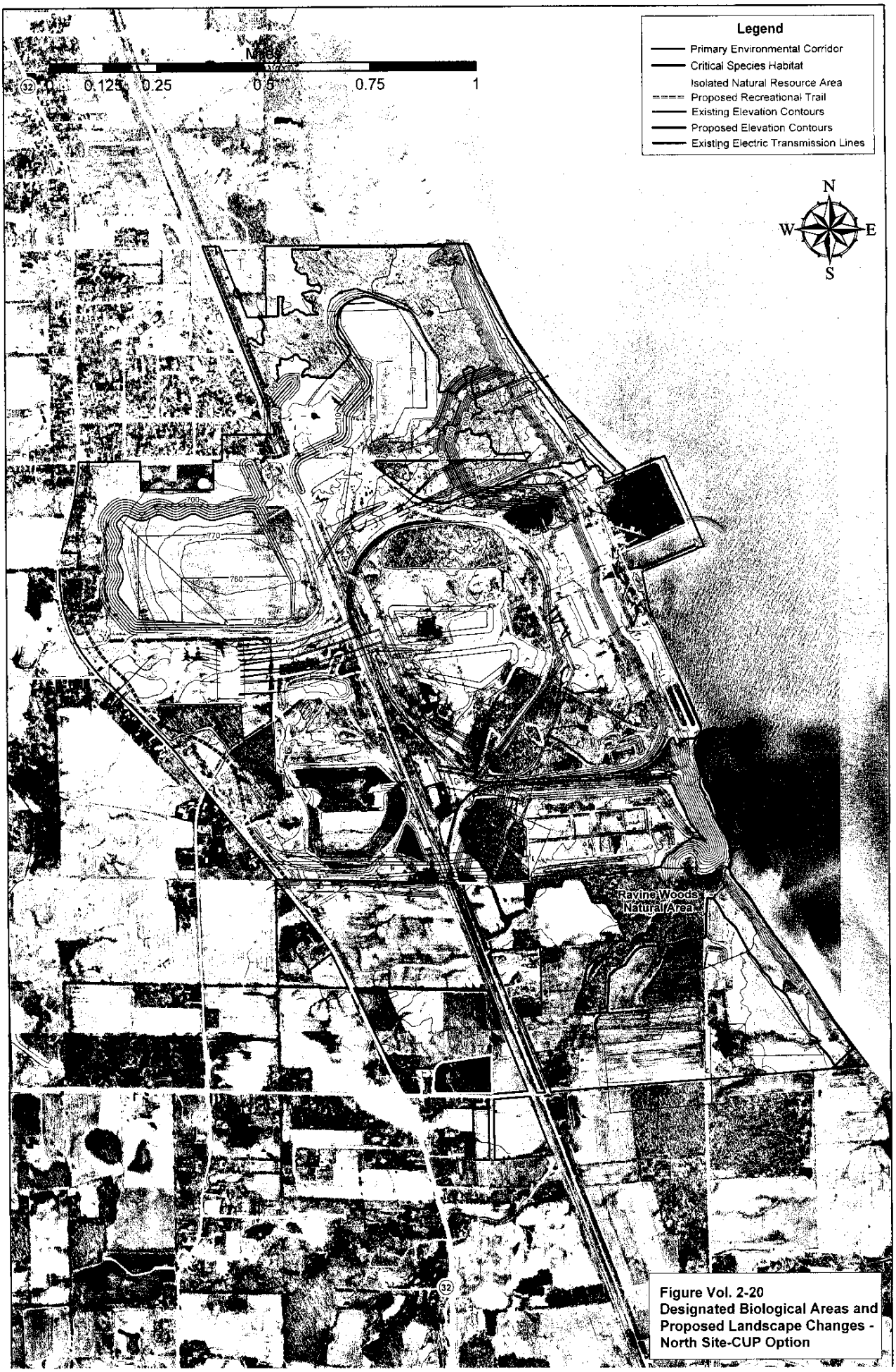


Figure Vol. 2-20
Designated Biological Areas and Proposed Landscape Changes - North Site-CUP Option

Figure Vol. 2-21
Existing Land Use In Project Area

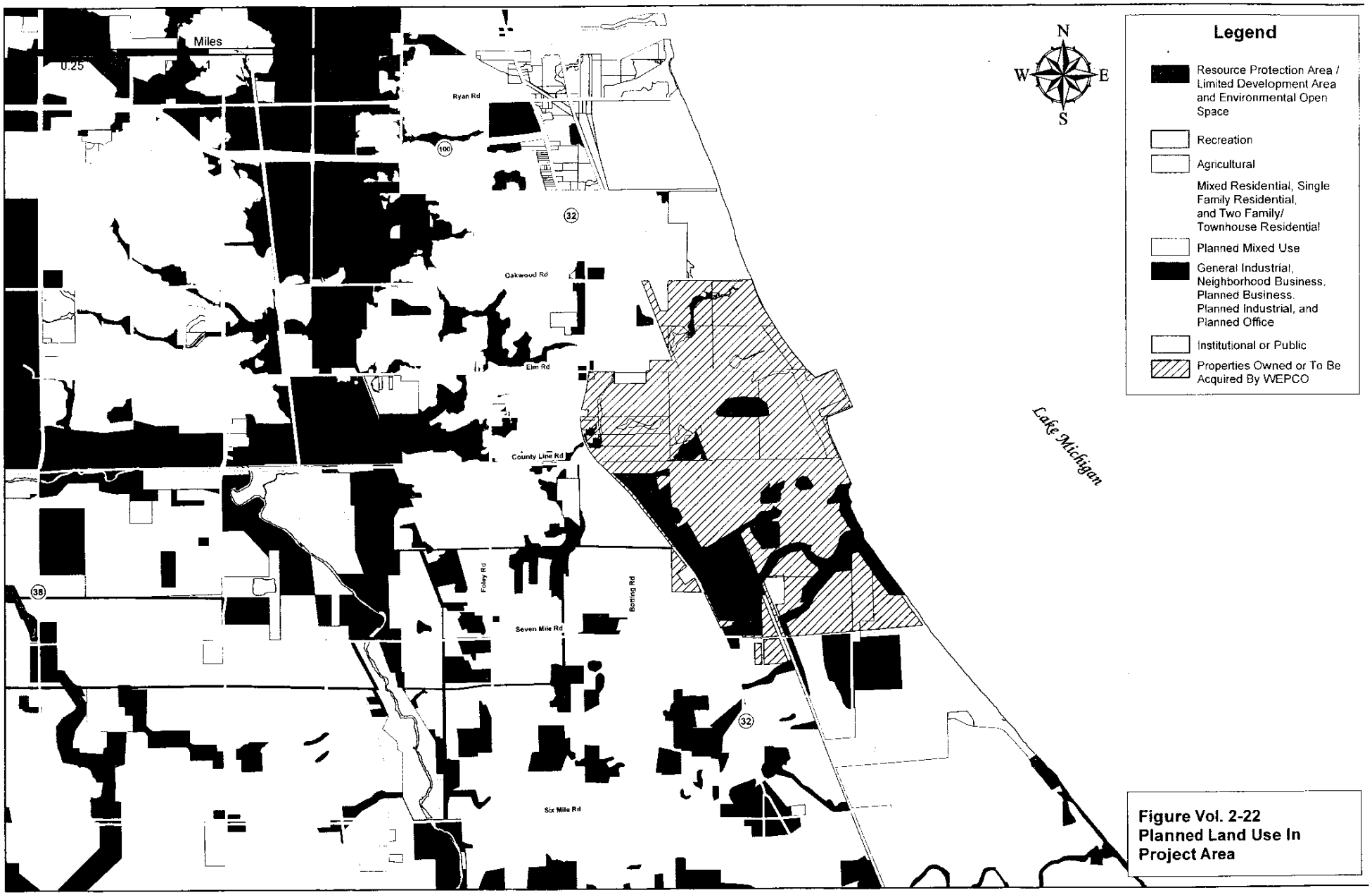


Figure Vol. 2-22
Planned Land Use In Project Area

Figure Vol. 2-23
Existing Residences And Other Buildings

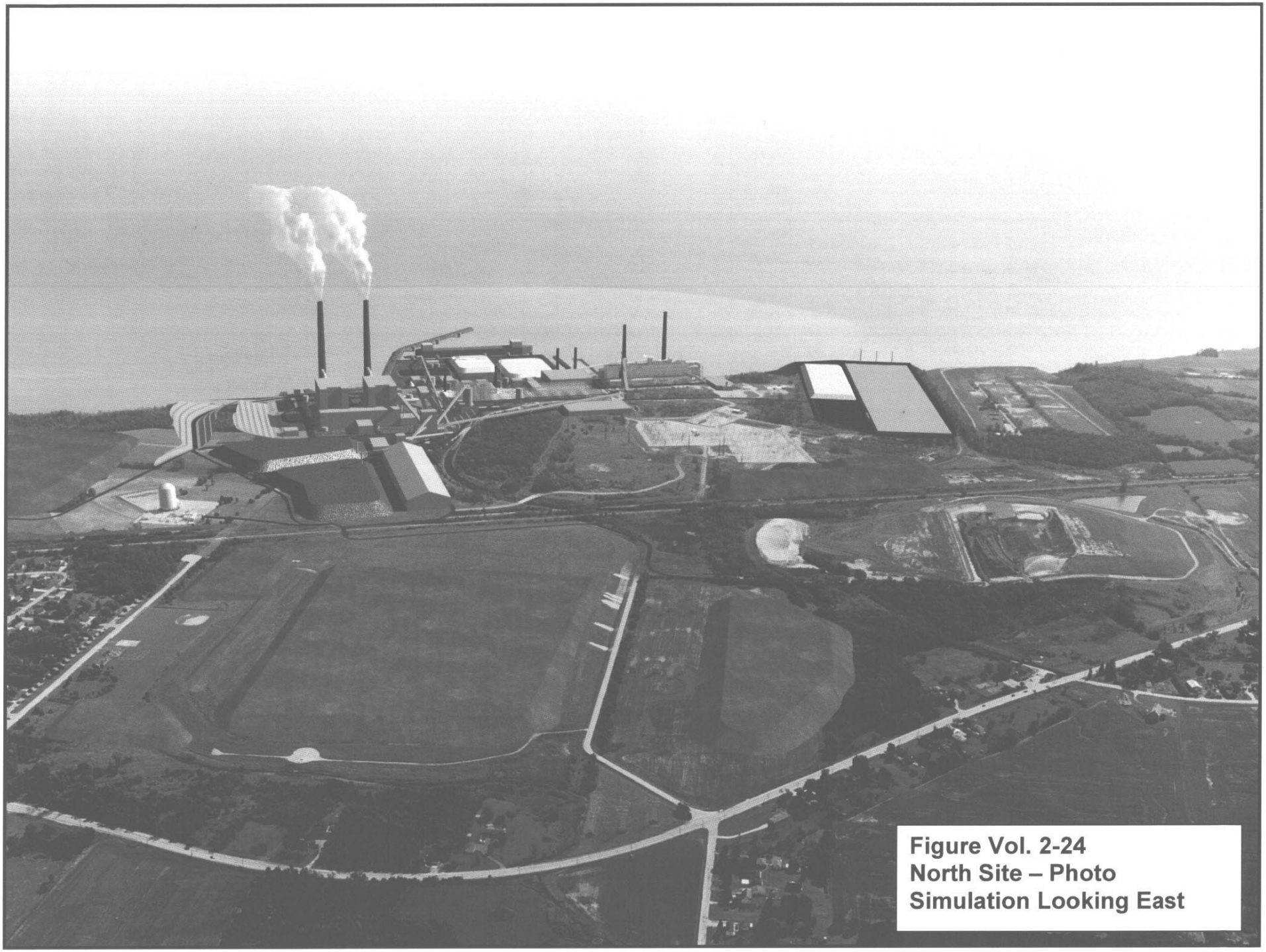


Figure Vol. 2-24
North Site – Photo Simulation Looking East

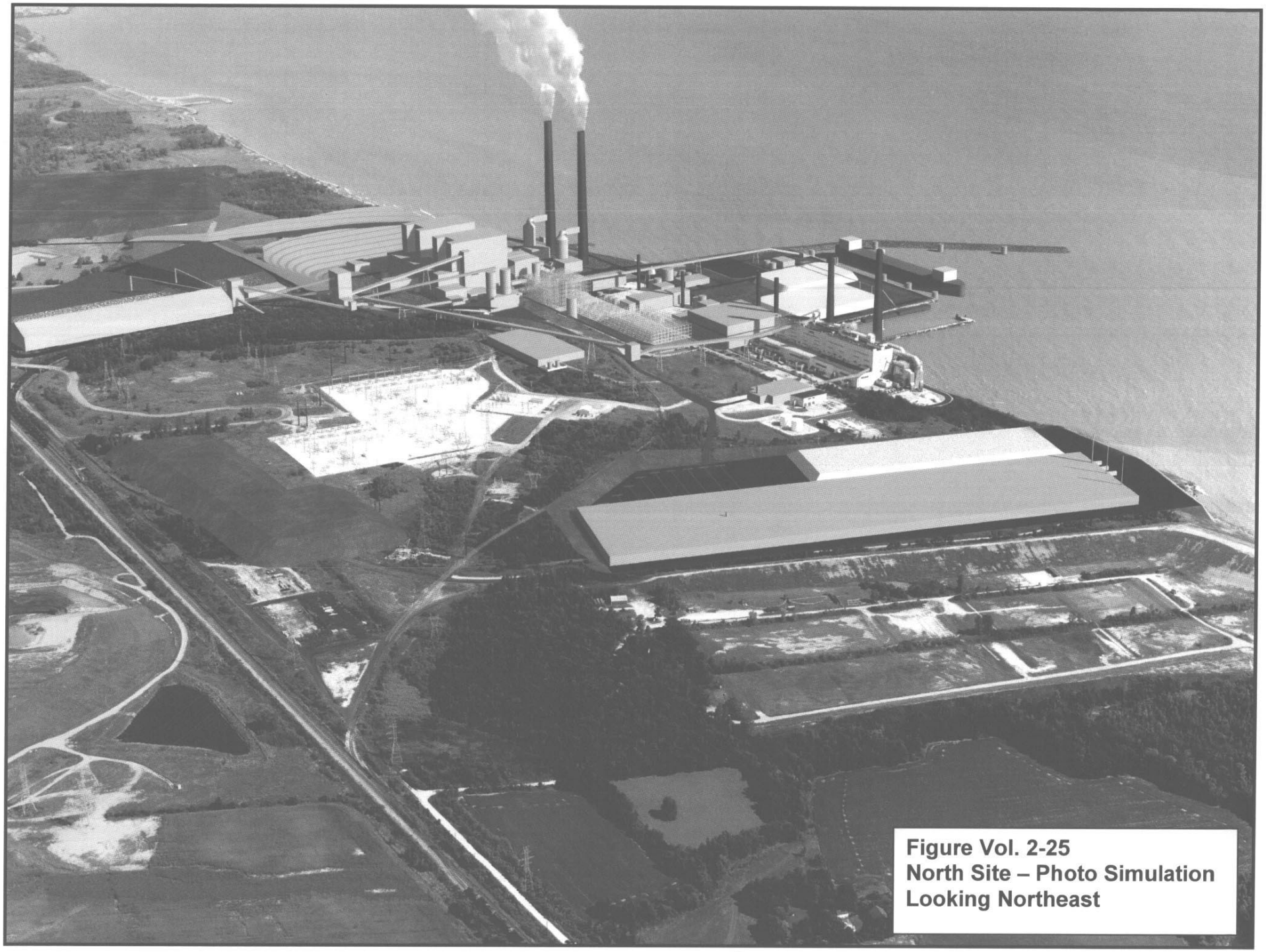


Figure Vol. 2-25
North Site – Photo Simulation
Looking Northeast

Figure Vol. 2-26
North Site – Photo Simulation
Looking West

Figure Vol. 2-27
South Site – Photo Simulation
Looking East

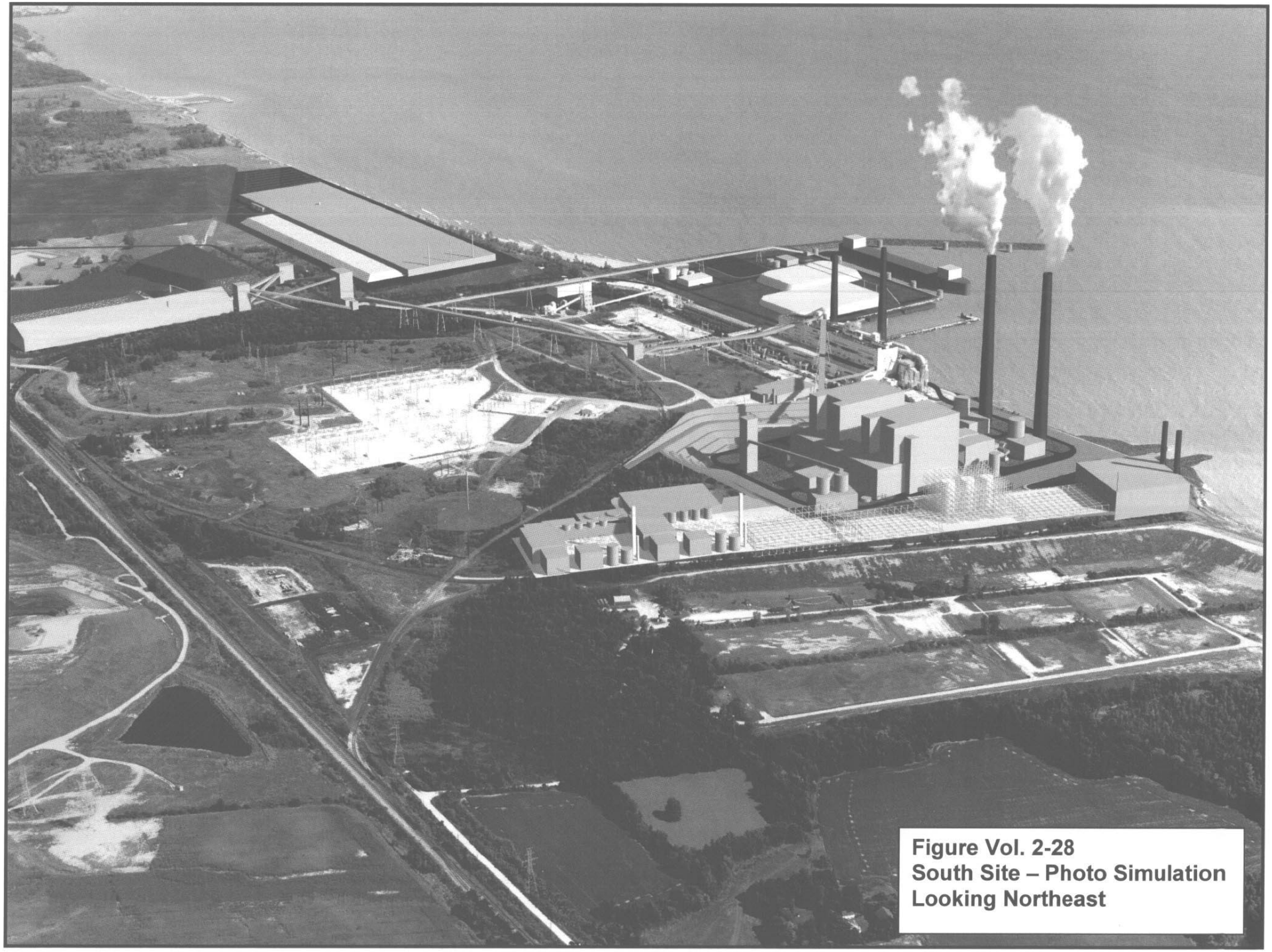


Figure Vol. 2-28
South Site – Photo Simulation
Looking Northeast

Figure Vol. 2-29
South Site – Photo Simulation
Looking West

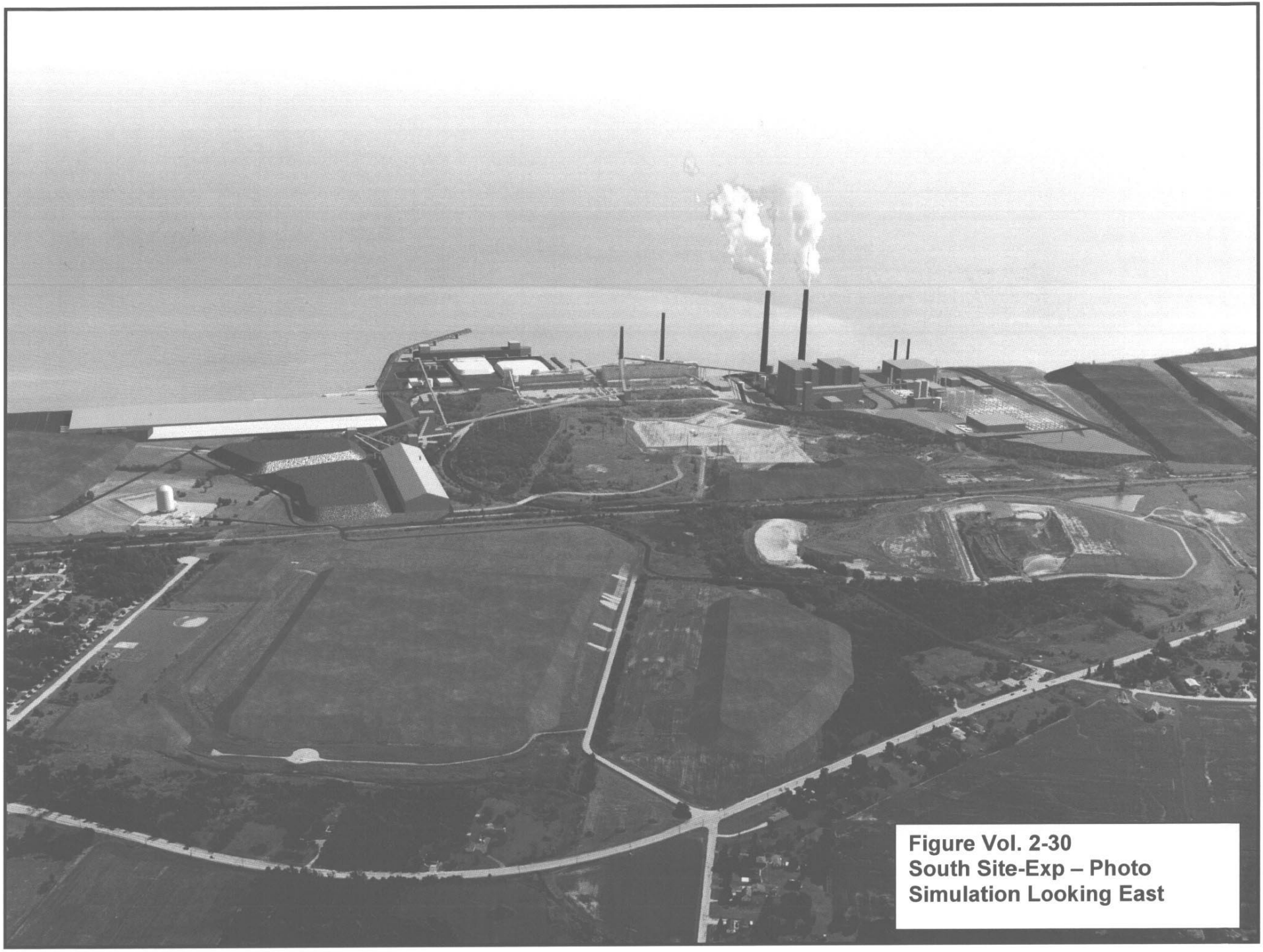


Figure Vol. 2-30
South Site-Exp – Photo Simulation Looking East

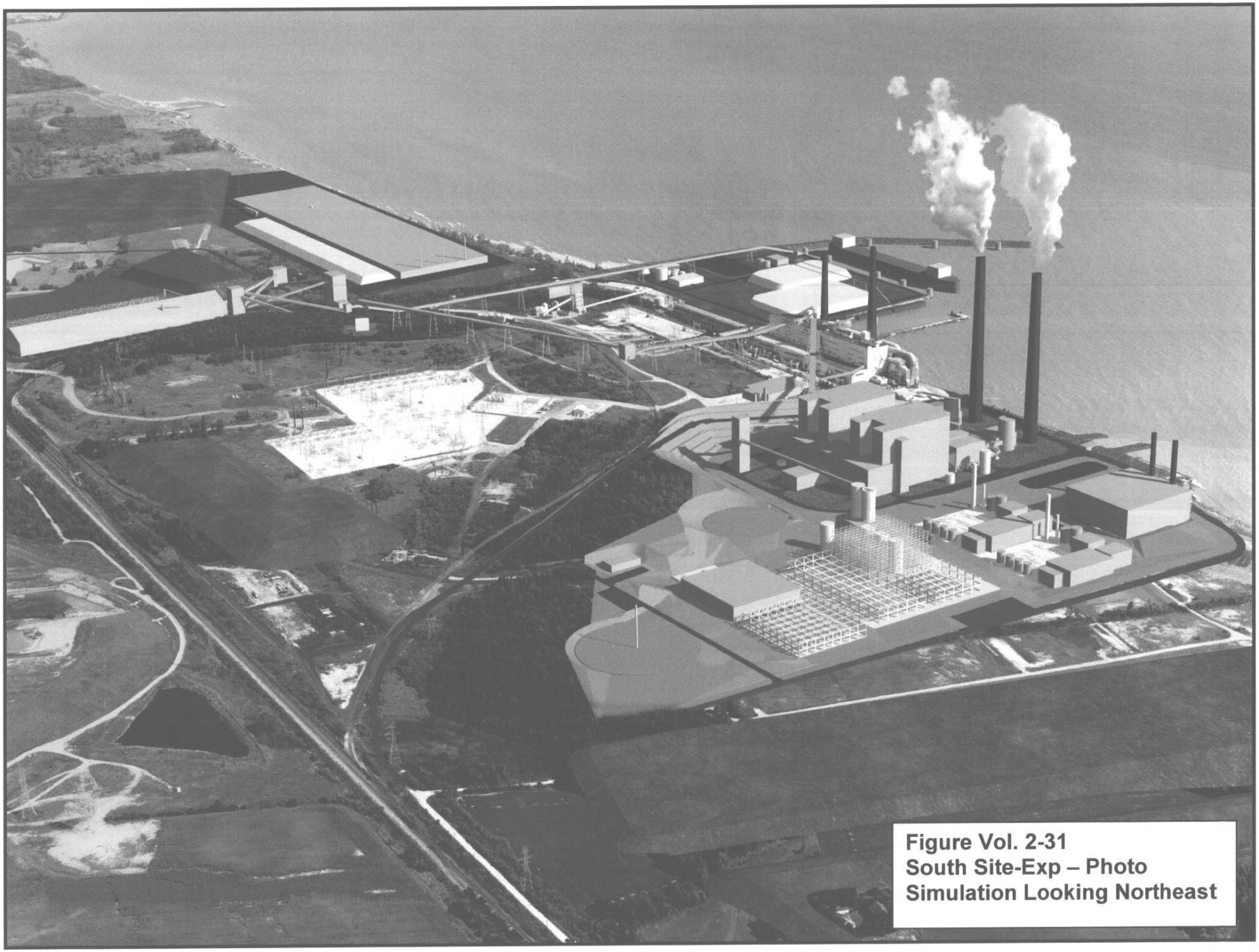


Figure Vol. 2-31
South Site-Exp – Photo Simulation Looking Northeast

Figure Vol. 2-32
South Site-Exp – Photo Simulation Looking West

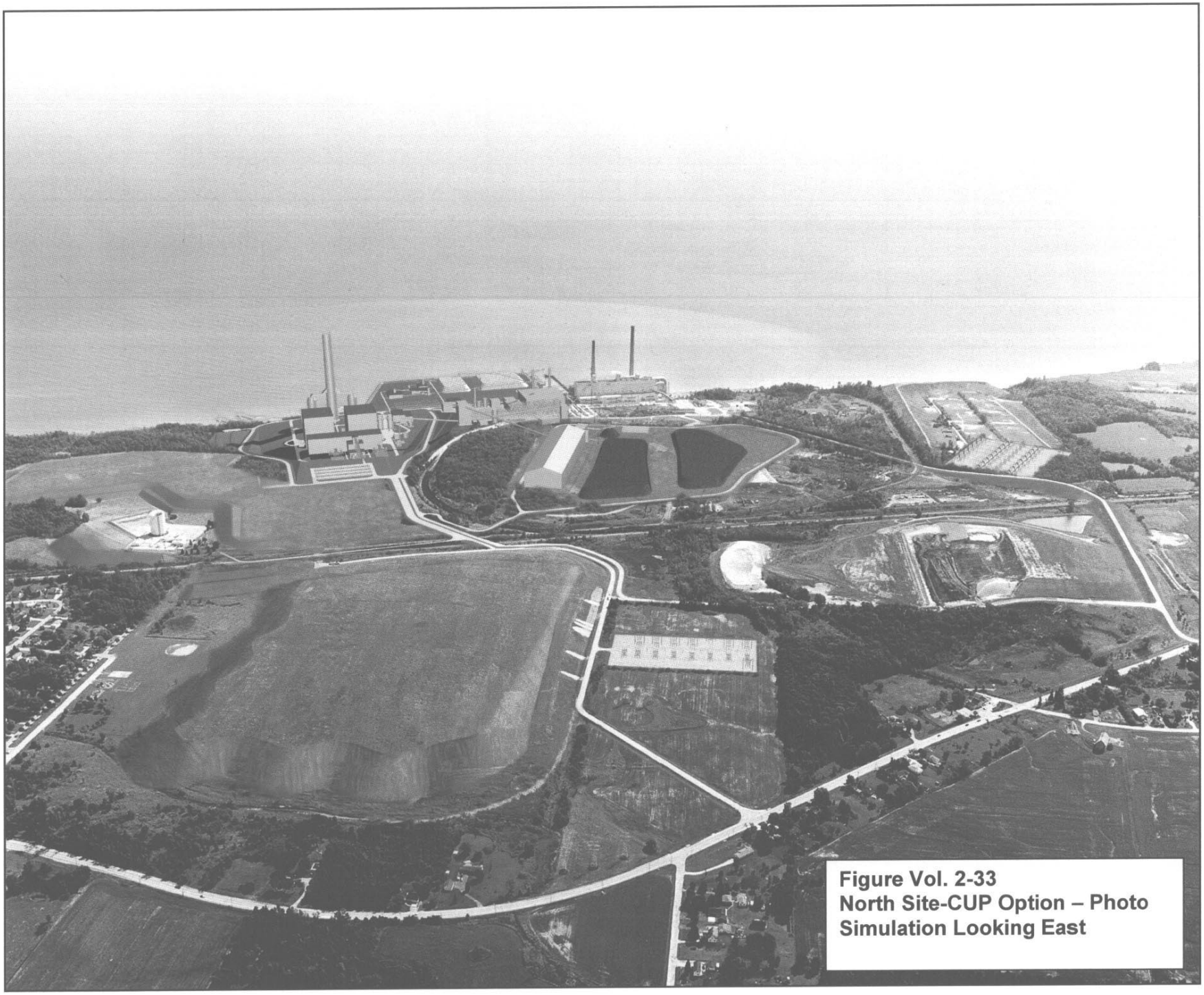


Figure Vol. 2-33
North Site-CUP Option – Photo Simulation Looking East

Figure Vol. 2-34
North Site-CUP Option – Photo Simulation Looking Northeast

Figure Vol. 2-35
North Site-CUP Option – Photo Simulation Looking West

Figure Vol. 2-36
Nighttime Light Emissions For Wisconsin and Surrounding Areas

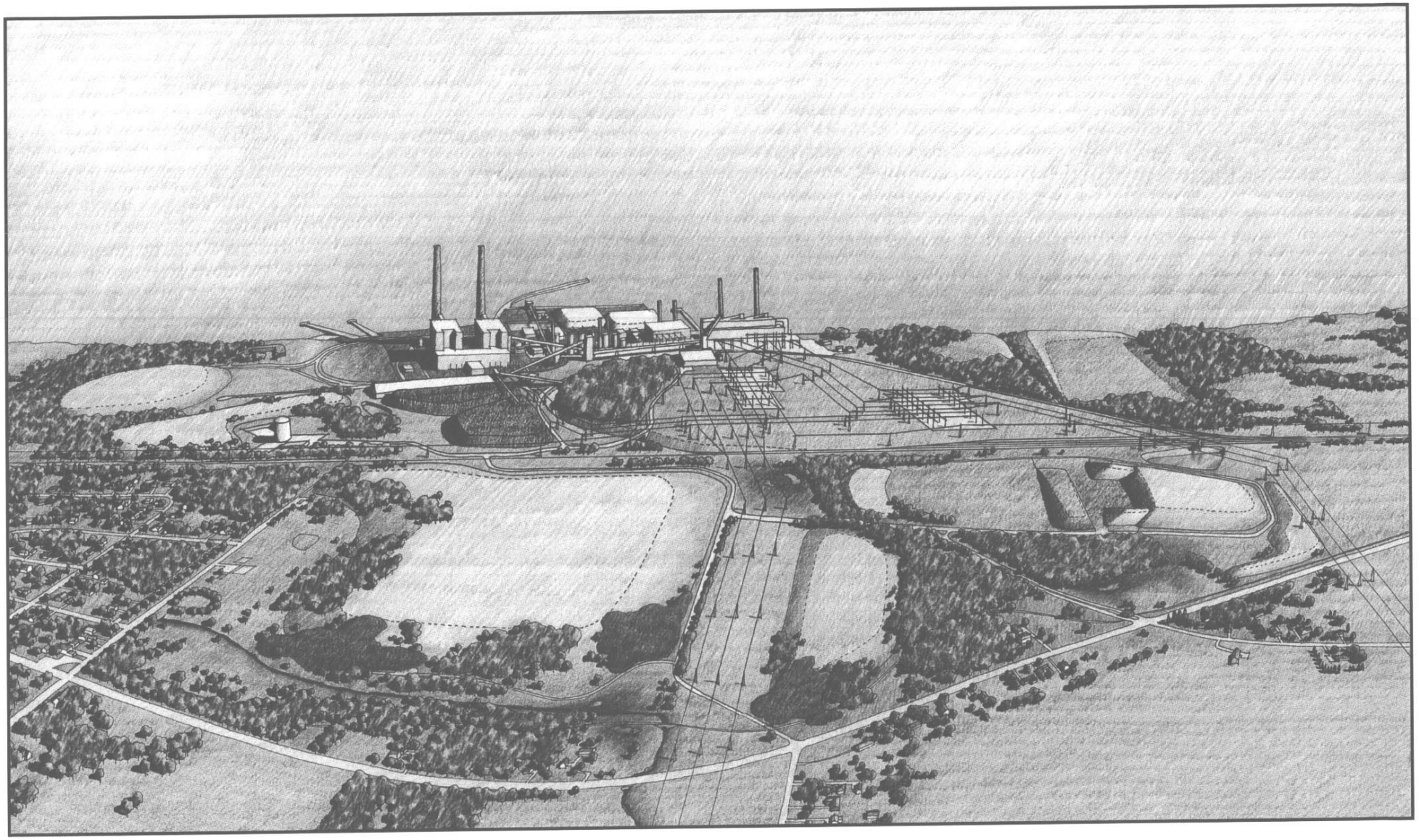


Figure Vol. 2-37
View of ERGS Looking East

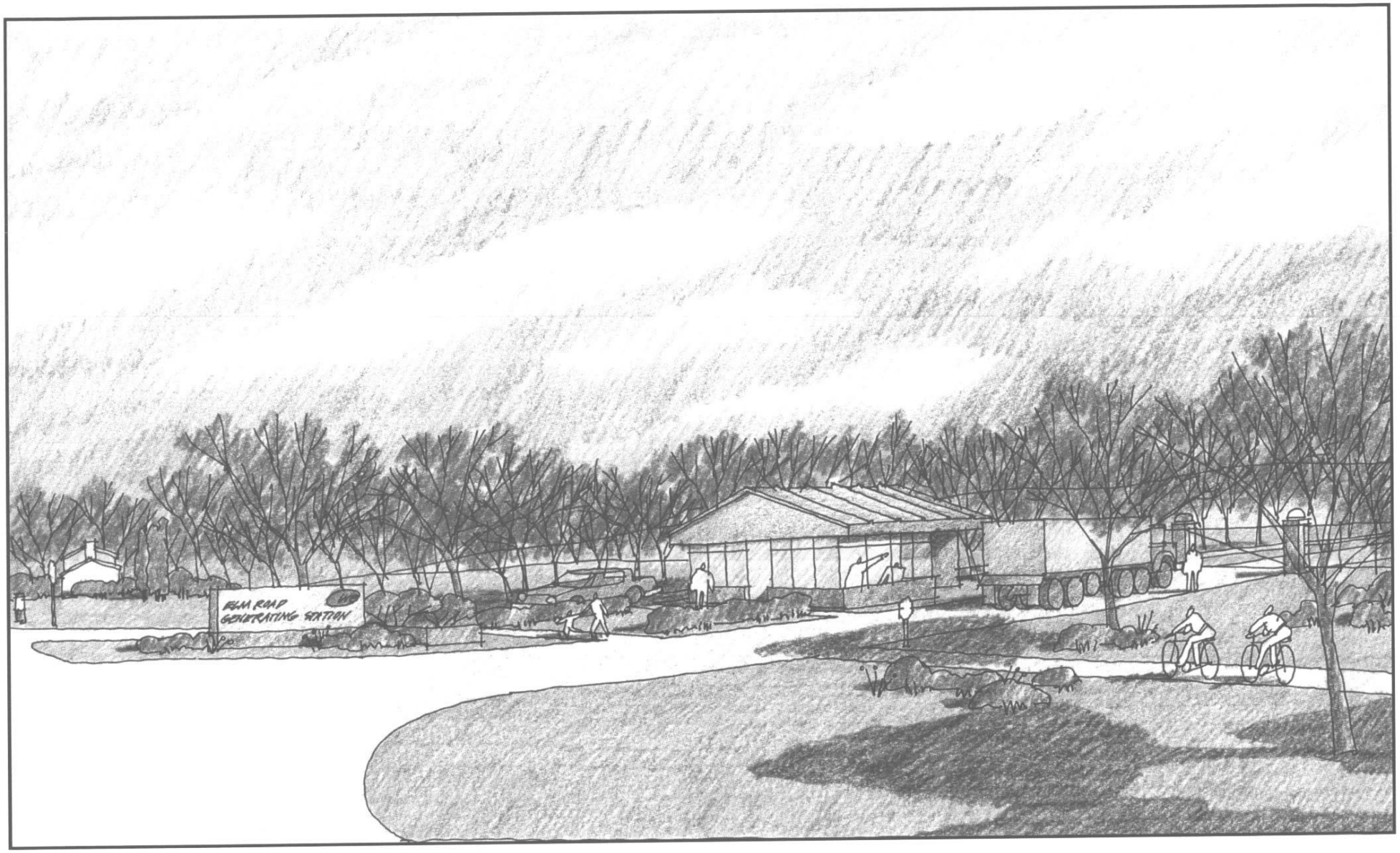


Figure Vol. 2-38
View of Highway 32 Plant Entrance

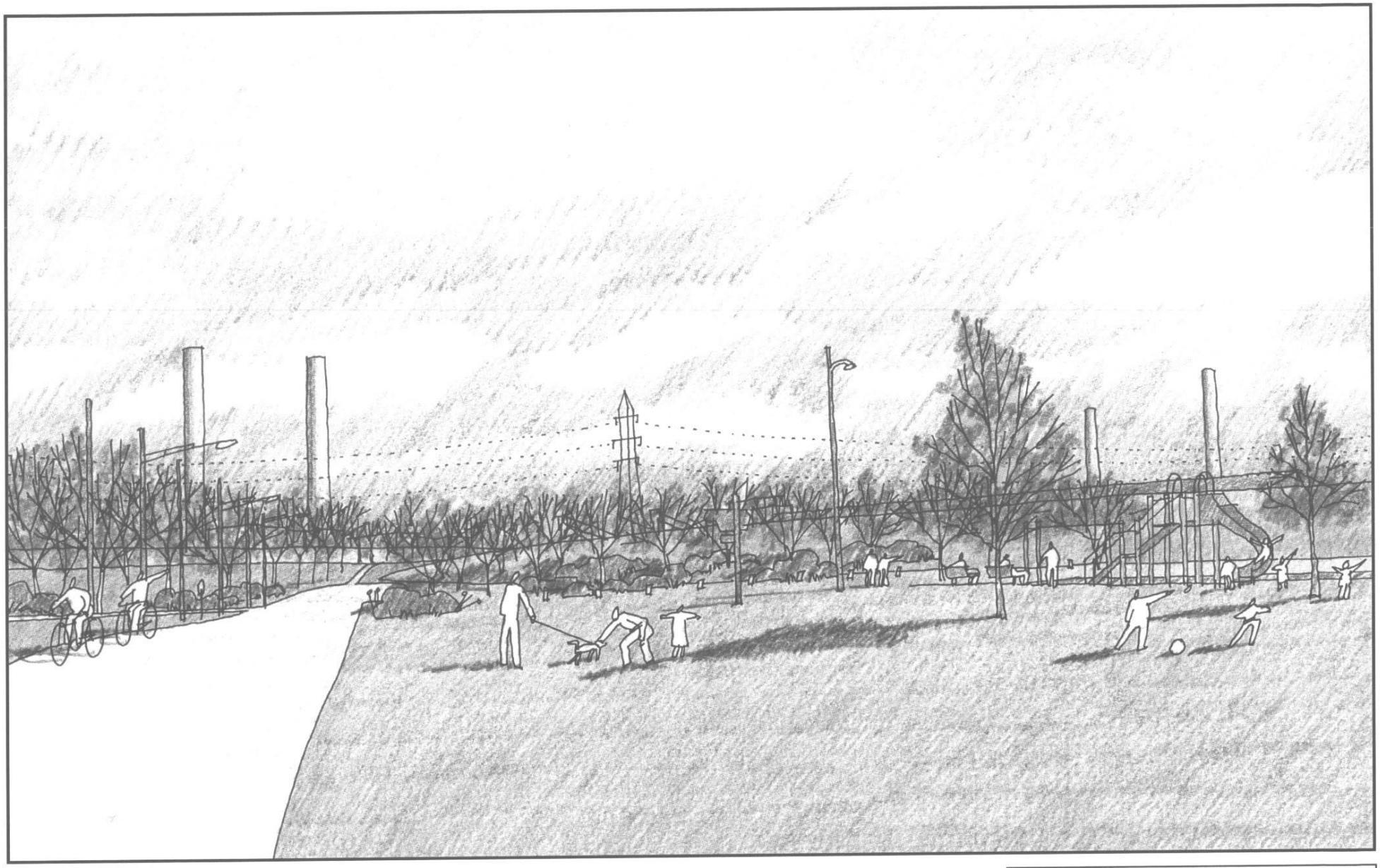


Figure Vol. 2-39
View of Haas Park at Elm Road

Figure Vol. 2-40
View of Public Access and Employee Entrance at Oakwood Road

APPENDIX

(Supplemental appendix, *Final Environmental Impact Statement: Elm Road Generating Station – Volume 3*, accepted per court order dated 2/24/05)
WI Elec. Power Co., W.E. Power, LLC and WI Energy Corp

July
2003

PUBLIC SERVICE COMMISSION OF WISCONSIN
DEPARTMENT OF NATURAL RESOURCES

Final Environmental Impact Statement

Elm Road Generating Station – Volume 3

Docket 05-CE-130

Date Issued, July 2003

Introduction

The applicants, most parties to this docket, and over 270 individuals provided written comments on the ERGS draft EIS. Many members of the public also provided oral comments regarding the draft EIS to PSC and DNR staff during the public meetings conducted in the city of Oak Creek and the town of Caledonia during late May 2003. Comments from the applicants, parties, and the public generally provided substantive information, constructive criticism, or questions regarding the content of the draft EIS. Some comments were related to PSC and DNR review procedures or expressed personal opinions about the proposed project. All written comments postmarked by June 15, 2003 and the information obtained during public information meetings were considered in the development of this final EIS.

All members of the public who submitted comments that specifically addressed issues or questions about the draft EIS have been listed in Table 1 below and the topics or questions that they addressed are also listed. These comments are not reproduced in Volume 3 due to production problems (scanning difficulties, being handwritten, etc), however, they are available for review at the PSC.[1] Public comments that expressed a personal opinion about the project and whether it should be approved or not, without addressing the draft EIS, were read and acknowledged, but the names of these commenters are not included in Table 1.

All comments from parties or organizations that were submitted to the PSC have been reproduced in this volume of the final EIS.

During the review of the comments on the draft EIS, PSC and DNR staff pulled questions or statements from the written and oral comments and they have reproduced below. PSC or DNR staff has responded to each of the questions or statements. In many instances, the comments received prompted PSC and DNR staff to perform additional analyses for particular issues. In these cases, the results of that additional analysis are usually in the text of Volume 1 of the final EIS and a reference to that analysis is provided in Volume 3. In other circumstances, further investigation by staff into the arguments being made by a particular commenter led staff to the conclusion that its original assumptions and analyses were accurate. In these situations, the reasoning behind the original assumption or analyses are more fully described in Volume 3.

Many of the comments were extremely useful in pointing out omissions, typos, or errors in staff's analyses that have been corrected in the final EIS. Because of the press of time and statutory deadlines, it was not possible to respond in writing to each question or comment received. It is our hope that the questions and statements covered in the following section are representative of the major concerns and issues that the public and the intervenors believed needed to be addressed in the final EIS.

The questions and statements along with staff responses have been grouped according to the issues covered by the chapters in Volume 1. For example, comments and staff responses related to air emissions are found under the Chapter 7 heading in this volume.

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[1] Contact Jeff Kitsembel, Case Coordinator, at (608) 266-9658 or at jeff.kitsembel@psc.state.wi.us.

The staff of the PSC and DNR have given careful consideration to all of the comments received and have attempted to reflect as many of the comments as possible in the text of the final EIS as well as this volume. We appreciate all of the time, effort, and careful thought on the part of all of the commenters who read the draft EIS and provided the input that was so valuable in producing the final EIS.

Table 1 Summary of Public Commenters and the Topics Addressed

Commenter	Topics Addressed
Daniel Bach	There is no air quality/health impact study. Believes that the comparison with highway numbers minimizes the ERGS impact, that the train/traffic data is suspect, that there should be a more thorough discussion of property values and that the BACT is still unresolved.
Jim Baker	The pollutant dispersion areas will change due to a lower stack height. The EIS should include a complete, comprehensive risk assessment.
John Berger	The draft EIS doesn't fully explain that gas prices could go down. The emission credits used by WEPCO won't be available for commercial/industrial businesses. The final EIS should disclose full cost of needed transmission facilities. The economic analysis should include costs associated with health care and lives lost.
Carla Beyerl	The loss of woodlands, wetlands and shoreline needs more emphasis. The permanent jobs created will be very specialized and may be filled with staff displaced by the closing of the Port Washington coal units. How many entry level jobs will be created? The issue of transmission lines should be more fully discussed. The EIS should show the area that will be served by the plant.
Dorothy Bocciardi	The cost analysis should include all externalities (mercury, road infrastructure, disposal of by-products, etc).
Rick Burt	The air modeling should include fumigation effects, periodic transport of pollutants from the Chicago area, secondary emissions from diesel trains, secondary emissions from coal dust from open rail cars, and the new height of the stacks for the North Site. The need for additional rail crossing modifications at Four Mile Road should be discussed.
Richard Clark	Health impacts and the cost of health care should be included.
Frank Egerton	The Welland Canal opened in 1892. (Page 183)
Barbara Eisenberg	The EIS should discuss the Navitas wind proposals for Shawano and the Upper-Midwest. Conservation and DSM should be a part of an integrated alternative. The EIS should look at what other states are doing and should discuss energy demand throughout the year (when is it the highest, what sector uses the most).
Dorothy Feeney	Health impacts associated with the proposed coal-fired plants should be evaluated. Expand the discussion of renewable technologies.
Carla Freeman	Discuss why coal (and not natural gas) is the fuel of choice. The

	reburning of flyash should be more thoroughly discussed. The demand for energy doesn't appear to require building ERGS.
John Graham	Human health costs should be included in economic evaluation.
Alec Granger	Costs associated with externalities should be included. Why wasn't the retirement of Oak Creek Units 5 & 6 announced earlier?
William Guenther	The effects of the project on tourism and sport fishing should be discussed.
Mary Ann Hernke	Train and traffic congestion increases local air pollution. Windows crack due to the rumble and vibration of trains. Discuss these impacts.
Jane Hutterly	Health impacts associated with the proposed coal-fired plants should be included, as well as impacts on the water table and aquatic life.
Gretchen Kalmer	Why does the EIS contain only air modeling done by WEPCO?
Robert Keller	The EIS should discuss the difference between the permitted emission rates and pollution caps (EPA agreement).
S. Kniesly	More information on mercury and coal dust and diesel emissions from trains should be included. The EIS should also include a discussion of WEPCO's compliance record.
Bill Lavalette	The information in Table 4-1 is outdated. Include a better evaluation of the wind potential in Wisconsin. Avian mortality caused by turbines should be discussed in more depth. The Production Tax Credit may not apply.
Sally and Mike Madden	There needs to be more research on cost, availability of alternative power sources, health issues, economics of air pollution and traffic.
Frances Martin	The effects of air pollutants on in-land waters should be discussed.
Stephen Mawn	The EIS lacks a meaningful discussion of health impacts.
Vicky Mayer	Describe the responsibility of the Joint Commission on the Great Lakes. Is their approval required?
Frank Michna	Train data is inaccurate.
Michael Miller	Wind power in the EGEAS runs should not be limited to 250 MW.
Robert Nemanich	Discuss the future probability of non-compliance with air emission regulations. The EIS should discuss wrongful deaths since 1995 due to non-compliance.
Nancy Pierce	The impacts to navigable waters, health impacts and the effects of transmission line upgrades should be discussed more thoroughly.
Bruce Renquist	There are hidden costs that should be disclosed (transmission lines, rail impacts, maintenance).
Linda Robers	Discuss potential for accidents and spills during shipment of sulfuric acid.
Leroy Roberts	What will be the effect on new and expanding businesses? What effect will the proposed plants have on emission credit trading?
Tedine Ross	Fuel diversity should be more thoroughly examined. There should be more discussion of the source and transportation of natural gas.
Thomas Rutkowski	The discussion of hazardous air pollutants should be expanded.
Jo Sandin	More information is needed about the impacts on fire, police and medical staff in the event of a catastrophic accident.
Wayne Stroesser	Does "least cost" include all externalities? It should include costs associated with lives lost, acid rain, smog, health impacts, mercury reduction costs, toxic emissions, global warming, maintaining the

	railroad, and coal mining environmental costs.
Brad Stong	The EIS needs to analyze more alternative sites.
Jeff Systma	Health impacts associated with the proposed coal-fired plants and the cost of transmission lines should be evaluated and discussed. Impacts of once-through-cooling, dust from coal handling, and site alternatives should be discussed more thoroughly.
David Ultrag?	A "big picture" discussion of our dependence on foreign fuel sources is missing.
Tom Ward	EGEAS should be allowed to choose more than one natural gas-fired plant.
Jay Warner	Tables 7-29 and 7-33 aren't consistent with respect to mercury data. Why are the emissions of the super-critical auxiliary boilers lower than those for the super-critical unit? Expand the discussion of the impacts of HAPS, particularly Hg and HF.
Andy Weber	EIS needs to explain the issue of coal and ash leaching. The differences between WEPCO's ads about coal delivery and the information in the draft EIS needs to be explained. The potential impacts of barging ash off-site should be evaluated in the final EIS. The effects of a wallboard plant are unclear. The impacts of hazardous air emissions (including those from reburning of ash) need to be explained more completely.
Dona Wininsky (American Lung Assoc.)	The draft EIS fails to address health impacts.
Sharon Worthy	The final EIS should consider the effect of lake breezes in keeping pollutants concentrated near the shore.
Unsigned	A comparison of the air emissions from coal and natural gas should be included.
Unsigned	How long will the plant emissions be trapped in the Lake Michigan basin by sea/shore breezes? Would the increased coal train traffic prevent the establishment of a Chicago-Racine-Milwaukee commuter rail?

Following is the question and response section of Volume 3. We attempted to list the commenter(s) that raised the question or made a statement. Due to the large volume of comments, we may have inadvertently attributed the question or statement to the wrong commenter or not to all of the commenters that had similar concerns.

Chapter 2 PTF Costs and Financing Mechanism

***The benefits of the lease arrangement with respect to reducing adverse impacts of wholesale electric competition and enabling smaller utilities to purchase baseload capacity should be recognized.* – (WPPI)**

The final EIS already indicates that price-regulated leases do mitigate horizontal market power concerns. The final does not cover small utilities purchasing long-term capacity because FERC and US DOJ guidelines indicate that long-term capacity markets beyond three years are competitive markets that have been deregulated.

***The risk of cost overruns is actually lower in the current environment of low interest rates and low inflation.* - (WPPI)**

An overrun is an overrun and risk is unaffected by low interest rates and inflation. The magnitude of the risk is clearly affected and the final EIS speaks to the magnitude.

***The EIS overstates the impact of adding baseload capacity too soon.* – (WPPI)**

This issue is best managed by adopting a proper materiality threshold which the final EIS does.

***Externality costs, such as the cost of future pollution controls, health impact costs, morbidity and mortality, etc. should be taken into consideration when assigning costs to the project.* – (Town of Caledonia, Sierra Club, Clean Wisconsin, SC Johnson)**

The final EIS speaks to the effect of externalities. Additional EGEAS modeling incorporated monetization of SO_2, NOx and Hg. Morbidity and mortality issues are addressed to some extent by EPA standards. Potential health impacts and morbidity and mortality are discussed in greater detail in a response to a related question in Chapter 7 of this volume.

***A 13.7% rate of return (ROR) assumption is too high, based on historical and other current projects. The cost analysis should be redone using a lower ROR.* – (SC Johnson)**

The final EIS indicates that lower RORs would strongly support using ratebase financing for this project rather than a lease.

Chapter 3 Need for Baseload Capacity in Southeastern Wisconsin

***The historical outage data indicates that natural gas combined-cycle plants are as reliable as coal-fired generation. Inputs to the EGEAS model should be adjusted to reflect a more accurate outage rate of natural gas technology.* - (SC Johnson)**

***The 2% outage rate, suggested by the applicants, for the ERGS facility is too low based on historical data. Historical outage rates are closer to 6-7% per year.* - (SC Johnson)**

A 5 percent forced outage rate was used in EGEAS for all combined-cycle units and a 2 percent outage rate was used for the SCPC units. The 2 percent value is based on a best case average for coal plants. However, there is little data for combined-cycle units in Wisconsin for comparison. Staff will continue to research this issue and attempt to provide more information at the time of the hearings.

The peak growth demand assumption is too high. **– (SC Johnson)**

The final EIS includes a lower demand EIA forecast for energy and demand as well as a sensitivity in which load growth is further reduced by available DSM.

Discuss the yearly energy demand in WEPCO's service territory -- when is it highest, and which sector uses the most energy. **– (Barbara Eisenberg)**

Energy usage is highest in the month of August (per WEPCO's 2001 Annual Report to PSCW. The industrial sector uses the most energy.

Include the perspective that ERGS provides a hedge against early retirement of baseload nuclear generation units. **- (WPPI)**

WPPI is correct here, but this is best handled qualitatively as there is no probability known about nuclear retirements. Such a probability would be needed to do a proper hedging cost/expected benefit analysis.

The 1000 MW of cost-effective energy efficiency savings identified in staff's analysis (Chapter 4) should be incorporated in the demand forecast in Chapter 3. **– (SC Johnson)**

The lower EIA forecast is being adjusted to include even more energy efficiency than modeled in the draft EIS.

Provide a need analysis that assumes that the current economic showdown would continue into the planning period. **– (Clean Wisconsin)**

History shows that recession slowdown would, at best, change the timing of new plants by a few years. If the slowdown is permanent, timing can be greatly affected. Growth forecasts of the US economy do not suggest a permanent slowdown, so it was not modeled.

Chapter 4 Alternatives to the Proposed Project

The EGEAS model does not incorporate many subjective factors, such as the fact that wind generation is not a suitable substitute for baseload coal generation. **– (WPPI)**

One subjective factor that is included is the capacity of the plant allocated to meet the reserve margin. Only 20 percent of the total wind capacity is considered. Other alternatives utilize 100 percent of the capacity towards meeting the required reserve margin.

The risks of high natural gas prices are not adequately captured in the draft EIS. Suggestion for an EGEAS run in which the high-natural gas sensitivity is 50% over base natural gas prices. Another run should be done that includes CO_2 monetization and a high-natural gas sensitivity to reflect the high demand and price for natural gas if CO_2 is monetized. **– (WPPI)**

EGEAS modeling has adapted the applicant's best forecasts for gas and coal fuel prices. These appeared reasonable. 2003 Base Case gas prices are already $6.50 in the model. By 2007 the base price is $4.50 which is what most consensus forecasts predict. Commenters are free during briefing to suggest an ever higher gas price interpretation. Using significantly higher gas prices would stop gas plant construction. This aspect is obvious, therefore modeling is not needed.

Add a discussion of an integrated resource alternative **– (Clean Wisconsin, Sierra Club, R. Owen)**

PSC staff views the EGEAS run that includes the DSM-EIA load growth sensitivity as an integrated alternative. Under the Optimal scenario (through the year 2014), this alternative includes 600 MW of simple-cycle CTs, both 545 MW Port Washington combined-cycle units, the two SCPC units (in 2012 and 2013), and 280 MW of wind capacity.

Energy efficiency analyses are inadequate and outdated. Acknowledge that STEP doesn't address energy efficiency potential in the industrial sector. Include more discussion about the potential for additional load management opportunities. **– (Sierra Club, Clean Wisconsin, CUB, R. Owen)**

Both the applicant and PSC staff conducted an energy efficiency analysis, but these analyses have several shortcomings. The most significant of the shortcomings of Commission staff's analysis is that the data used is outdated and incomplete. However, it is currently the best information available. Commission staff does not have sufficient resources to complete a comprehensive energy efficiency potential study. The STEP Study, upon which Commission staff's analysis is based, was a multi-year endeavor using the resources of a consultant and numerous utility staff. Estimating energy efficiency potential is difficult. This difficulty is due not only to the lack of data regarding the savings of energy efficiency measures, but also the uncertainty regarding the actions customers will take in response to energy efficiency information and incentives. Commission staff's analysis compensates for the lack of information by varying several assumptions in its analysis, resulting in several energy efficiency scenarios. The scenarios provide a broad range of energy efficiency potential. The most aggressive of these scenarios, which assumes a market potential of 85 percent, identifies more than 600 MW of additional energy efficiency potential in 2011. This is far more than the additional 47 to 146 MW in 2011 identified by the applicant's consultants using a data-intensive measure-specific analysis.

Neither the applicant's nor Commission staff's energy efficiency analysis included an estimate of the energy efficiency potential of other utilities or entities that have rights to acquire a portion of ERGS-- Madison Gas and Electric Company; Wisconsin Public Power, Inc.; and Dairyland Power Cooperative. The need assessment of the applicant includes a sensitivity that indicates that

it has need for the entire 1830 MW if no other entities acquire a portion of ERGS. It is therefore appropriate that the energy efficiency analysis include only the potential of the applicant. If another entity requests approval from the Commission at a later date to lease a portion of ERGS, Commission staff would conduct a needs and energy efficiency potential analysis for that entity, at that time.

Changes were made to the energy efficiency discussion in Chapter 4 of the final EIS to indicate that the avoided generation costs used in the STEP Study are outdated and likely underestimate the energy efficiency potential. Changes were also made to identify the failure of STEP to include avoided transmission and distribution costs as a weakness of staff's analysis.

***The Base Case should reflect at least a reasonable level of energy efficiency.* – (SC Johnson)**

The final EIS will include a new sensitivity using a lower EIA demand and energy forecast (as in the draft EIS), but it will also be further lowered to incorporate more energy efficiency.

***Improve the discussion of Wisconsin wind potential, including off-shore wind.* – (Clean Wisconsin, R. Owen)**

A section of text related to off-shore wind has been added to Chapter 4.

***The stated costs for biomass are too high and the potential described is too low.* – (R. Owen)**

PSC staff reviewed and utilized EIA data when preparing its assumptions for the EGEAS modeling.

***BASE Case construction costs for natural gas plants are too high* – (SC Johnson)**

For the gas plants, the final EIS uses actual bid prices from Calpine, but those prices cannot be revealed due to confidentiality.

***CO_2 monetization costs should be added to the Base Case. Costs of other pollutants should also be monetized - only SO2 allowances are monetized.* – (SC Johnson)**

Monetization of Hg, SO_2, NO_x, and CO_2 have been examined in the final EIS.

***Per the consent decree, the potential retirement of Oak Creek Units 5 and 6 should be included in an EGEAS model run, as should the possibility of just installing controls. Consider dispatch effects.* – (City of Oak Creek)**

EGEAS modeling performed by PSC staff included retirement of OCPP units 5 and 6 in 2012 as a sensitivity run. Staff also performed a sensitivity run that retired all units (including units 5 and 6) at 60 years of life. The cost of pollution controls for these units from 2012 forward were not included however, since they are not known at this time.

***Describe transmission line interconnection and transmission service costs for all of the alternative scenarios (i.e. the Optimal plan, Calpine, ERGS, and ERGS w/o IGCC)* - (Clean Wisconsin)**

Due to the complexity of transmission alternatives and the uncertainty related to future load centers, this analyses cannot be performed within the time allowed or to any degree of certainty.

Chapter 5 Fuel Diversity Perspectives

***Provide more information about the ability to transport natural gas into Southeastern Wisconsin---what is the current capacity? Would new facilities be needed?* - (CUB)**

This issue is being investigated by PSC staff and additional information may be presented in testimony at the hearing.

***Provide a comparative analysis of air emissions for natural gas vs. coal.* - (Town of Caledonia)**

Such a comparison has been provided in Appendix C.

***ANR Pipeline Company states in reference to problems experienced on the ANR Pipeline system last winter as follows: "[A] reference to a single unique situation hardly acts to validate that there is a legitimate concern about the reliability of natural gas pipelines to provide service at contracted levels."* – (ANR Pipeline)**

Any potential reliability problem on an interstate pipeline is a concern for natural-gas-fired generators because such generators tend to have no back-up supplies of natural gas or alternative fuels. That is not to say that delivery problems should be viewed as a fatal flaw associated with natural-gas-fired generators. No energy delivery system is 100 percent reliable.

If electricity is to be provided reliably by natural gas-fired generators all parts of the natural gas delivery system must work together to ensure that natural gas can be delivered reliably. ANR states in its comments that its pressure problems affected not only electric generators, but all of its customers last winter. ANR also notes that it was able to remedy the situation within a matter of hours. Such quick responses to pressure problems will continue to be necessary in the future so that system integrity of the natural gas and electrical systems can be maintained.

ANR asks that comments about the reliability of electric generators due to pressure problems be removed from the EIS. That does not appear to be appropriate. Natural gas-fired generators must be served at relatively high pressures. ANR acknowledges that it did have some difficulty

maintaining pressure last winter, but suggests that this was a unique situation. Even if the actual problem had not occurred, it would seem prudent to mention the possibility that pressure problems could threaten the reliability of natural gas-fired generators.

To its credit, in the end ANR was able to avoid major outages of service last winter. ANR and other interstate pipelines serving Wisconsin have had a generally good track record of providing reliable service. That does not mean, however, that reliability problems will not arise in the future. Just as the possibility of a derailment of a coal train bound for the Elm Road facility can be considered in assessing reliability of coal-fired generation, so can the possibility of pressure problems on the pipeline system be considered in assessing the reliability of natural gas-fired plants. Neither represents a fatal flaw associated with the type of plant in question. It seems reasonable to mention both in the final EIS.

***"Natural gas prices can be forecasted into the future notwithstanding their season to season variability, because long-term trend lines establish a basis for such forecasting."* – (SC Johnson)**

It is true that natural gas prices can be forecasted based on long-term trends in the historical data. What is critically important, however, is that the forecasts from such a model be accurate and that they appropriately reflect the inherent volatility of the data in question. When data are statistically non-stationary, as is the case with natural gas prices, long-term trend models, such as the one recommended by S.C. Johnson, tend to produce very poor forecasts relative to other models.[2] While it may appear to be a simple model, the random-walk model used in the draft EIS is much more sophisticated in a statistical sense than is a trend model, and research has shown that the random-walk model will tend to produce more reasonable and more accurate forecasts.[3]

Economic research indicates that long-term trend models significantly overstate the true precision with which time series data can be forecasted. Confidence bands around trend-based models are almost always far too narrow relative to the future observations of the data.[4] The long-term trend model attempts to force a set of rigid assumptions, which clearly do not apply here, onto the natural gas price data. Such a trend-based forecast is therefore likely to be a highly unreliable indicator of future natural gas prices.

For a trend model to be valid in this circumstance one of the conditions that must be satisfied is that natural gas prices must have, among other things, a constant long-term variance.[5] If this condition is not satisfied, then the trend model does not provide useful forecasts of the degree to which natural gas prices can vary. We can see that the variance of natural gas prices is far from constant. In recent years prices have been much more volatile than those of the prior periods, as is shown in the following chart.

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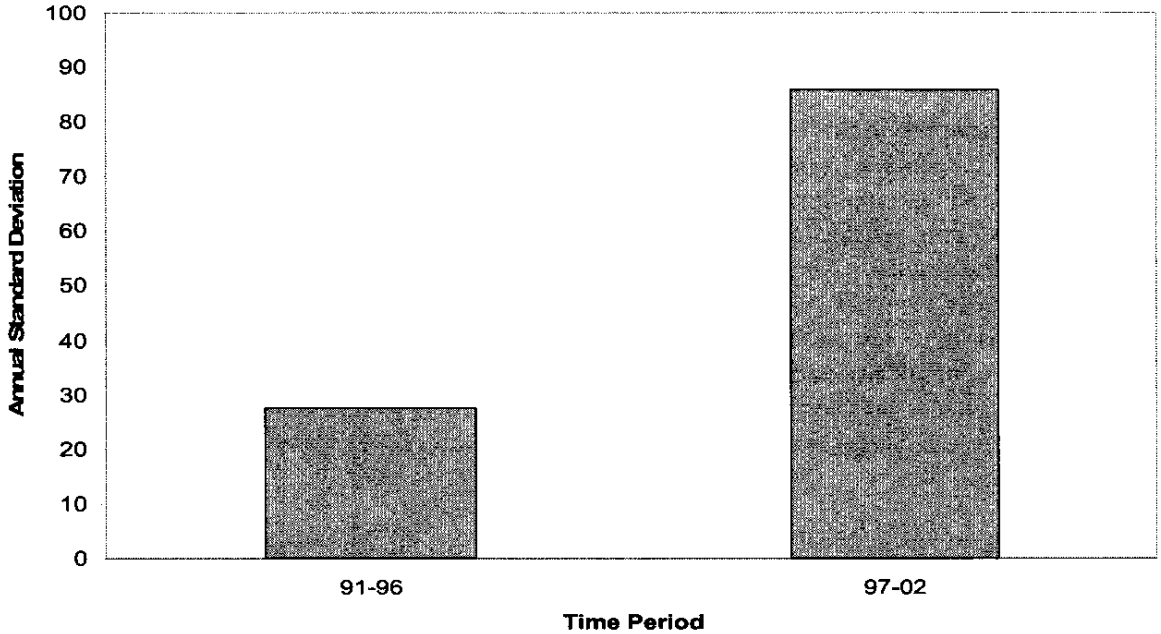
[2] For a discussion of stationarity and non-stationarity see Alan Pankratz, Forecasting With Univariate Box-Jenkins Models, John Wiley & Sons, 1983, p. 133.

[3] See Robert Pindyck and Daniel L. Rubinfeld, Econometric Models and Economic Forecasts, McGraw-Hill, 1981, p. 497.

[4] See, for example, Eduard J. Bomhoff, Financial Forecasting for Business and Economics, The Dryden Press, 1994, pp. 26-27.

[5] This is referred to as strict stationarity. See Jonathon D. Cryer, Time Series Analysis, Duxbury Press, 1986, p. 14.

Changes in the Volatility of Natural Gas Prices Over Time



The chart shows that the standard deviation of natural gas prices in the six-year period from 1997 through 2002 is three times as great as it was in the prior six-year period. That means that if the data from the earlier period are used to develop the trend in prices the future volatility of those prices is likely to be significantly understated. The prior period data, therefore, cannot help us to develop a statistically valid forecast, unless one uses a non-stationary model, such as the random-walk model used in the DEIS, or an advanced econometric technique such as an autoregressive conditional heteroskedasticity (ARCH) model.[6]

One can demonstrate, using actual natural gas price data, how poorly a long-term trend model forecast would typically fare against a forecast developed by the non-stationary random-walk model. If we use a long-term trend model based on the 1991-1999 natural gas price data, we would obtain a 95 percent prediction interval of prices in the year 2002 ranging from $2.51 to $3.00 per MMBtu. That forecast interval significantly understated the potential change in natural gas prices as the actual price for the year 2002 turned out to be $3.49 per MMBtu, which is 16 percent higher than the highest level suggested by the long-term trend model's prediction interval.

On the other hand, the 95 percent prediction interval for 2002 from the random-walk model, based on the same 1991-1999 data, ranged from $1.66 per MMBtu to $4.39 per MMBtu. The actual result was 20 percent lower than the high price suggested by the random-walk model forecast, or well within the range of forecasted prices.

The random-walk model uncovers the true volatility inherent in the natural gas price data in way that a long-term trend model cannot. Even though a price as high as $3.49 per MMBtu was never observed in the data used to develop the model, the random-walk model anticipated the 2002

[6] A discussion of ARCH models is beyond the scope of this EIS. Interested readers should see, for example, Stephen Taylor, Modelling Financial Time Series, JohnWiley & Sons, 1986, p. 107.

actual price as a real possibility. The trend model, which places the same weight on prices observed in 1991 as it does on prices observed in 1999, tends to produce forecasts that are tied closely to the actual data. It cannot anticipate a run-up in price to a significant degree, which is what happened in the case of natural gas prices.

While being tied to the actual data has an intuitive appeal, it turns out to be the very cause of the inaccurate forecasts from the model. The future values of economic series are not tied to past values in the manner that the long-term trend model assumes they are. The natural gas prices observed over the past several years have made that point quite clear. In fact, that is the problem with using long-term trend models to forecast the future—economic variables often deviate substantially from past values, as has been the case for natural gas prices. The long-term trend model assumes that no such deviations will occur, or when they do, the data will return to the long-term trend line. Such is rarely the case.[7] Its own characteristics, therefore, make the long-term trend model a fairly inaccurate forecasting tool. The results observed here are not the exception, but rather represent the typical poor forecasting performance of long-term trend models.

The random-walk model, on the other hand, assumes that noticeable deviations from historic levels are quite likely, as has occurred in the case of natural gas prices. Even though the highest price in the 1991-1999 dataset was $2.98 per MMBtu, the random-walk model estimated that over the three year forecast interval (2000-2002) natural gas prices could spike up to $4.39 per MMBtu, which represents an increase of 47 percent over the highest historic price level observed at the time the forecast was prepared. This is summarized in the following table:

Comparison of Forecasting Approaches
Predicting Natural Gas Price in 2002[8]
Based on Data from 1991-1999
$ Per MMBtu

Model	2002 Low Price Forecast	2002 High Price Forecast	Highest Observed Price in 1991-1999 Period	2002 Actual Price	Actual Price Within Prediction Interval?
Long-Term Trend	$2.51	$3.00	$2.98	$3.49	NO
Random-Walk	$1.66	$4.39	$2.98	$3.49	YES

Even the random-walk model, however, did not anticipate the natural gas prices observed this year. The 2003 upper prediction limit based on the 1991-1999 dataset was $4.73 per MMBtu. It appears that the average wellhead price of natural gas for the year will exceed that level. Nevertheless, this does not support the use of the long-term trend model. Despite the fact that its forecast was too low, the random-walk model was a much better predictor than was the long-

[7] See Walter Enders, Applied Econometric Time Series, John Wiley & Sons, 1995, pp. 181-185.
[8] Prediction intervals are based on 95 percent confidence, or alternatively, with an alpha of 5 percent.

term trend model, which suggested that the upper limit on natural gas prices in the year 2003 was only $3.36 per MMBtu.

The random-walk prediction intervals are many times as wide as the trend-based regression prediction intervals for good reason. The seemingly tight prediction intervals from the trend models are illusions that do not reflect reasonable expectations as to the variability of future natural gas prices, as has been demonstrated with the actual data.

Even if we were convinced that the natural gas price data did tend to realign themselves with the historic data, a model that would adapt to the data better than a long-term trend model is a stationary Box-Jenkins autoregressive moving average (ARMA) model. We fit the following ARMA model to the natural log[9] of monthly natural gas prices from January 1992 through July 2003:

$$\ln(\text{Gas Price}_{t)} = 0.09 + 0.90 \times \ln(\text{Gas Price}_{t-1)} + \varepsilon_{t-1}$$

The fact that the coefficient on the lagged gas price variable is close to 1.0 confirms again that the data are likely non-stationary.[10] By fitting this model the forecast will be constrained by the historic prices, which is a highly questionable assumption to make for this data. In fact, the high first-order autoregressive parameter suggests that such a condition should not be imposed.[11]

Setting that concern aside for the moment, however, we can examine the prediction intervals from this model to see that the error inherent in any proper forecast of natural gas prices is likely quite high. If we use this model to produce forecasts that revert to the mean level over time we can be 95 percent confident that in five years the wellhead price of natural gas will range from a low of $1.01 per MMBtu to a high of $5.88 per MMBtu. This demonstrates that even if the data do revert to mean levels, which is unlikely based on the analysis of the autocorrelation structure of the data, the prediction interval for a five-year forecast is still almost $5.00 per MMBtu wide.

Random-walk-based forecasts, such as the one used in the DEIS, typically produce prediction intervals that are several times wider than those produced by trend models. This makes the random-walk-based prediction intervals appear to some to be "too wide." While the width of the prediction interval may be troubling to some, it simply reflects the variability of the data. Everyone could agree that it would be easier to predict natural gas prices accurately if they were not so volatile. The fact is that natural gas prices are, however, extremely volatile. It is more productive to accept that natural gas prices are very difficult to predict and attempt to address that volatility through price hedging, for example, than it is to try to manipulate the prediction interval in ways that will mask the true volatility.

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[9] Natural logs are used to adjust for the heteroskedasticity of natural gas prices. Another approach that can be used to adjust for this problem is to use the square root of the data. See Arthur S. Goldberger, A Course in Econometrics, Harvard University Press, 1991, p. 272. Some adjustment must be made if the variance of the residuals is to have a constant variance.

[10] For a discussion of the approach suggested for choosing between a stationary model and a non-stationary model, see G.E.P. Box and Gwilym M. Jenkins, Time Series Analysis: Forecasting and Control, Holden-Day, 1976, p. 192.

[11] The non-stationarity of the data is also confirmed by the slow decay of the autocorrelation function as the order of the autocorrelation increases. If the data were truly stationary, the autocorrelation function should decay fairly rapidly with an increasing order. See Charles R. Nelson, Applied Time Series Analysis for Managerial Forecasting, Holden-Day, Inc., 1973, pp. 75-76.

Forecasting economic data into the future is a daunting task. Trend-based regression models produce forecasts that appear to be relatively precise, but that precision belies an underlying problem with the model. The more properly specified random-walk model tells the Commission to be prepared for long-term natural gas prices perhaps as low as $1.50 per MMBtu and perhaps as high as $10.00 per MMBtu. This may seem like a wide range, but a tighter prediction interval does not seem to be consistent with the actual data.

WPPI Comments

The need to represent the high degree of volatility in natural gas prices is supported by the comments of WPPI on the draft EIS. WPPI calls for a scenario analysis that includes an increase in natural gas prices that are "at least 50 percent over the base price."[12] The analysis from the random-walk model suggests that even a 50 percent increase in the assumed price might be conservative.

Comments in Other Proceedings

MGE Energy is proposing to construct a generating facility under the lease generation statute.[13] In that proceeding Dr. Richard Ferguson, who is testifying on behalf of RENEW Wisconsin suggests that it is not reasonable to expect that North American natural gas production will increase to meet projected demand.[14] He also argues that liquefied natural gas (LNG) will not provide a ceiling on natural gas prices, as some experts have suggested.[15] At page 14 of his testimony he concludes: " I expect prices we see in today's gas markets to become commonplace during the decade ahead with potential spikes to higher values than we saw last March and April." Dr. Ferguson has laid out a scenario for sustained high natural gas prices over the next decade. S.C. Johnson suggests that natural gas prices will return to more historic trends rather than remain at the current high prices. Both of these scenario forecasts are included in the range of possible prices suggested by the random-walk model.

Conclusion

The random-walk analysis of natural gas prices presented in the DEIS is a valid means of forecasting future natural gas prices. The model forecast encompasses the scenarios of some experts who suggest that natural gas prices will remain high, if not trend higher, as well as the scenarios of experts who suggest that natural gas prices will revert to lower historic trends. The random-walk model is, therefore, consistent with the evidence that natural gas prices are very difficult to forecast and that a wide range of prices should be considered as possible.

The trend model suggested by S.C. Johnson is not appropriate for forecasting volatile time series, such as natural gas prices. It is likely to produce less accurate forecasts than the random-walk model, and it is likely to understate significantly the true volatility of future natural gas prices.

No modification to the analysis of future natural gas prices is required for the final EIS.

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[12] Comments of WPPI at p. 6.
[13] PSCW Docket 05-CE-121.
[14] Direct testimony of Richard B. Ferguson, Docket 05-CE-121, p. 4.
[15] *Ibid*, p. 10.

Chapter 6 Overview of Proposed Sites and Technologies

Discussions of the Wallboard plant are inconsistent and confusing; is it part of the proposal and/or analyzed features or not? **- (City of Oak Creek, SC Johnson, Andy Weber)**

The discussion of the possible wallboard plant in Chapter 6 of the EIS has been expanded.

Add discussion about how accidents or spills related to the sulfuric acid shipments would be handled. **- (Linda Robers)**

Sulfuric acid is used for various industrial purposes and routinely shipped across roads and rail systems. Rules and appropriate procedures exist for avoiding spills and containing and cleaning up spills should they occur.

Describe the controls that would be installed to reduce coal dust during handling and storage.

Many methods would be employed to reduce coal dust during handling and storage including sprays, planting vegetation on reserve coal piles, and enclosure of the coal piles. For details see the Fugitive Dust section of Chapter 11.

Chapter 7 Air Emissions

Provide a description of the consent decree (EPA and WEPCO, the cooperative multi-pollutant agreement (WEPCO and the DNR), and the WEPCO/Oak Creek agreement. Explain how each agreement would interact with and affect the expected emissions and air modeling results for the proposed ERGS facilities. Explain the cumulative effect on local and regional air quality. **- (CUB, City of Oak Creek, SC Johnson)**

<u>Proposed EPA Settlement (Consent Decree)</u>
WEPCO and the U.S. Environmental Protection Agency (EPA) announced in April 2003 that they had reached a tentative settlement to resolve alleged violations by WEPCO of federal PSD rules. Details concerning the alleged violations were not presented in EPA's formal complaint and were not shared with DNR prior to the closing of the public comment period for the proposed Consent Decree that would formalize the settlement. For this reason and other reasons, Wisconsin's attorney general requested that EPA extend the public comment period. DNR has since been informed that EPA and WEPCO instead intend to revise the proposed Consent Decree based on comments received from the state of Michigan, and initiate a new public comment period. EPA must review any comments received before deciding whether to lodge the Consent Decree in federal court.

The proposed Consent Decree is detailed and complicated. Most importantly, it would require WEPCO to install pollution control equipment and technologies on specific existing coal-fired

units in Wisconsin and Michigan on a fixed schedule spanning the next ten years. Newly controlled units would not be allowed to exceed specified maximum emissions rates for NOx and SO_2. In addition, the proposed Consent Decree would establish system-wide mass emission caps and system-wide average emission rate limits for NOx and SO_2 from the existing coal-fired units. New units would not be included in the system-wide caps or limits. Finally, the proposed Consent Decree states that if one or more new units are constructed at the Elm Road Generating Station, WEPCO would limit the combined emissions of SO_2, NOx, PM, mercury, VOCs, hydrochloric acid, hydrofluoric acid, and sulfuric acid from both Oak Creek Power Plant and Elm Road Generating Station to 38,400 tons per year, collectively.

More information about the proposed settlement is available at the following website:

http://www.epa.gov/compliance/resources/cases/civil/caa/wepco.html

Cooperative Agreement

On September 30, 2002, DNR and WEPCO signed a Multi-Emission Cooperative Agreement (MECA) under Wisconsin's Environmental Cooperation Pilot Program, a voluntary program authorized by s. 299.80, Wis. Stats., for the purpose of encouraging superior environmental results. Under the MECA, WEPCO volunteered to reduce air emissions of NOx, SO_2, and mercury from the company's existing coal-fired boilers in Wisconsin. The four coal-fired boilers at Oak Creek Power Plant that existed in 2002 are among those covered by the MECA.
The MECA calls for reductions in NOx emissions to achieve a system-wide average for the coal units that existed in 2002 of 0.25 lb/mmBtu by October 2007 and 0.15 lb/mmBtu by October 2012, on both an annual and an ozone season basis. SO_2 emissions will similarly be reduced to a system-wide annual average of 0.70 lb/mmBtu by October 2007 and 0.45 lb/mmBtu by October 2012, and annual mercury emissions will be reduced 10 percent by October 2007 and 50 percent by October 2012 from 1998-2000 levels. The 2012 targets represent roughly 50-60 percent reductions in each of these three pollutants from year 2000 levels. In return for these voluntary emission reductions, DNR granted WEPCO flexibility on certain specific regulatory requirements that would normally apply to fossil fuel power plants. This flexibility is limited to procedural and administrative requirements only (e.g., routine reporting), and does not include any relief whatsoever from current or future emission limits or pollution control requirements.

The MECA does not and will not change any of the regulatory requirements that would apply to the Elm Road Generating Station, nor does it preclude the possibility that WEPCO's total system-wide emissions could increase, due to contributions from company-owned units in Michigan or from proposed new coal units that did not exist in 2002. It should be noted that the Elm Road proposal could have a significant effect, however, on what WEPCO does to meet the commitments in the MECA. This is because MECA includes an incentive for WEPCO to retire old coal units and replace the lost generating capacity with new, cleaner units. Specifically, if a coal-fired unit at Oak Creek Power Plant is replaced with one or more new units at Oak Creek (or Elm Road), NOx and SO_2 emissions from the new unit or units may be used in the system averaging to meet the specified reduction targets of MECA, but only to the extent that the unit or units replace actual coal heat input at Oak Creek. Actual coal heat input in this context means the average seasonal/annual heat input to the replaced coal-fired unit over the last two seasons/years prior to the retirement of the coal-fired unit.

A copy of the MECA is available at the following website:

http://www.dnr.state.wi.us/org/caer/cea/ecpp/agreements/wepco2/agreements/finalagreement.htm

Relationship between MECA and Proposed Settlement (Consent Decree)

The MECA and the proposed EPA settlement are mostly complementary and in no way contradictory. Most of the pollution control projects that WEPCO plans to undertake over the next decade will serve to satisfy requirements of both agreements, but there are a few differences that should be noted. The proposed Consent Decree requires NOx and SO_2 emission reductions that go beyond the voluntary commitments made by WEPCO in the MECA -- well beyond, in the case of SO_2. Without question, the proposed Consent Decree would require WEPCO to apply pollution controls beyond what the company envisioned when it signed the MECA. This does not obviate the need for the MECA, however, because the MECA includes mercury reduction commitments that go far beyond what would be required under the proposed Consent Decree or what would be achieved coincidentally through NOx or SO_2 controls required under the Consent Decree.

Relationship between the Consent Decree and the ERGS emissions

On April 29, 2003, a consent decree between WEPCO, the US EPA, and US Department of Justice (DOJ) was lodged with the District Court for the Eastern States of Wisconsin, which resolved allegations by EPA and DOJ that WEPCO failed to obtain PSD permits for certain activities that EPA and DOJ allege constituted major modifications under the CAA. As set forth in the Consent Decree, WEPCO denied and continues to deny the allegations and maintains that it has been and remains in compliance with the CAA. With the lodging of the Consent Decree, the company has begun to undertake actions to meet the schedule and requirements set forth in the Decree. The parties expect that the Court will enter the Consent Decree within the next several months, following the conclusion of the public comment period.

WEPCO provided the following information regarding the Consent Decree on June 27, 2003. The Consent Decree requires WEPCO to implement the following changes at the Oak Creek Power Plant (OCPP) no later than December 31, 2012.

- Retire Units 5 and 6
- Install FGD scrubbers (or equivalent sulfur dioxide control technology approved by EPA) on Units 7 and 8 to achieve either a 30-day rolling average emission rate of not greater than 0.100 lb/MMBtu SO_2 or a 30-day rolling average SO_2 removal efficiency of at least 95 percent.
- Install SCR equipment (or equivalent NOx control technology approved by EPA) on Units 7 and 8 to reduce nitrogen oxide emissions to levels not less than 0.100 lbs/MMBtu.

WEPCO has informed the DNR that the consent decree will result in emission reductions of SO_2 and NOx at the Oak Creek site. WEPCO also provided the following table that compares the expected SO_2 and NOx emissions in 2013 following the construction of the ERGS units and implementation of the consent decree with the emissions from the OCPP Units 5-8 in 2002.

	SO_2 (tons per year)	NOx (tons per year)
2002 Oak Creek Units 5-8	12,547	6,519
2013 Oak Creek Units 5-8	2,906	1,453
2013 ERGS facilities	6,356	3,809
2013 Total	9,262	5,262

WEPCO also informed the Department on July 1, 2003 that on June 30, 2003, the Company was contacted by US EPA with information that the Company had made a clerical error in assigining sulfur dioxide allowances to individual units at Valley Power Plant for the year 2002. Specifically US EPA informed the Company that it had assigned thirty-three (33) fewer allowances than necessary to its #3 Boiler. There was no exceedance of an emissions limitation at the Valley Power Plant, or at any other unit in the Wisconsin Electric system as a result of this error. The Company expects written notification of the error from USEPA within the next week, which will set forth the procedure and deadline for re-allocating allowances. As a result of the clerical error, Wisconsin Electric will pay a penalty pursuant to sec. 411 of the CAA.

***Emission rates assumed for the existing units are unrealistically high based on the consent decree and the WEPCO/Oak Creek agreement.* - (City of Oak Creek)**

The emission rates used in the air modeling analyses were provided by the applicant in its air permit application.

***Calculated CO_2 emissions numbers for the ERGS are inaccurate.* – (R. Owen, Sierra Club)**

The discussion related to CO_2 emissions has been revised and updated in the final EIS.

Evidently there will be no attempt to sequester carbon dioxide. What effect will this large amount of CO_2 have on global warming?

Under average operating conditions, the two SCPC units are expected to emit 8.4 to 8.9 million tons per year of greenhouse gases. This is about six percent of statewide greenhouse gas emissions in 2000.

Explain the statement in the Draft EIS page 151 " Currently, there are no regulatory requirements for individual projects such as the proposed ERGS to reduce or eliminate CO2 Emissions. At any rate, requirements to reduce emissions from this facility may be counterproductive if those requirements restrict this facility's utilization, since this project would be more efficient than the existing coal-fired generation equipment that it would displace."

This statement says that we can reduce greenhouse gas emissions by replacing older less-efficient power plants with newer more efficient power plants, and that this may be a better way to reduce emissions than by restricting emissions from the proposed ERGS power plant.

Add more discussion about global warming to the EIS text **- (R. Owen)**

The EIS discussion about global warming has been expanded and updated.

Discuss the cost effects of global warming.

There will most likely be economic consequences of global warming in Wisconsin. It is not possible to quantify the dollar costs of global warming because of the uncertainty about exactly what the impacts will be and the difficulty in assigning costs to environmental or health impacts. Some of the potential costs to Wisconsin could include:

- Costs to great lakes shipping due to low water levels (decreased cargo capacity per ship and/or increased dredging costs)
- Costs to rebuild or modify docks, piers, and boathouses due to lower water levels
- Losses to revenue due to decreased opportunities for winter recreation (decreased snow and ice cover reduces opportunities for skiing, snowmobiling, and ice fishing)
- Increase in health care and sick day costs due to increased mosquito-borne and water-borne diseases and lower air and water quality
- Potential crop losses due to drought and flooding
- Potential for increased flood damage
- Losses due to more frequent and severe forest fires

Describe periodic transport of pollutants from the Chicago area and their contribution to southeast Wisconsin's non-attainment status. **- (Rick Burt)**

There are literally millions of sources of ozone precursor pollution that contribute to the ozone air quality problem in Lake Michigan including local sources (Milwaukee and Chicago) and some sources that contribute from as far away as Texas. In general, on ton by ton basis the closer the source is to the problem the more it contributes to the problem.

Provide updated air modeling analysis to include new stack heights on both North and South Sites **– (Clean Wisconsin, SC Johnson)**

WEPCO has conducted an initial air modeling analysis based on the lower stack heights at the South Sites and provided its results to the DNR for use in this final EIS. However, that analysis

did not incorporate the BACT refinements that DNR would require if the facilities were approved and built on those sites.

***Provide information on the human health effects, morbidity, and mortality related to the emissions of the proposed ERGS facilities. Include effects on children, people with deceased lung capacity, or other sensitive receptors.* – (Sierra Club, Clean Air Task Force, Town of Caledonia, American Lung Association, W. Guenther, S. Mawn, B. Nitz, W. Stroessner)**

The chemicals found in emissions from coal-fired power plants are known to adversely affect the respiratory system (as well as have other effects), depending on the concentrations and the duration of exposure.

Several scientific studies in recent years have found a relationship between increased levels of air emissions from these types of sources and increased respiratory symptoms. This means that people with existing lung diseases such as asthma, bronchitis, emphysema, and other diseases could experience an increase in the severity and frequency of symptoms as a result of increased emissions. There is evidence in the scientific literature that increases in particulate matter levels can also cause morbidity and mortality as well. Infants and children breathe in more air per pound of body weight and are perhaps more susceptible due to developing immune and nervous systems and other factors related to growth. Children can also be more active and spend more time outdoors and experience increased exposure to outdoor air pollution as a result. In addition, mercury is emitted from coal-fired combustion. Mercury has been associated with neurological and other effects (here the main exposure route is through ingestion of fish).

In summary, there are numerous hazardous air pollutants released into the air from coal combustion. Past DNR analyses have evaluated the virgin fossil fuel exemption and found that, from the inhalation perspective, the risks resulting from well controlled facilities with tall stacks are low. Thus, a facility that meets applicable Wisconsin DNR requirements would not be likely to cause a significant inhalation risk. It is also true however, that as concentrations of air pollutants increase, even if they are below a federal or state standard, that there is a likelihood of increased respiratory symptoms and other adverse health effects occurring. For example, in the case of fine particulate matter ($PM_{2.5}$), when US EPA evaluated the available data on health effects vs. exposure, there was no clear threshold that defined a safe vs. unsafe level of exposure.

The area will continue to violate the National Ambient Air Quality Standards for ozone. The analysis supplied by Environ, a consultant for WEPCO, shows only minor effects from the addition of the ERGS facilities. However, on certain days, the NOx reductions at the Pleasant Prairie generating facility resulting from WEPCO's consent decree with EPA, result in a disbenefit or an increase in ozone concentration. In general, those local increases in concentration are offset by concentration reductions further downwind and on other days.

***Describe how EPA Clear Skies Report determined that 200 pre-mature deaths can be prevented by reduction of emissions.* - (R. Nemanich)**

The Clear Skies Initiative was introduced into Congress on behalf of President Bush. EPA conducted an analysis of the health benefits associated with the reduction in emissions resulting

from implementation of the proposal. EPA's most recent estimates of the health benefits of Clear Skies are included in the table below:

Benefit Category (2020)	Clear Skies Act 2002	Clear Skies Act 2003
Total health benefit ($1999) (Alternative estimate)	$93 billion ($11 billion)	$110 billion ($21 billion)
Premature mortality (Alternative estimate)	11,900 (7,000)	14,100 (8,400)
Chronic bronchitis	7,400	8,800
Hospitalization/ER visits	11,900	30,000
Non-fatal heart attacks	*not modeled*	23,000
Minor respiratory illness & symptoms	15 million days (includes 370,000 days with asthma attacks)	12.5 million days (includes 180,000 days with asthma attacks and 200,000 school loss days, a new benefits endpoint for 2003 analysis)

Provide more information about the expected air emissions during the construction phase of the project. **– (Clean Wisconsin)**

Emissions from construction related diesel activities and construction related dirt and dust are considered to be secondary emissions. It is difficult to quantify the emissions for inclusion in a dispersion model due to the small size of the individual sources. In addition, the low-level nature of much of these emissions would prevent significant transport off the property. Control of these emissions is required under fugitive dust regulations and would be addressed through site-specific fugitive dust plans.

Why are the emissions of the super-critical auxiliary boilers lower than those for the super-critical unit? **– (Jay Warner)**

The SCPC auxiliary boiler is rated at 242 mmBtu/hr and would be operated 2,000 hours per year. The SCPC coal fired boiler is rated at 615 MW and would operate 8,760. Thus, the expected emissions from the SCPC auxiliary boiler are much lower then from the SCPC coal-fired boiler.

It is unclear if the "virgin fossil fuel exemption" would apply if landfilled ash is re-burned. Explain this issue further. **- (SC Johnson)**

Virgin fossil fuel is defined in s. NR 445.02(11), Wis. Adm. Code. "Virgin fossil fuel" means any solid, refined liquid or refined gaseous fossil fuel with a Btu content greater than 7,000 Btu/lb

which is not blended with reprocessed or recycled fuels. Group 2 virgin fossil fuels consist of coal and residual fuel oil.

The definition of "coal" is found in s. NR 400.02(22e), Wis. Adm. Code. "Coal" means all solid fuel classified as anthracite, bituminous, subbituminous, or lignite by ASTM designation D388-92, incorporated by reference in s. NR 484.10, Wis. Adm. Code.

The information on ash fuel was provided in the original air permit application to the DNR, dated December 2001.

WEPCO has indicated in the DNR's air permit application that the fly ash and bottom ash meet the definition of coal and are therefore exempt from the requirements of NR 445. The analyses include an evaluation of the Coal Rank in accordance with ASTM Method D388-92. The ash samples indicate coal ranks of lignite, bituminous, and anthracite coals.

The hazardous air pollutants (HAPs) emissions from combustion of virgin fossil fuel 2 vented from a stack which has downwash minimization stack height are exempt from the emission limits under NR 445.

A facility is a major source of federally regulated hazardous air pollutants if one or more federally regulated HAPs are emitted at greater than 10 tons per year or if emissions of one or more federally regulated HAPs exceed 25 tpy. The expected HAPs from the ERGS were reviewed in the draft EIS and for the final EIS. Table 7-17 in the final EIS summarizes the HAPs emissions expected from the different emission sources at the proposed ERGS. The proposed ERGS is a major source under 40 CFR Sec 63.41 and thus subject to case-by-case MACT requirements for HAPs. Table 7-18 summarizes the case-by-case MACT proposed by WEPCO.

Air quality impacts related to ash re-burning have not been disclosed. **– (Sierra Club, Andy Weber)**

See the response to the question directly above.

Even if hazardous air pollutants are exempt from NR 445, the potential health impacts of these pollutants, such as arsenic and chromium, must still be assessed and described. Use a risk assessment using standard EPA methodologies. The multi-pathway risk assessment should look at both cancer risks and non-cancer toxicity. **- (SC Johnson, Sierra Club, Clean Air Task Force)**

The DNR has examined the impacts of virgin fossil fuel combustion in great detail in the past and found that due to the presence of control devices and tall emission stacks, the impact from this industrial sector is well below a level of concern due to inhalation impacts, and thus is not a significant risk from an inhalation pathway. Arsenic, hexavalent chromium, and several other carcinogens are emitted from coal-fired combustion sources and the analyses in the past have shown that these carcinogenic chemicals are not expected to be in high enough concentrations to present a high risk (the DNR uses standard EPA methodologies when examining inhalation cancer risks).

With respect to pollutants that can bioccumulate in the food chain, it is possible to conduct a multi-pathway risk assessment. However, this type of analysis is very difficult to do, requires many assumptions to complete, and is very labor intensive. The DNR currently has no "in-house" capability to conduct this type of analysis. As a result, the DNR has, in the past, had to contract with outside consultants to conduct such an analysis. The only time such an analysis was completed was for a proposed medical waste incinerator (circa 1990). No multi-pathway analysis related to the ERGS facilities is planned at this time.

The discussion of $PM_{2.5}$ should be expanded and modified. Discuss the fact that $PM_{2.5}$ is caused by the reaction of gaseous pollutants in the atmosphere and by direct emissions from coal-fired power plants.

The principal comments of $PM_{2.5}$ are classified as elemental carbon, organic carbon, ammonium nitrate, ammonium sulfate, and crustal material. NOx and SOx emitted in a power plant plume react in the atmosphere to form ammonium nitrate and ammonium sulfate. Organic carbon in power plant plumes also reacts in the atmosphere to form a variety of organic particles. Elemental carbon is emitted directly from power plants.

$PM_{2.5}$ is a better indicator of human health impact than PM_{10}. NAAQS for $PM_{2.5}$ is 15 ug/m^3, what is the potential for exceeding this standard? **- (SC Johnson, Sierra Club, Clean Air Task Force, W. Stroesser)**

WEPCO submitted an analysis of the regional $PM_{2.5}$ impact that demonstrates ambient air quality standards would be attained and maintained. From the analysis supplied by Environ, a consultant for WEPCO, it appears that the $PM_{2.5}$ standard would not be violated as the result of the additional emissions at the ERGS facilities. The analysis indicates that the $PM_{2.5}$ effects would be minor. However, one should consider the $PM_{2.5}$ analysis to be preliminary at this point. When WEPCO's consent decree with EPA is considered, there would be a net decrease in $PM_{2.5}$ concentrations. Again, the change would be expected to be relatively minor.

Evaluate the proposal's adverse mercury impacts. How much would the proposed coal-fired units contribute to fish consumption advisories? How much mercury will be loaded into rivers and lakes? One teaspoon of mercury is enough to contaminate a lake. **– (Sharon Morgan, SC Johnson)**

In its ***Mercury Study Report to Congress*** issued in December 1997, US EPA found that "a plausible link exists between past and present, human-caused, atmospheric emissions of mercury in the U.S. and the increased concentrations of mercury that have been found in the environment and in freshwater fish". However, the report goes on to state that "an apportionment between mercury sources and mercury in environmental media and biota cannot be described in quantitative terms with the current scientific understanding of the environmental fate and transport" of mercury. Since our scientific understanding of the impact of mercury emissions on the environment is still developing, a specific answer to these questions is not possible.

We know that mercury in the environment is the result of both natural and anthropogenic (man-made) activities. In the atmosphere mercury exists in three basic forms - elemental mercury vapor, particle bound mercury, and reactive gaseous mercury. Depending on the form of mercury emitted, the type of emission source and the meteorological conditions, mercury air emissions from a specific source may be deposited back to the earth locally, regionally or on a global scale.

What realistic percent reduction in mercury does WEPCO intend to reach? WEPCO told the DNR Citizen's Advisory Committee for Mercury Emission Reduction that the industry could not clean up mercury emissions by more than 10 percent in ten years, 40 percent in fifteen years, and nothing greater than 40 percent. The EPA and DNR target a 90 percent reduction in mercury. **– (Wayne Stroessner)**

WEPCO has 17 existing coal-fired boilers that are affected by the reduction requirements that would be imposed by the rules in ch. NR 446 Wis. Adm. Code adopted by the Natural Resources Board at their June 2003 meeting. These rules require that WEPCO achieve a 40 percent reduction in mercury emissions from coal combustion by January 1, 2010, and an 80 percent reduction by January 1, 2015. These 17 coal-fired boilers are capable of emitting approximately 1300 pounds of mercury annually based upon the mercury content of the fuel they use. Under the adopted rules WEPCO must limit mercury emissions from its existing boilers to approximately 780 pounds per year beginning in 2010. In 2015 mercury emissions would be limited to approximately 260 pounds per year. The DNR believes that these are realistic expectations based on the mercury control technology that currently appears most promising.

Discuss the mercury content of bituminous vs. sub-bituminous coal and the ability of various technologies to capture mercury. **- (Sierra Club)**

Electric utility boilers are fired primarily by either bituminous or sub-bituminous coal. It was found that bituminous coal used in 1999 in utility boilers contained an average 8.65 +/- 0.08 (mean +/- 95 percent confidence interval) pounds of mercury per trillion BTU heating value. The sub-bituminous coal contained approximately one third less mercury at an average 5.77 +/- 0.08 pounds per trillion BTU. This data was compiled by the Electric Power Research Institute in it's analysis of the ICR fuel sampling data obtained for all U.S. electric generating units greater than 25 MW[16].

The ICR data also demonstrated that control of mercury is higher for bituminous coal due to a higher chlorine content than sub-bituminous coal. But within each class, the amount of mercury collected varies by the type of pollution control equipment. For units with only a fabric filter, the mercury removal was, on average, 90 percent for bituminous coal and 72 percent for sub-sub-bituminous coal.[17] Other tested units firing bituminous coal and with a fabric filter had additional control equipment, including two with a wet FGD system and three with a dry SDA system, with

[16] (Chu, 2000) "An Assessment of Mercury Emissions from U.S. Coal-fired Power Plants", Electric Power Research Institute, Palo Alto, Ca, TR-1000608, September 2000.

[17](Kilgroe, 2001) "Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report, US Environmental Protection Agency, Research Triangle Park, NC, EPA-600/R-01-109, December 2001.

both configurations demonstrating 98 percent mercury removal. Applying the demonstrated control efficiencies to the average mercury content of bituminous and sub-bituminous coal results in the following emission rates:

Fuel Class	Mercury Content (lbs/Tbtu)	APCD	% Capture	Emission Rate (lbs/Tbtu)
Bitum	8.65	FF	90%	0.87
		SDA / FF	98%	0.17
		FF / FGD	98%	0.17
Sub	5.77	FF	72%	1.62

Additional information summarizing the proposed mercury rules. **– (Clean Wisconsin)**

There are four electric utilities in Wisconsin that are significant sources of atmospheric mercury each emitting 100 pounds or more of mercury annually, based on historic reporting of their emissions. These four "major" electric utilities include Alliant Energy (AE), Dairyland Power Cooperative (DPC), WEPCO (WE) and Wisconsin Public Service Corporation (WPSC). The following are the provisions of the rules adopted by the Natural Resources Board at their June 2003 meeting that require these major utilities to reduce mercury emissions from their 42 existing coal-fired boilers. These rules would be within ch. NR 446 Wis. Adm. Code. The objective of the proposed rule is to set limits on the emissions of mercury into the ambient air from electric utility sources as a means of reducing atmospheric mercury deposition to the environment and specifically to water bodies with fish consumption advisories.

Mercury Baseline – By October 1, 2005, major electric utilities would be required to submit a report to the DNR with the following information:

1. Average coal usage for the years 2002, 2003, and 2004.
2. Sample test results of the fuel mercury content from coal in 2004.
3. Results of emissions testing with the mercury capture efficiency of currently installed air pollution control equipment.

The results of coal usage and coal mercury content would be used to determine a mercury baseline for each major electric utility and will be the point from which mercury reductions will be required.

Mercury Emissions Cap – The emissions testing with current mercury control efficiency will be used along with the established mercury baseline to establish a mercury emissions cap for each major electric utility. Beginning January 1, 2008, major electric utilities would not be allowed to exceed their mercury emissions cap.

Compliance Plan - By October 1, 2007 and October 1, 2011, utilities would be required to submit a compliance plan to the Department with a proposal detailing how the utility intends to comply with the baseline emission reduction requirements in the rule.

Reduction Requirements – Major electric utilities would be required to achieve the following reductions in mercury emissions from baseline emissions by the following dates after rule promulgation:

1. By January 1, 2010 – 40 percent reduction.
2. By January 1, 2015 – 80 percent reduction.

Compliance – Major electric utilities would be allowed to achieve compliance using a combination of control technology, fuel switching, efficiency in boiler operation, boiler shutdown, or emissions trading between major electric utilities.

Multi-pollutant Option – Major electric utilities would be allowed to pursue a multi-pollutant reduction approach for mercury and other air pollutants.

Variances – In consultation with the PSC, the DNR would be allowed to grant variances to major electric utilities based on a demonstration that the technology or economic costs are not feasible.

Electric Reliability Waiver – A waiver from an annual mercury emission limitation may be approved if the cause of excess emissions is related to an issue of electric reliability. The PSC would be consulted and a 30-day public comment period with a hearing opportunity would be offered.

Evaluation Reports – The DNR would be required to prepare a rule assessment report to the Natural Resources Board by January 1, 2009, taking into consideration electric reliability, scientific and technology developments, multi-pollutant reduction approaches, and federal regulatory activity. The report would include an evaluation of the feasibility of achieving the seven- and twelve-year reduction requirements and recommendations for corrective actions and rule revisions. The DNR would be required to update the report by January 1, 2013. In addition to these evaluation reports, the DNR would be required to submit a report within six months of promulgation of federal regulations or enactment of a federal law that requires mercury reductions from sources affected by this rule.

New Sources – New sources with allowable mercury emissions of 10 pounds or more per year will be required to apply BACT (Best Available Control Technology).

Source Reporting – All sources with emissions of 10 pounds or more of mercury per year would be required to meet the measurement and reporting requirements of the rule.

***Monetize mercury impacts.* – (Dorothy Bocciardi)**

Specific estimates of the costs of mercury contamination are difficult to do. The two most important impacts are public health and tourism.

The WDNR is concerned about mercury because the pollutant has unique properties that allow it to persist in the environment and bioaccumulate in terrestrial and aquatic system food chains. This bioaccumulation problem poses a human health risk for people that consume mercury-

contaminated fish. Mercury is a potent neurotoxin that crosses both the blood-brain and placental barriers. Children and developing fetuses are most at risk from the effects of mercury exposure. US EPA has determined that children born to women with blood concentrations above 5.8 parts per billion are at some increased risk of adverse health effects. About 8 percent of women of childbearing age had at least 5.8 parts per billion of mercury in their blood in 1999 – 2000. Mercury also affects both fish-eating birds and mammals.

In addition to the health risks caused by elevated levels of mercury in the environment, the WDNR is also concerned with the important economic consequences associated with a potential reduction of recreation and tourism activities. Each year the DNR sells approximately 1.5 million fishing licenses (1 million are residents) generating approximately $1.1 billion in expenditures to the state. Adding to license sales is the significant revenue provided by sales of food, lodging, gasoline, and sporting equipment related to fishing as an activity with a total yearly economic impact of approximately $2.1 billion statewide. The sport fishing industry accounts for approximately 30,500 jobs in the state each year. Based on data from the American Sportfishing Association, Wisconsin ranked 6th among states in 2001 in overall economic output (more than $2.3 billion) from fishing. Although there is no data to suggest a decrease in fishing license sales, the DNR is concerned that the continual listing of fish consumption advisories because of elevated levels of mercury could cause a corresponding decrease in recreation and tourism and have a direct economic impact on the state.

Will the mercury consumption advisory ever be lifted?

Currently, we cannot say with any certainty when fish consumption advisories for mercury will cease for any waterway. However, trends monitoring of mercury in fish tissue will continue to be performed by the WDNR so we can determine the effect of mercury reduction actions as well as determine when consumption advisories can be modified or eliminated.

***Discuss why a spill of a few drops of mercury require a fire department hazardous material response while coal-fired power plants can emit tons of mercury into the atmosphere.* – (Harvey Radke)**

Indirectly mercury air emissions lead to contamination of the environment. Mercury from natural and anthropogenic sources is released to the atmosphere, where it is transported and may be deposited in terrestrial and aquatic ecosystems. A small portion of this mercury is converted by bacterial action to a more toxic form, methylmercury, which can bioaccumulate in fish. Bioaccumulation is the build-up of a substance in an organism from the surrounding air or water, or through the consumption of contaminated food. Elevated methylmercury levels may lead to a decline in wildlife populations and may affect human health from the consumption of sufficient quantities of contaminated fish.

Direct mercury exposure at high levels can also cause health problems. Thus a mercury spill is of immediate concern and precautions must be taken to prevent exposure.

Mercury is a neurotoxin in most of its chemical forms. A neurotoxin can cause damage to the brain and central nervous system. Mercury also affects the kidneys and lungs. Methylmercury,

one of the most toxic forms of mercury, is known to affect learning ability and neurological development in children.

Show that the proposed source will comply with the Lowest Acheivable Emission Rate (LAER) for VOC emissions. Do SCPC units meet LAER requirements if the SCPC technology has higher VOC emission that the IGCC technology that WEPCO has included in the proposal? – **(SC Johnson, Andy Georgoulis, Susan Jensen, Donald Paasch, Susan Greenfield, Wayne Strossner)**

Wisconsin DNR implements its New Source Review (NSR) program based on the federal air permit requirements of the Clean Air Act, federal regulations and USEPA guidance. In evaluating a project such as the Elm Road Generating Station under the federal NSR requirements, the resulting permit must require Best Available Control Technology (BACT) for air pollutants for which the area is in attainment with air quality standards, and technology that results in the Lowest Achievable Emission Rate (LAER) of air pollutants for which the area is not attaining air quality standards. Both BACT and LAER are evaluated using a top down approach set forth by EPA. The top down approach evaluates the emission control strategy that would result in the lowest emission rate to determine if the strategy is feasible. For BACT purposes, if this strategy is found to be infeasible, then the strategy that results in the next lowest emission rate is evaluated and so on until a feasible strategy is determined. While the top-down review does allow for the review of pollution control strategies, it does not specifically allow for consideration of different process technologies.

SCPC and IGCC are considered different process technologies. As such, emission control strategies are evaluated for BACT/LAER purposes by analyzing those strategies available to each under EPA's top down approach. The DNR in its review of the air permit application will establish appropriate BACT/LAER limits for the proposed emission units. Tables 7-11 to 7-22 in the draft EIS summarizes the BACT/LAER emission limits proposed by Wisconsin Electric for the SCPC boilers, auxiliary boilers, diesel engines, IGCC and material handling processes .

Also, in the review of the BACT analysis, the DNR does not evaluate the cost of future air pollution controls.

Provide a description of the sources and analysis process used to generate the ambient air quality data. – **(Clean Air Task Force, SC Johnson)**

Every three years, the dispersion modeling team collects information from all monitoring sites for the previous five years. Monitors with less than three complete years of data are not considered further. The appropriate design value is selected from each year (second highest value for short-term standards) and the 3, 4, or 5 values per monitor are averaged. The team then assigns values to each county based on how the area around the monitor best represents the county. In addition, trends and previous monitoring weigh into the decision. Since most monitors are located near a source of pollution, it is challenging to obtain representative data. The values used in Milwaukee County are based on monitors located throughout the county including sites in downtown Milwaukee.

Air quality monitoring stations used to establish background (ambient) concentrations of air pollutants are not appropriate. **(City of Oak Creek)**

See the response to the question directly above.

The final EIS should indicate if the Compliance Assurance Monitoring (CAM) rule applies to the SCPC units. **- (Clean Wisconsin)**

The proposed Elm Road Generating Station (ERGS) will be subject to the Compliance Assurance Monitoring (CAM) rule requirements established under 40 CFR Part 64 for the ERGS SCPC boilers for particulate matter, and for some material handling systems utilizing baghouses. The auxiliary boilers, emergency diesel equipment will not utilize control devices as defined in Section 64.1 of the CAM rule, and therefore CAM requirements will not apply to these units. The only IGCC control device that meets the relevant definition in the CAM rule is the diluent injection system used to control nitrogen oxide emissions. Since this unit will also have a 40 CFR Part 75 CEMS system for the measurement of nitrogen oxide emissions, thus this unit would not be subject to CAM requirements because of the acid rain program exemption. The facility will be required to submit a CAM plan as required under 40 CFR Part 64. The DNR will include the appropriate monitoring requirements in the operation permit.

The EIS fails to quantify the potential for significant air quality improvements if the new units are built and dispatched ahead of existing units. **(City of Oak Creek)**

The EIS does not attempt to quantify any potential air quality improvement from dispatching the new combustion units ahead of the existing units because WEPCO is not subject to any PSC or DNR requirement to dispatch and operate their combustion units on an air quality priority basis.

Discuss the inconsistencies between the pollutant levels being requested in the air permit, the pollution caps in agreements, and expected pollution levels WEPCO is touting to the public in its ads and public meetings. **(Sierra Club, Robert Keller)**

The emission levels that WEPCO has proposed its air permit application are those emission limits applicable to the three proposed combustion units to satisfy the statutory criteria for permit approvability (i.e., to meet LAER/BACT [Lowest Achievable Emission Rate/Best Available Control Technology] emission limits and to ensure that ambient air quality standards and air increments are protected).

Separate and distinct from the air permitting process for the ERGS project, WEPCO is subject to other air emission limits, based on:

- WEPCO's agreement with the city of Oak Creek to limit its total emissions of eight pollutants from the combined OCPP and ERGS facility to the total amount of those pollutants emitted in calendar year 2000, if PSC approves one or more of the proposed ERGS units;

- WEPCO's environmental cooperative agreement with DNR to reduce NO_x, SO_2 and mercury emissions from its coal burning power plants in Wisconsin;
- WEPCO's Consent Decree with US DOJ, US EPA and Michigan to reduce NOx, SO_2 and particulate emissions from its coal burning power plants in Wisconsin and Michigan.

While these other agreements/decrees impose additional requirements for air emission reductions on WEPCO, it is not incorporated into the air permit applications for the ERGS project.

Provide information related to the effects of localized air pollutants at specific locations in the residential neighborhoods nearest to the plant. **– (SC Johnson)**

The dispersion modeling analysis submitted by WEPCO includes receptor locations around the facility and demonstrates that all applicable ambient air quality standards are attained and maintained at all points, including in the residential neighborhoods nearest the plant. This determination includes the impact of the facility and a regional background concentration that is calculated from a representative monitoring location.

Provide information about the current status of the air permit applications for the ERGS. **– (SC Johnson, Carla Freeman, Andy Weber, Clean Wisconsin, town of Caledonia, Calpine)**

The air permit application was deemed not complete by the DNR at the time of the issuance of the draft EIS. The air quality analysis information in the draft EIS was based on information in the air permit application submitted by WEPCO. WEPCO has provided additional information on the air permit application between April 16, 2003 and June 27, 2003. The DNR is currently reviewing the additional information submitted and making a determination on the completeness of the air permit application. The DNR is also currently performing the air quality modeling analyses for all four of the operating scenarios as provided by WEPCO on June 2, 2003 and June 27, 2003. The DNR will provide updates of its air permit review including the modeling analyses in its testimony at the CPCN hearings.

More discussion is needed regarding the "fumigation" effects (off-shore breezes) on localized air quality. **- (Sharon Worthy, SC Johnson, Rick Burt, William Guenther)**

Due to elevated release height of power plant plumes, it is not likely that shoreline fumigation or recirculation play a significant role in air pollutant concentrations.

WEPCO performed an analysis of inversion breakup events using the US EPA approved Shoreline Dispersion Model (SDM). The procedures followed in the analysis are consistent with both State and Federal dispersion modeling policy. The report submitted indicates that impacts of the facility during fumigation events will attain and maintain all applicable ambient air quality standards.

Will WEPCO be able to meet 2007 air quality standards? Will southeast Wisconsin ever be designated as an attainment area? How long will we have to use reformulated gasoline? **- Sarah Denoto-Kniesly**

Our attainment demonstration for the 1-hour ozone standard indicates that we will achieve attainment of the 1-hour ozone standard in 2007. However, it does not appear that building the Elm Road facilities has much bearing on the 2007 attainment date since the first unit is not scheduled to begin producing power until sometime in 2008.

EPA has begun implementing the new 8-hour ozone standard. One again southeastern Wisconsin will be designated as ozone attainment area. This will trigger another planning cycle. The DNR will work with neighboring states to further reduce ozone concentrations in the Lake Michigan Region. The federal Clean Air Act requires the use of reformulated gasoline in the Milwaukee area regardless of attainment status. Congress will need to revise the Clean Air Act to change the requirement.

Chapter 8 Water Resources

Discuss DNR permitting requirements that apply to the proposed wetland fill and evaluate if such filling (or associated impact) would be permissible under State wetland water quality standards.

The placement of fill in a wetland requires a Water Quality Certification from the DNR under s. 281.22 and s. 281.37, Wis. Stats. and NR 299, Wis. Adm. Code. Applicants must comply with the requirements under NR 103, Wis. Admin. Code requiring the applicant to submit a Practicable Alternatives Analysis which evaluates alternatives that would avoid or minimize wetland impacts taking into consideration cost, available technology and logistics in light of the overall project.'s purpose. The DNR will make a determination whether WEPCO has shown that no practicable alternative exists that would avoid or minimize impacts to the wetlands and whether the proposed activities will result in significant adverse impacts on wetland functional values.

The DNR staff will work with WEPCO during the permitting process to evaluate the functional values of all wetlands and will encourage WEPCO to avoid or minimize the wetland impacts where practicably possible.

Describe the WPDES permitting process.

Both federal (40 CFR Part 423) and state (Ch. NR 290, Wis. Admin. Code) regulations establish effluent limitations for power plants. Parameters typically limited for coal-fired power plants that utilize once-through cooling are: suspended solids, oil and grease, pH, and various metals. A WPDES wastewater discharge permit will limit the concentrations of potentially harmful constituents in the effluent, and will include all of the requirements of the federal and state regulations. In addition, to account for potentially synergistic affects of individual chemical-specific pollutants, the treated effluent will also be required to pass whole effluent toxicity tests.

Requirements for compliance with s. 316(b) of the Clean Water Act are also included in WPDES permits.

The DNR intends to reissue the existing WPDES permit for the OCPP based on the addition of the first SCPC unit. The permit would be modified as the additional two new units are brought on-line. The existing OCPP permit sets limitations on the **mass** (pounds per day) of suspended solids and oil and grease that can be discharged into Lake Michigan. This is in addition to **concentration** (mg/L) limitations. Ch. NR 207, Wis. Admin. Code, also known as Wisconsin's "anti-degradation" rule, is intended to prevent the lowering of water quality resulting from new or increased discharges.

WEPCO plans to install a new wastewater treatment system, which would treat the wastewater generated by both the existing units 5-8 and the two new SCPCs. WEPCO also plans to install a new wastewater treatment system, which would treat the wastewater generated by IGCC facility. Under the anti-degradation rule, anyone proposing a new or increased discharge of pollutants must demonstrate that the discharge does not result in a lowering of water quality, in this case Lake Michigan. WEPCO has confirmed its intention to design a treatment system to ensure that the combined OCPP and ERGS wastewater does not exceed the mass limits for oil and grease and suspended solids under the current OCPP permit (for Units 5-8). In a July 2, 2003 letter, WEPCO has advised the DNR that it is not requesting an increase in limits.

Ch. NR 108, Wis. Admin. Code, requires DNR review and approval of the treatment system before it can be put into operation. This is an added safeguard for ensuring that effluent limitations will be met. By meeting both federal and state water quality standards, adverse impacts to aquatic life are not expected from the intake or from the discharge of this treated wastewater.

Assess the effects of the proposed dredging.

Chapter 8 of the final EIS discusses the results of the sediment quality investigation and potential impacts of constructing the water intake and other harbor construction activities. See the additional discussion of waste management rules in Chapter 9, Solid and Hazardous Waste and Remediation, of the EIS.

***Use of the CORMIX model for assessing thermal impacts may be inappropriate due to the water temperatures of Lake Michigan. Describe the modeling assumptions and analysis used to analyze thermal impacts to Lake Michigan.* – (SC Johnson, Lake Michigan Federation)**

In its engineering report, WEPCO proposes to raise the temperature of the water it takes in from Lake Michigan to cool the condensers by 12^{0}F. WEPCO proposes an on-shore discharge of the heated cooling water.

The DNR is currently working with an advisory committee (which includes fisheries biologists, engineers, and members of the regulated community) to develop a thermal standards rule. Our latest projection is that the rule will be promulgated in the summer or fall of 2004. At the time the draft EIS was being prepared, the DNR did not have sub-lethal temperature criteria for all months, specific to southern Lake Michigan. Furthermore, there was still considerable debate

over the monthly acute and sub-lethal criteria. We now have the criteria for all months, and there is consensus within the committee as to the validity of the criteria.

Based on the anticipated maximum flow rate of 700 MGD for each of the three new units, a temperature rise of 12^0F above the ambient lake temperature, and the default mixing zone area of 3,125,000 ft^2 for an onshore discharge, the combined discharge of the three units would exceed the calculated daily maximum temperature limit for the months of July, August, and September. The discharge would also exceed the calculated average temperature limit for the months of May through November.

Providing a separate cooling water outfall structure for the IGCC unit would still result in daily maximum and average temperature limitations exceedances for the months indicated above; and the exceedances would occur for both the IGCC outfall and the combined SCPCs outfall. However, as pointed out in the draft EIS, the formula for calculating temperature limitations can be very conservative because only heat loss to the atmosphere is considered. Heat loss caused by entrainment and mixing of receiving water is not included.

In order to apply the most currently available criteria, and to include the effect of mixing due to naturally-occurring near-shore currents, WEPCO and its consultants are developing thermal models of the proposed discharge. EPA's CORMIX model will be used for the near-field region. The MIKE 21 two-dimensional hydrodynamics model, developed by the Danish Hydrologic Institute, will be used for the far-field region. Output from EPA's GLERL existing model of Lake Michigan currents will be used as input to both the CORMIX and MIKE 21 models.

Assuming the DNR validates the modeling results, the next step in the process of establishing temperature limitations for the discharge will be to look at the indigenous aquatic community in the proximity of the power plant and determine how the various species might be impacted. The DNR intends to reissue the OCPP WPDES discharge permit with temperature limitations that reflect the current status of the thermal standards rule. If WEPCO's proposed flow rate and temperature have the potential for causing criteria exceedances, then there is a suite of options open to WEPCO to comply with thermal standards including, but not limited to:

- Increasing the cooling water flow rate. This would allow a lower discharge temperature.
- Configure the discharge conveyance to effect more rapid mixing.
- Provide multi-port diffusers to effect a larger mixing zone
- Provide a 316(a) demonstration. Under s. 316(a) of the Clean Water Act, a person can demonstrate that effluent limits that might otherwise be applicable to a power plant are more stringent than necessary to protect aquatic life.

A concern has been raised regarding the applicability of the CORMIX model at low water temperatures due to buoyancy. The proposed discharge is occurring in less than ten feet of water depth. For this reason, vertical mixing does not need to be considered and the CORMIX model is appropriate. It should also be pointed out that between 39^0F and 32^0F, there is a 0.006 lbs/ft^3 density difference in water. In light of the shore discharge, with the thermal plume rapidly reaching both top and bottom of the water column, this density difference may be neglected.

As for the issue of cumulative impacts, the DNR has advised WEPCO that any thermal plume overlaps must be accounted for in the modeling.

Identify the area of the mixing zone(s). **– (Lake Michigan Federation)**

Additional text has been added to the thermal discharge discussion in Chapter 8 of the final EIS.

SCPC and IGCC discharge calculations were analyzed separately. There is no cumulative analysis of the total project effects and the effects of the existing thermal discharge plus the new ERGS facilities. **– (Sierra Club, SC Johnson)**

The analysis presented in the DEIS did not take into account potential overlaps of thermal plumes from the proposed SCPCs and IGCC cooling water discharge, and existing cooling water discharges. A more refined thermal impact analysis, discussed in Chapter 8 of the final EIS, takes into account potential overlaps.

Details are lacking with respect to the design of the water intake and there is no discussion of possible mitigation strategies to minimize impingement and entrainment impacts. **– (Sierra Club, Lake Michigan Federation)**

The latest information indicates that WEPCO is favoring the construction of a tunnel, 32 feet in diameter, that would be approximately 200 feet below the bed of the lake. This design also includes intake cribs that would be placed over the intake shafts, intended to slow the intake velocity. The intake structure would be approximately 40 feet below the lake surface.

WEPCO continues to work with the DNR to determine the final location of the intake in order to minimize the structure's impact on aquatic species. In 2003, additional ichthyoplankton sampling will be focused on this proposed intake location. The data presented in this report, along with earlier data presented in 2002, would be used to help establish the appropriate location, design, and operational parameters for achieving compliance with applicable impingement and entrainment reduction criteria.

Discuss other possible alternatives to once-through cooling.

Once through cooling water and closed-cycle cooling are commonly used cooling alternatives. WEPCO has proposed to use once-through cooling water for the ERGS. The Clean Water Act does not prohibit the use of once-through cooling water, nor does it compel anyone to use closed-cycle cooling. DNR does not have the authority to require closed-cycle cooling for this project.

Once-through cooling should be more thoroughly discussed, especially how once-through cooling can be deemed to be BTA. Other cooling alternatives should be discussed. WEPCO should demonstrate that once-through cooling is BTA. **– (Lake Michigan Federation, CUB, SC Johnson)**

EPA has promulgated regulations for cooling water intake structures for **new** facilities, and has **proposed** regulations for cooling water intake structures for **existing** facilities. Both the promulgated 316(b) regulations for new facilities and the proposed 316(b) regulations for existing facilities provide for site-specific alternatives to the use of a cooling tower. Currently, US EPA and the DNR disagree on which regulation is applicable to the ERGS facilities. It has been the DNR's position that the proposed "existing facility" regulation is applicable to the ERGS project. The EIS states that, regardless of the characterization of the proposed units as new or existing under the 316(b) requirements, the WPDES permit will require Best Technology Available (BTA).

If ultimately the DNR and EPA agree that the intake should be regulated under the promulgated "new facility" regulation, then WEPCO would request a site-specific determination of the BTA. At that juncture, the DNR would require the comparative impact analysis of closed versus open cycle cooling.

If ultimately the DNR and EPA agree that the intake should be regulated under the proposed "existing facility" regulation, then the DNR will require WEPCO to demonstrate that the location, design, and operation of the intake will reduce fish and shellfish impingement mortality by 80 to 95 percent and entrainment by 60 to 90 percent. Fish deterrent systems, barrier nets, modified Ristroph screens with fish return systems, aquatic filter barriers, variable speed pumps, fine mesh traveling screens, angled and modular inclined screens, and low pressure spray washes may be used.

Siting of the intake is also critical for minimizing impingement and entrainment. In general, the littoral zone of large lakes, such as Lake Michigan, serve as the principal spawning and nursery area for most species of freshwater fish, and is considered one of the most productive areas of the waterbody. The placement of the intake structure beyond the littoral zone should reduce impingement and entrainment. The 2002/2003 study that WEPCO is currently conducting is intended to be part of that demonstration.

If WEPCO is unsuccessful in demonstrating the percent reductions, it would seek a site-specific determination of BTA. At that juncture, the DNR would require the comparative impact analysis of closed- versus open-cycle cooling.

Evaluate the cumulative regional effects of DNR's decision deeming the ERGS an "existing facility" under Section 316(b) of the CWA. **– (Lake Michigan Federation)**

Currently, US EPA and the DNR disagree on which regulation, "new facility" or "existing facility" is applicable to the ERGS. It has been the DNR's position that the proposed "existing facility" regulation is applicable to the ERGS project. The DNR cannot forecast the cumulative regional effects and precedence of this decision at this time. The EIS states that, regardless of the characterization of the proposed units as new or existing under the 316(b) requirements, the WPDES permit will require Best Technology Available (BTA). BTA requirements should minimize impingement and entrainment.

Additional analysis of long-term effects of the proposed water intake on fish (especially yellow perch) is needed based on the results of the 2003 study completed in February.

A second round of onshore and offshore ichthyoplankton collections are being taken in the months of May through September 2003. Additional ichthyoplankton sampling is to be focused more precisely at the proposed intake location, located approximately 9,000 feet offshore in 40 feet of water.

Describe the project's impacts on the sport fishing and tourism industries. – **(W. Guenther)**

See the discussion in Chapter 8 of the final EIS related to construction and operation of the proposed project.

Discuss any responsibility or jurisdiction of the Joint Commission on the Great Lakes with respect to this project. - **Vicky Mayer**

The International Joint Commission (IJC) is an independent bi-national organization established by the Boundary Waters Treaty of 1909. Its purpose is to help prevent and resolve disputes relating to the use and quality of boundary waters and to advise Canada and the United States on related questions. The IJC has six members. Three are appointed by the President of the United States, with the advice and approval of the Senate, and three are appointed by the Governor in Council of Canada, on the advice of the Prime Minister.

IJC approval is not needed for the project.

More information about the International Great Lakes Commission is available at http://www.ijc.org/ijcweb-e.html

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Chapter 9 Solid and Hazardous Waste

Waste disposal effects of ash re-burning should be more thoroughly discussed. - **(Sierra Club)**

WEPCO is planning for ash reburn at a maximum rate of 5 percent of the coal. The benefits of the reburn are discussed in Chapter 9 of the EIS. The only way for WEPCO to realize these benfits is to be able to market the by-products, however. It has been determined that on a pound to pound basis, five times more ash is produced by burning ash than coal. Most of the ash would be coming from the OCPP property. There are two closed landfills that are scheduled for excavation and reburn. Also four early ash disposal areas may have to be excavated due to construction or site remediation. WEPCO is eager to remove the ash from these sites and reburn it. However, the reburn would not begin until a sustainable ash beneficial use market is attained. Without a large ash beneficial use market the reburn would have adverse impact on the existing landfill capacity. If 5 percent ash is reburned from the beginning of operation for the two SCPC plants , the landfill capacity would be reduced by 35 percent. Additional landfill space may be needed sooner than expected.

Provide more discussion about existing coal leaching problems at the closed Oak Creek North Landfill, efforts to address them, and the potential for additional coal leaching on page 236. **- (Andy Weber)**

Groundwater impacts in the vicinity of the Oak Creek North Landfill were addressed by WEPCO in 1999 and 2000. Cover soils were added in isolated areas to eliminate low spots and to increase cover thickness where deficient. Also, a drainage channel on top of the cover, where surface water was coming in contact with ash, was repaired. Groundwater quality appears to have improved since these remedial actions were completed.

The ERGS proposal includes short- and long-term improvements to the Oak Creek North Landfill to minimize future potential environmental impacts resulting from the landfilled ash at the Oak Creek North Landfill.

A component of the proposed ERGS construction process includes improvements to the slope and permeability characteristics of the landfill cover. These improvements are expected to minimize the generation of leachate due to infiltration of surface water. The fuel source for the three proposed ERGS power generation units will include up to five percent recovered ash. As much as 270,000 tons of ash could be recovered annually and reburned in the proposed units. The Oak Creek North Landfill is identified as the primary initial source of ash fuel for the ERGS units. Ash presently stored in the Oak Creek North Landfill would be completely removed, eliminating any future risk of groundwater impacts caused by the landfill. See the final EIS section on environmental monitoring for Oak Creek North.

Discuss the potential adverse environmental impacts of ash disposal in landfills and early ash disposal areas, such as the formation of leachate and surface water runoff that could pollute groundwater and surface water, and the engineering features that are designed to prevent environmental impacts. **– (SC Johnson, Don Schantzen)**

Ash storage cells in the active Caledonia Ash Landfill are constructed with a compacted clay liner and leachate collection at the base of the cells. As ash reaches final grades in the cells, the cells are covered with an engineered cap consisting of compacted clay, rooting zone, topsoil and vegetation. The landfill perimeter is graded to route clean surface water away from the active cell(s) and to the site sedimentation basin. Leachate is routinely removed from the Caledonia Ash Landfill and trucked to a licensed treatment facility. Groundwater quality in the vicinity of the Caledonia Ash Landfill is monitored by a series of groundwater monitoring wells.

Ash stored in the closed landfills and early ash disposal areas on-site are covered with soil to prevent direct contact of surface water with the ash. Any leachate that migrates from the ash deposits into the surrounding soil is naturally attenuated by the thick clay layers underlying the site. Groundwater quality is monitored with a network of groundwater monitoring wells around closed landfills. Groundwater quality is not monitored around early ash disposal areas. However, these areas are targeted for remediation in near future.

Monetize the cost of by-product disposal **– (Dorothy Bocciardi)**

WEPCO plans to utilize the by-products from ERGS and receive revenues from the sales of the coal combustion products. As the markets develop similar to its current ash utilization program, WEPCO expects that revenues from ash sales will eventually exceed the ash management expenses. In the event that WEPCO is unable to market some of the by-products, the material will either be stockpiled for later use in accordance with DNR rules or disposed in a licensed landfill. As stated in Volume 3 of the ERGS Environmental Report, WEPCO has landfill capacity at its Caledonia, Pleasant Prairie, and Highway 32 landfills, and there is capacity at other commercial landfills in southeastern Wisconsin. Unit costs for disposal in landfills owned by WEPCO depends on the quantities being landfilled and will vary due to economies of scale. The range of costs to dispose of coal ash in the Caledonia landfill is approximately $22.00/ton to $38.00/ton. Disposal in other landfills owned by WEPCO will be higher due to increased transportation costs and will be approximately $30.00/ton to $46.00/ton. Costs to dispose ash in commercial landfills (tipping fees plus hauling) are estimated to be in a similar range with comparable hauling distances.

***Identify the plans that are in place to address sulfur and slag if utilization does not reach 100% within 10 years?* – (Calpine)**

WEPCO has identified substantial landfill capacity at the Caledonia, Pleasant Prairie and Highway 32 Landfills. Landfill capacity has also been identified at other area commercial landfills. WEPCO coal combustion products marketing companies have indicated the ability to use 100 percent of the slag production within three years of unit commissioning (see Mineral Solutions letter dated 10/2/01 in Appendix Z, Volume 3 of the ERGS Environmental Report). Sulfuric acid is presently in short supply and imported to this region from Canada. Experience from existing IGCC plants indicates that commercial quality sulfuric acid production is being produced and utilized. (See Rowell Chemical Corporation letter dated 11/16/01 and Milport Enterprises Inc. letter dated 10/12/01 in Appendix Z, Volume 3 of the ERGS Environmental Report.)

***Will scrubber sludge be tested for mercury? Could the scrubber sludge be characterized as solid or hazardous waste?* – (Lake Michigan Federation)**

Yes, the scrubber sludge would be tested for mercury. Scrubber sludge would be characterized in accordance with solid and hazardous wastes guidelines. It is too early to speculate but it is more likely to be classified as solid waste based on its specific elemental and leaching characteristics. Wallboard manufacturing companies have approached WEPCO with an interest in obtaining synthetic gypsum from the scrubbers. (See National Gypsum Company letter dated 11/11/01 and Lafarge Gypsum letter dated 10/8/01 in Appendix Z, Volume 3 of the ERGS Environmental Report.)

***Would solid sulfur or sulfuric acid be characterized as "products" or "waste"?* – (Gasification Technologies Institute)**

WEPCO would need to characterize the waste and get DNR approval for use as a commercial product. The sulfuric acid is expected to be sold and meet commercial quality standards, and

therefore should be considered a "product." However, DNR has made no determination on this issue at this time.

***Identify the plans that are in place regarding sulfuric acid disposal if the acid can not be sold and is a waste.* - (Calpine)**

The typical way of disposing of sulfuric acid is neutralization with a base. For many systems, the neutralizing agent is sodium hydroxide which forms the salt, sodium sulfate. However, for large quantities, the neutralizing agent may be different to end up with a more marketable product. For instance, if lime were used calcium sulfate (gypsum) would be created which can be used in dry wall manufacturing which would be a compatible use with the synthetic gypsum already expected from the proposed unit scrubbers. If ammonia or ammonium hydroxide (aqueous ammonia) is used, ammonium sulfate is produced which can be potentially used for fertilizers.

Chapter 10 Land Resources

***The DEIS mentions the North Site grasslands harbor five of the state's seventeen grassland birds that depend on the area for most or all of their breeding cycles. Was this issue looked into any more by someone at the DNR? What are the effects of these birds no longer have anywhere to breed?* – (Tom Williams)**

The 2003 grassland bird survey was conducted about one week later in the season this year compared to 2002. The survey involved walking around the two landfills looking and listening for birds. The birds seen/heard were pretty much the same species from last year, except for the Dickcissel. Bird species included bobolink, savannah sparrow, meadowlark, yellowthroat, red-wing blackbird, willow flychatcher, goldfinch, barn swallow, and tree swallow. The landfill south of Elm Road had a large number of bobolinks. At one point, 21 male bobolinks were counted in one group. Of the species heard this year, the bobolink is the only one that is a species of concern for Partners in Flight, US Fish and Wildlife and the DNR.

Grassland habitat is scarce cover type in Wisconsin, and North America for that matter. Wisconsin only has about 0.1 percent (2,000 acres) of the original prairie acreage (2.1 million acres) left and so nesting habitat for these birds is at a premium. If the grassland cover is lost, these birds will be forced to relocate, which will be difficult due to the lack of grassland habitat in the landscape. As a result, if these areas are lost it is possible that many of these individuals will not find suitable breeding habitat.

Relocation to suitable habitat will not be an easy task. The search will put additional stress on the birds that could affect nesting success and bird survival. In searching for new sites they will expose themselves to a variety of dangers- predators, dogs, cats, cars, etc. And even if they do find suitable habitat they will still have to compete with resident grassland songbirds to stake out new territories.

Overcrowding of remaining grassland areas has the potential to impact resident birds on these areas. With overcrowding, there is an increase in territorial disputes among grassland songbirds.

An increase in the number of birds using the area puts additional strains on resources (e.g., cover, nesting areas, food, etc.) in the area. These impacts have the potential to affect the songbird's health and ability to successfully produce offspring.

It is unclear what coordination has occurred with the EPA and FERC, and no reference to the Army Corps' role in complying with Section 106. More detail is needed to understand what has been done by federal agencies to comply with Section 106. – **(US Army Corps)**

Section 106 and Tribal Coordination - It is unclear what, if any, coordination has occurred with any potentially interested Native American Tribes. – **(US Army Corps)**

From the beginning of its CPCN review, the PSC has requested continuous updating of the status of WEPCO's compliance with historic property protection laws. The documentation available indicates that, to the time of EIS preparation, the State Historic Preservation Officer (SHPO) has had no official notification of substantial federal interest and WEPCO has made no documented effort to work with federal agencies to begin the Section 106 process with the SHPO. Thus, as shown in Table 1-2, the CPCN historic properties review for the ERGS has been under the state law and not Section 106. There is text in Chapters 1 and 10 about Section 106 to account for the fact that the federal law might be invoked during the CPCN review.

In the meantime, the PSC, as a state agency, must comply with the state version of the National Historic Preservation Act, in Wis. Stat. § 44.40. The state process does not necessarily involve federal agencies or Native American Tribes. An attempt has been made to clarify the state process as well as its relationship with, and the status of, the Section 106 review in Chapter 10.

Table 1-1 (inVolume 1) shows that there is some federal interest in the ERGS project, but none of the interest could be applied to a Section 106 review as of the time the draft EIS was issued. In general, the EPA has abrogated its responsibilities under Section 106 in Wisconsin. The Wisconsin DNR is now working on an agreement with the SHPO to handle all formerly-considered EPA permits as state permits under the state preservation law (Wis. Stat. § 44.40, which is currently being applied to the case through the CPCN process). The FAA interest shown in Table 1-1 relates to clearance standards and hazard determinations, which historically have been difficult for the SHPO to apply to Section 106. In this case, there is still no visible FERC interest. The Army Corps has historically minimized its area of potential effect (APE) to the wetlands under its permit consideration, often leaving large portions of the proposed project before the Commission with no historic properties protection except the state law. It is often difficult in power plant and utility line projects to ascertain with the SHPO whether the Section 106 APE would cover the project before the Commission or not. Again, in this case, at the time the draft EIS was issued, the applicant and federal agency had not made it clear yet.

With the recent interest expressed by the Army Corps in the entire ERGS project, the PSC has notified the SHPO and WEPCO that there appears to be substantial federal interest in the project at the Army Corps, recommending that Section 106 be followed from here on. According to the WHS, which is also the SHPO for the state of Wisconsin, once Section 106 applies, its requirements for the applicant supersede the requirements of the state law. Staff believes that the Army Corps compliance with Section 106 will elucidate the coordination and work to be done by

federal agencies in compliance with the federal law, including appropriate coordination with potentially interested Native American Tribes.

Chapter 11 Community Impacts

***Impacts related to train traffic are not adequately discussed and there are numerous inaccuracies and omissions. Effects on Three Mile Road and the remainder of Racine County grade crossings should be analyzed.* – (SC Johnson, Town of Caledonia, CUB, Frank Michna)**

The Railroad section of Chapter 11 of the final EIS has been updated and expanded to include more information about new railroad facilities related to the ERGS and effects on traffic. Although staff recognizes that there would be additional delays at other grade crossings in Racine and Kenosha Counties due to the increase in train traffic, an evaluation of these delays or potential traffic congestion is beyond the scope of our expertise and could not be accomplished within the statutory review time limits.

Would the increased coal train traffic prevent the establishment of a Chicago-Racine-Milwaukee commuter rail?

No, commuter rail would still be an option. This is discussed in the final EIS

***The impacts of the proposed ERGS facilities on the land use plan of the town of Caledonia have not been assessed.* – (Town of Caledonia)**

Refer to the section on the Potential Conflicts with Land Use Plans in Chapter 11.

***Provide more information on how police, fire and medical staff would respond in case of a catastrophic accident.* - (Jo Sandin)**

That specific information is not yet available, but it will be, as explained in the EIS. "The conditional use permit (CUP), granted by the city of Oak Creek for the proposal, requires WEPCO to file two Fire Protection and Emergency Management Plans for the Property – one for the construction period, and one for the operations period. In addition, the CUP requires construction contractors to meet with the Police Chief to discuss security plans and procedures."

Both the city of Oak Creek and the town of Caledonia have the capability to respond to catastrophic accidents. The city of Oak Creek Fire Department has 39 full-time firefighters of which 26 are firefighter/EMTs and 13 are firefighter/paramedics. Capabilities include fire response, emergency medical services (EMS) and paramedic services, Hazmat -Level B, confined space and technical rescue, disaster planning and mutual aid from neighboring communities.

The town of Caledonia has 38 full-time firefighters of which 19 are firefighter/EMT and 19 are firefighter/paramedics. Capabilities include fire response, emergency medical services (EMS) and

paramedic services, recognition/operation in Hazmat, confined space and technical rescue, disaster planning and mutual aid from neighboring communities. In addition, there are resources available in nearby Racine and Milwaukee Counties, and WEPCO has on-site emergency and fire equipment and trained personnel.

Ownership issues related to Four Mile Road need to be clarified. **– (Town of Caledonia)**

The EIS describes the current ownership of Four Mile Road. The County and the Town have evidently been discussing possible changes in the portions of road for which each have responsibility. The EIS mentions that as part of the description of the existing environment.

Additional train traffic related to limestone transport (if not barged in) has not been included in the train impact discussions. **– (Town of Caledonia)**

WEPCO proposes to barge limestone to the site

Health impacts related to idling diesel train engines should be discussed. **– (Town of Caledonia, Rick Burt)**

Emissions from locomotive idling are considered as a secondary emission. These emissions are not under the control of WEPCO and cannot be accounted for within the air permit. It is difficult to quantify these emissions due to the varying idling time.

The rumble and vibration of trains causes windows to crack. These types of impacts should be discussed. **– (Mary Ann Hernke)**

Vibrations are an effect of low-frequency noise that can be associated with trains, large engine operation or other causes. Coal trains associated with the existing OCPP units and the new ERGS facilities account for only some of the train traffic passing through the area on a daily or weekly basis.

The property value discussion should be revised. **- (Daniel Bach)**

The draft and final EIS review the current state of research regarding the relationship between power plants and property values. These studies illustrate the difficulty in drawing any statistically significant, quantifiable conclusions, much less applying a conclusion to different regions and facilities. What can be inferred from these studies is that individual preferences may outweigh obvious disamenities and that the value people place on property varies greatly from individual to individual.

Describe any measures that would be in place to reduce security concerns -- this will be the sixth largest coal-fired plant in the nation if all of the proposed units are built. It could be a terrorist target.

WEPCO's response to this issue is as follows: "The company recognizes the potential for terrorist attack on any of its facilities, whether power plant or of another type. In fact, power plant facilities are merely one class of potential target among many of the nation's critical infrastructures. The measures that the company may take to address the risk will be consistent with what we perceive to be the probability of attack and which would be cost-effective in mitigating that risk. In any case, the specific measures to be taken and their expected effectiveness cannot be revealed.

The company has met with the Marine Safety Office of the U.S. Coast Guard's Milwaukee station. These meetings were predicated on the newly signed Maritime Transportation Security Act, PL 107-295. We discussed the feasibility of establishment of security zones around critical structures and the application of certain intrusion detection systems and vessel barriers. The specific measures to be taken and their expected effectiveness cannot be revealed.

The company maintains a budget to support a variety of security measures which are applied across a number of company facilities including the existing OCPP. The completed ERGS site would likely have a larger security budget requirement than currently allocated to the site but the size of the budget and the types of measures to which the monies are proportioned cannot be revealed. The planned budgets would be sufficient to meet what we perceive to be the most credible threats."

The employment discussion should be expanded to discuss more clearly the types of jobs available. Also, there will be a loss of jobs at the Port Washington Power Plant, thereby offsetting the new job numbers at ERGS. **– (Carla Beyerl)**

The employment section in Chapter 11 has been updated to provide more information.

Reproduced Comments of Parties and Organizations follow in alphabetical order

Comments on the Draft Environmental Impact Statement, submitted by ANR Pipeline Company

ANR Pipeline
an El Paso company

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June 12, 2003

Mr. Jeffery Kitsembel
Public Service Commission
P.O. Box 7854
Madison, WI 53707-7854
jeff.kitsembel@psc.state.wi.us

Re: Docket No. 05-CE-130

Dear Mr. Kitsembel:

ANR Pipeline Company ("ANR") is submitting these comments to correct a false impression created by certain statements in the Draft Environmental Impact Statement ("DEIS") for the Elm Road Generation Station in Docket No. 05-CE-130. In particular, the DEIS states that the use of natural gas causes an additional reliability concern because electric generators require that the natural gas be received at high pressures of 450 psig or above. According to the DEIS, since a local distribution company (LDC) only needs low pressures for reliable service, the high pressures needed by the electrical generator makes that electric generator, even one holding firm contracts, less reliable than the LDC. The DEIS then tries to validate this concern by referring to a January 23, 2003 situation on ANR where the pipeline had difficulty maintaining pressure on its system for a few hours.

There are two problems with these statements. First, the purported distinction between an electric generator and an LDC is in many cases false. The Public Service Commission of Wisconsin is aware that many LDCs require high pressure from interstate pipelines in order to provide reliable service. Indeed, ANR has contracts with local utilities in Wisconsin that require pressures that are above 500 psig. More importantly, a reference to a single unique situation hardly acts to validate that there is a legitimate concern about the reliability of natural gas pipelines to provide service at contracted levels of pressure for either an electric generator or an LDC.

Second, a one-time temporary difficulty does not mean that natural gas is not reliable. Due to a congruence of certain unique circumstances and unexpected equipment failures, there were certain pressure maintenance issues that occurred in the extremities of ANR's system on January 23, 2003. However, not only did these pressure issues affect all customers (not just

generators) but that situation was corrected in a matter of hours. Moreover, ANR has taken steps which will help to ensure that the same set of conditions will not reoccur. The simple fact is that it is hard for any other energy system to compete with the reliability of natural gas pipelines. Indeed, it is important to note that even in the unique circumstances of January 23, 2003, ANR's pressures in the area of the Elm Road Generation Station would have been more than sufficient to serve an electric power plant. ANR serves over 10,000 Mw of electric generation across its system and does so in a safe and reliable manner.

ANR requests that any statements concerning the lack of reliability of an electric generator due to the requirement of high pressures from natural gas pipeline be removed from the final EIS. ANR wants to emphasize that it is not opposing the Elm Road Generating Plant or making other comments. However, the statements described above, which could portray a misleading picture, act to cast doubts on the integrity of the EIS process. In order to ensure that the EIS is providing an accurate portrayal of the benefits and detriments of the proposed project, the statements concerning the reliability of electric generators based on the pressure necessary from natural gas pipelines should be removed from the EIS.

Respectfully submitted,

ANR PIPELINE COMPANY

/s/ Christopher D. Young

Christopher D. Young
Senior Counsel

Comments on the Draft Environmental Impact Statement, submitted by the Army Corps of Engineers

PSCW EIS REVIEW COMMENTS
ELM ROAD GENERATING STATION
Army Corps of Engineers
7-3-03

The U.S. Army Corps of Engineers is involved in the proposed Oak Creek power plant expansion due to the requirement for a Clean Water Act Section 404 permit and a Rivers and Harbors Act Section 10 permit for work in wetlands and navigable waterways. The Corps will need to comply with the National Environmental Policy Act (NEPA) in processing the permit applications for the proposed project. The NEPA regulations require the Corps to become involved as early as possible in the state or local review process, to ensure that environmental factors are considered at an early stage, and to assist applicants by outlining the types of information required for the Corps permit evaluation. Consequently, the Corps is commenting on the content of the PSCW EIS and also identifying areas where additional information or analysis is necessary for the Corps permit evaluation process.

GENERAL COMMENTS

1. The EIS identifies substantial resource impacts based on the proposal as described in the EIS. However, the applicant has informed the Corps that the document does not represent the most current project proposal. In this situation, it is difficult for the Corps to provide meaningful comments. A meeting has been requested between the Corps, FWS, PSCW, and WDNR to discuss the EIS and potential additions or revisions. Comments on the EIS are provided for discussion at this meeting.
2. The EIS appears to be incomplete in several resource areas, and does not address mitigation in the majority of the resource areas. Consideration and incorporation of appropriate mitigation should be an integral part of the proposed project.
3. Based on recent changes to the proposal and numerous statements in the EIS regarding incomplete data or analysis, the Corps questions whether the PSCW has received a complete application. Therefore, we suggest that the PSCW modify, suspend, or somehow revise the official time limit for the CPCN decision, to allow for completion of project modifications, incorporation of appropriate mitigation measures, and submittal of complete data for use in the EIS.
4. It is unclear from the text what coordination has occurred with other state and federal agencies.
5. There are several references to less or no need for the 3rd power-generating unit. Also, the EGEAS discussion is hard to follow, but it appears to show that implementation of a coal unit may not be necessary until 2022. It is hard to determine from the document which alternatives discussed in the EIS would be practicable alternatives under Corps CWA Section 404 regulations. Additional information is needed regarding the alternatives analyzed in the EIS.
6. For resource areas impacted by the proposed project, analysis of the significance of the proposal's impacts, when added to impacts resulting from past, present, and

reasonably foreseeable actions in the project area, are necessary for the Corp permit evaluation.

SPECIFIC COMMENTS

7. Page xxvii - More information is needed with regard to earth moving activities, as noted in the EIS, to adequately identify the noise, fugitive dust, and diesel fumes during construction.
8. Page xxix – Has the location of the intake crib been refined to a more specific location offshore?
9. Page xxix – The statement about compliance with thermal standards seems more definite than the discussion on page 210 would lead the reader to believe.
10. Page xxix – Is the statement about the reduced possibility of harbor construction up to date?
11. Page xxxi - Air Quality - The state EIS uses applicant supplied data and model results, but indicates that WDNR air quality analysis is underway.
12. Page xxxi – Air Quality – It appears that the FAA required lower stack height, discussed on page 344, is not reflected in the analysis. The revised stack height and corresponding WDNR air quality analyses should be incorporated into the EIS.
13. Page xxxiii – road impacts – will the proposed road improvements constitute a commitment and what is the position of the local road authority on the suggested road modifications? Coordination with the local road authority should be referenced in the EIS.
14. Page xxxiii - What are the demographics of the group west of the tracks on seven mile road?
15. Page 2 - Shooting Range - What is the federal review or oversight involved in the transfer of the shooting range property from the military?
16. Chapter 4 – Alternatives, page 66 – Did the comparison of coal and natural gas costs include total cost comparison, that includes pollution control costs, environmental costs, etc?
17. Chapter 4 – Alternatives, page 69 – The EIS should be updated regarding the pending CPCN for the Calpine plant.
18. Page 102/103 – Is the discussion of 500 (feet?) of additional fill to the north of the existing dock part of the lake fill discussed on page 211?
19. Page 117 – Is the gypsum wallboard plant a connected action, in relation to the proposed project?
20. Page 164, 175 - What is the cumulative impact of approaching 100% of the NAAQS for TSP and SO_2?
21. Page 179 – what is the cumulative impact to the shoreline?
22. Page 196 & 222 – Wetlands - It is unclear from the EIS whether steps were taken to avoid, minimize, or compensate for potential wetland impacts resulting from the project.
23. Page 203 - Water Intake Structure. It is unclear what measures will be taken to minimize entrainment and impingement impacts resulting from the intake structure.

24. Page 210 – Cooling Water Discharge - It is hard to tell from the document, but it appears that the thermal discharge would not meet state acute criteria during certain parts of the year. This issue needs additional discussion.
25. Page 211 – Is the 7 acres of lake fill for the proposed breakwater part of the project proposal. Would the total lakebed fill be 14 acres?
26. Page 253 – Threatened/Endangered Species – what coordination has there been with the U.S. Fish and Wildlife Service?
27. Page 256 - Section 106 – It is unclear what coordination has occurred with the EPA and FERC, and no reference to the Army Corps' role in complying with Section 106. More detail is needed to understand what has been done by federal agencies to comply with Section 106.
28. Page 256 - Section 106 and Tribal Coordination - It is unclear what, if any, coordination has occurred with any potentially interested Native American Tribes.
29. Page 271 – There is no discussion regarding how the effect of the wetland loss on wildlife use could be minimized or mitigated.
30. Page 284 – demographics - To comply with the Executive Order on environmental justice, the Corps will need to address whether the proposal has disproportionately high and adverse impacts to any minority or low-income populations. Information is needed beyond the basic demographic information as to whether there are any low-income or minority groups that would potentially be affected by the project.
31. Page 310 – the potential impacts of increased transport of hazardous materials are not addressed.
32. Page 326 – Noise - It is unclear whether the aggregate noise level resulting from construction and operation of the plant is included in the noise analysis.
33. Page 348 – Is the proposed harbor expansion discussed in this section different from the proposed activities described on page 211?

Comments on the Draft Environmental Impact Statement, submitted by the town of Caledonia

June 11, 2003

Jeffery Kitsembel
Public Service Commission
P.O. Box 7854
Madison, WI 53707-7854

RE: Docket number 05-CE-130
Comment by Town of Caledonia, Racine County, Wisconsin
on Draft Environmental Impact Statement: Elm Road Generating Station

Submitted via e-mail, with signed original w/ attachments to follow

Dear Mr. Kitsembel:

As per page "i" the Town of Caledonia is providing you with its comments on the Draft Environmental Impact Statement for the Elm Road Generating Station (EIS). The Town understands that "the purpose of this EIS is to provide the decision makers, the public, and other stakeholders with an analysis of the social, cultural, and environmental impacts that could result from the construction of three new coal-fired power plants and their associated facilities." As such, the Town's comments will focus on issues germane to this stated purpose.

Comments on Railroad Proposals and Impacts (pages 347-361)

Errors of fact
The Town perceives a number of statements as errors of fact. A listing of those follows.

Number of Crossings: Page 347 indicates the railroad "crosses four roads in the town of Caledonia with at-grade crossings." This is not true. Three Mile Road is an important east-west corridor with substantial traffic. At the point of its crossing, Three Mile Road represents our boarder with the City of Racine and is very near the active commercial area along STH 32 (Douglas Avenue) approximately 650 feet to the east. In addition to correcting the factual error, the impacts upon Three Mile Road must be investigated and reported. As Three Mile Road is a primary east-west route for residents of the Village of North Bay, much of the Village of Wind Point, and residential sections of both the Town of Caledonia and the City of Racine, the impacts of train traffic on this crossing must not be ignored.

Trains Blocking Crossings: The Town believes there are factual errors within this section of the report (beginning p. 349) and with the consultants report referred to. The Town, however, only

has anecdotal and sample data relative to blocking crossings so will therefore present our concerns below in the "Concerns with Accuracy of Information as Reported" section. Nonetheless our information clearly suggests factual errors.

Trains During July 19 and August 12: Page 352 reports that "30 coal trains passed Four Mile Road traveling to and from the Oak Creek site." The train logs provided by We Energies to the Town, ATTACHMENT A, indicates 35 trains should have been identified.

Traffic Volume on Seven Mile Road: The EIS estimates current traffic volume at Seven Mile Road, per a We Energies' consultant, to be "200 vehicles per day". The Town using TimeMark Delta III traffic counting equipment recorded an average daily traffic volume of 320 vehicles with a maximum of 655 during the 29 day period of October 22 through November 19, 2002. 13.8 percent of the days exceeded 500 vehicles.

Maximum Average Daily Time Blocked: Table 11-31 (p. 353) uses this confusing phrase numerous times. A "maximum average..." would be the peak in a series of average times. The table, however, indicates that it is the intent to average a series of maximum times (see footnote *). The table, therefore, should refer to "Average maximum daily time blocked." The table itself is confusing enough without this minor oversight.

Concerns with Accuracy of Information as Reported

The Number of Coal Trains: The Town disagrees with the information presented as to the number of coal trains that are expected. The Town believes that conclusions reported by WE Energies and repeated within this EIS needs to be investigated further and that the EIS must identify, clarify, and reconcile discrepancies between information reported elsewhere by WE Energies as to the number of coal trains (including in documents submitted to the PSC) and that reported within the EIS. The Draft EIS should then be ammended to reflect these corrections.

The EIS table 11-28 (p. 347) and the Power the Future Application – Supplement No. 2 under "Motor Vehicle Travel" both indicate the current number of trains is about 5-6 trains per week. The Town accepts this number because it accurately reflects that approximately 75% of weeks during normal operations experience 5 or 6 trains, based upon train arrival schedules for 2001 and 2002 as provided to the Town by We Energies.

Specifically, however, the Town believes the information presented in Table 11-29 (p. 349) of the EIS is not accurate and needs to be investigated independently and corrected. First, Table 11-29 of the EIS appears to rely upon the mean average number of trains, approximately 5, and not the average as previously reported, 5-6. That sixth train, which appears to no longer be given any consideration within Table 11-29, represents a 20 percent increase in traffic compared to a 5-train week. The mean average is not representative of the routine number of trains impacting the community because the mean average is reduced by the annual two week shut-down period, during which no coal trains come through, and by the apparent occasional period of reduced activity (for example, a 7 week period of reduced train activity in February and March of 2002 brings the mean average down while not accurately reflecting the typical train activity during the other 22 months of that period).

The Town's second objection to Table 11-29 pertains to the third footnote (***). This footnote indicates the possibility for an "increase by about one train for each category." It does not clearly indicate whether this increase is to be one in total or in cumulative (in other words, one for each category totals three trains more after the IGCC unit is completed). More importantly, after the preceding point is clarified, this additional train should not be hidden in the footnote. It should be reflected as part of a range to be stated within the body of the table, for example "7" should be "7-8." This footnote, in effect, appears to further reduce the number of trains that will potentially impact our community.

The third, and most serious, objection to Table 11-29 is that it simply cannot be accurate based upon information previously submitted by We energies. The Power the Future Application – Supplement No. 2 under "Impact of Increased Rail Deliveries" states "With 135 car unit trains, the increase in the number of trains per week is 3 per generating unit." This is volume is clearly not being reflected in the EIS. The EIS, therefore, dramatically reduces the number of trains from that reported as necessary by We Energies, without any acknowledgement or justification. Although the Application identifies this number as the "upper bounds" it appears to do so in comparison to reducing train traffic through deliveries by water, which appears to no longer be a serious consideration. Therefore, the "3 (trains) per generating unit" should be reflected in the EIS and the "All rail" column of Table 11-29 should reflect at least "8-9," "11-12," and "14-15."

Alternatively, the EIS must reconcile the number of trains previously reported as necessary and the numbers reported in Table 11-29. The reconciliation should be performed independently from We Energies to ensure accuracy and should consider such factors as car capacity versus actual amounts loaded per car. Furthermore coal train volumes should be able to be cross-checked in relation to power generation. In other words, if 5-6 trains per week currently provides coal sufficient for "X" MW's, how many trains are needed for the proposed increased power capacity? Obviously, it may be necessary to provide a factor to adjust for any improved burning efficiency newer plants may provide.

Once the discrepancies in Table 11-29 are corrected, the "Table summary" can be corrected to accurately and more objectively reflect the increase in train activity. The summary currently states (p. 349) that "the number of coal trains entering the Oak Creek site would stay about the same for installation of one SCPCC unit." Despite We energies previously indicating 3 new trains would be needed, increasing from "5-6" to 7 is still a two-fifths (40%) or one-sixths (17%) increase in trains, not "about the same."

Seven Mile Road: The Town disagrees with the conclusions and recommendations portrayed in the EIS, does not accept the recommendations of the Benesch report, and recommends discarding the Benesch report. The Benesch report recommends closing Seven Mile Road and constructing cul-de-sacs. As stated above in "Factual Errors" the Benesch report estimated traffic volumes at less than two-thirds their current level based upon traffic counts performed by the Town of Caledonia. The Town was unable to locate or identify within the Benesch report the source for the under-reported traffic volume number. Furthermore, the Town was unable to locate or identify within the Benesch report where any consideration was given to future road volumes. The Town is actively pursuing a multi-year, $270,000 neighborhood planning process

and the land-use consultant has verbally indicated that Seven Mile Road will become an increasingly significant east-west corridor. Future traffic volumes during the life of the proposed OCPP must be determined and applied to the decision process for Seven Mile Road.

The EIS, in fact, suggests addressing loss of an access road for emergency vehicles and loss of an access road for residents. The EIS indicates

> "Although not in the applicant's current proposal, a means to allow both passage of emergency vehicles and direct access to STH 32 for those residents with driveways just east of the railroad crossing has been considered. A private access road could be constructed which would involve an arched tunnel under the railroad." (p. 355)

Considering the correct current traffic volumes and estimated future traffic volumes (to be determined), it would not appear to make sense to build a private access road to, presumably, lower construction standards. The Town agrees that access must be maintained, but it should be maintained to all users. The Town objects to consideration of closing the Seven Mile Road crossing and believes the Benesch report should be discarded due an apparent bias as reflected in its reliance upon incorrect estimates and it failure to consider future demand.

Six Mile Road: The EIS seems to indicate that a rail crossing at Six Mile Road is recommended but that its approval would come after the fact of approval of the OCPP plans (p. 350, "Process for altering railroads and ownership). This is unacceptable. The EIS is responsible to analyze "the social, cultural, and environmental impacts that could result from the construction of three new coal-fired power plants and their associated facilities."(p. "i") If a decision is made based upon the "level of impacts that could result" that decision must be able to enforce and require the steps necessary to match the decision and mitigate its impacts. Furthermore, all steps necessary to acquire and build the necessary overpass should be a responsibility of the applicant, not of the Town. The Town should not be put in a position to take the lead on imminent domain issues as a result of a power plant expansion that we oppose and is detrimental to our community. The EIS must be ammended to reflect that any overpass and all requirements and costs of that overpass need to be part of the OCPP plan and not subject to subsequent and future deliberations or determinations.

It should be noted that the Town can not support an overpass at Six Mile Road, because the Town does not support the OCPP plan. If the Town were to give any indication of support for an overpass, the applicant would likely misrepresent such indication as a willingness to support the Power the Future Plan. We Energies has consistently misrepresented any discussion it has had with the Town, and the Town does not wish to provide We Energies with any more opportunity to mislead the public into believing the Town of Caledonia, in any way, supports the OCPP plan as proposed.

Four Mile Road: The Town objects to the conclusions and statements regarding Four Mile Road and believes an independent analysis of traffic volumes and train speeds at this crossing needs to be completed before the EIS can accurately reflect impacts that could occur based upon the

OCPP if approved, as is required of the EIS. The Town has multiple objections to statements and conclusions in the EIS relative to Four Mile Road.

First, as previously stated, the Town does not accept the conclusions of the consultant, Innovative Systems, relative to train speeds and impacts at Four Mile Road. Innovative Systems' evaluation and report are inaccurate and incomplete and, therefore, cannot be relied upon. As indicated above in "Errors of Fact," Innovative System identified 30 coal trains during their study period while We Energies indicated 35 trains arrived and departed during this same period. This is a 17 percent error or variance in relation to Innovative System's train count. This is a significant difference given the small sample size and may indicate either a bias or incompetence in the completion of the study. Either way, the study should not be relied upon.

Second, the Town objects to the implication within the EIS that the train speeds indicated by Innovative Systems can be relied upon. Innovative Systems apparent inability to count the trains accurately casts severe doubt upon their ability to accurately record times of all the trains, especially given the fact that they did not record, or report, all the trains. On the other hand, the Town and nearly every resident living east of the tracks can tell you that Innovative Systems' conclusions are not supported by reality. Both anecdotal and empirical evidence suggests much longer train times are common. Unfortunately, the current empirical evidence available does not represent a statistically significant sample. It does, however, indicate that an unbiased evaluation needs to be performed. The Town, similarly, installed a Police Department surveillance camera along side the tracks at various intersections. Unfortunately, only a few readings were taken at Four Mile Road. The Town, however, recorded times in excess of 11 and 15 minutes. Further study should be completed to correlate closing times at Four Mile Road with Six Mile Road and Seven Mile Road and to identify factors that cause times significantly in excess of those reported by Innovative Systems and portrayed in the EIS as accurate. More detailed review needs to be done to ensure all coal trains are captured and data for those trains needs to be cross referenced with Railroad and We Energies records to ensure trains from other users are not being attributed to the OCPP. More evaluation, independent of We Energies, must be completed to make any clear determination. Furthermore, the implication that 8-minute road closures are the maximum must be eliminated or proven to be without bias or error.

A third objection relative to the Four Mile Road stems from the following statements in the EIS. The EIS states and concludes, "The town of Caledonia is concerned about the increased amount of time that the trains would block Four Mile Road. The rail crossing of Four Mile Road is west of STH 32. While activity at the OCPP/ERGS site affects the crossing times of coal trains at Seven Mile and Six Mile Road, this is not the case at Four Mile Road."

<u>The Town strongly objects to the implications of this misleading statement.</u> The implication of these statements is that any additional road closures at this crossing are acceptable provided some operational delay at the OCPP is not causing that delay. Additional trains, in and of themselves, cause road closures, and each road closure, in and of itself, has a social and cultural impact on the Town. As indicated, an accurate study needs to be done to determine the true impact of additional trains, and these impacts need to be reflected in the EIS.

The EIS makes no reference to traffic counts along Four Mile Road. The EIS makes no reference to the fact that Four Mile Road is the community's most critical east-west corridor. The EIS makes no reference to the fact that the track is only approximately 800 feet east of the intersection of Four Mile Road (also CTH "G") and STH 32. The EIS makes no reference to the fact this nearby intersection of Four Mile Road and STH 32 is the central intersection in the Town and is located at the middle of our business corridor. The EIS makes no reference to the fact that current traffic volumes require individual vehicles to seek alternate routes during crossing closures due to coal trains to avoid back-ups into the intersection of a state trunk highway! The EIS makes no reference to the fact that the traffic counts for this road are expected to experience significant and continued growth.

The EIS inappropriately and with disregard for its own stated purpose indicates, "Any additional train traffic, even if unrelated to the ERGS project, would affect Four Mile Road in the same manner as the coal trains." On this basis, the EIS then ignores its responsibility to analyze "the social, cultural, and environmental impacts that could result from the construction of three new coal-fired power plants and their associated facilities." No such analysis is performed at the most critical social and cultural intersection in the community.

Given increased train traffic, 8 to 15 minute delays (yet to be determined accurately) would become common place. Given daily traffic volumes estimated to be in excess of 10,000 crossings per day (based upon a small sample set of days recorded by a TimeMark III traffic counter), 200-250 vehicles could be impacted in one 15-minute period during peak hours. The dependability and reliability of commuting through the town's central intersection would be put at risk. More frequent road closures could have a significant impact on commerce, productivity, and quality of life, each of which clearly fall into the "social" and "cultural" impact category. All of which, however, has been ignored in the Draft EIS.

A fourth objection to the Draft EIS relative to the Four Mile Road is that no review of a grade separation feasibility study was reported. This is further evidence that the EIS failed to meet its responsibility with regard to the impacts at Four Mile Road. Such a study was performed for both Six Mile Road and Seven Mile Road, but the Town's most critical intersection was ignored.

Three Mile Road: The impact of added closures at Three Mile Road should also be incorporated into the EIS. As stated above in "Errors of Fact," the crossing at Three Mile Road should be included in the report as it is in Caledonia, although the City of Racine lists this crossing on their inventory as well because the road represents the City/Town boarder at that point. Many of the same impacts affect Three Mile Road as affect Four Mile Road. Three Mile Road is actually closer to STH 32 (only about 650 feet away) and can therefore handle fewer cars delayed due to road closings caused by trains.

Dumping Time, Air Testing of Brakes, and Removal of Bad Order Cars: Page 351 references dumping time, air testing of brakes, and removal of bad order cars as reasons for significant road closures at Seven Mile and Six Mile Roads. The report fails to clarify, however, if trains are just being added, why are not the existing trains already causing 240-minute closures and every departing train causing at least a 60 minute delay from air testing of brakes? Is some other

operational action or activity occurring that is causing trains to now have this significant impact? The EIS should clarify why these impacts will now occur with the added trains.

Current Rail Traffic: Table 11-28 (p. 347) does not indicate that the numbers related within the table represent round trips. Therefore, there are actually twice as many road closures as the number of trains indicated. This point should be clarified in the table otherwise the information presented on page 352 relative to the study performed by Innovative Systems appears to be wrong or appears to suggest table 11-28 is wrong. Page 352 indicates that 91 trains passed the intersection in a 25-day period. This exceeds the numbers in Table 11-28 unless all of the trains in Table 11-28 are round trip trains. It should be noted that, given the train traffic results stated on page 352, the statement "Coal delivery...now account for about half of existing rail traffic..." appears to be overstated. The actual results during the study period was less than one-third while the table data actually portrays between 35 and 43 percent.

Additionally, on page 326 the statement, "At full capacity... the proposed project would result in a roughly 40 percent increase in local train traffic" needs to be modified to reflect "in total local train traffic from all sources." As is, it is too easy for an individual to mistake the sentence as an indication of only a 40 percent increase in coal train traffic, since this is the section heading.

Table 11-31 Maximum Time Trains Entering and Leaving the OCPP Site Would Block Seven Mile, Six Mile, and Four Mile Roads (averaged over a 7-day week): The content and intent of this entire table needs to be revisited after all of the above issues are addressed. As indicated above, the road blockages indicated for Seven Mile, Six Mile, and Four Mile Roads are inconsistent with current activity. (See detailed descriptions above)

Table 11-20 & Table 11-21: The purpose for and intent of Table 11-20 and 11-21 needs to be explained or clarified. Does We Energies have some plan or intent to service numerous trains on a single day? Table 11-20 shows the impact at Seven Mile Road of 8 trains arriving and departing on a single day, and Table 11-21 shows the impact at Six Mile Road of 6 trains arriving and departing on a single day. Only 5 times during all of 2001 and 2002 did multiple trains arrive at OCPP on the same day, and in each instance one train arrived very close to midnight at either the start or end of the day. In fact, page 356 indicates the current 16 hours to unload one train would be reduced to about 5 hours. Therefore, unless We Energies intends to handle more than one train at a time, which has not been indicated, these tables present impossible scenarios. This being the case, these tables serve no realistic purpose except to misrepresent likely impacts.

Social and Cultural Impacts: The section on "Railroad Proposals and Impacts" (beginning page 347) completely fails to meaningfully address the impacts of added train traffic caused by the Power the Future plan. The Draft EIS states "the purpose of this EIS is to provide the decision makers, the public, and other stakeholders with an analysis of the social, cultural, and environmental impacts that could result from the construction of three new coal-fired power plants and their associated facilities."

This section merely repeats We Energies stated positions on the matter: We Energies will mitigate impacts at Six Mile Road and Seven Mile Road by building an overpass and closing the

road respectively. The social, cultural, and environmental impacts themselves are never discussed except for loss of an access road for emergency vehicles, loss of an access road for residents, and the potential conflict with future commuter train traffic. There are significant, real social and cultural impacts that have been ignored and, in light of the remaining crossings and our objections to the proposed mitigation at Six and Seven Mile Roads, must be discussed in the EIS.

Impacts such as quality of life concerns relative to the dependability of travel times through our community, for example, have been ignored. Families and individuals often plan travel times to work and school, for example, down to precise minutes. Nearly tripling the occurrence of trains (according to We Energies submissions indicating three trains per plant) will significantly affect this quality of life issue. Late arrivals to work and school are generally not acceptable.

The impacts on commerce and economic development also should not be ignored. These vehicles that are delayed are full of people who lose productivity for each train at which they are stopped. Employees are late; deliveries are late; suppliers are late. The economic engine of the Town of Caledonia sputters every time a train runs through our community. Impacts such as these two examples <u>are</u> the social and cultural impacts of the train proposal and should not be ignored, as is currently done within the Draft EIS.

Failure to State Effects on Impacts of the Delivery Methodology of Alternative Fuels (Natural Gas): Other sections of the EIS relate the impacts of the coal proposal relative to impacts of alternative fuel sources, for example natural gas. The same should be done for the "Railroad Proposals and Impacts" section. Nowhere does the Draft EIS state an important fact: all of the negative impacts of coal delivery train traffic go away if coal is not the fuel source. This comparative point should be made.

Diesel Emissions From Rail Engines: The Town objects to no reference to health concerns, particularly related to respiratory ailments, in this section (p. 357). To simply state that "no entity regulates diesel emissions from rail engines" and, therefore, conclude that it has no impact, is erroneous and is not consistent with the stated purpose of the EIS.

Potential Safety Issues Associated With Increased Rail Traffic: This section (p. 357) must be modified because the conclusion stated is unsubstantiated by the information provided. This section provides accident statistics based upon the number of miles and indicates the number of additional miles that will be traveled in Wisconsin. The section then concludes that by reducing the number of crossings "this would lower the potential for accidents between rails and vehicles in Wisconsin." No evidence or calculation is provided to support this statement. Accident rates are not provided "per crossing" and no calculation is provided to offset the reduction in crossings with the increase in trains. To the contrary, one could logically argue that a 7 percent reduction in crossings in Wisconsin or even the proposed forty percent reduction in crossings in Caledonia would be more than offset by a more than 100% increase in trains (at three new trains per power plant). The conclusion reached in this section, if even accurate, is clearly unsubstantiated by the information provided.

Table 11-34 Participants in Railroad Workshops: The Town objects to the inclusion of this table within the EIS. When this table is put in context with the text on page 358 relative to a new rail underpass on Six Mile Road, it gives the appearance that the Town of Caledonia (through the participation of the Town Engineer) supports the conclusion reached. The suggestion that an underpass be built on Six Mile Road is a recommendation by We Energies to try to draw attention away from the severe negative impacts train traffic would have upon Caledonia. To then give merit to We Energies proposal by attributing it to the unsuspecting attendees at the meeting is inappropriate, misleading, and unfair. The table should be stricken and the text on page 358 should be drafted to clearly indicate that this is a proposal by a consultant of We Energies and nothing more.

Limestone Transport and Storage: The EIS should more clearly address the impacts of limestone transport (p. 112). If transport is to be via rail, the details must be outlined in Chapter 11. As stated above, trains have impacts. The impact of any additional trains caused by the OCPP plan, whether carrying coal or limestone, needs to be identified. No information is given relative to train volumes, lengths, or numbers. As such, the Draft EIS is negligent in not addressing its potential impacts.

Comments on Air Quality Impacts

Total Quality: The expected degradation of air quality, as reported in the Draft EIS, must be emphasized more strongly in the final EIS. A focus on a healthy and healthful environment must be a key component of an EIS. If any plan puts the public at an increased risk of negative health impacts, those impacts must be more clearly and more adamantly emphasized.

Air Modeling: The final EIS should not be prepared or released until air modeling analysis in relation to lower stacks as required by the FAA has been completed, released, reviewed, and comments have been received. The Executive Summary indicates that new air modeling will be performed and the analyses will be presented in the final EIS and/or at the hearings for this project. Inclusion of the results in the final EIS without a public comment opportunity precludes the public from offering its comments on the results. Lowering the stacks could significantly degrade the regional area quality to the point where substantially greater public outcry is generated. The public must be allowed to weigh in on the conclusions prior to the completion of the Final EIS.

Public Health Impacts: The impact on public health is likely the most significant long-run impact of the decision on Power the Future. Although the Draft EIS (chapter 7) does identify some of the public health impacts of the pollution types identified, it is woefully negligent in emphasizing the effects of the identified pollution types. The release of pollutants, which is well documented in the Draft EIS, is the result of the OCPP plan. The impact of the pollutants, however, is the effects those pollutants have on the environment and people. This aspect of the impact of the added pollution is not sufficiently addressed in the Draft EIS. At a minimum Chapter 7 should include a table identifying the pollution type and the public health hazards associated with that pollutant.

Comments on Land Use

The EIS has failed to adequately address the issue of the impact of the proposed plans upon the land use plan of the Town of Caledonia. The Draft EIS acknowledges and briefly describes the Town's land use plan, but the social, cultural, and environmental impacts of the OCPP plan were supposed to be reviewed. The impacts upon the land use plan and its components were ignored by the Draft EIS. The land use plan is a central document to a community that shapes the community's development patterns, which, in turn, shapes your social and cultural structure and characteristics. It also significantly affects the environmental character (the look and feel) of the community. Issues such as development rates, housing stock types, land values, sense of community, road and traffic patterns, and access to Lake Michigan are all influence by land use. Nonetheless, this entire issue of the impact of the Power the Future Plan upon the land use plan and patterns in the Town of Caledonia has been, for the most part, ignored by the Draft EIS. This topic must be considered more thoroughly to meet the stated purpose of the EIS.

Comments on Costs

External Costs: The Town believes all external costs associated with use of coal as a fuel source must be incorporated into the final EIS cost estimates. Issues such as the cost of mitigating and addressing related negative public health impacts and the future cost of addressing increased pollution standards (such as revised mercury standards) must be included. The OCPP will have plant lives of 40-45 years; therefore, all the potential costs during those 40-45 years must be considered. Failure to do so builds a bias into the Final EIS.

Return on Capital Investments: Additionally, the Town believes that the EIS must clearly distinguish that the laws of the State of Wisconsin provide for a guaranteed return on capital investments to Utility Companies and, therefore, a project with higher capital costs is more likely to be preferred by a company with a profit motive. The Town recognizes that it is not an expert in utility financing, but understands that this return-on-capital provision is built into law. As such, this issue becomes strong motivation for a profit-based company to pursue a strategy that is capital intensive compared to other alternatives. Any factor that could so clearly and dramatically impact the decision making process must be considered an "impact" and, therefore, must be included in the EIS. Without such a statement, there is a de facto bias built into the EIS suggesting that the proposal is based only upon other cost and environmental factors.

For example, on page 93 under "Economic Issues" the statement "that choosing a coal facility carries its own significant economic risks" should clearly indicate that this is a risk to the consumer, not to the provider. In fact, given the lack of a "hold to" cost feature and a guaranteed return on capital investments, cost overruns are arguably beneficial to We Energies.

Future Pollution Standards: The Town believes that the EIS should reflect the potential costs of possible future pollution controls at least to the same extent that the EIS reflects the potential for dramatic variability in the cost of natural gas. The cost of natural gas has always fluctuated. Similarly, the United States and State of Wisconsin have always pursued higher environmental standards. Increases in pollution standards will occur just as surely gas prices will fluctuate. The EIS must adequately address these potential, or eventual, costs.

Comment on the Cost Impact of the Agreement Between WEPCO and the City of Oak Creek (p. 28-9 and p. 292)

The Town understands the logical conclusion that with an agreement with Oak Creek in place, the cost of the agreement becomes an apparent cost of the project. The Town, however, objects that the EIS does not identify related impacts on other neighboring communities and identify, estimate, and include those costs as a cost of the project as well. If the EIS accepts the Oak Creek agreement as an impact, those impacts should be estimated for each similarly affected community. If, however, the components of the Oak Creek deal are not related to social, cultural, or environmental impacts, the EIS should state as much and the cost of the Oak Creek Agreement should be referenced for information within the EIS but excluded from consideration in the final EIS evaluation.

If, for example, We Energies announced publicly (and placed a bond in trust) that it would voluntarily donate 50 million dollars to Wisconsin charities if the OCPP plan is approved, does that cost become a cost of the project? Just because the money is paid out does not make it a cost of the project. In this unusual example there is no relationship between the impact of the plan and cost paid out by the plan. The Oak Creek Agreement, realistically speaking, is such a voluntary agreement. The potential costs for all communities of the impacts addressed in the agreement should be included in the EIS or the EIS should state that this is not, in truth, a cost of the OCPP plan.

Comment on Pollution Emissions

Page 95 "Air emissions" must more expansively delineate the distinctions in the air emissions profile for coal-fired and natural gas-fired options. The impact upon public and environmental health must then be included as well. This section dramatically understates the true impact of the coal-fueled option. This forgone opportunity of cleaner air must be more clearly considered and addressed as a cost or impact of a coal-fueled power plant. Although Chapter 7 addresses air emissions (and should be referenced with Chapter 5 for easy referral), it does not adequately address the comparative air emissions patterns, costs, and impacts.

Comment on Community Impacts

Caledonia objects to being excluded from the list of "Communities closest" to the site (p. 277). The Town believes the impacts to which it will be subjected from the plan as proposed qualifies the Town according to the standards identified. If not, the standards need to be modified since part of the site is in Caledonia.

Miscellaneous Comments

Revenue Sharing: Table 11-6, p. 296, is not clear and should list estimated payments by year.

Existing Traffic Volume on Local Roads - Table 11-22: It appears that "Earle" should be "Erie." It appears that traffic on Seven Mile Road east of STH 32 is underestimated, as previously stated.

Future Plans for Four Mile Road: Page 317 indicates "Plans exist to exchange this ownership. When the County acquires Four Mile Road west of STH 32..." This language should be specific as to the "plan" in reference. As is, it implies the Town is part of the plan to exchange ownership. The Town currently has no such plan.

The Town of Caledonia respectfully requests consideration of the points addressed above and expects action will be taken on the above factual errors, comments, concerns and objections. We further request that the final Environmental Impact Statement reflect the necessary changes. Please contact Mark W. Luberda, Town Administrator, with any questions concerning this letter.

Sincerely,

Susan Greenfield
Chairman

Comments on the Draft Environmental Impact Statement, submitted by Calpine Corporation

05-CE-130

WISCONSIN PUBLIC SERVICE COMMISSION

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ATTORNEYS AT LAW

June 13, 2003

DELIVERED BY MESSENGER

Lynda L. Dorr
Secretary
Wisconsin Public Service Commission
610 North Whitney Way, 2nd Floor
Madison, WI 53705-2729

Dear Ms. Dorr:

Re: Draft Environmental Impact Statement
Elm Road Generating Station
Docket No. 05-CE-130

Enclosed for filing are the original and 21 copies of Calpine Corporation's comments to the Draft Environmental Impact Statement prepared for the Elm Road Generating Station.

If you have any questions concerning this matter, please feel free to contact me.

Yours very truly,

Peter L. Gardon

Peter L. Gardon

Madison\111443PLG:LT

Encs.

cc Mr. Joseph D. Condo (w/enc.)

MFC
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CALPINE

June 12, 2003

Jeffery Kitsembel
Public Service Commission of Wisconsin
610 North Whitney Way
Madison, WI 53705

RE: Elm Road Generating Station, Docket No. 05-CE-130

Dear Mr. Kitsembel:

Calpine Corporation submits this letter in response to the invitation to comment on the Draft Environmental Impact Statement (DEIS) prepared for the Elm Road Generating Station (ERGS) that has been proposed by Wisconsin Electric Power Company (WEPCO) and affiliates. In light of the fact that Calpine has submitted an alternative proposal for the Commission to consider in this docket, Calpine very much appreciates the opportunity to provide comments to the DEIS. The references that follow are identified by chapter, page number, and paragraph in the DEIS.

One overarching concern of Calpine is the lack of certainty to the proposal, particularly related to the overall financial and environmental costs this proposal will impose upon Wisconsin citizens and ratepayers. In a myriad of ways, the ERGS proposal contains uncertainties that in other Certificate of Public Convenience and Necessity (CPCN) proceedings before the Commission have been resolved so as to avoid the potential situation where the Commission conceivably approves a project that is not permittable. These issues include, but are not limited to:

- Transmission interconnect costs and environmental impacts;
- Environmental impacts of interconnecting facilities, including Chapter 30 wetland impacts;
- Section 316(b) water quality issues, including intake and discharge structures and potential need for cooling tower facilities;
- Impact to air modeling analysis due to uncertainty over stack height;
- Impact to demand forecast due to potential retirement of older units due to WEPCO settlement with the U.S. Environmental Protection Agency (USEPA).

Despite the comprehensive analysis provided in the DEIS, the areas of uncertainty detailed below clearly indicate, at a minimum, that further analysis is needed to give the public an adequate opportunity to consider the potential impacts related to one of the most expensive pending electric generating projects in the United States. In addition, it is unclear whether an extensive Chapter 30 alternatives analysis will be required by the Department of Natural Resources for the site or the offsite facilities that impact wetlands. The DEIS indicates that there will be wetland impacts on the site and the rail corridor. To the extent that new or expanded transmission facilities are required, it is highly likely that

there will also be Chapter 30 wetland impacts associated with those facilities. This alternatives analysis is at least as extensive as the alternatives analysis required by the Commission.

In the proceeding related to Calpine's proposed Sherry Energy Center, the Wisconsin Department of Natural Resources (WDNR) took the position that Chapter 30 required a thorough review of alternatives, including alternative generating technologies and alternative projects that could be built or purchased, due to the wetland impacts of an associated water line and gas pipeline. The gas pipeline facilities associated with the Sherry Energy Center, like the ATC transmission facilities for the ERGS, were separate jurisdictional facilities for which no application was currently pending. WDNR, however, took the view that, since the plant could not be operated without the interconnecting facilities, the presumed impacts of the gas pipeline required the applicant to review and explain alternatives, including consideration of purchasing other previously approved projects. WDNR's stated position on this issue should be applied to the Elm Road proceeding as well.

Calpine believes that it would be prudent to delay the proceeding until further detail on these important issues becomes available. At the very least, Calpine recommends that a Final Environmental Impact Statement (FEIS) and CPCN for the ERGS proposal not be issued until (1) all applications directly related to the ERGS are submitted to WDNR and deemed complete by WDNR, (2) applications have been filed and reviewed by both the Commission and WDNR with respect to any necessary new and/or upgraded ATC transmission facilities, due to the sheer scope of that related project.

Calpine believes that the numerous environmental and economic uncertainties of the ERGS proposal should be weighted as material risk factors when considering alternate supply resources, such as Calpine's Fond du Lac and Fox facilities. This would help ensure that Calpine's competitive proposal is evaluated on a level playing field. Failure to take these important issues into consideration would discriminate against the merits of Calpine's proposal and would lead to a less-than-optimal result for Wisconsin's ratepayers and our environment.

In addition to these more general comments, Calpine's specific comments appear below:

Chapter 1, Page 3, third paragraph: Calpine wishes to note that not only must an affiliate agreement be reasonable and in the public interest, but also that the legislature, in its consideration of the leased generation statute, never intended for a leased generation proposal to be given any preference over any other proposal. This is in contrast to the specific statutory preference for natural gas over coal-fired generation. The law was passed simply to provide another option for construction of new generation.

Chapter 1, Page 15, third paragraph: Currently there is a disagreement between the WDNR and the USEPA over whether or not the ERGS proposal constitutes a "new source" under the requirements of Section 316(b) of the Clean Water Act. Based on recent discussions between US EPA and Wisconsin DNR about the classification of the

new structure under 316(b), there is some question about whether the 316(b) rules would apply to the new structure as a new (Phase I) or existing (Phase II) facility. Phase II facilities are currently not regulated because US EPA has not promulgated regulations detailing the specific best technology available (BTA) approach that will be required for Phase II-affected facilities. However, based on a review of correspondence between the agencies in question and discussions with WDNR, it appears that the classification of the new structure will have little impact on WEPCO's responsibility to meet the basic BTA requirements, namely that their facility will be required to do one of the following:

- limit approach velocity to less than 0.5 feet per second;
- demonstrate why an approach velocity of more than 0.5 feet per second would not have a significantly higher impact in impingement/entrainment than an approach velocity of less than 0.5 feet per second; or
- show that the cost of compliance to demonstrate an approach velocity of less than 0.5 feet per second is unreasonable.

Calpine believes that WEPCO's proposed once-through cooling system does not meet the BTA standards that will be required of a newly constructed intake structure under Section 316 (b), whether it is deemed to be an existing facility or a newly constructed facility. The information currently available is inadequate to determine if the proposed system is an environmentally feasible solution, and engineering and design changes necessary to meet the BTA requirements of 316(b) could make once-through cooling cost-prohibitive for ERGS. Accordingly, the Commission should require WEPCO to provide a revised submittal describing in greater detail how they propose to satisfy the BTA requirements of 316 (b), including the environmental and financial impacts associated with such an approach. This issue could lead to a major increase in the cost of the ERGS project.

Chapter 2, Page 28, final two paragraphs: The community impact payments to Oak Creek are a quantifiable, verifiable cost to the ERGS project and should be included in all analyses performed by the Commission.

Chapter 3, Page 38, last paragraph: The statement that the Fox Energy facility near Kaukauna is unlikely to built in the near future is inaccurate. Calpine recently purchased Fox Energy Company, LLC from MidAmerican Energy Holdings, and expects to commence construction on the facility in late summer 2003.

Chapter 3, Page 39, second paragraph: There are certain generalities in this paragraph that should be corrected. While it is true that many independent power providers (IPPs) face tight capital and credit markets as a result of the economic downturn and in the aftermath of the Enron scandal, Calpine has shown that it can finance and construct major new generating facilities as long as an economic power sales agreement is in place. Indeed, Calpine is currently building its Riverside facility in Beloit. These facilities have contracts with Wisconsin utilities that were not "reluctant" to enter into such contracts with Calpine. Numerous other Calpine projects with long-term contracts are also moving forward across the United States.

Chapter 3, Page 50, third and fourth paragraphs: These paragraphs conclude that approval of the ERGS proposal would not prevent the development of a competitive wholesale market in Wisconsin. Calpine strongly disagrees. If a utility is allowed to simply select itself to build any future generation project in Wisconsin, there will be no wholesale market to develop. Utility-owned, ratebase facilities essentially constitute long-term "take or pay" obligations to ratepayers that clearly impact the ongoing development of a competitive wholesale market. Additionally, in the 2002 Port Washington Generating Station (PWGS) proceeding, WEPCO stated that in fact, the 1,000 MW figure referred to by the Commission actually includes over 800 MW that were under contract to WEPCO prior to the PWGS proceeding (Abood testimony, pp. 708-09).

Calpine believes that if the ERGS is built as currently proposed in both timing and scope, it is highly unlikely WEPCO will consider any long-term contract with an IPP in the foreseeable future. As it is contemplated in the DEIS that Madison Gas & Electric Company and Wisconsin Public Power Incorporated will purchase power from the ERGS (see DEIS page 22), it is also highly unlikely that either of these utilities will enter into any long-term contracts with an IPP in the foreseeable future.

Moreover, the FEIS should recognize that the ownership and financing structure proposed for the ERGS represents an extraordinarily long-term obligation on the part of Wisconsin ratepayers compared with contracting for new generating supplies from third parties, such as IPPs. Most IPPs, including Calpine, would be willing to enter into "long-term" contracts of as little as 10 or 15 years. This inherently represents a much lower overall risk to ratepayers than locking in the high capital costs associated with the ERGS proposal for such an extended period. Indeed, Calpine recommends that the FEIS reflect at least one model run comparing the alternative sources for a period of no more than 15 years.

Chapter 4, Page 69, third paragraph: Calpine believes that it is never the case that a formal competitive process is unreasonable. WEPCO would appear to agree, as it conducted such a process for the construction of the ERGS facility (see DEIS page 15). WEPCO also has current requests for proposals (RFPs) in place for 200MW of wind and 100-400 MW of peaking power. Only the generation to be potentially filled by the ERGS project was deemed to be untenable for a competitive process. Calpine strongly agrees with the Commission's statement that "the use of competitive forces does foster cost discipline that ultimately benefits ratepayers", and is grateful that the Commission is engaged in an unbiased analysis of the proposals before it.

Chapter 4, Page 69, fourth paragraph: Note that the Commission has in fact granted the CPCN for the Fond Du Lac Energy Center. The final order was issued on May 5, 2003. The Fond du Lac Energy Center has received all permits, including those issued by WDNR, necessary to start construction.

Chapter 4, Page 71 et. seq. (general comment on EGEAS inputs): The Commission appears to have accepted the "full 30-year expansion plan" as the relevant

timeframe for various EGEAS scenarios. Calpine believes that the Commission should not simply accept the premise that a 30-year planning horizon is necessarily in the public interest.

Due in particular to the high capital costs of the ERGS, it clearly benefits the ERGS proposal to run the model over the longest timeframe possible in order to obtain an optimal level of amortization of these capital costs, especially when compared with lower capital cost projects such as Fond du Lac and Fox. Calpine believes the FEIS should include shorter model runs to determine how the optimal integrated resource portfolio changes based on time limits. Since longer planning horizons generally have more uncertainty and therefore more risk than shorter planning horizons, it is important to determine if ratepayers might, indeed, be better off under a 10- or 15-year expansion plan, rather than a full 30-year expansion plan.

Chapter 4, Page 78, first paragraph: Calpine believes that a $10 million materiality threshold is the correct one for the Commission to use. Given that ratepayers pay for WEPCO's proposal, Calpine would take the position that something even less that $10 million is in fact material. This is especially true in light of the fact that unlike the Port Washington proceeding, there are very serious environmental policy decisions in this docket that will impact Wisconsin for decades.

Chapter 4, Page 78, second paragraph: Calpine believes that failure to include the $266 million in transmission costs into the analysis leads to a materially inaccurate result. The fact that such costs may be part of a separate CPCN proceeding does not remove them from ratepayers' balance sheets. Calpine believes that the transmission cost figures for the ERGS proposal, as well as for Calpine's proposals, must be included in the EGEAS runs, in order for the analysis to have any true meaning. Calpine's proposal is more economic than WEPCO's even when several uncertainties are not included. If transmission costs, CO2 monetization and coal plant cost overruns not covered by WEPCO are included, such an EGEAS run would result in Calpine being the clear, unequivocal winner.

Moreover, the DEIS errs in suggesting that the existing American Transmission Company (ATC) interconnect study for the ERGS proposal may overstate expected interconnect costs. While such costs may, in fact, be higher or lower than the $266 million projected by ATC for a variety of currently unpredictable reasons, it is inappropriate to speculate on the level of those costs until an updated interconnect study is complete, which ATC has suggested will not occur until later this year. In lieu of an updated study, there is no choice but to use the existing published study, especially in comparison to Calpine's competitive alternative, which also has a complete interconnect study on file. This is the only way to ensure an "apples to apples" comparison that does not unfairly discriminate against Calpine's proposal.

Specifically, Calpine strongly recommends that the respective ATC projected interconnect costs for the ERGS should be included in the EGEAS runs reflected in the FEIS. In addition, Calpine believes that the FEIS should explore why the projected

interconnect costs for the ERGS proposal are so high and disproportionate to all other pending ATC interconnect requests. Absent further information, this suggests that the existing transmission system surrounding Oak Creek has little if any excess capacity and is not, therefore, an optimal location for significant new power generation. In any event, this is a significant, known potential cumulative impact that should be discussed thoroughly in the context of the pending proceeding.

Chapter 4, Page 79, third paragraph: Calpine has previously in these comments discussed the notion that the ERGS proposal has a number of major cost questions and other uncertainties surrounding it. Calpine agrees with the Commission's introduction of the notion that it is premature to issue permits now for facilities that will not begin operation until 2011, especially in light of such uncertainties.

Chapter 5, Page 83, first paragraph: Over 70 percent of the energy consumed by WEPCO customers is produced by coal (which is far above the national average of around 50 percent), and only three percent is produced by gas. Therefore, WEPCO's statements that fuel "balance" requires the construction of a massive coal-fired project are inconsistent. To the contrary, as Wisconsin becomes more dependent upon coal than other regions of the United States, it becomes more vulnerable than other states to future environmental liabilities such as stricter mercury rules or regulatory caps on carbon dioxide emissions.

Chapter 5, Page 85, third through fifth paragraphs: The DEIS poses the notion that while there is no real possibility that we will run out of natural gas in the foreseeable future, the natural gas used in the future will be more expensive. However, the DEIS also recognizes that higher gas prices will lead to increased exploration and new areas of production, and that the final result may be an expanding resource base at prices lower than what currently exist (page 87, second paragraph). Historically, the natural gas market has shown a great deal of resiliency in terms of matching supply and demand, and it is vital to avoid making long-term decisions based on short-term market behavior.

Additionally, the fact is that coal prices have shown volatility in the past as well. Between September 2000 and 2001, coal prices nearly doubled. Historically, coal prices lag the price volatility of natural gas but still have been highly correlated to gas price changes, as coal owners seek to extract economic advantage. Lastly, it is the general case that power generators' fuel costs are not necessarily correlated to the spot price of any fuel, because they have either signed long-team contracts for the fuel supply and/or have hedged against short-term volatility.

Chapter 5, Page 88: An extrapolation from the number of megawatts of gas-fired generation being added in the United States to reach conclusions about increases in gas consumption can be misleading. First, many of the reported megawatts represent simple cycle combustion turbines that will operate relatively few hours each year. Second, in many parts of the country, including the Northeast, Texas, and California, new combined-cycle generating facilities will displace power production from older steam plants that previously consumed large quantities of gas. In these situations, because the newer-

technology plants are able to produce the same electric output with roughly one-third less fuel, gas consumption for power generation can actually decrease when new gas-fired capacity is added. U.S. EIA currently predicts that U.S. gas demand will grow at an average annual rate of 1.8 percent through 2025, and that new electric generation will account for only about half of that growth.

Chapter 5, Page 89, fourth and fifth paragraphs: In today's market, power generators have a range of gas supply options. Firm and interruptible transportation contracts with pipelines are two of these options, but generators can also enter into capacity release agreements with existing holders of pipeline entitlements, or contract for gas supplies delivered directly to the plant. It is also becoming more common for power generators, local gas distribution companies and other end users to purchase gas supplies at regional market centers, such as the Chicago hub, instead of buying gas all the way back at the supply area in Oklahoma, Louisiana, or Alberta. Because market centers aggregate supplies from multiple pipelines and supply basins, and are often supported by underground gas storage facilities, this is generally a more cost-effective and reliable contracting approach than committing to gas supplies and pipeline transportation from a specific gas producing area.

Chapter 5, Page 90, first paragraph: It is standard practice in tolling arrangements for the buyer (generally the utility) to contract for a portion of firm gas supply. Also it is Calpine's practice to maintain adequate alternative fuel supplies at its facilities serving Wisconsin. The appropriate level of firm pipeline capacity will be different for each plant, and will evolve over time as generating requirements and gas supply and transportation conditions change.

Generators have strong incentives to maintain fuel arrangements that will allow them to reliably meet their contractual obligations to supply power. Although it may appear from a reliability perspective that having a gas-fired generator control more firm pipeline capacity should always be better than less, it is not in the public interest to require power generators to hold more pipeline capacity than is needed. Such a policy would create environmental costs associated with unnecessary pipeline construction, and would lead to higher power generation costs, which would be ultimately reflected in the prices consumers pay for electricity.

Chapter 5, Page 90, all paragraphs: Calpine agrees that pipeline service reliability is an important issue for all consumers of natural gas in Wisconsin. However, as more gas-fired generating facilities are constructed for baseload power supply, and the gas delivery infrastructure in the state is developed to satisfy these new requirements, the reliability of the gas pipeline system serving the state will increase. To discourage new gas-fired generation because the gas transmission facilities needed to serve these loads are not in place today is illogical, since it ignores the fact that natural gas pipelines can only be approved and constructed after there is a demonstrated need for the facilities. In fact, during 2002 more than 3,571 miles of pipeline and a record 12.8 billion cubic feet per day of natural gas pipeline capacity were added to the national pipeline network,

clearly demonstrating that the natural gas transportation industry remains able to quickly respond to changes in local and regional demand.

Moreover, pipeline improvements that are anchored entirely or primarily by power generation requirements, such as the ANR Westleg expansion that was recently approved by the Federal Energy Regulatory Commission, provide economic and reliability benefits to all gas users on the pipeline system. These reliability and efficiency benefits to the natural gas system should be taken into account evaluating new gas-fired generation against non-gas alternatives.

Chapter 5, Page 92, fifth and sixth paragraphs: Power generators generally maintain a portfolio of natural gas supply contracts with pricing terms that dampen the effects of short-term price volatility on power generation costs. Depending on the objectives of the power purchaser, fuel costs can be stabilized with fixed-price fuel contracts or financial hedges.

Chapter 5, Page 95, first through third paragraphs: The DEIS assumes that coal plants always use once-through cooling systems and natural gas plants always use cooling towers. This is not true. Natural gas plants proposed by Calpine in Wisconsin have been designed with cooling towers in order to minimize environmental impacts to the water source (ground or surface waters) and the receiving body. In certain instances, Calpine has sought to re-use water from private treatment facilities such as a paper mill in Wisconsin Rapids for the Sherry Project, so as to avoid the consumptive use issues associated with taking waters of the state. Similarly, Calpine's Fox Energy Center will utilize treated effluent from the Heart of the Valley wastewater treatment facility to provide cooling water for its Fox Energy Center, avoiding use of existing surface or underground sources of water. Due to the uncertainty involved in permitting its proposed water use facilities (the uncertainties have been described above), WEPCO should analyze the alternative of using cooling towers. This alternatives analysis should be made available for public review and comment.

Chapter 5, Page 96, fourth bullet point: The statement is made that reliability issues with power generation increase as the percentage of natural gas generation increases. Reliability involves many more issues than just fuel supply, and the DEIS has not provided a sufficient level of information that demonstrates natural gas supplies are less reliable than coal. Further, an analysis of reliability also should include operational reliability in addition to fuel reliability. Coal-fired plants, by the nature of their process, have significantly more events that result in unplanned outages than do gas-fired combined-cycle plants. For example, coal-fired plants often face steam boiler tube leaks and fuel handling problems that result in either reduced output or unit downtime required to accommodate repairs. The DEIS has made no effort to evaluate the impacts of such events on overall reliability, which calls into question whether the analysis fully evaluates all reasonable issues that may impact reliability.

Reliability is not just a function of fuel type, but is also a function of location and diversity of supply. Indeed, locating such a significant portion of Wisconsin's new energy

generation at one location, such as Oak Creek, presents reliability issues in and of itself. This is especially true given the extraordinarily high projected transmission interconnect costs, which suggest that the existing grid can support little, if any, new generating capability at that location.

Chapter 6, Page 98, sixth paragraph: The DEIS makes numerous references to negotiations that are underway for the purchase of a federally-owned parcel of land that is currently used as a shooting range. No information is provided on the status of those negotiations or the potential impacts to the ERGS project if the negotiations are not successful. By contrast, Calpine was required to show proof of ownership or rights to exercise ownership prior to a completeness determination for all its various projects in Wisconsin in order to meet the alternative site requirements in the CPCN guidelines. WEPCO should (i) identify the environmental condition of the land as it will likely assume all liabilities associated therewith, (ii) the land that WEPCO would sway for the 70-acre parcel, and (iii) a binding contract for the land, whether purchase agreement or option. In the event that WEPCO cannot show proof of rights to the land, alternate plans should be provided.

Chapter 6, Page 114, second paragraph: WEPCO proposes that each unit would require about 460,000 gallons per minute of cooling and service water into the system, or about 662 million gallons per day. This is about 189 times more water than would be required by a comparably sized gas-fired combined cycle plant. From another perspective, the water used by a combined cycle gas-fired generating facility like Calpine's Fond du Lac facility in an entire day would keep one of the ERGS units operating for about 8 minutes. Most of this water will be obtained by WEPCO through its intake structure; however, Table 6-3 indicates that nearly one million gallons per day would be obtained from the local city water supply. Such a substantial demand for water could place additional demands on the potable water supply and treatment capacity of the City of Caledonia, which could have an adverse impact on of local citizens, particularly during drought conditions. Furthermore, while the ERGS plant would increase the temperature of water discharged back to Lake Michigan by about 12 degrees Fahrenheit, the discharge from Calpine's Fond du Lac plant would be only be warmer than the receiving water at Lake Winnebago by about one degree in winter and two degrees in summer.

Chapter 6, Pages 115 and 125, Figures 6-7 and 6-10: The water balances detailing water flows of the proposed ERGS appears to be missing some data, i.e. total inflow from Lake Michigan at the lower left of the figure. The Commission should require that WEPCO provide all information on each component of the water balance diagram so that a clear and complete understanding of the water consumption of the proposed ERGS project can be had.

Chapter 6, Page 117, second from last paragraph: WEPCO states that its proposed IGCC unit is based on the Texaco Gasification Power System, and that information presented herein is preliminary. However, Texaco has developed and recently brought into operation two IGCC units in Italy that are roughly the same size as

that proposed for ERGS. If the Commission intends to authorize this unit, WEPCO should be required to provide significantly more information than what has been presented in this application before the FEIS can be completed or a CPCN can be issued. Alternatively, the IGCC should be dropped from the proposed CPCN due to a lack of credible information necessary to support a full and complete evaluation.

Chapter 6, Page 126, final paragraph: There is no basis cited for the proposition that within 10 years, the utilization of sulfur and slag will grow from zero to 100 percent. What landfill capacity plans are in place in the event this exponential growth does not in fact occur?

Chapter 7, Page 138, first paragraph: The DEIS refers to WDNR's State Implementation Plan (SIP) and its provisions that relate to efforts to attain the ozone standard. Currently, the Milwaukee area, which includes the proposed site of the ERGS, is classified as severe-17 nonattainment for the federal 1-hour ambient air quality standard for ozone. Provisions of Title I of the Clean Air Act Amendments of 1990 require that areas that are classified as nonattainment must make reasonable progress toward attainment by the applicable deadline. The progress demonstration includes an ongoing evaluation of existing emissions sources, new sources added to the airshed, and the impacts of emission reduction measures, among other factors.

With respect to ERGS, Calpine is concerned that an additional 5,200 tons per year of NOx emissions each year will place the attainment progress of the Milwaukee area in jeopardy. Currently, Milwaukee is covered by a Section 182(f) exemption from nonattainment provisions as they apply to NOx emissions, meaning that NOx reductions are not currently believed to be supportive of ozone attainment. However, it is not clear that WDNR has evaluated the impact of an additional 5,200 tons per year of NOx emissions on the airshed attainment model.

Furthermore, Calpine is concerned that such a substantial increase in emissions from existing levels will result in more areas being classified as nonattainment for the impending eight-hour ozone standard, which USEPA is preparing to establish in the next several years, and could result in loss of the 182(f) exemption for the Milwaukee nonattainment area. Withdrawal of the 182(f) exemption could result in significant emission reduction requirements in the area, which could result in new emission controls and requirements for emission sources not previously regulated such as on-road mobile sources, i.e., cars and trucks; off-road mobile sources like farm machinery and equipment, boats, snowmobiles and other recreational vehicles, in addition to large stationary industrial sources.

Chapter 7, Page 141, fourth paragraph: This paragraph states that WEPCO's PSD and NSR applications are not yet complete. In prior cases, the Commission stated that such air permit applications must be complete in order for the public to adequately consider the impacts of the proposed project.

Chapter 7, Page 148, final paragraph: In prior applications, the Commission has required Calpine to state specifically its onsite chemical storage plans, as well as a complete list of type and quantities of such chemicals, prior to being issued a completeness determination. WEPCO should be required to provide the same level and type of information for the ERGS proposal.

Chapter 7, Page 151, third paragraph: The DEIS notes that, due to the phased construction schedule proposed for the ERGS, WEPCO may be granted as much as 90 months (7.5 years) in which to complete construction of the proposed units. Calpine notes that, while WDNR has granted minor increases in timeframes to complete construction – and such accommodations can be considered reasonable based on specific circumstance, contemplation of a 90 month permit is markedly inconsistent with federal PSD regulations and common practice regarding NSR/PSD permits. Regulatory agencies typically include a deadline in permits so that sources cannot preserve current best available control technology (BACT) determinations and regulatory interpretations indefinitely. It is very likely that significant advancements in BACT, along with other area-specific air quality issues, e.g., loss of 182(f) exemption requiring nonattainment requirements for NOx, will change during the course of 90 months after permit issuance. Though WDNR is likely to require a BACT update 18 months before start of construction, this does not address other air quality issues that may be avoided through an excessive construction deadline, such as nonattainment requirements for LAER and emission offsets. Calpine believes that such a lax construction deadline represents an inappropriate action with respect to protection of air quality, as well as an example of preferential treatment that is afforded to WEPCO and not to other applicants.

Chapter 7, Pages 163 through167: There are several issues regarding the DEIS description of the air dispersion modeling analysis that is required for the ERGS project. It is noted on page 163 that the stack heights for the South and South-Exp sites must be reduced by approximately 200 feet to mitigate air navigation hazards to the John H. Batten Airport in Racine County. However, the DEIS also discusses how WEPCO has failed to complete its analysis of the impacts from the two southern sites. Calpine raises two objections to this situation.

First, it begs explanation as to how an adequate environmental impact analysis can be developed for a facility where no air dispersion modeling has been completed. The public and interested parties have no idea what the final impacts of the southern proposed sites, and cannot make an informed evaluation of the proposed facility. Given the thin margin of compliance with several NAAQS standards – especially that of particulate matter and SO2 – it seems nearly impossible that WEPCO could show compliance with these requirements considering stack heights that would be reduced by more than 30 percent. Additionally, this calls into question whether the South and South-Exp sites are legitimate alternative sites – a clear and specific requirement of state regulations and CPCN guidance.

Second, as stated previously on other issues, Calpine and other IPPs were not granted completeness determinations on CPCN applications until all air dispersion modeling

analyses were completed and the results were made available to the Commission for incorporation into the DEIS. The DIES statement that the revised modeling analysis will be made available as part of the FEIS is not sufficient to allow the public and interested parties a legitimate opportunity to effectively review and develop comments/testimony in response.

Calpine also has concerns regarding the modeling results associated with the North site, particularly with respect to several pollutants that are very close to the applicable NAAQS and Class II Increment limits. Table 7-24 provides data regarding multiple pollutants and ERGS contribution to consumption of the available Class II increment. However, the DEIS provides no discussion regarding the amount of Class II increment that is available, i.e. how does the proposed ERGS expansion relate to existing sources of pollution under these various parameters?

For example, ERGS is expected to contribute approximately 62.9 $\mu g/m^3$ toward the 24-hour standard of PM_{10}, and background contributions of PM_{10} constitute another 56 $\mu g/m^3$, which represents a total combined PM_{10} impact of about 120.9 $\mu g/m^3$. Under the increment analysis, however, approximately 28.1 $\mu g/m^3$ of the Class II increment (of a maximum of 30 $\mu g/m^3$) is consumed by the ERGS project alone. Table 7-24 and the surrounding discussion make no reference to the available Class II increment for PM_{10}, nor do they address the contribution of existing PM_{10} sources in the area that also may be consuming a portion of the Class II PM_{10} increment.

Presumably, if the ERGS project represents approximately half of the total contribution (in addition to other nearby sources) of PM_{10} regarding the 24-hour NAAQS, it follows that other contributing sources also consume Class II increment. This situation occurs for each of the six modeled pollutants, and in no case is a representation is made regarding existing available/consumed increment. What is most disturbing is that, in light of the substantial deficiencies noted above, the DEIS states that:

> "Judging from WEPCO's air modeling and PSD increment results, the ERGS would appear to quality for a DNR permit." (Chapter 7, page167)

The DEIS then states two sentences later that:

> "DNR analyses would also examine the cumulative impacts of each unit at each site so that the effects of adding each unit into the others can be seen."

Taken together, it appears that the DEIS recognizes that WEPCO's modeling submittal is substantially deficient, but makes the presumption that the project will satisfy all modeling-related concerns. Moreover, WEPCO has recently filed testimony in this proceeding indicating that yet another configuration of exhaust stacks – one involving a single common stack for both SCPC units – is being evaluated for ERGS. There is a clear question as to whether the public and interested parties will ever have an opportunity to fully evaluate WEPCO's proposal as it impacts ambient air quality in the context of this CPCN proceeding. Considering the relatively large impact on ambient air

quality shown even by the partial modeling results provided in the DEIS, Calpine believes that air dispersion modeling results for the ERGS project are inadequate and that the Commission must provide the public and interested parties a legitimate opportunity to fully evaluate and comment upon the complete modeling analysis.

Chapter 7, Page 169, second paragraph: The expanded ERGS project would result in new annual emissions of 9,785 tons per year and 5,245 tons per year of SO2 and NOx, respectively. The DEIS narrative indicates that this would result in less than one-half of one percent of statewide emissions of each of these pollutants. However, compared with total statewide emissions of 303,049 tons per year and 193,795 tons per year, respectively, ERGS would represent an increase in Wisconsin's total annual SO2 and NOx emissions of 3.2 percent and 2.7 percent, respectively.

Chapter 8, Pages 187 through 189: The DEIS provides data on entrainment and impingement studies obtained almost 30 years ago while at the same time noting on page 189 that major shifts in nutrient loading have occurred in the southern basin of Lake Michigan over the past several decades. Calpine's experience in Wisconsin with the CPCN process has been that updated studies for the specific areas of impact must be completed and made available for public review as part of the process. Other examples of studies that should be considered inadequate include to zooplankton tows conducted in Illinois (page 190), the thermal studies conducted in 1976 (page 194), the incomplete Lake Monitoring Study (page 206), and evaluations of historical properties (page 256).

Chapter 8, Pages 194 through 199: The DEIS discusses the water consumption and intake rates for both the existing Oak Creek Power Plant and the proposed ERGS addition. On pages 194 through 195, OCPP is stated to have a maximum water intake rate of approximately 1,165 million gallons per day (mgd) and an average rate of about 978 mgd, with a total consumptive use of about 68,000 gallons per day. Page 195 describes approximately 3.4 mgd of wastewater from several sources that is discharged back to Lake Michigan through a number of outfall structures. However, there is no discussion of the total discharged volume. In addition, page 198 begins a discussion of the proposed combined OCPP/ERGS water intake/discharge system, and specifies that OCPP currently takes in about 1,015 mgd from, and discharges about 988 mgd to, Lake Michigan, which indicates a total consumptive load of more than 27 mgd. Clearly, this is inconsistent with the statements made on page 194 regarding consumption use of water, which states that the rate of consumption is about 400 times less.

Also, the DEIS provides a water balance in Figure 8-5 (page 199) that features only a few discharge volume flow rates, and few/no intake or internal flows. Although some data is provided in tabular form on pages 200-201, it is very difficult understand the water balance based on what has been provided. Further, the inconsistency of water use data regarding the OCPP discussion calls into question whether the flows presented on pages 200-201 can be verified. Calpine requests that this information be provided to the public and interested parties before additional evaluation of the ERGS application can proceed.

Chapter 8, Page 203, first paragraph: Calpine has mentioned this issue previously in these comments. The USEPA has stated that it does not believe that the ERGS is an existing facility for purposes of the 316(b) regulations. If the ERGS is so deemed a new facility, the cost of the facility may rise by a dramatic amount. It is difficult to discern how the Commission can make a full and thorough analysis of this proposal given this serious uncertainty.

Chapter 8, Page 214, fourth paragraph: The DEIS notes that there are several options available to WEPCO for the disposal of dredge materials, but does not describe the impacts, including number of truck movements, truck routes, traffic management plans, description of the fuel oil facilities and expected usage thereof during the almost continuous excavation process, etc., of any one of the options. While it may be true that the specific option to be used will be decided prior to obtaining a Chapter 30 permit, assuming that WDNR deems the dredging and disposal of the material to be a permittable activity after its review of the impacts and alternatives to the proposed project, the impacts of all options should be described in the DEIS so that the public may review and comment upon them.

Chapter 9, Pages 232 through 234: The DEIS describes how the operation of the IGCC unit will produce approximately 60,000 tons per year, or 62,400 gallons per day of sulfuric acid as a byproduct. Although there is some discussion of sale of this material as a byproduct, there is no discussion of how WEPCO would handle and dispose of this hazardous material in lieu of sale. Calpine requests that the Commission and WDNR explore this issue further and force WEPCO to provide additional information on its plans for non-saleable hazardous products, such as sulfuric acid. This information should include, but not be limited to, cost impacts, potential disposal sites, and environmental impacts associated with hauling the materials.

Chapter 9, Page 234, fourth through seventh paragraphs: WEPCO's plans to excavate massive amounts of material to provide for the planned once-through cooling system will result in significant quantities of material that must be applied, backfilled, landfilled, or otherwise handled. One of the more troubling questions is the fate of unregulated material that was disposed of at OCPP before such material was regulated by WDNR. Based on WEPCO's site plans, it appears that approximately 2 million cubic yards of material will need to be landfilled off-site, some of this possibly at hazardous landfill sites. At this time, WEPCO has provided no information about the environmental conditions of the waste or how it proposes to handle this waste. Calpine believes that WEPCO must be required to thoroughly sample the materials expected to be excavated and make clear its plans for handling such a large quantity of unregulated waste material.

Chapter 10, Pages 250 through 253: The DEIS describes that the OCPP/ERGS site contains significant land resources that stand to be heavily impacted by the proposed ERGS project. Specifically, OCPP/ERGS is home to about 200 acres of primary environmental corridor (PEC), much of which is used as a migratory pathway for birds traveling along Lake Michigan, as well as a wintering habitat for some bird species. Much of this PEC would be impacted/destroyed regardless of the site that was chosen for

the ERGS project. In addition to habitat, the OCPP site also is home to several plant and animal species that are listed as either endangered, threatened or of special concern by WDNR. WEPCO's description of the ERGS site as a "brownfield" is contradicted by the immense impact on the PEC and other sensitive environmental areas. This is clearly an area where WDNR's alternatives analysis should be implicated.

Chapter 10, Pages 257 through 274: Depending on the site chosen, construction of ERGS would result in the loss of significant amounts of wetlands, woodlands, beachfront bluff and other important habitat. Specifically, construction of ERGS would result in:

- excavation and placement of between 7.3 and 10 million cubic yards of soil and other material, which would result in construction of several major berms and major alterations to site topography;
- destruction of between 9 and 21 acres of wetland isolated natural resource areas;
- removal of as much as 700 feet of Lake Michigan beachfront or as much as 1,900 feet of existing streambed;
- loss of nearly 2 acres of wooded critical species habitat near the rail loop; and
- elimination of between 75 and 87 acres of primary environmental corridor, which serves as a migratory pathway and wintering area for several bird species.

In addition, three sites of archaeological / historical interest are located within the proposed site development area, including two campsite/village sites and one projectile point discovery site.

By contrast, Calpine's proposed Fond du Lac project would impact:

- no archeological / historical sites;
- no critical species habitat areas;
- no threatened or endangered species;
- no isolated natural resource areas;
- minimal areas of shorelines of the Lake Winnebago and East Fond du Lac River during construction of the plant's water intake structure and associated pipeline, respectively, on a temporary basis; and
- one minor wetland area comprising approximately 0.3 acres that is currently part of an existing agricultural field and deemed to be of low quality.

Also of note, prior to the grant of a completeness determination for the Fond du Lac CPCN application, Calpine was required to re-route the water and gas pipeline routes leading to its proposed alternate site to avoid an area of remnant mesic prairie contained in the Oakfield Prairie Natural Resource Area. Calpine's original proposal included the installation of water and gas pipelines along an abandoned railroad line over a length of approximately ¼ mile through the Oakfield Prairie area. WDNR and the Commission expressed concern about invasive plant species that may become established as a result of construction of the pipelines, and Calpine was directed to find another route before

additional evaluation of the CPCN application would take place. In response, Calpine agreed to re-route the pipelines away from the Oakfield Prairie area.

Calpine urges the Commission to reevaluate wildlife and habitat impacts of the proposed ERGS and reconcile the treatment of this project with its recent actions and positions taken on other projects. It seems very clear that multiple acres of major habitat, vegetative and wildlife impacts associated with WEPCO's ERGS proposal should be deemed of material concern.

Chapter 10, Page 275, first paragraph: Construction of ERGS would result in new exhaust stacks of between 470 and 675 feet in height, depending on the site chosen. Because these structures will be constructed near the lakeshore and within the existing PEC, there is a strong possibility for additional injury and death to migratory birds that follow a path along the proposed ERGS site.

Chapter 11, Page 277, last paragraph: The DEIS states that the transmission upgrades necessitated by the ERGS will include construction of one new 345 kV line of about four miles. This is incorrect. In addition to this four-mile line, a new line from Pleasant Prairie to Libertyville, Illinois (23 miles) or a new line from Big Bend to Paddock (56 miles) will also need to be built. In addition, there may be little difference in terms of local environmental impact between a "new" and an "upgraded" 345kV transmission line, especially if the upgrades involve new poles, conductors and widened rights-of-way. The most important issue, however, is that these cost and impacts remain uncertain and unknown, until and unless a revised ATC interconnect study is complete and applications for the relevant jurisdictional facilities have been filed.

Chapter 11, Page 278, last paragraph: The statement that WEPCO has no plans to retire any of the existing Oak Creek units appears inaccurate, in light of the USEPA penalty, settlement and recent WEPCO public announcements.

Chapter 11, Page 292, fifth and sixth paragraphs: The DEIS notes that construction of the three proposed ERGS units will take at least four, six or eight years, depending on how many units are authorized. By contrast, Calpine plans to construct the Fond du Lac facility in approximately two years, resulting in a significantly shorter period during which construction-related environmental impacts would be present.

Chapter 11, Pages 321, 322: According to the labels on Figures 11-3 and 11-4, WEPCO's noise modeling analysis does not include the impacts associated with critical service equipment such as coal handling, coal trains, cooling fan tonal noise, etc.

Chapter 11, Page 324, first and second paragraphs: The DEIS states that the modeling of noise impacts from the proposed ERGS project was based on actual recorded values from WEPCO's Pleasant Prairie plant with addition of a 2 dBA "adder". Calpine notes that this approach is inconsistent with the Commission's guidance for modeling noise impacts from proposed facilities.

Calpine was directed by the Commission in the course of several power plant projects, most recently the Fond du Lac and Sherry facilities, that noise data must be provided for each significant source of noise energy and modeled discretely. Although the Commission allowed Calpine to use measured data from an adjacent power plant during evaluation of the Fond du Lac project, the noise estimates from Calpine's proposed facility all were based on vendor-provided information and were specific to the equipment being proposed. By contrast, the Pleasant Prairie facility is not even a SCPC facility, which contradicts any claim that the facilities are similar enough to follow a surrogate noise modeling protocol. Also, as noted on page 318, a 3 dBA increase in noise energy is "barely perceptible" to the human ear, so addition of this 2 dBA factor to provide a level of conservatism appears to have little meaningful benefit.

Additionally, the Commission and WDNR have not required WEPCO to provide noise data on the air separation unit (ASU) associated with the proposed IGCC unit. ASUs are a significant source of noise at IGCC plants, and the DEIS should include this source – as well as all of the other support sources – that have been omitted from the noise modeling analysis.

Moreover, the DEIS has not presented any information regarding impacts of noise on the dBC range, nor has it offered any information regarding octave band noise impacts. Both sets of information are required according to Wisconsin's noise modeling protocol guidance.

Finally, the DEIS has provided no information on location of nearby noise receptors, modeled noise impacts and cumulative sound levels in a tabular format. Although Figures 11-3 and 11-4 do provide some information regarding relative noise impacts superimposed on a map of the proposed site area, there is no accompanying data with which to further evaluate impacts to the nearby surroundings.

Chapter 11, Page 362, last paragraph: The DEIS notes that ATC has not yet applied for approval of any of the transmission work associated with the ERGS. It is therefore a very valid question as to whether or not it is prudent for the Commission to issue a CPCN for the ERGS in advance of such transmission approval. It is likely that, if the ERGS is approved, WEPCO will begin work on the ERGS, with the implication to the Commission being that failure to subsequently approve a transmission project of at least $266 million is no longer an option for the Commission.

General Comment: As a general matter, we note that there is no discussion or analysis of electromagnetic fields (EMF) that may result from the WEPCO proposal. We point out that Calpine, even though no new transmission lines would be constructed in connection with the Fond du Lac Energy Center, was required to perform an EMF analysis on the transmission line that would receive and transmit the power output from their facility. By contrast, no analysis or discussion of EMF impacts have been addressed for the WEPCO proposal despite the fact that nearly three times as much electric power will be transmitted away from the facility, and approximately 30 miles of new

transmission lines will need to be constructed.

Thank you for the opportunity to comment on this matter.

Sincerely,

Joseph Condo
Senior Counsel
Calpine Corporation

Comments on the Draft Environmental Impact Statement, submitted by Citizens for Responsible Power

PSC Comment Sheet

Proposed Elm Road Coal Units

May 19 and 20, 2003 Draft EIS Comment Meetings

PSC Docket 05-CE-130

FROM

Name_____

Address_____

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Phone_____

E-mail_____

Representing_____

_____

PLEASE DEPOSIT AT THE INFORMATION MEETING, OR...
To mail, fold this sheet (our address is on the back), or add additional sheets and put in an envelope, and send to:

Jeff Kitsembel
PUBLIC SERVICE COMMISSION
PO BOX 7854
MADISON WI 53707-7854

My comments on the draft EIS are:

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Additional sheets are included: ___ Yes ___ No

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Citizens for Responsible Power would like to compliment the DNR and PSC for an objective and comprehensive Draft EIS. However we believe the following areas need to be addressed before the Final EIS is issued:

1.0 EGEAS analysis: the current analysis only includes up to 20% cost over run; additional EGEAS runs should include 30% and 50% cost overruns. Potential cost over runs of this magnitude are not unreasonable. There hasn't been a new coal plant built in Wisconsin since the mid-1980's and there are many unknown and ancillary costs unique to the PTF coal plants relative to the alternatives.

Some examples of unknown and ancillary costs include: unidentified plant/ pollution control complexity, transmission/ interconnection, rail upgrades, rail overpass, massive excavation of lake bluff, water intake, dredging, harbor reconstruction, environmental mitigation of wetlands, critical habitat and environmental corridors.

On page 21of the DEIS: "PSC engineering staff believe, at this time, that the cost overrun potential for the ERGS is about 10 percent for the SCPC units…" What basis is the PSC using for this belief? Wisconsin Energy has a history of cost overruns dating back to the Pleasant Prairie coal units, which were 30 to 40% over budget. In 1997 WEPCO mismanagement caused the lengthy shutdown of the Point Beach nuclear plant and generated over a $100-million repair cost overruns. More recently, WE's portion of the Guardian pipeline project has inflated to $97.5 million from the original estimate of $62 million.

2.0 Railroad/ Coal Trains: DEIS is deficient in this area drawing much of data from We Energies and WE's consultant Benesch (Grade Separation Feasibility Studies report).

First, We Energies does not plan to deliver coal via lake ship due to high cost and declining lake levels. Also the total number of trains stated in the DEIS doesn't make sense nor does it correspond to the numbers stated in WE' PTF application or Benesch report. The current plant at 1,100MW uses 5.5-trains/125 car /week and the DEIS states 11-trains/135 car /week at 2,930MW (with the 3 new PTF units). Under PTF this is a 270% increase in current generation; therefore the 14-trains/135-car/ week stated in WE's application and the Benesch report mathematically makes more sense than the DEIS.

The DEIS and Benesch only address 7-Mile, 6-Mile and to a lesser extent 4-Mile road. There's no mention of 5-Mile or 3-Mile road and the 19 at grade crossings in Racine. Benesch reported only minor impacts at 5-Mile and 4-Mile. Through out Racine and Caledonia the 9,000 ft long trains travel less than 30 mph and slow significantly as they approach the ERGS, sometime stopping as far back as 4-Mile road.

The Town of Caledonia has not agreed to close 7-Mile road because the traffic counts are running at 320 to 655 vehicles per day, which is much greater than 200 vehicles per day Benesch reported. Future development of this area must be accounted for since the area is zoned for residential at .7 to 2.2/acre. The area east of the tracks has 130 acres of developable land, this would allow for approximately 90-285 dwelling units.

3.0 Air Emissions: according to the DEIS concentrations of particulate matter, especially total suspended particulates (TSP 24-hour), PM10 (24-hour), and SO2 (both 3-hour and 24-hour) would increase substantially due to operation of the ERGS.

Since several of these pollutant concentrations are approaching 100 percent of the NAAQS, it's therefore it's imperative the DNR complete Shoreline Dispersion Modeling (SDM). SDM examines the inversion of the cool lake air breaking down in the warmer air over land and pollutants mixed down to the ground

The Draft EIS fails to address the severe adverse health impacts of PM2.5 fine particulates. According to DNR ambient monitoring data the Milwaukee area has annual average concentrations of PM2.5 that are very close to the applicable annual standard.

4.0 Interconnection/ Transmission costs: the DEIS discusses the projected $266 million in new and/or expanded high voltage electric transmission facilities that would be necessary to connect the proposed ERGS coal units. The alternate to the ERGS, a combined-cycle project in Fond du Lac, has an estimated connection cost of $26 million. The interconnection/ transmission costs are a substantial part of the overall cost of the project and therefore needs to be included when evaluating alternative proposals.

The size and location of all proposed ATC transmission lines should be shown on a detailed map. The maps ATC provided the PSC in DEIS (Figures Vol. 2-4 thru 2-7) only give rough idea of the transmission line routes.

Comments on the Draft Environmental Impact Statement, submitted by the Citizens' Utility Board

Comments of the Citizens' Utility Board on the
Draft Environmental Impact Statement for the Elm Road Generating Station
PSCW Docket No. 05-CE-130

The Citizens' Utility Board (CUB) would first like to express its appreciation to Commission and DNR Staff who within a far too limited time period have had to put together a coherent framework for a comprehensive analysis of a complex proposal. Our comments are focused on areas where CUB believes that increased analysis and discussion are necessary and appropriate to allow a reasoned decision of the various pivotal issues present in this case. We have not commented on certain areas of the DEIS because we were aware that other parties would be focusing comments on those areas which we would generally adopt.

Summary

CUB's comments primarily focus on what it believes are several key issues and areas for which additional or revised information and analysis is required for the FEIS. Those areas include: (1) clearer and additional estimations of and comparisons of the potential cost of the proposed ERGS project and ERGS project alternatives; (2) additional information on important factors affecting the type and timing of resource additions appropriate to ensure reasonable rates, reliability and acceptable environmental and social impacts; (3) the need for consideration of an integrated resource portfolio option (i.e. an enhanced energy efficiency/load management, renewable resource and generation alternative); (4) additional and better information relevant to the fuel choice issue; (5) the potential projects' impacts on transmission systems; (6) additional analysis of potential changes that could effect the background and cumulative air emissions for the proposed ERGS units; (7) the issue of the

viability and alternatives to once through cooling at ERGS and the implications if once through cooling is neither a legally available option nor the "least cost" option at ERGS; and (8) the need for additional analysis and information on the potential impacts of increased rail traffic on communities and areas outside of the immediate area of the proposed site.

CUB will present its comments by Chapter.

I. Chapter 2 PTF Costs & Financing Mechanism

(1) On page 21, the DEIS states that: "PSC engineering staff believe, at this time, that the cost overrun potential for the ERGS is about 10 percent from the SPC units and somewhat greater from the IGCC unit." It would be appropriate to explain the primary bases for this judgment in the FEIS.

(2) On pages 25 through 28, there is a discussion comparing the rate and cost impacts between the proposed facility leases as proposed by We-Energies and the use of a traditional ratebasing approach for the proposed ERGS units. We believe that two important additions should be made to this discussion.

First, information should be provided that shows the change in any present net value differences if key financial or economic parameters are modified. For example, if a change in ROE is made (e.g. from 12.9% to 12.7%) what percentage does that change cause in costs under a ratebase approach, under the lease approach and for the present value difference between those approaches. Providing these types of sensitivities would present important information in considering the impacts of these approaches under a range of possible outcomes in this case. A reasonable number of such permutations on key financial parameters (ROE and equity portion of capitalization) and economic parameters (e.g. a 40 versus a 30 year lease) would be valuable.

Second, it would be desirable to highlight which cost factors most affect the present cost difference between a ratebase and a lease approach even assuming the same financial and economic parameters. For example, deferred tax credits would be handled differently under the two options: (under the rate base approach these credits would be flowed back to ratepayers over time while under the lease approach it appears tax law would require these credits to stay with the unit owner).

In this same vein, the discount rate used to calculate present value is important to the result. For example using a higher discount rate (such as the pre-tax economic cost of capital for a utility) will tend to produce smaller absolute present value differences between the rate base and lease approaches while a lower discount rate will widen the absolute difference. The FEIS should explicitly state the discount rate used to calculate the present values to be compared and explain why that is an appropriate discount rate to use for such comparative purposes.

Finally, since We-Energies is also proposing an IGCC unit, it is appropriate to provide such comparisons for all three proposed units in addition to only the two SPC units. All cost calculations and runs should also include the proposed "community mitigation" payment to Oak Creek that We-Energies has agreed to make.

II. Chapter 3: Need for Baseload Capacity

(1) On page 39 and more specifically on page 43, there is discussion about transmission system constraints that limit transfers between northern Illinois and Wisconsin. It would be useful to have a discussion of the potential to "correct" this situation as well as the likely time frame in which to do so and the implications, if any, for the need to build the three proposed plants within an appropriate time frame if such a constraint did not exist. In effect, the FEIS

should address whether such an option is a viable or superior alternative to meet some or all the demand to be met by the proposed ERGS project.

(2) On page 43, under "Planned Capacity…", it appears that Oak Creek 5 rather than Oak Creek 1 was meant to be the unit referred to.

III. Chapter 4: Alternatives to the Proposed Project

(1) On page 65, it is stated that We-Energies' commitment to renewable energy development (i.e. through its collaborative) "is conditional upon approval of the entire PTF project, including the ERGS projects." While this may accurately reflect the statement of a specific witness, the agreement creating the Renewable Energy Collaborative (REC) explicitly states the opposite. CUB suggests that the REC agreement is controlling as to We-Energies efforts to achieve at least a 5% share of its power supply from renewable energy by a date certain.

(2) Additional EGEAS runs: There are three additional sets of EGEAS runs that CUB believes are very important to include in the FEIS.

(a) A set of runs using the cost for the proposed ERGS SPC units plus 10% would reflect the potential risk to ratepayers consistent with WE's proposed lease that allows the approved cost by the Commission and up to 10% for overruns etc. if approved by the Commission as the ultimate sum to be collected through the lease generation agreements. For the SPC units, a 10% adder would be appropriate. Such a run should also be done for all three proposed units (for the IGCC unit, a 15% adder would be appropriate to be consistent with the proposed lease terms submitted by the Applicants).

The approved costs plus potential cost overrun adder (at least for the two SPC units) ought to be treated as an "additional" base case for all the scenario runs performed in the DEIS and shown in Tables 4-4 through 4-8 (except for the high coal construction case)

(b)There should be a run(s) which incorporates both the Staff's ranges for both estimated energy efficiency and renewable savings. As is appropriately pointed out on page 55, energy efficiency and/or renewables may only substitute for part of a resource block needed, but could change the type and/or timing of capacity needed to meet the remaining block of supply need. A combined run of energy efficiency and renewables for the ranges estimated by Staff would help provide useful information on this issue (see also page 61 about the potential value of an integrated resource portfolio). Staff may have contemplated this type of run when it suggests in the DEIS that an "integrated resource" run would be included in the FEIS.

Finally, the FEIS should more fully discuss the potential additional load management opportunities available and the potential impacts on the proposed ERGS project (either to unit need, type and/or timing) alone or as part of an "integrated resource" alternative. There is nothing in the DEIS to justify a conclusion that all cost-effective load management opportunities are currently being captured by We-Energies.

(3) The EGEAS runs provide useful information as to the potential type and timing of future resource additions. However, as inferred in a number of places in the DEIS, there may be other important factors that effect the type and timing of resource additions including a balancing of the cost of accelerating certain resource blocks versus the potential benefits of moving a

resource acquisition forward (e.g. potentially increased operational flexibility, increased flexibility to address potential contingencies or increased reliability under a broader set of scenarios). (e.g. DEIS at pages 35-36, 78-79)

The FEIS should identify and discuss potential factors (and the parameters) that could positively effect changing the timing for the addition of resource units to something different than that indicated by EGEAS runs and their potential implications for what is an "optimal plan" considering all relevant factors (e.g. not limiting the acquisition of wind resources to allow further cost reduction through expanded market competition, the capture of economies of scale, and accelerating other potential technological and business organization improvements).

IV. Chapter 5: Fuel Diversity

There are several places in the DEIS which discuss the potential cost and supply reliability prospects for natural gas (e.g. page 36 and pages 84-93). It would be useful to coordinate these discussions especially in terms of: (1) presenting data about the current ability to transport natural gas into eastern Wisconsin and what available capacity is there given future expected needs: is there a limit given the existing infrastructure and how close are we to it? and (2) the implications, if any, of increased natural gas usage for electric generation, especially baseload generation, for both natural gas and electric customers in Wisconsin (e.g. what are the implications, if any, for storage, for potential gas transmission rates on natural gas user prices or other implications of substantial natural gas fired generation use in the winter as the DEIS suggests needs to be considered on page 36).

The DEIS discusses natural gas resource adequacy, price and price volatility, and gas delivery availability and reliability. While CUB does not necessarily concur with some of the inferences drawn in this discussion, the issue of gas delivery

ability needs far more information in the FEIS. How much more natural gas can Wisconsin import before there is a need for new inter or intrastate facilities and what effect do existing and currently approved plants have on when such expansion might be needed? What are the potential implications of this situation for this case? There is a need for solid information in the FEIS on these issues.

A similar need to more fully address potential coal plant reliability issues in the FEIS is appropriate. In particular, additional information about potential forced outage percentages for coal units should be provided.

V. Chapter 6: Overview of Proposed Sites

Chapter 6 addresses the potential projects' impacts on the transmission systems and the costs of such impacts on the total costs of various projects (e.g. ERGS w/o IGCC versus "Calpine").

The direct connection costs to the "ATC grid" for ERGS by unit and the "Calpine" option (at least for the Fond du Lac unit) are already included in the DEIS. However, the costs that would be created for the ATC grid from ERGS or "Calpine" (the costs of necessary improvements to move the power over the ATC system to customers) are not known, albeit for different reasons (i.e. ERGS cost estimates are based on outmoded load additions assumptions which may effect the result of prior calculations and there is no "Calpine" information available on such "ATC grid" impact costs).

While these latter costs would be included in ATC tariffs, there seem to be two important questions which the FEIS must address: (1) what are the costs created by ERGS or "Calpine" that would be recovered in the ATC tariffs and/or (2) to what extent are these "but for" costs? (i.e. would be incurred at some point anyway to "reinforce" the T&D system in southeast

Wisconsin but are accelerated by either of these projects). If the above information is not available, it is difficult to see how the Commission can address the question about comparative impacts of different alternative projects on the basis of total costs as that issue is raised on page 78 of the DEIS.

The issue of comparative transmission costs requires further additional discussion in the FEIS. If there will not be comparative costs for the alternative projects, then additional discussion about whether these are primarily "but for" costs could be very important. (e.g. see pages 363-364). It is CUB's understanding that because of the way in which ATC models new interconnections that (in addition to assumptions about what new units will come on line earlier in the queue) at some point a new addition (not necessarily a large unit) may tip the balance in requiring a substantial upgrade in the existing area T&D infrastructure. This cost is in effect "socialized" into ATC tariffs because the area upgrade costs could be of a sufficient magnitude to deter even an appropriate plant addition if all such costs were imposed directly on the specific project.

It therefore would seem important to understand whether "ATC grid" cost impacts are the unique consequence of a specific plant being accommodated into the system or due to a plant's timing which happens to be the final incremental load addition that tips the balance as noted above. While the DEIS recognizes these distinctions, the FEIS should be much clearer as to which categories of "ATC grid" cost impacts the ERGS and the "Calpine" projects seem to be, if no such area cost impact estimates are available for each project. The FEIS should also discuss the potential implications for determining how to calculate total costs to allow potential projects such as ERGS w/o IGCC to be compared to other projects such as "Calpine".

VI. Chapter 7: Air Emissions

It would appear necessary and appropriate for the FEIS to calculate the background emissions set forth in Chapter 7 based on the recent agreement between Oak Creek and We-Energies (and potentially the proposed Consent Decree pending between We-Energies and the federal Department of Justice) and to draw appropriate observations about the potential impact of ERGS on air quality if such actions as contemplated in these agreements were made. While judgment will certainly be needed in doing this, the adoption of either the Oak Creek agreement or the proposed Consent Decree (or whatever resulted in such actions being taken) clearly will seem to effect the cumulative impact resulting from adding some or all of the proposed ERGS units.

VII. Chapter 8: Water Resources

The issue of once through cooling needs far more discussion than presented in the DEIS. There are several reasons: (1) there still is an issue whether We-Energies can legally use once through cooling at ERGS (DEIS at page 203) and (2) there is no discussion of the potential alternatives to assess whether there are better alternatives when all economic and non-economic factors are considered or because it is determined that once through cooling cannot be used under any circumstances. The answers to these questions would certainly seem to have meaningful impacts on the proposed ERGS project including but not limited to the overall cost of the proposed ERGS project and potential project alternatives.

VIII. Chapter 11: Community Impacts

On page 277, the DEIS notes that train traffic along the entire rail corridor could have community impacts at some distance from the actual plant site. However, it is hard to find a focused discussion of the potential impact of increased rail traffic on communities along the Union Pacific line including noise, vibration, traffic

and land development the further one gets from the ERGS site (e.g. in Racine County). These potential impacts require increased discussion in the FEIS. Such analysis (as well as for the entire rail corridor) must consider rail traffic both going to and coming from the ERGS site in its assessment of potential impacts.

Conclusion

The information and analysis on the issues noted above need to be improved and augmented for the FEIS if the purposes of a FEIS are to be satisfied. In making these comments, CUB recognizes the limitations on available resources and time that hindered Commission and DNR Staff in identifying and/or presenting a full presentation on the issues in the DEIS. CUB appreciates the effort that has gone into preparing the DEIS which we know will result in an even better FEIS.

Dated this 12th day of June, 2003.

Respectfully submitted,

_____

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cc. PTF Phase II service list

Comments on the Draft Environmental Impact Statement, submitted by the Clean Air Task Force

CLEAN AIR TASK FORCE

Reply to: 231 W. Main, Suite 1E Carbondale, IL 62901 (618) 457-0137 (618) 457-0513/fax
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June 12, 2003

Mr. Jeffery Kitsembel
Public Service Commission of Wisconsin
P.O. Box 7854
Madison, WI 53707-7854

Re: PSC docket number 05-CE-130, Comments on the Draft EIS

Dear Mr. Kitsembel:

The Clean Air Task Force is a national environmental organization that is headquartered in Boston and operates across the nation. Our mission is to maintain and restore healthy air. We accomplish this mission through research, advocacy and education. We have been a member of RESET since shortly after its founding.

We welcome the opportunity to comment on the Draft EIS (DEIS) for the of the Elm Road expansion. Because many of our concerns have been raised by other RESET member organizations in their DEIS comments, we will focus on only two issues. These issues are the failure of the DEIS to monetize the health damage associated with $PM_{2.5}$ and the failure of the DEIS to capture the full value of natural gas plants.

Monetizing $PM_{2.5}$ Health Damage

The DEIS makes only passing reference to the health damage associated with fine particles. These particles can be directly emitted by power plants, or they can form downwind of the stack as sulfur dioxide and nitrogen oxide are converted to sulfates and nitrates. The DEIS correctly links fine particles with health impacts such as premature deaths, asthma attacks, and other lung ailments. Scientists generally agree that the response to these pollutants is linear. Therefore, adverse impacts continue at ambient air concentrations that are below national air quality standards. The failure to quantify and monetize these impacts is a major shortcoming in DEIS.

There are several approaches that could be used to quantify the number of deaths and other health impacts associated with coal plant emissions. The approach most applicable to the Oak Creek expansion has been published in peer-reviewed articles by Harvard researchers Jon Levy and Jack Spengler.[1] In this approach, the PM

[1] See Levy, J. I., Spengler, J. D., et al. *Using CALPUFF to Evaluate the Impacts of Power Plant Emissions in Illinois: Model Sensitivity and Implications*. 36 Atmospheric

emissions of specific plants are modeled and a damage function is applied to estimate health endpoints such as premature deaths and asthma attacks. These impacts are monetized using standard EPA protocols. Abt Associates[2] and USEPA[3] used similar approaches to estimate impacts from larger groups of power plants.

Absent detailed modeling, the DEIS could apply a monetization approach used by the United Nations Development Programme[4]. In this approach, PM damage in the United States is estimated using data from the European Commission's ExternE Programme. The UN report identifies $5.3/MWH of PM damage associated with a conventional coal plants meeting BACT. For an IGCC plant, the damage is about $.53/MWH, and an NGCC plant has PM damage of $.37/MWH. Table 8.1 from the UN study that details these findings is attached to these comments.

The values from the UN study may need some adaptation for use in Wisconsin. First, these damage estimates are based upon the low economic valuations for European conditions. This choice places less value on human life and disease than is found in USEPA's valuation methodology. This very conservative choice may understate PM damage in $/MWH by a factor of three or more. Furthermore, BACT for conventional coal plants in the UN report assumed no SCR and a lower sulfur coal than is proposed at Elm Road. This has the effect of overstating the impact of nitrogen oxides and understating the impact of sulfur dioxide relative to Elm Road's SCPC units.

<u>The true economic value of natural gas plants is underestimated in the economic analysis found in the DEIS.</u>

Combined cycle natural gas plants, if properly designed and sited for the purpose, can later be converted to IGCC plants. This conversion might be desirable should the gap between natural gas prices and other fuels as coal or petroleum coke make this switch advantageous. This option has an economic value that is not captured by the DEIS. As a result, the DEIS undervalues natural gas plants. This may skew the EGEAS models away from building combined cycle natural gas plants and toward building SCPC units.

Environment 1063-1075 (2002). and Levy, J. I., Spengler, J.D., *Modeling the Benefits of Power Plant Emission Controls in Massachusetts,* v. 52, 5-18, J. Air & Waste Manage. Assoc., (2002).

[2] "Death, Disease and Dirty Power", available at http://www.catf.us/publications/index.php

[3] Clear Skies Act, Technical Support Package, September 2002, available at http://www.epa.gov/clearskies/technical.html

[4] "World Energy Assessment", United Nations Development Programme, Chapter 8, (September 2000) . This report is available on the web at http://www.undp.org/seed/eap/activities/wea/drafts-frame.html

This option value is no small matter. The problem with Power the Future is that it locks consumers into paying for capital-intensive coal plants. This is an irreversible decision. If WE Energies predictions about future regulations, gas prices, and construction costs are wrong, the cost of electricity under PTF will be much greater than the company predicts. Because a natural gas plant has the option value of using other fuels when converted to IGCC, consumer's financial risk due to changing conditions is reduced.

The DEIS needs to consider two changes: 1) Adding an option value to the natural gas plants that reflects their higher economic value, and/or 2) Modifying the inputs to the EGEAS modeling so that the model can build combined cycle gas plants and later convert them to IGCC plants.

A scenario with an "NGCC to IGCC" plant would likely have a higher NPV than a pure NGCC scenario or a pure IGCC scenario because the combination plant could generate revenue sooner than a pure IGCC plant and generate more revenue in later years than a pure NGCC plant. Furthermore, because the cost of conversion takes place in later years, the discounted costs for an "NGCC to IGCC" plant might be lower than a pure IGCC plant.

The key technical barriers to the conversion include:

- Using a site that has both rail access for coal and natural gas access.

- Designing from the beginning the natural gas plant so that the power block could later accommodate syngas. The cost of converting the turbine from natural gas to syngas is roughly $25/KW of installed capacity in today's dollars. The cost of expanding the HRSG is minor if enough space is reserved at the beginning to add additional cooling tubes.

The EGEAS modeling in the DEIS assumes availability of the IGCC plant of only 75%-85%. This availability assumption is too low for both the pure IGCC plant considered in DEIS and an "NGCC to IGCC" plant. The 75%-85% availability applies to today's IGCC plants that run on a single gasification train with no spare gasifier. This situation describes the Polk, Florida IGCC plant and the Wabash Plant in West Terre Haute, Indiana. WE Energies proposes a spare gasifier in their WDNR air permit. Gasification plants that have a spare gasifier (such as Eastman Chemicals acetic anhydride plant in Kingsport Tennessee) have availabilities of over 98%. The impact of the low availability assumption is to underestimate the NPV of both the pure IGCC plant and the "NGCC to IGCC" option. The DEIS did not consider the use of petroleum coke in the IGCC plant. Unlike SCPC units, IGCC plants can use this low cost fuel. The sensitivity analysis of the EGEAS modeling should examine the economic impact of this fuel.

Thank you in advance for your consideration. If you have questions or need clarifications, please contact me at (618) 457-0137 or jthompson@catf.us

Sincerely,

John Thompson
Advocacy Coordinator

TABLE 8.1. EMISSION RATES FOR AND ESTIMATED COSTS OF ENVIRONMENTAL DAMAGE FROM AIR POLLUTANT EMISSIONS OF FOSSIL FUEL POWER PLANT (LOW VALUATION FOR TYPICAL EUROPEAN CONDITIONS)

	Emission rate (grams per kilowatt-hour)			Low estimate of costs of environmental damages (dollars per thousand kilowatt-hours) a				Environmental damage costs relative to NGCC
Primary air pollutant	SO2	NOx	PM10	SO2	NOx	PM10	Total	Total
Average U.S. coal steam-electric plant, 1997	6.10b	3.47 b	0.16 c	15.9	13.9	0.7	30.5	82
New coal steam-electric plant with best available control technology d	0.46	0.87	0.15 c	1.2	3.5	0.6	5.3	14
Coal IGCC plant e	0.075	0.082	0.0025	0.2	0.33	0.01	0.54	1.5
NGCC plant f	—	0.092	—	—	0.37	—	0.37	1

a. Environmental damage costs from power plant air pollutant emissions are assumed to be 25 percent of the median estimates of Rabl and Spadaro (2000) for typical power plant sitings in Europe. (The Rabl and Spadaro calculations were carried out under the European Commission's ExternE Programme. Nearly all the estimated costs of environmental damages are associated with adverse health impacts; the economic values of health impacts were estimated on the basis of the principle of willingness to pay to avoid adverse health effects.) Rabl and Spadaro considered a wide range of pollutants, but the only significant damage costs were from SO2, NOx, and PM10, for which their median estimates of damage costs (in dollars per kilogram) were $10.44, $16.00, and $17.00. Damage costs at 25 percent of the median estimates of Rabl and Spadaro (equivalent to one standard deviation below the median) are assumed, to put a conservatism into the calculation to reflect the scientific uncertainty. b. Average emission rates in 1997 for U.S. coal plants, whose average efficiency was 33 percent (EIA, 1998b). c. In 1990 PM10 emissions from U.S. electric utility coal power plants amounted to 245,000 tonnes (Spengler and Wilson, 1996) when these plants consumed 17.1 exajoules of coal (EIA, 1998b), so the PM10 emission rate was 14.34 grams per gigajoule—the assumed emission rate for all steam-electric cases in this table. d. It is assumed that the new coal steam-electric plant is 35.5 percent efficient; that the coal contains 454 grams of sulphur per gigajoule (1.08 percent sulphur by weight), the average for U.S. coal power plants in 1997 (EIA, 1998b); that SO2 emissions are reduced 95 percent, a commercially feasible rate; and that the NOx emission rate is 86 grams per gigajoule—achievable with advanced low-NOx burners that will be commercially available shortly; e. It is assumed that the coal integrated gasifier combined cycle (IGCC) plant is 43.8 percent efficient, based on use of steam-cooled gas turbines (see table 8.4); that the emission rates equal the measured values for the Buggenum coal IGCC plant (Netherlands): 10.0 and 0.3 grams per gigajoule of coal for NOx and particulates, respectively, as well as 99 percent sulphur recovery (data presented by Co van Liere, KEMA, at the Gasification Technologies Conference in San Francisco, 17–20 October 1999); and that the coal contains 454 grams of sulphur per gigajoule. f. It is assumed that the natural gas combined cycle (NGCC) plant is 54.1 percent efficient, based on use of steam-cooled gas turbines (see table 8.4); and that the NOx emission rate is 9 parts per million on a dry volume basis (at 15 percent O2), corresponding to an emission rate of 0.092 grams per kilowatt-hour.

Comments on the Draft Environmental Impact Statement, submitted by Clean Wisconsin

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OF COUNSEL:
PETER E. McKEEVER

July 10, 2003

VIA EMAIL

Jeffrey Kitsembel
Public Service Commission
610 N. Whitney Way
Madison, WI 53705

Re: Application of Wisconsin Electric Power Company
Docket No. 05-CE-130

Dear Mr. Kitsembel:

Enclosed please find the Comments of Clean Wisconsin (f/k/a Wisconsin's Environmental Decade) on Draft Environmental Impact Statement in the above-referred-to matter.

By copy of this letter, a copy of the document has been delivered via email or U.S. Mail to all parties on the service list, as well as Michael Thompson of the DNR via email.

Thank you for your attention to this matter.

Sincerely,

GARVEY & STODDARD, S.C.

Pamela R. McGillivray

PRM:jf
Enclosure
cc: Service List

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Electric Power Company; Wisconsin Energy Corporation; and W.E. Power, LLC; for a Certificate of Public Convenience and Necessity	))))	**05-CE-130**

COMMENTS OF CLEAN WISCONSIN (F/K/A WISCONSIN'S ENVIRONMENTAL DECADE) ON DRAFT ENVIRONMENTAL IMPACT STATEMENT

INTRODUCTION

Clean Wisconsin (formerly Wisconsin's Environmental Decade ("WED") respectfully submits the following comments to the Draft Environmental Impact Statement ("DEIS") prepared jointly by the Public Service Commission staff ("PSC Staff") and the Department of Natural Resources staff ("DNR staff").

Clean Wisconsin has approximately 5200 members statewide and approximately 2500 members in the greater Milwaukee area. For more than 30 years, Clean Wisconsin (as WED) has been a leading environmental group in the state of Wisconsin in identifying and addressing the environmental and public health impacts of the electric utility industry.

Clean Wisconsin recognizes that both PSC and DNR staff are constrained by resources and time and have provided much helpful information for the public to understand We Energies' ("WE") Elm Road

Generating Station ("ERGS") proposal and alternatives to that proposal. Nonetheless, as is repeatedly recognized in the text of the DEIS itself, numerous issues have been left unanalyzed or unfinished in the draft that need to be provided in the Final Environmental Impact Statement ("FEIS").

STANDARD OF ANALYSIS

The PSC must base its decision whether to grant a CPCN for a project on an EIS that satisfies the requirements of the Wisconsin Environmental Policy Act, Wis. Stat. § 1.11 ("WEPA"). Pursuant to WEPA, the EIS must set forth a detailed statement that adheres to the guidelines (referring to 40 C.F.R. Part 1500 et. seq. [hereinafter "NEPA Guidelines"]) established under the National Environmental Policy Act, 42 USCA § 4331 et seq. ("NEPA"). Moreover, the PSC must follow its own rules establishing criteria for preparing an EIS for a large electric power generating facility. *See* Wis. Admin. Code § PSC 4.30. Wisconsin courts have held that federal law construing NEPA is persuasive authority in construing WEPA. *Wisconsin's Environmental Decade v. PSC*, 98 Wis.2d 682, 693, 298 N.W. 2d 205, 209 (Ct. App. 1980) (hereinafter "*WED IV*"); *see also Larsen v. Munz Corp.*, 167 Wis.2d 538, 482 N.W.2d 332, 342 (1992) (finding that courts may look to federal cases interpreting NEPA for guidance in interpreting Wis. Stat. § 1.11).

Under WEPA and NEPA, the EIS must "enable an agency to take a 'hard look' at the environmental consequences of its proposed action."

WED IV, 98 Wis.2d at 690, 298 N.W. 2d at 208. An EIS must "ensure that environmental information is available to public officials and decision-makers before decisions are made and before actions are taken. The information taken must be of high quality." 40 CFR § 1500.1. Therefore, pursuant to WEPA, the PSC's rules, and NEPA Guidelines, the EIS must contain adequate information to "evaluate reasonably foreseeable, significant effects to the human environment and significant socioeconomic effects of the proposal and its alternatives." Wis. Admin. Code § PSC 4.30(1)(b). The analysis must include an "evaluation of the positive and negative effects on the local and regional environments, including the proposed action's direct, indirect and cumulative effects." Wis. Admin. Code § PSC 4.30(3)(b)1. It must also provide an analysis of the mitigation techniques that will minimize impacts from the proposal. Wis. Admin Code § 4.30(3)(b)3.

The evaluation must be sufficiently detailed to allow the decision-maker to take a "hard look" at the environmental impacts on the local and regional level. The EIS prepared for this case failed to provide the requisite information to enable the PSC to take a hard look at the human and environmental impacts, particularly those created by emissions of pollutants from the proposed coal plants.

SUMMARY OF COMMENTS

Overall, Clean Wisconsin has concerns that the application from Wisconsin Energies ("WE") is a moving target. Throughout the DEIS,

there is language that suggests that the PSC and the DNR do not yet have the final information that the agencies need to assess the applications that have been filed with the respective agencies. It is Clean Wisconsin's position that an FEIS must be based on a complete proposal to meet the adequacy requirements of Wis. Stat. § 1.11 ("WEPA"). However, Clean Wisconsin is aware of the fact that staff is required to prepare the EIS within the expedited schedule set by statute once the Commission determines an application to be complete. Therefore, these comments based on the information provided in the DEIS are made without waiving Clean Wisconsin's completeness concerns.

CHAPTER 3: NEED

Demand forecast

p. 45: The DEIS states that "[t]he projections for future growth appear reasonable and are based on a growing economy. If the recent economic slowdown were to continue, the need for additional generation may not be forthcoming or simply delayed." Based on current trends, Clean Wisconsin urges Staff to provide analysis assuming that there is a continued economic slowdown into the planning period.

Energy Efficiency, Renewable Resources and IRP

p. 55: Clean Wisconsin supports the restatement of the Commission's duty under the Energy Priorities provisions[1] as stated on p. 55-56. However, to provide information from which the Commission may make its determination under the priorities law, the energy efficiency and renewable resources sections of the DEIS must be supplemented, and an integrated resources alternative must be added.

P. 58: PSC staff indicates the shortcomings of its energy efficiency potential analysis, namely changes in the energy efficiency market since the STEP study and Advance Plan 8 were completed. Moreover, PSC staff indicates that STEP did not adequately address industrial efficiency. Clean Wisconsin urges PSC staff to update this analysis and provide an up-to-date evaluation of efficiency measures available. As indicated by PSC staff, the efficiency review in the FEIS must ensure that the record contains a reasonable basis from which to judge available efficiency under the Energy Priorities law.

P. 59: Likewise, in analyzing the availability of wind capacity, the DEIS does not address off-shore wind development, indicating that such development would not be cost-effective. Yet, given the highest average

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[1] Wis. Stat. § 1.12(4): Priorities. In meeting energy demands, the policy of the state is that, to the extent cost-effective and technically feasible, options be considered based on the following priorities, in the order listed:
(a) Energy conservation and efficiency.
(b) Noncombustible renewable energy resources.
(c) Combustible renewable energy resources.
(d) Nonrenewable combustible energy resources, in the order listed:
1. Natural gas.
2. Oil or coal with a sulphur content of less than 1%.

wind speeds in the state are off-shore in Lake Michigan, and given the fact that wind power does not create air pollution, off-shore wind warrants further discussion. Moreover, the 20% credit to reserve margin for wind seems overly conservative. (DEIS, at 71.) Clean Wisconsin would suggest examining whether that number is conservative in practice.

Finally, Clean Wisconsin believes it is imperative that PSC staff develop an integrated resource approach as an alternative. As stated above, the Energy Priorities law requires the Commission to prioritize energy efficiency and renewables and then gas, and, only if none of those can cost effectively replace coal, then coal may be chosen. As staff explained the Commission's duty under the priorities, first the Commission must determine whether "energy efficiency exists to substitute for all or part of the energy demand" and, second, the Commission must determine what can provide the rest under the priorities. (DEIS, at 55.) To do this effectively, PSC staff must examine the correct mix of resources to meet the demand through an integrated planning alternative.

Staff's willingness to significantly rework these sections, and include an IRP alternative, is particularly critical given that Clean Wisconsin requested intervenor compensation to address DSM, renewable resources and integrated resource planning issues, but was

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3. All other carbon-based fuels.

denied funding by the Commission. During its open meeting, the Commissioners indicated that they were denying funding to Clean Wisconsin to review efficiency and renewables, in a large part, because the Commission felt that the PSC staff would adequately address these issues. Clean Wisconsin has been unable to retain an expert to address these issues, therefore, its members' interests are reliant on the work of the PSC staff.

EGEAS Summary

P. 78: The DEIS states: "[T]ransmission cost associated with the ERGS project are $266 million. . . . Comparative costs estimates for any necessary transmission system expansion elsewhere in the state to accommodate specific projects other than ERGS are not presently available." Clean Wisconsin urges Staff to provide comparison costs associated with interconnection to the proposed alternatives--optimal, Calpine, ERGS, and ERGS with no IGSS, as well as other proposed alternatives that may be proposed by other parties in their comments on the DEIS.

CHAPTER 7: AIR EMISSIONS

Generally, the air emissions chapter relies heavily on the information provided by WE in its air modeling permits. For example, on p. 146, the DEIS states that "[t]he air quality analysis information in the draft EIS is based on the air pollution control permit application information provide by WEPCO." Likewise, on p. 167, the DEIS

summarizes WE's air impact analysis under the PSD program and states that "[t]hese results remain to be confirmed by DNR analysis." Clean Wisconsin understands that there is a bit of a time problem in preparing the FEIS in that WE has not yet submitted complete permits applications to the DNR (DEIS, at 141), therefore, DNR staff have not been able to corroborate the results or independently analyze the inputs. The DEIS states that "it is expected that DNR's air modeling analysis will be mostly completed by the time of the final EIS is issued . . . . Testimony related to the completed analysis will be provided by the DNR at the time of the project hearings." (DEIS, at 133 (emphasis added).) Clean Wisconsin believes it is imperative that the FEIS is based upon the DNR's completed analysis for air modeling, rather than WE's. The lack of independent analysis is troubling considering that the DEIS concludes throughout that the SCPC and IGCC units would be in compliance with the various standards and impacts to the affected area are small. (See e.g., DEIS at 168-174.) It is certainly premature to make such conclusions before conducting independent analysis.

Comments of EH&E on behalf of Clean Wisconsin

Additionally, attached hereto are the comments to Chapter 7 prepared by Environmental Health and Engineering (EH&E) on behalf of Clean Wisconsin to be incorporated into these comments by reference. Please note that EH&E is preparing two damage function analyses that will yield estimates of external costs of the ERGS project and plans to

provide that data to PSC staff before intervenors' direct testimony is due so that PSC staff may incorporate those figures into its re-runs if they so choose.

Consent Decree

After the DEIS was issued in this case, on May 15, 2003, the consent decree between Wisconsin Energies and the Environmental Protection Agency was printed in the Federal Register, thereby allowing members of the public to comment on the proposed agreement before it is review by the district court. (See 68 Fed. Reg. 26354, May 15, 2003). Assuming that consent decree will be signed by the district court, Clean Wisconsin believes that the agreement should be taken into consideration in the FEIS. The consent decree allows WE options for limiting certain emissions within the next ten years. For example, by December 31, 2012, WE must take the following actions on units 5 and 6 at Oak Creek to reduce NO_x and SO_2: Install and operate appropriate emission controls <u>or</u> retire the units by December 31, 2012. Additionally, on units 7 and 8, WE must install FGD (flue gas desulfurization technology) by December 31, 2012. The FEIS should reflect the changes to dispatch assuming the close of those plants for each of the alternatives and should reflect the changes to dispatch if only modifications are made to the existing plants for each alternative (p. 73). In particular, Clean Wisconsin is interested in whether the addition of

the emission control options cited in the consent decree creates a net negative environmental impact (in terms of emissions).

Miscellaneous

p. 135: The DEIS states: "The goal of the second phase is to reduce emissions by over 2 million tons per year beginning in the year 2000. NOx emissions increased 9 percent between 1982 and 2001 and decreased 3 percent between 1992 and 2001." (Emphasis added.) Please verify that year and provide further description regarding the above statement.

p. 139: The proposed mercury rules are mentioned, it would be helpful to summarize those rules in the text.

p. 149: The DEIS states that "[i]t remains to be seen whether the [Compliance Assurance Monitoring ("CAM")] rule would apply to the SCPC units. WEPCO has indicated that it believes that the CAM rule would not apply to the IGCC unit . . . . The DNR is in the process of verifying this point." This information should be included in the FEIS.

p. 151: The DEIS states: "Currently, there are no regulatory requirements for individual projects such as the proposed ERGS to reduce or eliminate CO_2 emissions. At any rate, requirements to reduce emission from this facility may be counterproductive if those requirements restrict this facility's utilization, since this project would be more efficient than the existing coal-fired generation equipment that it would displace." (emphasis added.) Please explain this statement.

p. 163: Clean Wisconsin understands that new information on air modeling has been provided by the WE in April 2003 and on June 2, 2003 that alters the proposed stack height. The air quality impacts related to stack heights must be revised to reflect the actual proposal from WE regarding the North and South Sites. Moreover, the air modeling must reflect stack heights that are acceptable to the FAA. Clean Wisconsin predicts that air quality in the area will worsen with those reductions in stack heights.

p. 175: As stated in the chapter summary, the construction phase air impacts have not been assessed in the DEIS due to applicants' failure to provide that information. Clean Wisconsin urges the DNR to require that information from WE for the FEIS because of the substantial potential impact to quality from diesel equipment and air-borne dirt and dust associated with construction.

CONCLUSION

Clean Wisconsin and its experts at EH&E are available to answer any questions PSC or DNR staff may have about these comments so that they can be as efficiently as possible be addressed in the FEIS to ensure WEPA requirements are met.

Date: June 13, 2003.

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June 12, 2003

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RE: Comments on the Proposed Elm Road Generating Station Draft Environmental Impact Statement (EH&E 12808)

Dear Attorney McGillivray:

The purpose of this letter is to provide comments on the air quality impacts analysis contained in the Draft Environmental Impact Statement (DEIS) for the Elm Road Generating Station (ERGS). The Public Service Commission of Wisconsin and the Wisconsin Department of Natural Resources (DNR) prepared the DEIS based on the Wisconsin Electric Power Company (WEPCO) permit application for the ERGS. Environmental Health & Engineering, Inc. (EH&E) has reviewed the DEIS analysis with regard to impacts of projected air pollutant emissions from the ERGS.

The key limitations of the DEIS include: lack of any analysis of particulate matter less than 2.5 micrometers in aerodynamic diameter ($PM_{2.5}$), lack of consideration of secondary particulate information, omission of health impact estimates, and lack of consideration of uncertainty in the air modeling analysis. The limitations of the DEIS are described in detail in the sections that follow.

SUMMARY OF THE DRAFT ENVIRONMENTAL IMPACT STATEMENT

The National Environmental Policy Act of 1969 requires that federal agencies prepare detailed analyses of any of their actions that significantly affect the quality of the environment. Environmental impact statements are the result of this requirement. The DEIS for the ERGS summarizes the projected impacts that the ERGS will have on the state of Wisconsin. The DEIS

describes environmental impacts, as well as cultural and social implications of the proposed station expansion.

The DEIS is an analysis of the permit application for the plan proposed by WEPCO to construct three electric generating stations adjacent to the existing 1,150 megawatt (MW) Oak Creek Power Plant (OCPP). Two of these units will be 615 MW supercritical pulverized coal boilers and are scheduled to go into service in 2007 and 2009. The third unit will consist of one 600 MW integrated gasification combined cycle unit scheduled to begin service in 2011.

The DEIS provides a description of the project, alternatives, environmental impacts to natural resources, costs, and other aspects of the ERGS proposal. The DEIS also includes a summary of the air quality modeling results provided by WEPCO and their analysis of the capacity of the local air shed to absorb the impacts of the proposed expansion with respect to National Ambient Air Quality Standards (NAAQS) and State of Wisconsin standards for total suspended particulate matter (TSP), particulate matter less than 10 micrometers in aerodynamic diameter (PM_{10}), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), and lead (Pb).

The air quality modeling results provided by WEPCO (pages 164 – 170) for the cumulative effect of the ERGS south-side facilities and background emissions state that the 24-hour concentration of TSP would be 99.8% of the Wisconsin secondary air quality standard. SO_2 emissions projected for the ERGS plus background levels of SO_2 in ambient air are estimated to yield three-hour and 24-hour average concentrations equivalent to 93.1% and 86.8% of the NAAQS respectively. Most of the prevention of significant deterioration (PSD) increment for 24-hour concentrations of SO_2 and PM_{10}, at 85% and 98.7%, respectively would be consumed by emissions from the proposed ERGS.

The potential for noteworthy air quality impacts associated with the ERGS is indicated by a consent decree filed by the United States government on behalf of the U.S. Environmental Protection Agency (EPA) against WEPCO for injunctive relief and the assessment of civil penalties for alleged violations of the prevention of significant deterioration, new source review provisions, and the federally-enforceable state implementation plans developed by the states of Michigan and Wisconsin.

Through the consent decree, the plaintiff (U.S. Government) alleges that WEPCO "failed to obtain necessary permits and install the controls necessary under the Act to reduce its sulfur dioxide, nitrogen oxide and/or particulate matter (PM) emissions and that such emissions can damage human health and the environment." The consent decree references the proposed ERGS specifically in addition to other WEPCO generating stations.

LIMITATIONS OF THE DRAFT ENVIRONMENTAL IMPACT STATEMENT

The Wisconsin Department of Natural Resources and the Public Service Commission of Wisconsin have identified a number of factors within the DEIS that need further examination, such as the analyses of the air modeling. Their opinion, as stated in the DEIS, is that the WEPCO permit application remains to be completed and the subsequent Department of Natural Resources analyses remain to be completed before a preliminary permit judgment can be made. EH&E adopts the opinions of the DNR with respect to the limitations of the DEIS and also has identified further limitations of the DEIS as follows:

Incomplete Assessment of Potential Air Quality Impacts

The DEIS contains comparisons of projected concentrations of air pollutants emitted from the ERGS with federal and state standards on common pollutants of coal burning power plants. As indicated in the DEIS, hazardous substances emitted from coal-fired power plants include metals, organic compounds, acid gases, sulfur, nitrogen, carbon dioxide, and PM. State and federal regulations impose limits on emissions and concentrations of many of these pollutants in ambient air. On the federal level, NAAQS set limits for time-weighted average concentrations of six criteria pollutants: CO, NO_2, ozone, Pb, PM_{10}, $PM_{2.5}$, and SO_2. State air standards also regulate ambient air concentrations of these and other pollutants.

The DEIS describes that, even if a facility meets the existing standards, questions remain regarding the potential for health impacts to sensitive individuals, such as children and the elderly. To elaborate on that point, elderly individuals typically suffer from one or several of a variety of respiratory and cardiovascular conditions, including chronic obstructive pulmonary disease, emphysema, asthma,[1] and heart disease. Cytokine interferon gamma (IFN-y) is

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[1] Weiss KB, Gergen PJ, Wagener DK. 1993. Breathing better or wheezing worse—the changing epidemiology of asthma morbidity and mortality. *Annual Review of Public Health* 14:491-513.

essential in defending against viruses and intracellular pathogens.[2] The decreased production of IFN-y that comes with age combined with respiratory and cardiovascular conditions may make the elderly particularly susceptible to environmental pollutants.[3] The EPA estimates that 4.8 million children under the age of 18 have asthma and that children have a special vulnerability to certain toxic substances, such as Pb.

The increase in air pollution levels may cause adverse impacts to respiratory symptoms of these sensitive individuals. Further studies examine health conditions or symptoms associated with sensitive populations and symptoms associated with PM_{10}, $PM_{2.5}$, NO_2, and SO_2. Comprehensive analyses of the potential for adverse effects of the proposed ERGS is not included in the DEIS. Inputs on how impact and toxicity information on pollutants from the Wisconsin emissions reporting data were determined.

Model Uncertainty

The DEIS does not appear to consider uncertainty associated with air dispersion modeling with respect to the potential for air pollutant emissions from the ERGS to exceed relevant air quality guidelines or standards. WEPCO used the Industrial Source Complex Short-Term 3 (ISCST3) model to evaluate air quality impacts of the ERGS. Air pollutant concentrations predicted using ISCST3 are typically considered to be accurate to within a factor of two (i.e., plus or minus 100%). Model uncertainty alone is sufficient to lead to exceedances of PM_{10} for the PSD increment. The lack of consideration of model uncertainty and the potential for conclusions of the DEIS to be altered is a significant limitation to the analysis.

Ambient Air Quality Data

The air quality data for Milwaukee and Racine counties was provided by WEPCO and presented in summary form in the DEIS. The source and accuracy of the data is critical for the completeness and accuracy of the proposed expansion analysis and its impacts on the PSD increment and attainment of NAAQS standards. Evaluation of NAAQS requires measurement and calculation of time-weighted average air pollutant concentrations in accordance with strict

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2 Ouyang Q, Cicek G, Westendorp RGJ, Cools HJM, Van Der Klis RJ, Remarque EJ (Reprint). 2000. Reduced ifn-gamma production in elderly people following in vitro stimulation with influenza vaccine and endotoxin. *Mechanisms of Ageing and Development* 121(1-3):131-7.

3 Ouyang, et al. 2000.

protocols promulgated by the EPA.[4] The DEIS does contain sufficient information for a reviewer to determine the extent to which the summary data presented are valid or appropriate for evaluation of the potential for compliance with the NAAQS. The Final Environmental Impact Statement should include an explicit description of the sources and analysis process used to generate the ambient air quality data presented in the DEIS.

Hazardous Air Pollutants

There are no risk assessments contained in the DEIS for mercury or other hazardous air pollutants (HAPs). Given the potential for HAPs to adversely impact human and ecological health, the possibility of effects from these pollutants should be considered as a part of the environmental impacts of the ERGS. According to the EPA, mercury emissions from coal-fired utility boilers account for approximately one-third of all anthropogenic emissions, the single largest anthropogenic source of mercury emissions to air.[5]

Arsenic is also emitted from coal-fired electric utility boilers. The EPA analyzed arsenic emissions from a set of hypothetical coal-fired electric generating stations and concluded that excess lifetime cancer risks could be as high as 1 in 10,000 for a pica child and 1 in 100,000 for a subsistence farmer residing near the facility.[6]

This comment letter is by no means an exhaustive summary of HAPs emitted from coal-fired power plants. The EPA reports footnoted above can provide the DNR and PSC with detailed guidance on approaches for evaluating the potential for negative health effects emitted from the ERGS and OCPP.

$PM_{2.5}$

Health evidence indicates that $PM_{2.5}$ is the fraction causally associated with adverse health effects. According to the EPA, exposure to PM can result in aggravation of respiratory conditions such as asthma, decreased lung function, increased hospital emissions, increased

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4 See for example, Federal Register 40 CFR Part 50 National Ambient Air Quality Standards for Particulate Matter, Final Rule, Vol. 62, No. 138, July 18, 1997

5 EPA 1997. Mercury Report to Congress. p. 3-5.

6 EPA 1998. *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Final Report to Congress, Volume 1*. EPA-453/R-98-004a.

respiratory symptoms and diseases, and in some instances, death.[7] Most epidemiological evidence points to $PM_{2.5}$ as a stronger causal agent for mortality and morbidity than gaseous SO_2 or NO_X.[8]

Primary PM is composed of two components: filterable PM and condensable PM. Filterable PM includes particles directly emitted by a source as a solid or liquid at stack or release conditions and captured on the filter of a stack test train. Condensable PM is material that is in vapor phase at stack conditions, but which condenses and/or reacts upon cooling and dilution in the ambient air to form solid or liquid PM immediately after discharge from the stack. The EPA typically assumes that all condensable PM is in the $PM_{2.5}$ size fraction.[9]

EH&E has obtained $PM_{2.5}$ monitoring data for 1998 – 2002 in the state of Wisconsin. Three-year annual average $PM_{2.5}$ concentrations in portions of Southeast Wisconsin are approximately 13.5 micrograms per cubic meter ($\mu g/m^3$) and range as high as 14.1 $\mu g/m^3$. According to emission factors published by the EPA, $PM_{2.5}$ accounts for approximately 90% of the PM emissions from coal-fired electric utilities. Thus, $PM_{2.5}$ emissions to the Southeast Wisconsin airshed from the ERGS may contribute to exceedances of the 15 $\mu g/m^3$ NAAQS for annual $PM_{2.5}$ levels. Given this potential, the Final Environmental Impact Statement for the ERGS should include a comprehensive analysis of background $PM_{2.5}$ concentrations and contributions from the ERGS.

Formation of Secondary PM: Secondary PM generally dominates the PM impacts from power plants and contributes to a large fraction of ambient PM in many locations. Nitrate, sulfate, and ammonium are often a majority of ambient $PM_{2.5}$. Secondary PM formed by SO_2 and NO_X was not included in the analysis.

Air quality models such as the ISCST3 by WEPCO and described in the DEIS do not address secondary PM. The omission of secondary PM can and should be addressed by the DNR and

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7 U.S. Environmental Protection Agency Office of Air and Radiation. *Explanation of Data Handling Requirements and Forms of the National Ambient Air Quality Standards for Particulate Matter.* Available on-line at: www.epa.gov/ttn/oarpg/naaqsfin.

8 Levy JI, Spengler JD, Hlinka D, Sullivan D, Moon D. 2002. Using CALPUFF to evaluate the impacts of power plant emissions in Ilinois: model sensitivity and implications. *Atmospheric Environment* 36:1063-1075.

9 EPA. 1998. *Compilation of Air Pollutant Emission Factors*, AP-42, Fifth Edition, Volume 1. Stationary Point and Area Sources. Available on-line at http://www.epa.gov/ttn/chief/ap42/index.html.

PSC using more sophisticated models such as the CALPUFF model and the associated atmospheric chemistry and post processing routines. The CALPUFF model is available from the EPA Support Center for Regulatory Air Modeling web site. Approaches to applying CALPUFF for modeling secondary formation of PM are described in the scientific literature, for example, Levy, et al. 2002.[10]

Incidence and Cost of Human Health Impacts: The analysis in the DEIS does not include estimates of the incidence or costs of adverse human health effects potentially arising from the proposed ERGS. Appropriate methodologies exist to conduct both epidemiological and quantitative risk assessments of potential mortality and morbidity associated with emissions from the ERGS. Levy et al. (1999) described a damage function model for power plants that has been used to evaluate negative externalities associated with emissions of PM and other pollutants from electric generating stations.[11] At a minimum, the ERGS Final Environmental Impacts Statement should note that analyses such as these are possible to conduct, but have been omitted.

If you have any questions regarding the limitations in the DEIS identified in this letter, please feel free to contact either of us at 1-800-TALK EHE (1-800-825-5343).

Sincerely,

Jennifer L. Somers, M.P.Aff.
Associate/Project Manager

David L. MacIntosh, Sc.D.
Senior Associate/Project Director

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10 Levy, et al. 2002.

11 Levy JI, Hammitt JK, Yanagisawa Y, Spengler, JD. 1999. Development of a new damage function model for power plants: methodology and applications. *Environmental Science and Technology* 33:4364-4372.

Comments on the Draft Environmental Impact Statement, submitted by the Gasification Technologies Council

05-CE-130

Gasification Technologies Council

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June 11, 2003

Jeffrey Kitsembel
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Reference: PSC Docket Number 05-CE-130

Dear Mr. Kitsembel:

The Gasification Technologies Council (GTC) is comprised of companies that provide technologies, equipment and services, or own and operate plants that account for more than ninety-five percent of the gasification and Integrated Gasification Combined Cycle (IGCC) capacity worldwide. The GTC was formed to promote the widespread use of gasification to utilize coal, petroleum coke, and heavy oils in an environmentally superior manner for the production of power, clean fuels and chemicals. The GTC does this by identifying the major issues affecting the use of gasification technologies, disseminating the opinions and positions of its members, collecting and analyzing information and data concerning gasification, and conducting educational activities concerning gasification technologies. A list of the GTC's membership is attached.

The GTC members have reviewed the subject draft environmental impact statement (DEIS), "Elm Road Generating Station", April 2003 and wish to provide comments on certain parts related to the proposed IGCC unit. Specifically, the GTC members feel strongly - based on their in-depth and first-hand expertise - that the DEIS does not accurately reflect either the current or future state of gasification/IGCC technology. The GTC takes particular exception to the conclusion in the DEIS that: "The IGCC unit, which is the third unit in the ERGS proposal, is not cost-effective under any scenario" (DEIS Executive Summary, page xxvii). The GTC offers these comments with the hope that the final EIS will contain a more thorough analysis and accurate conclusions with respect to the proposed IGCC unit.

Capital Cost and Performance

*Cover only
*MFC
*C018
*ALJ
*OGC12
Elec - CD to Jeff

A number of examples of IGCC cost and performance data from various sources are contained in the public domain reports and technical papers which are submitted with these comments. The cost data in the attachments are lower than the cost estimates in the DEIS and more accurately reflect current conditions and experience in the gasification industry. The same holds true for the performance data in these reports, which is more current that that used as the basis for the DEIS. During the 2011 time frame of the plant

described in the DEIS these costs are expected to be even lower and efficiencies are expected to be even higher.

It is the understanding of the GTC that WEPCO has not yet picked a supplier of gasification technology and that the application for the proposed IGCC unit may have been based on an out-of-date and/or overly conservative generic design. As such, there is considerable potential to reduce the capital costs from those published in the DEIS. Also, it is very likely that a final, optimized design would have a significantly better energy efficiency than what was used in the original application. The IGCC cost and performance figures in the Final EIS should be adjusted to reflect this.

Operating Cost and Flexibility

The DEIS describes Pittsburgh #8 as being the design coal. While gasification can certainly use this feedstock, the technology has the flexibility also to produce synthesis gas cleanly and efficiently from lower cost coals and carbon-based feedstocks such as petroleum coke or materials that would otherwise be disposed as waste. Again, the attached documents provide information and examples of gasification/IGCC's feedstock flexibility and how it can reduce operating costs. The Final EIS should recognize this and address it in the economic assessment of IGCC.

Plant Availability

The DEIS portrays IGCC's availability as being less than that of PC-boilers. In fact, an IGCC plant of the size described in the DEIS should be able to achieve comparable availability to that of a PC-boiler by either (a) running the combined cycle unit on backup fuel (natural gas or distillate oil) at times when syngas is not available, or (b) by employing multiple gasifiers, including a spare gasifier (an approach which Eastman Chemical uses to achieve 98-99% syngas availability as described in the attached Eastman presentation). In fact, by doing either (a) or (b), a 2011 IGCC should achieve availability that is at least comparable to PC-boilers. Again, the attached documents provide information and examples of IGCC's availability. The Final EIS should recognize this and evaluate IGCC's economics using at least the same availability assumption as for PC-boilers, if not a higher availability assumption.

With consideration of these more up to date and accurate input assumptions for IGCC's capital cost, efficiency, operating cost and availability, the GTC feels an IGCC unit will prove to be cost-effective under a number of the Final EIS scenarios.

Environmental Performance

The data tables in the DEIS appear to accurately quantify superior environmental performance of the IGCC unit compared to the super critical pulverized coal (SCPC) units. However the prose in the DEIS makes no recognition of this superior performance. It merely notes that IGCC meets New Source Performance Standards, rather than that it far surpasses those standards. Likewise, there is no economic benefit given for this

superior environmental performance; whereas the GTC feels that a fair comparison would (a) recognize in the prose of the EIS that IGCC provides superior environmental performance and (b) include in the IGCC economics discussion an appropriate credit for this performance. As air emissions standards become more strict, the environmental performance of IGCC will take on added economic benefits because the technology can achieve greater emissions reductions at lower cost than other coal-based technologies. This should be reflected in the Final EIS.

In addition, the DEIS incorrectly implies that IGCC causes potential environmental problems by removing sulfur from the syngas prior to combustion. It refers to the solid sulfur or sulfuric acid products as potential hazardous waste. They are, in fact, saleable products, as has been demonstrated many times over at existing gasification facilities.

Scale Up

The DEIS says "IGCC cost estimates are less certain because IGCC plants in the 500+ MW range have not yet been built anywhere in the world" (Executive Summary, page xx). This is true of coal IGCC, but not heavy oil IGCC. Also, the proposed 500+ MW designs are multiple train units and the individual trains are consistent with what is currently built for coal, so scale up is not as significant an issue as the DEIS implies.

The fact that IGCC units are cost effective is proven by the commercial success of the two plants currently running in the U.S. in Indiana and Florida. Along with the fact that few coal fired plants of any type have been built in the US in recent years, there may be a particular hesitation in the electric utility industry to build the next generation of IGCC units. It should be noted, though that such hesitation has not been the case for other industries (like chemicals and refining) who have enthusiastically embraced gasification and IGCC. The attached documents describe this in detail, in particular the many refinery IGCC's (based on pet coke or refinery bottoms as feed) which have been built or are being built today.

The GTC feels that once additional new coal based IGCC units are being built and shown to be commercially successful and environmentally superior, the standard for coal-based electric generating plant will be IGCC. All of the benefits of clean, coal-based electric generation will be realized. Any future requirements for CO_2 capture/sequestration and movement to a hydrogen economy will also be supported by the capabilities of gasification technology.

As previously mentioned, to provide up-to-date information on gasification technologies, recently published papers, reports and conference presentations from the U.S. Department of Energy and GTC members are enclosed. These provide a basis for the contention that IGCC technology is already competitive and will become more so in the future.

GTC and its member companies would be pleased to discuss or amplify on any of these matters with the Wisconsin Public Service Commission or Department of Natural Resources.

Sincerely,

James M. Childress
Executive Director

Attachments (all forwarded in both paper and electronic versions)

GTC Membership List

Clean Coal Technology Evaluation Guide (Executive Summary), U.S. Department of Energy, December 1999

Major Environment Aspects of Gasification-Based Power Generation Technologies, U.S. Department of Energy, December 2002

Clean Coal Technology Options – A Comparison of IGCC vs. Pulverized Coal Boilers, O'Keefe & Sturm, ChevronTexaco Worldwide Power and Gasification, October 2002

Comparative IGCC Cost and Performance for Domestic Coals, P. Amick, D. Breton, Global Energy, October 28, 2002

Eastman Gasification Services, Gasification Overview Presentation, D. Denton, Eastman Chemical Company, June 6, 2003

IGCC Gas Turbines for Refinery Applications, R. Jones, N. Shilling GE Power Systems, May 2003

IGCC – Leadership in Clean Power from Solid Fuels, R. Jones, N. Shilling, GE Power Systems, November 2002

Members of Gasification Technologies Council

Air Liquide America*
Air Products and Chemicals, Inc.*
Aramco Services Company*
Bechtel Corporation*
BOC Gases*
ChevronTexaco*
The Dow Chemical Company*
Eastman Chemical Company
Emery Energy Company
Fluor Corporation*
Foster Wheeler Energy International Inc.*
General Electric Company*
Global Energy, Inc.*
Kentucky Center for Applied Energy Research
Linde AG
MG Lurgi Engineering
MITRETEK Systems, Inc.
Parsons Energy & Chemicals Group Inc.*
Praxair, Inc.*
Sasol Technology
Shell Global Solutions B.V.*
Siemens Westinghouse Power Corporation*
Snamprogetti S.p.A.
Tennessee Valley Authority*
Uhde*
UOP
Waste Management & Processors, Inc.*
We Power*

*Member of the Board of Directors

Comments on the Draft Environmental Impact Statement, submitted by the Lake Michigan Federation

LAKE MICHIGAN FEDERATION

June 13, 2003

Jefferey Kitsembel
Public Service Commission
P.O. Box 7854
Madison, WI 53707-7854

Dear Mr. Kitsembel:

The Lake Michigan Federation ("Federation") welcomes the opportunity to submit these comments on the Draft Environmental Impact Statement (DEIS) for the proposed Elm Road Generating Station. The Federation is the oldest citizens' group dedicated to protecting the health and beauty of Lake Michigan through a combination of law, policy, education, research and economics. We have serious concerns about the impacts of this proposal on Lake Michigan, and the failure of the document to describe them in adequate detail. The document it is so grossly deficient that a *revised draft EIS* should be released prior to completion of the final EIS. It is a well known fact that once a selected alternative is presented in the final EIS, it is very difficult for the public to effectuate reevaluation of the selected alternative or otherwise make changes in the plan.

Cooling Water Intake Structure

The portion of the DEIS that addresses the cooling water intake structure is seriously deficient because it lacks basic data necessary for the public to effectively review the decisions of state and federal agencies. Cooling water intake structures have direct impacts on the lake both because of the thermal discharge associated with them and because of the potential impingement and entrainment of adult, juvenile and larval fish, and fish eggs. The DEIS fails to address either of these in sufficient detail, to such an extent that it appears the DEIS was issued prematurely. We will address each of our concerns in more detail below.

<u>The Section 316(b) Determination is Contrary to the Weight of the Evidence.</u>

Section 316(b) of the Clean Water Act (CWA) states that, "the location, design, construction and capacity of cooling water intake structures [shall] reflect the best available technology for minimizing adverse environmental impacts." The level of technology that will be required under the regulations is dependent upon whether the facility is considered a "new" or "existing" structure. According to Appendix C of the

DEIS, the Wisconsin Department of Natural Resources (WDNR) has determined the facility should be considered an "existing" facility and therefore subject to less stringent technology requirements. This decision appears contrary to the overwhelming weight of the evidence which suggests that the facility should be considered a "new facility," especially when compared to the criteria set forth under the applicable federal regulations.

It appears that the facility which is the subject of the DEIS should be considered a "new" facility because the weight of the evidence suggests it is a "substantially independent" and separate facility. According to U.S. EPA, "in those situations where there is new construction but less than total replacement of an existing facility, the classification decision should be based on the degree to which the constructed facility functions independently of the existing source." (55 Fed. Reg. 40501). In other words, the relevant question that should be asked is, "to what extent is the new facility integrated with the old?" According to WDNR, the new units will only share a few facilities with the existing older units, including the cooling water intake structure, the electrical switchyard and the coal delivery system. Arguably the intake structure is the most significant, but, according to official comments issued by the U.S. EPA in conjunction with NPDES regulations, "if the only connection between the new and old facility is that they are supplied with steam, electricity or cooling water from the same source.... then the new facility will be a new source." (53 Fed Reg. 40601) Therefore, the fact that an existing facility may share cooling water intakes with a new facility is not a sufficient basis on which to determine a facility should be considered "existing.". Additional factors also weigh in favor of finding that this proposed facility represents a significant enough addition to warrant being considered a "new" and independent facility. The footprint created as a result of the new construction will be substantially larger than the current facility footprint. In fact, all three proposed units will be built on virgin or "greenfield" territory. The new capacity will represent an additional 150% of capacity and the amount of cooling water utilized will increase by more than 100%. Even the ownership of the facility is different. All of these factors together suggest that in fact this facility is an entirely separate and independent entity. When compared to the numerous and significant other factors establishing the separateness of this facility, the "shared" facilities between the old and proposed new units would be insignificant by comparison.

<u>The Specific Intake Design Should Be Fully Described in the DEIS.</u>

Regardless of whether the facility is considered a "new" facility or an "existing facility", the current intake design does not rise to the level of the "best available technology." Rather than velocity caps, the facility should be required to implement a number of additional mitigating measures to meet this standard. First, and foremost, they should install wedge wire screens to exclude fish eggs and adult, juvenile and larval fish from being drawn in (or willfully swimming into) the intake system, and appropriate mesh size of the screening must be taken into consideration. Additional mitigation measures would include, but are not limited to, a low intake velocity of about .5 feet per second. The last open cycle power plant constructed on the Great Lakes was the Campbell Plant built in Michigan in 1981. Even at that time, over twenty years ago, the consensus was that

wedge wire screens, not velocity caps, should be and were installed to prevent fish impingement and entrainment.

The DEIS's Proposed Intake Design Will Result In Substantial Fish Impingement and Entrainment Rates.

The DEIS gives no consideration to the impacts on local pollutions of fisheries, including yellow perch which would potentially be the most impacted fish population. The DEIS suggests, without supporting evidence, that by extending the intake crib further out into Lake Michigan, fish populations will not be impacted. This is not a credible conclusion, and is in fact refuted by several recent reports. According to a recently produced study by Wisconsin Electric Power Company (WEPCO), the abundance of yellow perch larva is just as high at the proposed 40 foot depth contour as it is at a near shore location. ("Oak Creek Power Plant and Proposed Elm Road Station Cooling water Intake and Lake Monitoring Study," prepared for WE Energies by EA Engineering, Science and Technology, February 2003). In addition, Wisconsin yellow perch populations are particularly vulnerable to impacts from this facility. According to a report produced last year by the Lake Michigan Technical Committee, Wisconsin yellow perch levels are currently at significantly low levels, only 3% of 1980 levels. ("Status of Yellow Perch in Lake Michigan and Yellow Perch Task Group Progress Report", Report of the Lake Michigan Technical Committee) At a minimum, the DEIS should cite to these and other relevant studies of impacts to Great Lakes fish populations, to give the reviewer some sense of the potential this facility might have.

It appears that the practical result of the DNR's decision to adopt an open cycle design, with technology that does not qualify as BTA, will be significantly high fish mortality rates. According to a study undertaken from July 1991 to July 1993 at the Zion Nuclear Power Plant in Zion, Illinois, about 30 miles south of the proposed facility, mortality rates for yellow perch at a power plant with roughly half the volume of this proposed facility would be 40%. ("Impingement and Entrainment Study at Zion Nuclear Generating Station, July 1991-July 1993, produced by Lawler, Matusky and Skelly Engineers for Commonwealth Edison). Doubling that figure to reach the same level of volume as the proposed facility results in an estimated mortality rate of nearly 80%. The DEIS must be redrafted to at least make some projected estimates of fish mortality rates.

The DNR's Decision On the Intake Design Has the Potential to Create Cumulative Impacts around the Great Lakes

The weakness of this section is particularly troublesome because of the potential regional impacts that this single decision may ultimately have on Lake Michigan and its aquatic life. If this facility is built as an open cycle facility it will constitute the single largest intake of lake water on Lake Michigan. Further underscoring the significance of the decision is the fact that this facility would represent the first open cycle design for a power plant on the Great Lakes to be constructed in over twenty years. Open cycle designs are significantly cheaper to construct than close cycles because they do not require the construction of cooling towers like closed cycle. Open cycle designs are also illegal in Indiana and Illinois. If the Public Service Commission permits this facility as

an open cycle design it will open the door to a potentially massive expansion of power plants around the Great Lakes without regard to impacts on fisheries.

Impacts from Thermal Pollution are Inadequately Addressed.

Finally, the DEIS fails to even address the issue of thermal pollution. There is no apparent indication that the applicants are going to comply with water quality standards, and there has been no attempt to identify a mixing zone, for instance. This complete lack of analysis is contrary to federal requirements. The decision of the Wisconsin State Supreme Court issued in 1970, which, among other things, found thermal limits to be unconstitutional, rested its conclusion on the outdated determination that state regulations cannot be more restrictive than federal regulations; this finding is clearly contrary to the current federal regulatory scheme. According to federal regulations for "establishing limitations, standards, and other permit conditions applicable to state NPDES programs," a facility cannot obtain a National Pollution Discharge Elimination System (NPDES) permit without complying with applicable water quality standards." (40 C.F.R. 122.44(d)(1)) Therefore, at a minimum, the WDNR needs to develop a thermal standard that will be applicable to this facility, through the WPDES program. This standard should be discussed in the EIS. The public should not have to depend on interacting in the WPDES system to get a chance to review the proposed thermal standards.

Water Withdrawal

Coal burning power plants of this magnitude could cause large quantities of water to evaporate through cooling, and be lost to the Great Lakes system. In fact, the DEIS states that slightly more than 3 mgd of Lake Michigan water will be consumed as a cumulative total of the new and existing units. This is a fairly substantial net loss of a limited resource. The state of Wisconsin, which is participating in efforts to develop standards to protect the Great Lakes against such consumptive loss, must ensure that this project is not rushed through before it can be evaluated against such standards.

Mercury & Scrubber Sludge Reusal

The DEIS states that the scrubber sludge will be recycled and incorporated into wallboard which will be manufactured on site. This proposal is troubling for two reasons. First, it appears that there will be no requirement to test the sludge for mercury. Why not? Second, how will the mercury be prevented from leaching out of the wallboard? Neither of these very significant issues are discussed in the DEIS.

* * *

The Lake Michigan Federation submits these comments on behalf of its many members that love and enjoy the lake. These comments were submitted in consultation with Jim Fossum, a former fisheries biologist at the United States Fish and Wildlife Service, with an expertise in the impacts of hydroelectric power on fish populations. Should you have any additional questions please do not hesitate to contact me at 312-939-0838, ex. 3 or losullivan@lakemichigan.org

Sincerely,

Laurel O'Sullivan
Staff Counsel

Comments on the Draft Environmental Impact Statement, submitted by the city of Oak Creek

Oak Creek

CITY
ADMINISTRATOR

June 10, 2003

Mr. Jeff Kitsembel
Case Coordinator
Public Service Commission of Wisconsin
P.O. Box 7854
Madison, WI 53707-7854

Subject: Response to Draft Environmental Impact Statement
Elm Road Generating Station (Docket No. 05-CE-130)

Dear Mr. Kitsembel:

On behalf of the City of Oak Creek, RMT has reviewed the April 2003 Draft Environmental Impact Statement (DEIS) prepared by the Public Service Commission staff for the Wisconsin Energy Corporation's (WEC) Certificate of Public Convenience and Necessity (CPCN) application for construction of three large electric generating facilities to be located within, and adjacent to, the City of Oak Creek (PSC Docket No. 05-CE-130, the "Elm Road Project").

Your staff and the Department of Natural Resources (DNR) staff should be commended for digesting and clearly presenting the details of such a complex development.

Our comments to that document are attached in a separate document. They include input provided by Kamperman and Associates on noise issues, and Christensen Associates on financial issues. In general, our comments focus on the issues in common with the Conditional Use Permit (CUP) approved by the Oak Creek Common Council on June 3, 2003 (attached) and the Development Agreement signed by the City and WEC on April 3, 2003. Other issues are also presented for your consideration.

The City requests that the PSC consider each of the items outlined above for consideration in preparation of the final EIS. Ultimately, the City wants the CUP and April 3, 2003 Development Agreement with WEC included in the CPCN as conditions, if the Oak Creek site is selected for development.

Sincerely,

Robert L. Kufrin
City Administrator

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File Name: d:\files\powerplant\2003_06\comments to psc on deis.doc
Printed: 06/10/03 8:35 AM
Created: 06/09/03 8:04 PM
Revision Number: 7

BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Application of Wisconsin Electric Power Company; Wisconsin Energy Corporation; and W.E. Power, LLC; for a Certificate of Public Convenience and Necessity for Construction of Three Large Electric Generation Facilities, the Elm Road Generating Station, and Associated High Voltage Transmission Interconnection Facilities to be Located in Milwaukee and Racine Counties	05-CE-130

COMMENTS OF CITY OF OAK CREEK ON DRAFT ENVIRONMENTAL IMPACT STATEMENT ON ELM ROAD GENERATING STATION

The City of Oak Creek, Wisconsin is the community in which We Energies' (a subsidiary of Wisconsin Energy Corporation (WEC)) existing 1,100 megawatt (MW) Oak Creek Power Plant (OCPP) is located and in which it is proposed that the new facility, the Elm Road Generating Station (ERGS) would be constructed. The ERGS would consist of two super-critical pulverized coal (SCPC) units and one integrated gasification combined-cycle (IGCC) unit.

The City of Oak Creek (City) has about 30,000 residents. It is located in southeastern Milwaukee County on Lake Michigan. In addition to the existing OCPP, the City includes large residential areas and retail, commercial and other industrial facilities.

The City, after extensive negotiations, entered into an Agreement dated April 3, 2003 with WEC. A copy of the Agreement has been submitted and received by the Commission as part of the CPCN application process. In addition, WEC has applied for rezoning of a portion of the Oak Creek property and a Conditional Use Permit (CUP). After meetings and negotiations with WEC's and City's representatives, a meeting with the Plan Commission and public meetings to elicit public concerns and comments, the rezoning and a CUP were unanimously

approved by the Plan Commission on May 13, 2003 and unanimously approved by the City Council on June 3, 2003. A copy of the Agreement and the ordinances approving the rezoning and CUP are attached.

The City's comments relate primarily to air emissions (including total emission limitation standards, enforcement mechanisms, air monitoring and reporting requirements), environmental and economic impacts (caused by the construction and operation of the proposed ERGS and community mitigation payments to partially offset or reduce these impacts), other community impacts (including inter alia plan approvals, grading, fire protection, security, emergency medical services, noise, traffic and other matters covered by the City's CUP), and technical concerns.

I. AIR EMISSIONS

A. General Comments on the Air Quality Impact Analysis

The Air Quality Impact Analysis is based upon the overly conservative methods used to account for (or in effect double count) existing background concentrations and for the total lack of consideration of We Energies Multi-Plant Environmental Cooperative Agreement, the conditions in the City's April 3, 2003 Agreement with WEC, and the proposed EPA Consent Decree. The air quality impact analysis in the Draft Environmental Impact Statement (DEIS) fails to quantify the potential for significant improvements in air quality in southeast Wisconsin that may result from the proposed project and the above related initiatives, particularly if the new units are approved and dispatched ahead of the existing units.

B. Impact of Agreements

On September 30, 2002, We Energies and the DNR signed a Multi-Plant Environmental Cooperative Agreement, tied to other approvals for this project, that would require We Energies to make system-wide emission reductions at its then-existing coal fired plants of over 50 percent.

Then, on March 31, 2003, the Oak Creek Common Council approved an Agreement with WEC, which was fully executed on April 3, 2003, that will limit total emissions from the combination of new and existing generating units to calendar year 2000 levels (38,400 tons per year) beginning immediately for the following selected air pollutants: sulfur dioxide, nitrogen oxides, particulate matter, mercury, volatile organic compounds, hydrogen fluoride, hydrogen chloride, and sulfuric acid mist. This list represents the air pollutants of primary concern with respect to potential health impacts. Finally, in its proposed Consent Decree with We Energies (April 29, 2003), the EPA has included this same provision, only starting at a later date. The proposed Consent Decree will require We Energies to make further emission reductions beginning in 2013.

Even without these agreements, air quality improvements are probable if the project is approved and if the new units are dispatched ahead of the existing units (dependent of course on the total output from the Oak Creek and Elm Road stations). It is certain that emission reductions and air quality improvements will be realized if the new units displace generation currently provided by existing units because the emission rates per Megawatt-hour of electrical energy provided by the proposed units will be lower than emissions rates for the existing units.

The Environmental Impact Statement does not, but should, contain an evaluation of the impacts of potential scenarios based on the Agreement with the City, the proposed Consent Decree, and potential dispatch of new units ahead of the existing units. To illustrate the potential for improved air quality if the project is approved, the following table compares the emission rates from the generating units contained in the air quality impact analysis discussed in the DEIS, emission rates required under the Oak Creek Agreement, and emission that would result under the proposed EPA Consent Decree.

Pollutant	DEIS [1] (Tons/Yr)	Oak Creek Agreement [2] (Tons/Yr)	EPA Consent Decree (Proposed) [3] (Tons/Yr)
Sulfur dioxide	162,169	24,900	14,540
Nitrogen oxides	20,530	12,000	9,022
Particulate Matter	7,088	770	2,603

Footnotes:

(1) Of these figures, emissions from existing units are 152,340 tons (93.9%) of sulfur dioxide, 15,173 tons (73.9%) of nitrogen oxides, and 5,905 tons (83.3%) of particulate matter.

(2) The Agreement limits total emissions to 38,400 tons per year as stated above. The figures in the table are based upon calendar year 2000 Actual Emission Rates.

(3) Assumes 100% Capacity Factors

Based on the annual limitations in the Oak Creek Agreement and the proposed EPA Consent Decree, if one assumes the hourly emission rates used in the air quality analysis for the DEIS, the facility could only operate for 1,170 hours per year or 680 hours per year, respectively. Clearly, for a base-load power plant these would be an unrealistic operating schedule.

C. Inaccuracies in the Impact Assessment

We believe the general description of the processes used to assess impacts to existing air quality to be misleading. The presumed existing air quality in the region is based upon ambient air monitoring conducted at significant distances from the proposed project site, in environments very different than found in Oak Creek and Caledonia. For example, the agencies rely upon data collected at the following monitoring sites to characterize the existing ambient air quality:

Pollutant	Monitoring Site Used to Characterize Milwaukee County	Monitoring Site Used to Characterize Racine County	Distance to the Proposed Elm Road Generating Station
SO_2	MATC downtown 739 West Juneau Milwaukee	Green Bay East H.S. 1415 East Walnut Brown County	15 miles to MATC; 135 miles to Green Bay
TSP	Franklin Pumping Station 5800 West Alwood Franklin	Franklin Pumping Station 5800 West Alwood, Franklin	9 miles

PM_{10}	Great Lakes Water Institute 600 East Greenfield Milwaukee	Great Lakes Water Institute 600 East Greenfield, Milwaukee	13 miles
NO_x	UWM 2114 East Kenwood Milwaukee	Harrington Beach 531 Highway D, Ozaukee County	16 miles to UWM; 44 miles to Harrington Beach
CO	MATC downtown 739 West Juneau Milwaukee	MATC downtown 739 West Juneau Milwaukee	15 miles

The MATC downtown site, used to establish the existing air quality in Milwaukee County for sulfur dioxide and carbon monoxide, and Racine County for carbon monoxide, is heavily influenced by vehicle traffic and its high-density urban characteristics. Likewise, the UWM site used to establish existing conditions in Milwaukee County for nitrogen oxides (NO_x) is influenced by its intra-urban setting and local vehicle traffic. The Franklin Pumping Station site used to establish existing conditions for total suspended particulate matter is influenced by nearby quarrying operations. The monitoring site at the Great Lakes Water Institute used to establish existing conditions for inhalable particulate matter (PM_{10}), is heavily influenced by its intra-urban location and activities associated with the port of Milwaukee. For these reasons, the monitoring stations used to characterize the existing air quality are not appropriate for the proposed project site. At the very least, the background concentrations from these stations likely overestimate the true background concentration in the proposed projects worst-case impact areas. At worst, they grossly mischaracterize and invalidate the air quality assessment.

The agencies further characterize existing regional concentrations of air pollutants based on a five-year arithmetic average (in this case for the 5-year period of 1995-1999) of the second highest values occurring each year, to compute a background concentration for pollutants with short term (3-hour, 8-hour, 24-hour) National Ambient Air Quality Standards (NAAQS). This

background concentration is then assumed to occur all of the time, without regard to wind direction. For pollutants with annual standards, the five-year average of the annual concentrations are assumed to characterize existing conditions. This method biases the resulting background concentration on the high side. In this particular case, it leads to a conclusion that future air quality will approach unacceptable levels. While such an analysis may be appropriate for the DNR's regulatory purposes, such a conservative analysis should be made clear to the general public. It should also be made clear to the general public that this conclusion (regarding potential air quality approaching unacceptable levels) is the result, not of expected emissions from the proposed units, but because of the emission rates assumed for the existing units, which in lieu of the aforementioned agreements, are unrealistically high.

The method for evaluating worst-case air quality impacts due to proposed and (especially) existing emission sources is too conservative in that the procedure can double-count the impact of the existing sources at the existing OCPP by first having them directly in the model as an emission source (and assuming them to be operated at continuous 100% load conditions) and, secondly, by assuming that emissions from the existing sources contributed nothing to the presumed existing background concentrations.

Specifically, in the air quality analysis, existing OCPP units 5 through 9 have been assigned a total emission rate in excess of 152,340 tons per year. Actual emissions from the existing units, as reported in the EPA's Clean Air Markets web site, were only 24,887.5 tons in calendar year 2000, less than one-sixth of the emission rate used in the air quality impact analysis. Further, the proposed "new" units were assumed to add approximately 9,832 tons of sulfur dioxide emissions per year, just 6.1 percent of the emissions contained in the modeling study.

A statement is made in the DEIS that the concentrations of sulfur dioxide (3-hour and 8-hour) would "increase dramatically" if the new units were approved. Such a statement is inaccurate as it fails to recognize that the majority of the modeled impacts are due to the assumed and unrealistically high emission rates from the existing units, not the proposed new units, coupled with the assumption that the existing units do not contribute to background concentrations.

In reality, if all agreements and restrictions regarding the existing units were taken into account, an analysis could be presented in the DEIS that, realistically, leads to a conclusion that if the new units are approved and dispatched ahead of the existing units, substantial improvements in air quality would result.

It is also important to note that for most pollutants and averaging times, the highest concentrations reportedly occur when winds are off Lake Michigan. Even under these conditions, a background concentration is added to the modeled result, even though there are no upwind sources for over 75 miles. This practice again biases the reported results to a higher concentration than can reasonably be predicted given the proposed project location.

D. Minimization of Particulate Impacts

The PM_{10} (24-hour) and TSP (24-hour) impacts as determined by the modeling studies, approach the limits of acceptability at nearly 100 percent of health and welfare based standards. These impacts are highly dependent on location of the various fugitive dust sources, including coal storage piles, roadways, etc. These impacts can be reduced by strategic placement of such features, away from site boundaries, toward the interior of the site. It is appropriate to minimize human exposure to these air contaminants even though other environmental impacts may increase. This is why the City's CUP has required that the coal storage and handling facilities be moved within the rail spur loop, approximately 2,000 feet southeast of the intersection of Elm

Road and the railroad tracks. This revision to the site layout will mitigate potential impacts to the residents of the Oakview #3 and Barton Oaks subdivisions as demonstrated by revised air quality modeling. Moving the coal storage inside the rail loop results in nearly a 10 percent reduction in predicted TSP impacts.

E. Enforcement Mechanism

The Oak Creek Agreement provides for specific enforcement provisions (see Agreement ¶ 1.D). In addition, the incorporation of the total air emission limitation standards in the proposed U.S. v. WEPCO consent decree, upon approval by the U.S. District Court for the Eastern District of Wisconsin, also makes federal enforcement available including civil penalties, injunctive and contempt relief.

F. Air Monitoring and Reporting Requirements

In addition to the generally applicable federal and state emission discharge reporting requirements, the Oak Creek Agreement requires the installation and operation of two critical air monitoring stations at the Elm Road Monitoring Site and at the Carrollton Monitoring site in the community which, based on air modeling, will measure emissions in the community (and not at points 9 to 135 miles away and subject to potential other sources.) (See Agreement at ¶ 1.E. 1.&2.). The Agreement also requires that the air emission monitoring results be reported to the City of Oak Creek as well as DNR. (See Agreement at ¶ 1.E.3).

Further, the proposed WEPCO consent decree will require air emission monitoring and reporting (See Consent Decree, § § V.E., VI.E.,VII.C. and XII.)

G. Air Summary

Finally, it should be noted that the air quality impacts are the most important of all environmental issues related to this project. They have the greatest potential to impact public health and welfare, as well as public opinion regarding the entire development. It is in the best

interest of all parties involved that the presentation of the air impacts reflect, as accurately as possible, the existing and expected conditions at the site. We suggest that the PSC and DNR take a closer look at the information presented in the DEIS; review the latest DNR, City, and EPA agreements; and make a more realistic presentation of these conditions in the final EIS.

II. ENVIRONMENTAL AND ECONOMIC IMPACTS

A. Scope of ERGS Project

The proposed ERGS project will result in the construction and operation of the sixth largest electric generating facility in North America in the Oak Creek community of about 30,000 residents. The construction project will take 8 years from 2004 to 2011 including construction 24 hours per day, 7 days a week. It is estimated that over 10 million cubic yards of soil will be excavated and graded. It is further estimated that this will be the largest construction project in Wisconsin dwarfing the construction of Miller Park or the Milwaukee freeway system. At peak, there will be about 1,200 workers employed in the construction and there will be about 2,780 vehicle trips per day into and out of the site. In addition, there will be numerous rail and barge deliveries to the site during the construction period.

The new and existing facilities will be located on prime high value lake front property. The presence and size of the facility impacts planned redevelopment activity in the eastern portion of the City and stints local property tax base growth in a prime area of the City. There will be substantial impacts on the City's services including among others, it's firefighting, paramedics, emergency medical services, police, water, sewerage treatment, engineering and building inspection, traffic, roads, public works maintenance and service. City residents during the 8 years of construction will be subjected to substantial traffic and noise impacts.

Unlike all other residential and business property owners in Oak Creek, WEC's OCPP and ERGS, are exempt from real estate property taxes that fund the costs of City government

and services. Even though WEC follows current law, it cannot pay a fair and equitable share of local real estate property taxes under current law. The compensation to the City of Oak Creek under the public utility distribution of shared revenue for an additional 1,830 MW of new coal power will increase only $6,000 annually from current payments to the City to the maximum of $750,000. This amount can only be seen as miniscule when viewed in light of the overall impact to the community. The $750,000 payment represents only about:

- 0.07% of the revenues We Energies may earn from the proposed power plants,
- 0.4% of the return on equity that may be earned by We Power,
- 2.6% of the revenue that may be collected by the State of Wisconsin, and
- 5.3% of the value of property tax revenues that might be collected if the proposed power plants were not exempt from property taxes.

The compensation provided by current state law to a municipality hosting a power plant is extremely low when compared to revenue streams captured by others. The level of compensation is also low when considering the impacts of construction and operation borne by the host community. A more equitable compensation for host communities would be to provide revenues similar to what any other industrial facility would provide for an equivalent development.

In the case of Oak Creek, tax revenues for an equivalent industrial facility to that proposed would conservatively generate $14,000,000 annually, including the standard manufacturers and equipment exemptions in Wisconsin tax code M-P and M-R. Of this $14,000,000 in property taxes annually, about $10,000,000 would be for local purposes including municipal government, water and sewer and local schools. The Agreement between the City and WEC provides a maximum payment of $2,500,000 annually, if all three new units are built. Adding this to the expected $750,000 from shared revenues provides a total compensation of $3,250,000 annually, if all three proposed units are built. Even taken together,

this compensation to the City represents only about one-third of the foregone property tax revenues. Furthermore, a payment of $2,500,000 to the City would impact a 400 kWh residential rate-payer by adding only about $0.48 annually in electric costs. For keeping the largest construction project ever in the state, and the 6th largest power plant in North America out of other rate-payers "back yards", this level of compensation more than passes any reasonableness test.

The inadequacy of payments to host communities has been under review by many interested parties for the past few years. The current legislature is considering changes to the shared revenues formulas that recognize the disparity between what payments the host community receives and the impacts felt by hosting a large power pant. The City has been following this legislation closely and would like to highlight some notable differences between payments to the host community in the form of utility payments under the shared revenue formulas and payments to the host community under the Agreement between the City and We Energies. In particular, the City would like to stress the long-term nature of any decision to build the proposed power plants. If the proposed plants are built, the City will experience the impacts of these plants for at least the next 40 years and perhaps longer. In this context, it is important to understand that that the outcome of any changes to utility shared revenue is uncertain at this time and any changes that might occur will continue only at the discretion of the legislature and the governor. As a result, even if new legislation does provide additional compensation from shared revenues to host communities, this compensation could be reduced by future legislatures. Thus, the size of future payments under shared revenue formulas are subject to much uncertainty. While the City believes that this additional compensation does not represent unreasonable compensation for agreeing to live with the proposed plants for at least the next forty years, it is

not at all certain at what level this compensation will occur or even that it will continue for the life of the proposed plant. Finally, the City would note that because the proposed legislation does not change the gross revenues tax on electricity production, any additional payments arising from the proposed changes to shared revenue are unlikely to affect We Energies' rate payers.

This massive base load electric generating facility will provide electrical power to WEC's more than one million customers,[1] as well as providing power to other utility customers outside the WEC service territory. Residents and business customers in Oak Creek will use about 3% of the electric power generated,[2] but the City, its residents and businesses will suffer the construction impacts and the impacts during the more than 40 years of operation of the facility.

Most significantly, all of WEC's rate payers will benefit from the enormous capital and operations savings from the sitting of the plant in Oak Creek as compared to other sites such as in Pleasant Prairie, Haven or Milwaukee.

B. Property Values

The DEIS (at p. 296-98) briefly discusses impacts on property values in the City of Oak Creek and the Town of Caledonia and the author's opinions of several hedonic studies. The City respectfully disagrees. With respect to this strawman argument, first, it must be noted that impacts on property values are only one of the substantial impacts sustained by the City. Second, the City respectfully disagrees with the authors' opinions and interpretations of the economic studies.

C. Mitigation Payment

Subject to Commission approval, the Oak Creek Agreement provides that WEC will make an annual payment to the City if one unit is approved of $1,500,000; an additional

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1 From WEC's website.

2 Estimate based on 30,000 residents = 10,000 residences and 5kW required per household, including all home, and business uses of those households.

$750,000 if a second unit is approved; and an additional payment of $250,000 if a third unit is approved. (See Agreement ¶ 3). If approved by the Commission, this amount of the mitigation payment is independent of any increase or decrease in the public utility distribution of shared revenues.

The DEIS suggests (page 29) that "Whether these payments should be recovered and what is an appropriate level may be key issues at hearing in the case". The City suggests that there should be no doubt that these mitigation payments should be recovered and that they are at least appropriate in this case because of the magnitude of the impact to the community and insignificance of the amount affecting the rate-payer.

III. OTHER COMMUNITY IMPACTS

A. Rezoning and CUP Process

As noted above, WEC applied to the City of Oak Creek for rezoning and a CUP. After review by City staff and meetings and negotiations between WEC and City representatives, a meeting and presentation to the Plan Commission, public meetings and a public hearing to elicit community concerns and impacts, the Plan Commission and the Common Council on behalf of the City, exercising its municipal police powers unanimously approved the rezoning and a CUP on June 3, 2003. A copy of the rezoning and CUP ordinances are attached hereto.

B. Matters Covered by Rezoning and the CUP.

The rezoning allows the property to be used for power plant development. CUP seeks to address City responsibilities under statutes or ordinances, community concerns, and seeks to lessen, or reduce, where possible, impacts on the community. Among other things the CUP addresses land use, plan approvals, fire protection, security, emergency medical services, grading, buildings and set backs, construction hours, water, sewer, signage, traffic and

roadways, noise during operation and construction, inspections, lighting, and coal storage and handling.

C. Noise During Operations.

Besides air emission impacts, the most significant environmental impact issue for the City is noise. Kamperman and Associates and Hessler and Associates provided substantial input to the City and WEC, respectively, on this issue. Many discussions on this topic primarily centered on whether or not industrial or residential standards should be used during the operations period. Standards are set in the CUP.

D. Noises During Construction

The DEIS acknowledged that the Commission staff did not evaluate noise impacts during construction because WEC did not present sufficient data on the topic in its application. The City recognized this shortcoming and addressed this with WEC as part of the CUP. Setting noise levels during construction projects is not typical. However, the magnitude and duration of this project necessitate some responsible and reasonable regulation in this regard. The CUP addresses this by requiring noise monitoring stations consisting of automatic data recorders at strategic locations to measure noise levels on a continuous basis, and setting noise levels for construction periods that are protective of the Barton Oaks and Oakview #3 residents, yet allow flexibility for construction of the site.

The key issue during construction is limiting the areas of construction, times of construction, and setting noise limits before and after the screening berms are constructed. The CUP establishes limits, where appropriate, to protect the residents during the most sensitive times of the day and year and days of the week, while providing WEC the flexibility to construct the screening berms as quickly as possible to minimize noise impacts during the majority of the

construction period. Standards become more restrictive as the project progresses and the major earthwork ends.

The data recording requirements, compliance protocols, and penalties for non-compliance are established to provide the City daily access to noise level measurements for quick detection, response, and resolution of noise exceedances, if they occur.

IV. TECHNICAL CONCERNS

In addition, there are a number of specific technical concerns with the DEIS.

A. Specific Comments

On page 28, the text reads:

> 5. WEPCO will work with the city on a conditional use permit basis to minimize noise and traffic issues.

The CUP was never limited to noise and traffic issues. The text should be modified to reflect that the CUP is used to address all City concerns, not just noise and traffic.

On page 35, it appears in the paragraph following figure 3-5 that the agency is attributing the reduction in kWh production in 1997, for WEPCO generating units built after 1960, to the extended outage at the Kewaunee nuclear plant. The statements should be clarified to indicate that the state-wide reduction that occurred in 1997 is attributable to the extended outages at the Point Beach and Kewaunee nuclear plants.

On page 43, (Planned capacity retirements and nuclear relicensing) it should be noted that Oak Creek Units 1 through 4 have already been retired. The final EIS should identify the unit that commission staff assumed to be retired in 2019. Additional considerations should be made for the potential that Units 5 and 6 may be retired before 2013, a possibility in light of the proposed EPA Consent Decree. Commission staff further speculated that Units 1 and 2 at the Point Beach Nuclear Power Plant would be successfully re-licensed. These assumptions have

significant impacts on the Needs analysis and should be re-examined. All potential options, the retirement of one or both of OCPP Units 5 or 6, along with the potential that one or both of Point Beach units are retired before 2013, should be considered, and a strategy should be formulated to address each of these options.

On page 60, the text fails to mention that gas-fired power plants also emit sulfur dioxide, volatile organic compounds, heavy metals (including mercury), and organic hazardous air pollutants including formaldehyde.

On page 94, it should be noted that natural gas transmission and distribution also relies on compression provided by fossil fuel fired engines.

On page 95, it should be noted that the City of Oak Creek considers cooling towers to be unacceptable due to the visual impact. Cooling towers would further adversely impact the heat rate of the plant, resulting in even greater emission rates assuming the net output remains constant.

On page 95, under Air Emissions, the following statement is made:

Mercury is not a pollutant emitted by natural gas combustion.

This statement contradicts information published by the EPA and statements made elsewhere in the DEIS. In its publication, Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Sources, (Table 1.4-4), the EPA reports that natural gas combustion emits 2.6×10^{-4} pounds of mercury per million cubic feet of natural gas combusted. Using this emission factor, a natural gas fired combined cycle plant with a heat rate of 7,800 Btu per kW-hr, generating 1,830 MW, could emit over 32 pounds of mercury per year.

Pages 117 and 239, and others refer to a wallboard plant. The final EIS should reflect that the wallboard facility is not considered part of the power generating facilities and, if located

in the City, will therefore require separate approvals and be taxed by the City like any other industrial or commercial operation.

Beginning on page 134, there are discussions of potential health impacts due to exposure to air contaminants emitted by coal fired power plants. These same air contaminants are emitted by virtually all combustion processes, including combustion of petroleum products (fuel oil and gasoline) as well as combustion of natural gas. Several additional points should be made in these sections:

- For the physical responses described, there must be exposure to unhealthy concentrations of the air contaminants.
- For particulate matter, it should be noted that all of Wisconsin has been tentatively classified as meeting the $PM_{2.5}$ standard.
- For nitrogen oxides, the national ambient air quality standard of 100 micrograms per cubic meter of air (annual average) should be mentioned.
- For nitrogen oxides, a figure of 0.1 ppm of air is mentioned as causing lung irritations and measurable decreases in lung function in asthmatics. However, no mention of whether such concentrations are expected as a result of the ERGS project could be found.
- For sulfur dioxide, no mention of the sulfur content in natural gas or commercial grades of propane was provided, as it was for coal and oil. Natural gas, after sweetening, contains as much as 20 grains of sulfur per 100 standard cubic feet.
- For sulfur dioxide, various health impacts are discussed, but no concentrations are provided that are correlated with these health impacts, and no mention is made of whether such concentrations are expected as a result of the ERGS project.

For greenhouse gases, it is important to identify the other sources of greenhouse gas emissions in Wisconsin. If electric utilities generate 33 percent of the greenhouse gases emitted in Wisconsin, what are the sources of the remaining 67 percent?

There is no mention of the system-wide reductions in emissions of mercury, sulfur dioxide, and nitrogen oxides, of over 50 percent from calendar year 2000 levels from the coal fired plants in the We Energies system that will be required under the Multi-Plant Environmental

Cooperative Agreement between We Energies and the DNR, if the PSC approves the ERGS proposal.

On page 148, a possible interpretation of the text is that the IGCC unit will not be subject to Section 112(g) of the Clean Air Act because such units are not identified by EPA as a source category that will be regulated under Section 112(c). Such an interpretation would appear to contradict guidance from EPA as found on its web site http://www.epa.gov/ttn/atw/112g/qanda12g.html) as presented below:

> Q1 Is this rule applicable only to sources in the source category list developed under 112(c)?
>
> A1 No. This rule applies to all new major sources of HAP (hazardous air pollutants) even if they are not yet on the source category list. This list contains the source categories for which EPA is to promulgate MACT standards. (The Clean Air Act requires EPA to list all categories of major sources of HAP. If it is brought to the EPA's attention that a category has not yet been listed, the EPA must then list it, unless the category is regulated under section 129 (see also #3 below)). The exception to this are source categories that were deleted from the list pursuant to 112(c)(9). See 40 CFR 63.40(e) or 61 FR 68399.

On page 153, under the Existing Air Quality section, the following statement appears: "Both counties (Milwaukee and Racine) are classified as moderate non-attainment for ozone." This statement is incorrect. Both counties are classified as severe non-attainment for ozone.

In Table 7-6 (page 153) the background concentration for SO_2 (24-hour) is stated as 7.8 micrograms per cubic meter. The correct figure is 57.8.

In Table 7-11 (page 157) there is no limit under the column for "Proposed Limit" for sulfuric acid mist, only units of Lb/mmBtu with a reference to a 12-month rolling average. An appropriate figure should be provided.

Also in Table 7-11, for VOC, there is reference to Note 4, which indicates this limit is based on a 96 percent reduction in the emission rate of the design bituminous coal. Does this note belong here or with sulfur dioxide?

In Tables 7-11 through 7-15, the term "LAER" appears in the table heading in the column "Proposed Limit (LAER)". Are these intended as LAER requirements?

On page 169 (Federal Acid Rain Program), the following statement appears:

> In order to operate, the ERGS would be required to buy allowances from another power plant that has reduced its emissions below the allowances allocated.

The OCPP currently has allocations totaling 30,506 allowances, more than enough allowances for its existing generating units and the ERGS units under the Agreement with the City of Oak Creek and the proposed EPA Consent Decree.

On page 170, further explanation of the NR 445 exemption for fuel ash should be provided. Should the reference to section NR 400.02(22e) instead be to NR 400.02(40)? The exemption in NR 445 applies only to "virgin fossil fuels" further defined as having a heat value of greater than 7,000 Btu per pound, which is not blended with reprocessed or recycled fuels. Does the fuel ash have a heat content of greater than 7,000 Btu per pound? Is the fuel ash a reprocessed or recycled fuel?

In Table 7-33, mercury emissions are erroneously stated as 0.962 tons from SCPC Units 1 and 2. The correct figure is 0.062 tons for each unit.

On page 175, under "Chapter Summary," the conclusions fail to recognize that fabric filtration is also effective to control particulate matter, including the PM_{10} fraction. Also, the following statement is made:

> Under WEPCO's modeling analysis, concentrations of particulate matter, especially total suspended particulates (TSP 24-hour), PM_{10} (24-hour), and SO_2 (both 3-hour and 24-hour) would increase substantially due to operation of the

> ERGS. Several of these pollutant concentrations are approaching 100 percent of the National Ambient Air Quality standard for the region.

This statement is inaccurate as it fails to differentiate between impacts due to the existing units and impacts due to the proposed ERGS project, treating impacts from both as if they result only from the ERGS project.

On page 175, the DNR cites ACGIH (2001) as the reference for determining an acceptable concentration in ambient air. The applicable provisions of NR 445 cite the threshold limit values and biological exposure indices for 1987 – 1988, which were published by the American Conference of Governmental Industrial Hygienists. The correct version should be referenced in making a comparison to acceptable concentrations in air. Additionally, in NR 445, ammonia is not identified as having a ceiling limit, and therefore, comparison of a one-hour average concentration in ambient air to ten percent of the ACGIH value is not appropriate.

On page 256, the topographic changes to the North Site should be modified to include the requirements in the CUP for the berms listed in the CUP. Figure Vol. 2-12, and possibly others, should be edited to reflect the configuration of the berms outlined in the CUP.

Starting on page 277, Chapter 11 - Community Impacts, fails to mention anything about the loss of taxable property that a power plant takes from the host municipality. This is a real impact to the community that should be discussed. As noted in the example above, the value of the lost tax revenue to the City if the proposed plant was a similarity priced industrial facility would be millions of dollars annually.

On page 285, under "Land Use Plans" it should be noted that on June 3, 2003, the Oak Creek Common Council approved a CUP for the property in Oak Creek.

The "Zoning" section beginning on page 290 should be updated to reflect that on June 3, 2003, the Oak Creek portion of the WEC property was rezoned and a CUP approved to allow power plant development. (See attached zoning ordinance.)

Page 293 should be updated to include a reference to the CUP indicating the water and sewer use have been agreed to for construction and operation of the plant in Oak Creek. If the ERGS is approved for the Town of Caledonia location, another source of water and sewer is needed.

On page 294, (Fire protection and emergency medical service), it is incorrect to imply that the Oak Creek Fire Department would serve any units as a first responder for any incidents occurring outside the borders of the City. The City will provide first response services only to facilities located within the City. If the new facilities are located in the Town of Caledonia, it and Racine County will receive shared revenues under current law, and should be expected to provide such services.

On Page 295, the $117.3 million figure incorrectly referenced the "net book value of the OCPP." The $117.3 million figure actually includes:

1) Production plant assets valued at $99,175,541;

2) Substation assets valued at $17,908,476;

3) General structures valued at $126,474.

For a total of $117,210,491. Thus, the value of the OCPP for shared revenue purposes is overvalued by $18.1 million.

On page 296, it should be noted that a 30-year depreciation schedule as compared to a 40-year schedule has significant negative financial impacts on local residents under the current

shared revenue program. It should be further noted that the current shared revenue program has a questionable future, and payments to local communities in lieu of taxes cannot be assured.

Also on page 296, the City takes issue with the statement that the property value advantages cited in the DEIS ("natural visual buffers and a feeling of space" and "a recreational trail") are real or even perceived advantages given that the trade-off is a location adjacent to a power plant. Potential buyers and sellers are aware of the proximity to the existing plant based on inquiries that the City has received, and these potential buyers and sellers have expressed concerns about the proposed development. The statements made here suggest that with all else being equal, given the choice of locations, that people will choose to live in this location. Unless this statement can be substantiated, the statement should be removed from the final document. Further, while one may be proposed, no recreational trail currently exists on the site.

On page 300 under "Fugitive Dust," the City's concerns with the potential for fugitive dust sources during construction and operation have resulted in the City's Agreement with WEC including a requirement for WEC to operate an ambient air quality monitoring station in the vicinity of Elm Road and Haas Park. This station is currently under development and will contain sampling equipment to monitor total suspended particulate matter (TSP) on a daily basis, and continuously monitor PM_{10} and $PM_{2.5}$. Corrective actions and possible enforcement will be taken if exceedances resulting from operations conducted by WEC are indicated.

Starting on page 303, "Reserve Coal Pile" should be amended to address the City requirement in the CUP to move the pile south, within the rail spur loop.

Starting on page 306, the "Traffic" section needs to be updated to reflect the changes in the CUP if the North Site is selected.

On page 319, it should be noted that Oak Creek does have an existing noise ordinance with a specific noise level threshold for industrial sources (Section 17.0810 of the Zoning Code), setting a limit of 62 dbA at the boundaries of Business Districts, and 58 dbA at the boundaries of Residential Districts. The recently adopted CUP sets additional restrictions on noise levels from the property and requires monitoring to demonstrate compliance with those limits. It also regulates all noise from the property, not just construction traffic impacts.

On page 328, the "Earth Moving" section should be updated to reflect the changes in the grading and berms outlined in the CUP which are to be developed if the North Site is selected for the ERGS plant.

The "Recreation" section on page 329 should be amended to include a discussion of the impact of increased barge traffic on the recreational use of Lake Michigan. The CUP includes a requirement to provide the City a report on this issue and work with the City to mitigate any impacts.

V. CONCLUSION

The City of Oak Creek respectfully requests that the PSC and DNR staff consider each of the items outlined above for consideration and inclusion in the final EIS.

If you have any questions regarding the details discussed above, please contact the City's legal and/or technical consultants.

Comments on the Draft Environmental Impact Statement, submitted by the Oshkosh Commercial Development Corporation

OSHKOSH CHAMBER OF COMMERCE

ADVOCACY COMMUNITY DEVELOPMENT LEADERSHIP

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WISCONSIN PUBLIC SERVICE COMMISSION

June 13, 2003

Jeffery Kitsembel
Public Service Commission of Wisconsin
610 North Whitney Way
Madison, WI 53705

RE: Elm Road Generating Station, docket no. 05-CE-130

Dear Mr. Kitsembel:

I am writing on behalf of the Oshkosh Commercial Development Corporation (OCDC) and appreciate the opportunity to comment on the Draft Environmental Impact Statement issued by the Public Service Commission and the Department of Natural Resources. OCDC is a private non-profit economic development corporation designed to foster economic growth in the Oshkosh area.

Cost, reliability and impact on the environment should all be key questions when Wisconsin makes long-term decisions related to power generation. Our belief is that the Calpine proposals in Fond du Lac and Kaukauna are sound choices not just for Wisconsin business, but for everyone in Wisconsin. We believe that the DEIS confirms our opinion.

Unquestionably, the Calpine proposal would result in less air pollution. Currently, air pollution from Southeastern Wisconsin makes its way up Lake Michigan to our region of the state. While this is not the only source of pollution in the Fox Valley, it is certainly one of the reasons that several area counties have been proposed for the non-attainment list for ozone. Fortunately, there is a clean and affordable source of electricity that the PSC should include as part of the answer to the energy needs identified in this proceeding.

The draft Environmental Impact Statement makes it clear that the Fond du Lac power plant proposed by Calpine is not only clean but affordable – in fact far less expensive than the Oak Creek proposal when all of the cost impacts are considered. Certainly, as customers served by WE Energies and/or American Transmission Company, we appreciate that.

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Lastly, the Fox Valley is one of the states major economic hubs that requires reliable energy service. Building at least a portion of the proposed capacity additions in the Fox Valley, as opposed to siting nearly 2,000 new megawatts of power at an already transmission-constrained single location, would help to ensure reliability for all Wisconsin customers.

In summary, we believe that the both the Fond du Lac project and Calpine's similar new Fox Energy project in Kaukauna deserve to be in the final mix of projects that the PSC chooses to meet our power needs.

Sincerely,

Rob P. Kleman
Executive Director
Oshkosh Commercial Development Corporation (OCDC)

CC: Jeff Thorkildsen, President, OCDC

Comments on the Draft Environmental Impact Statement, submitted by Robert J. Owen, Jr., P.E.

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June 12, 2003

Ms. Kathleen Zuelsdorff
WEPA Coordinator
Public Service o mission of Wisconsin
P.O. Box 7854
Madison, WI 53707-7854

Re: ERGS DEIS Comments—General, CO_2, Fuel Diversity, and Energy Efficiency

Dear Ms. Zuelsdorff:

Before addressing some specifics, permit me to offer a general objection to the PSC's approach to doing an EIS in this case. This effort was started too late, and consequently there has not been enough time for the public to address the DEIS in this case. The lack of time is compounded in some cases, such as the case of carbon dioxide, by misleading information in the DEIS.

These are my comments on the ERGS DEIS as to CO_2, fuel diversity, and energy efficiency, three important topics to which the DEIS did not do full justice.

Carbon Dioxide

Carbon dioxide is a topic which utilities and their regulatory marionettes such as your managers do not much like to discuss. However, it is a subject which the ERGS FEIS must discuss much more conscientiously than it was discussed in the DEIS.

I am told that the greenhouse gas emissions section of the DEIS on page 170 was reviewed by someone at DNR. Was the reviewer awake at the time?

Of the four CO_2 emissions figures prominently presented in the DEIS at page 170, two are erroneous, and none are adequately explained. The three last figures, for example, are taken from an early 90's DNR-sponsored study estimating year 2000 emissions. Nowhere does the DEIS mention this. The second-last figure inaccurately reports the study estimate. It was actually 46,300,000 tpy for transportation.

Most significantly, the ERGS figure <u>understates actual potential ERGS CO_2 emissions by at least a factor of 11, assuming 80% ERGS capacity factor.</u> This kind of error is appalling and indicates an inappropriately flip attitude toward a serious environmental problem, particularly in the context of a supposedly reviewed document issued by a supposedly expert agency.

Worse yet, this DNR and PSC-sponsored document had no input whatever from the DNR's climate-change specialist, Eric Mosher, who had directed the study the DEIS took figures from. He would undoubtedly have caught the error in ERGS emissions if given the chance to review or contribute to this DEIS. Why was he not given that chance?

A few days ago, you informed me in your inimitably imperious tone that you and your illustrious colleagues were too busy to discuss the DEIS further.

Could it be that the learned management of your august agency is and was not interested in discussing the potentially disastrous effects of continually increasing CO_2 emissions and atmospheric concentrations on the complex earth-atmosphere-ocean system on which human life on this planet depends and thus decided to exclude the one state employee most qualified to expound on this subject from the DEIS effort altogether?

Is this why Mr. Mosher first heard of the ERGS DEIS from me on June 5 when I asked him about the prior DNR study misquoted in the DEIS?

Given an opportunity to participate in the FEIS process, I am confident that Mr. Mosher would be able to assist you in improving the quality of your carbon dioxide work product by several orders of magnitude.

In the meantime, permit me to mention a few of the concerns scientists have about unchecked carbon dioxide emissions:

(1) they may heat the earth's atmosphere significantly, creating vast climate changes and displacing plant species by hundreds or even thousands of miles in a few decades;
(2) they may wreak havoc with agricultural and silvicultural systems which developed in a very different climate regime, imperiling the food supplies and livelihoods of billions;
(3) they may flood low-lying areas on the coasts and low-lying oceanic islands;
(4) they may create sudden climate shifts to colder climates in some regions, including Northeast North America and Northwest Europe, if they trigger shifts in major oceanic currents;
(5) they may cause a serious reduction of lake levels in the Great Lakes;
(6) they may increase the probability and severity of storms;
(7) they may increase the frequency of killer heat waves and ozone episodes;
(8) they may continue to curtail the x-country ski season here; and
(9) they may promote tropical diseases (e.g., west Nile virus) in areas like Wisconsin formerly free of such scourges.

Some of these possible effects are controversial among scientists. Even more so, most are controversial or even dismissed entirely by conservative ideologues.

However, most real atmospheric scientists of all political shades and stripes <u>are</u> concerned about global climate change. There is no dispute that carbon dioxide concentrations <u>have</u> increased drastically in the last 150 years and continue to rapidly increase. There is no dispute that much

of the world has seen a trend toward increasing mean temperatures in recent decades. There is very broad agreement that carbon dioxide is a major driver of the changes seen to date. There is broad concern about just where we may be headed among scientists even if there is none at all among agency marionettes and utility puppeteers at 610 Whitney Way in Madison.

The scientific concerns include concerns that CO_2 concentration increases may indirectly damage human health. Indeed, three states have commenced a lawsuit against EPA this very month contending that carbon dioxide emissions should be regulated as criteria pollutants under the Clean Air Act.

In putting carbon dioxide in context, it is important to consider the differing time scales on which a coal plant may be used as compared to another carbon dioxide-emitting appliance. WE proposes to operate its coal plants for about 60 years. This is about twice as long as a wind farm operates, three or four times as long as a furnace operates, and about six times as long as a car or truck operates. All of the other carbon dioxide-emitting devices will be replaced by newer, presumably cleaner, devices several times before the black elephant coal plants proposed in this case stop spewing carbon dioxide into the heavens. Indeed, our descendants may mostly be driving fuel cell vehicles powered by wind-generated hydrogen and living in off-grid homes powered by on-site hydrogen-fueled fuel cells well before these monstrous facilities are retired. WE is asking for the right to spew massive quantities of carbon dioxide well beyond the lifetimes of most of the readers of the FEIS.

You must disclose the scientific concerns about global climate change in the FEIS. Although you did not do so in the DEIS and are presently in violation of Wisconsin law, you can admit and correct your mistakes, fully disclose the scientific concerns, stop misleading and stonewalling the public, and write a much improved FEIS which treats CO_2 emissions as a real scientific concern, not an ideological diversion.

You must also disclose that carbon dioxide emissions may be taxed in the future, adding further economic insult to the injury to Wisconsin's economy associated with additional multi-billion-dollar purchases of out-of-state energy.

Please note that the European Union proposed penalty for carbon dioxide emissions above the cap level for which an emitter has allowances is 40 Euros/metric ton ($42.65/ton) for 2005 to 2008. Currently, forward contracts for carbon-dioxide emission allowances are trading at 5-7 Euros/metric ton ($5.33-$7.46/ton) in Europe. The WE "carbon tax" of $3/ton is a joke. Any real tax would be substantially higher than the market price of allowances.

After addressing the numerous deficiencies of the DEIS, you can resume dancing to the tune set by your WEPCo sycophant managers, "I'm your puppet," while quaffing some highly-carbonated beverage.

Fuel Diversity

The fuel diversity discussion in the DEIS is inadequate because it does not address how in-

creased use of renewable energy in Wisconsin could improve the diversity of the electric system and address some of the economic risks of excessive dependence on natural gas.

I believe part of the current difficulty with natural gas prices is a short-term problem likely to be resolved long before any ERGS coal unit can be brought on line. This problem may be associated with inadequate financing being made available to natural gas drillers, a side-effect of recent financial scandals in the energy industry. I believe it is highly probable that Congress will move aggressively to solve this problem before the year is over in the wake of recent statements of Alan Greenspan and that natural gas shortages will disappear by 2005 as drilling activity increases. The DEIS should focus on longer-term issues.

Longer term, adding renewable energy to our electric supply portfolio is a very effective way to dampen natural gas price spikes. While at present, natural gas mostly substitutes for oil and vice versa, in the long run wind energy could play a larger role in displacing both oil and gas, and this would likely have a beneficial influence on fuel prices. The FEIS should address this effect.

The DEIS mentions but gives insufficient emphasis to the economic characteristics of CT and CC gas-fired generation, especially versus wind generation in the next decade or two and solar generation as well in the longer term. Wind is low in operating cost (negative with tax credits), hence would readily displace natural gas in any utility's economic dispatch when available. Solar is also low in operating cost and would displace gas-fired generation.

Both wind and solar would reduce natural gas consumption to support the electric grid. This would tend to dampen upward pressure on gas prices. The FEIS should acknowledge this.

In addition, wind would tend to shift the mix of thermal generation toward lower-capital-cost, smaller, CT instead of CC or coal plants. These smaller plants could be integrated into the grid in a more distributed fashion, tending to generate transmission cost savings as compared to larger scale thermal generation plants. Solar P.V. installations would also have grid benefits in most of Wisconsin. PSC analyses reflected in the DEIS do not consider distributed grid benefits. With multi-billion-dollar transmission investments on the table in Wisconsin, it is high time to pay much closer attention to grid savings and costs of different generation sources.

Energy Efficiency

The DEIS makes an effort to deal with energy efficiency, but could be significantly improved with even minimal support from PSC management.

The shortcomings in this area are in no way the responsibility of the gritty half-time public servant who continues to do her darnedest to serve Wisconsin's citizens while her marionette managers systematically deprive her of the resources necessary to properly do her job. I salute Carol Stemrich, an example of courageous and conscientious dedication to public service! Carol's dedication and effort shine like a ray of sunlight through even the cloudy DEIS lens created in the cesspool of mismanagement and regulatory cooptation which is today's PSC.

What also shows through, however, is that PSC management refuses to implement Wisconsin's energy priority law, Wis. Stat. § 1.12(4), which unequivocally states that cost-effective energy efficiency measures are to be implemented first.

Instead of putting efficiency first, the commission appears to have adopted a policy of eliminating energy efficiency expertise first as it downsized its staff in recent years. We are now reaping the fruits of this grotesque misallocation of resources in the ERGS proceeding. There are huge gaps in knowledge as to the potential for additional cost-effective energy efficiency measures, and they are reflected in the DEIS. These are related to the fact that the PSC now has a single half-time employee, albeit an able one, Carol Stemrich, dealing with this subject matter.

They are related to the absence of energy efficiency studies in the last eight years.

They are also related to the fact that inept PSC Electric Division management, abetted by the "three wise monkeys" in charge (See No Evil, Hear No Evil, and Speak No Evil), has effectively absolved WE of its obligation to submit reasonable energy efficiency data in support of its "application" for ERGS. The responsibility for this misfeasance goes right to the top, where the AB/B duet/trio is apparently too busy serenading WEPCo with endless renditions of "I'm your puppet" to discharge its statutory responsibility.

It is time to change the music to a new tune more consistent with Wisconsin law and the clear economic interest of Wisconsin citizens in greater energy efficiency.

To this end, I propose that the Commission demand that WE forthwith provide sufficient data to permit determination of its additional cost-effective energy efficiency potential, and if WE does not do so, summarily dismiss the ERGS application before the hearing.

The legal justification for this is simple. Energy efficiency is Wisconsin's top priority resource. Wis. Stat. § 1.12(4)(a). The burden is on WE to prove that ERGS "satisfies the reasonable needs of the public for an adequate supply of electric energy." Wis. Stat. § 196.491(3)(d)2. This burden cannot be met if WE cannot disprove the hypothesis that energy efficiency can meet the postulated need. WE has pre-filed its case in chief, and it does not disprove the hypothesis.

The DEIS has some shortcomings, but it amply refutes WE's case in chief on energy efficiency.

What WE's case on energy efficiency does prove is that WE has contempt for the law and the applicable rule, PSC 111.53(d)1 & 2, and, by extension, the citizens of Wisconsin who would have to pay for its bad choice to prefer Pennsylvania coal over homegrown energy efficiency.

As the DEIS points out at page 54, almost "every dollar spent on coal . . . leaves Wisconsin and our economy," while "energy efficiency can . . . improve the state's economy in general."

WE is using the same consulting firm in the ERGS Case which self-destructed on cross-examination in the PWGS Case last year in the face of staff warning that this outfit is unable to supply

the information the PSC staff needs to make the requisite careful analysis of energy efficiency.

That the sleepy "regulators" at 610 Whitney Way have let the ERGS farce get this far is ample testament to the need for new blood to invigorate the penthouse level of the agency. To let it go any further would raise new questions about misfeasance in high places and whether something more sinister than poor management and garden-valley ineptitude is driving the forlorn derelict SS PSC, only recently provisionally rescued from shipwreck on transmission CPCN shoals, as it sputters, with no one to be seen at the helm, toward another generation CPCN ice berg or judicial review torpedo.

As to the substantive focus of the FEIS energy efficiency discussion, I have three additional comments.

First, the FEIS should recognize that studies based solely on avoided generation cost seriously understate the economic potential of energy efficiency. Efficiency avoids generator operation and construction, but it also avoids transmission and distribution construction. The resulting potential savings in T&D are large and are not accounted for in the STEP study, as I understand it. Consequently, the STEP study understates the real value of energy efficiency by at least $.02/kWh, even more in some cases. This means that the real economic potential for efficiency was much larger than the STEP study identified in 1995.

Second, the DEIS does make the point that energy efficiency has decreased in cost in many cases since 1995. The FEIS should also make the companion point that the cost of generation, typified by the likely total cost of ERGS in the range of $.05 per kWh, has increased since 1995. Again, this increases the real economic potential for energy efficiency.

Third, while the main focus of the DEIS is appropriately placed on energy efficiency potential for WEPCo, attention should be given in the FEIS also to the energy efficiency potential of other utilities or entities like MGE, WPPI and DPC which may share in ERGS ownership or control if this black elephant is built. They too have the obligation to capture reasonable energy efficiency savings before imposing this monstrosity on their customers. The universe of customers whose efficiency savings could avoid the need for the proposed ERGS plants is substantially bigger than WEPCo customers alone.

Very truly yours,

Robert H. Owen, Jr.
cc: Ms. Carol Stemrich
Mr. Ken Rineer
Mr. Eric Mosher
Mr. Jeff Kitsembel

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May 27, 2003

Mr. Paul Helgeson
Renewable Energy Engineer
Public Service Commission of Wisconsin
P.O. Box 7854
Madison, WI 53707-7854

Re: ERGS DEIS Comments on Renewable Energy Sources

Dear Mr. Helgeson:

These are my comments on the renewable energy portions of the ERGS DEIS at pages 59-66.

I view this section of the DEIS as very important, because several categories of renewable energy have the technical and economic potential to replace the proposed ERGS facility entirely. This point needs to be expressed more expansively in the FEIS.

An EIS is supposed to offer alternative visions. This one needs to offer a considerable expansion in vision. Renewable energy has a very exciting story to tell. Please tell it.

Wind

You identify wind as a renewable option for Wisconsin. It is a much bigger option than you acknowledge.

There are some minor errors in your wind discussion, which I understand you plan to correct in the FEIS.

I will discuss some more significant issues here, including (1) our state's wind power potential and (2) wind power productivity.

1. Wisconsin Wind Potential

The Commission staff continues in the DEIS to misuse the 1991 Battelle PNL "Windy Land" study in somewhat the same manner it was misused in the Port Washington Case last year. This study was written in an era when 100-200 kW wind turbines were commonly being installed on 30-35-meter towers. It must be used with caution today when 1.5-2.0-MW wind turbines are typically being installed on 70-80-meter towers, and when some turbines will soon be available with 100-meter towers.

The study is being misused in two ways. First, it is being used without regard to the actual increase in wind potential per square mile being achieved by today's larger-scale wind turbines. Second, it is being used by uninformed people to understate Wisconsin's usable wind resource.

As to the first point, I view 12 MW per square mile as a significant understatement of what is actually achievable with today's MW-scale technology. I believe an average of 15 MW per mile is closer to the current reality, and this is likely to increase further after 2003.

As to the second point, any analysis that does not examine increasing tower height is likely to seriously underestimate Wisconsin's economically available wind resource. Wind speed at inland Wisconsin sites increases rapidly with height above ground level. At most potential wind sites away from the Great Lakes, annual average wind shear exponents are at least .19 or .20 below 100 meters.

As a practical matter, any site identified as a Class 3 Site by the Battelle PNL study (i.e., 14.3 mph or higher at 50 meters), would have a Class 4 or higher wind resource (15.66 mph or higher) at 80 meters if it had even a .19 wind shear exponent. Thus, what the Battelle Study actually tells us, considering today's taller tower realities, is that Wisconsin has 3500 square miles of Class 4 or greater inland wind resource (mean 15.66 mph or higher) at 80 meters.

According to this height-corrected approach, assuming 15 MW per square mile, Wisconsin has an inland potential of 52,500 MW at Class 4 or better wind resource sites with today's commercial technology. With next year's or 2005's technology, this potential will be even higher.

While not all of this potential could be realized for various land-use-related reasons, enough could be realized to displace the entire energy production potential of ERGS.

It is completely indefensible to maintain that Wisconsin has only 2040 MW of Class 4 wind resource, as the DEIS suggests. Wisconsin has more than this in Class 5 potential inland.

Wisconsin also has substantial offshore potential in the Great Lakes, especially in Lake Michigan. This potential includes hundreds of square miles of depth of less than 100' in S.E. Wisconsin, especially off S. Milwaukee, Racine and Kenosha Counties. It also includes hundreds of square miles further offshore E. of Milwaukee in somewhat deeper water on the mid-lake ridge between Milwaukee and Muskegon. This potential is all Class 4 (most of it Class 5) or higher, with today's technology and would support about 20 MW per square mile with an extremely modest footprint of much less than one acre of surface affected per square mile. The Wisconsin waters of Lake Michigan could support thousands to tens of thousands of MW of wind development. The FEIS needs to acknowledge this potential rather than ignore it.

The DEIS is extremely unrealistic in its installation and operation cost estimates for offshore wind. Offshore wind in Southern Lake Michigan is likely to be significantly less costly to install and operate than projects in salt water. Lake Michigan has a considerably more benign installation, corrosion, and operation climate than the locales developed offshore in

Europe to date. Furthermore, Wisconsin's potential near-shore sites in Lake Michigan are ideally situated to tie into the ATC 138-kV transmission system in S.E. Wisconsin, so they would not be nearly as expensive as most offshore sites elsewhere to connect to the existing grid.

I believe that the DEIS installed cost estimate for offshore wind is at least $300 per kW too high for sites close to shore in S.E. Wisconsin, and even this cost will decline as offshore technology is further developed.

I also believe that the O&M cost of offshore wind in Lake Michigan will ultimately be only slightly higher than for inland sites. Lake Michigan's more benign climate as compared to the oceans of Northwest Europe is a significant factor in tempering O&M costs. There will be far fewer days when weather precludes maintenance on Lake Michigan. In addition, it appears that there will be no site lease costs for offshore sites in the lake, unlike inland.

The discussion in the DEIS suggests, incorrectly, that Wisconsin would need to develop low Class 3 Sites to produce large amounts of wind energy. This is simply not true with today's taller tower wind technology. Nor are Class 3 Sites as unproductive as the DEIS suggests.

2. Wisconsin Wind Power Productivity

Wisconsin has at least three sites at which apparent Class 3 wind resources have been developed for wind farm purposes. In each case, the wind farm has produced at over a .20 capacity factor, despite using smaller than optimal rotor diameters. Examples include the Montfort, Lincoln, and Rosiere Wind Farms.

In the case of Montfort, where FPL Energy is operating 20 ENRON Wind 1.5-MW turbines (70.5 meter rotor version) on 65-meter towers, the Badger Windpower entry on WEPCo's 2002 FERC Form 1 Report (p. 326) suggests that that project operated at a .24 capacity factor (including losses) in 2002 with regard to WEPCo's 25.5-MW share. This site was not expected to have a mean wind speed at hub height in excess of 15 mph.

At the Rosiere Site, MGE has operated 17 Vestas V-47/660-kW turbines on 65-meter towers since July 1999, achieving an average capacity factor of .23 for calendar year 2000 through 2002 (including losses). MGE's wind measurements at 65 meters at Tamarack and Eagle Roads averaged 15.1 mph for this three-year period. However, these measurements are made at a site which is somewhat windier than the average for the turbines in the Rosiere Wind Farm. I estimate that the mean for the average Rosiere wind turbine is significantly under 15 mph at hub height.

At the Lincoln Site, WPS has operated 14 Vestas V-47's on 65-meter towers since July 1999, achieving an average capacity factor of .21 for calendar year 2000 through 2002 (including losses). WPS has not measured wind speed at this site, but I measured the wind speed there at 10 meters for several years. I estimate that the mean for the average Lincoln turbine at hub height is about 14.5 mph. The cramped spacing of turbines at this site increases array losses.

The experience to date at these well-maintained wind farm sites indicates very clearly that well-planned Wisconsin Class 3 wind resource sites produce considerably better than .20 capacity factors. The use of a .20 capacity factor for Class 3 in economic modeling would be inconsistent with this state's growing experience with producing more wind energy at such sites.

Part of the reason for this greater-than-.20 capacity factor experience is that Wisconsin has lower mean temperatures and higher mean air densities on a sea-level-adjusted basis than are assumed in standard wind turbine ratings.

Also of interest is the experience of Wisconsin Electric at its Byron Wind Farm Site to date. From 2000 through 2002, the two Vestas V-47's on 65-meter towers at this site produced 9345 MWh, indicating an average capacity factor of .27, including losses. I also measured within about 100 meters of this site using a 10-meter tower for several years. This site is windier than the previous three sites, with a mean wind speed of about 15.8 mph at hub height, I estimate. This is a low Class 4 wind resource (at 65 meters), but this site is maintained by a Rosiere-Lincoln-based (Vestas) maintenance team, which has to travel at least two hours one way to get there; thus, it may have larger availability losses than a locally-maintained wind farm.

As you may be aware, the Vestas turbine is not optimized for Wisconsin wind conditions. It has a smaller rotor relative to generator size than such turbines as the GEWE 1.5 (77-meter) and NM82 (1.65 MW) wind turbines, which are machines more optimized for a Wisconsin-type wind regime and are both now available with 80-meter towers.

Wisconsin has not yet developed wind resources at mid-to-high Class 4 wind resource sites, although it soon will at such sites and Class 5 sites as new taller tower technology is employed. We can safely predict higher capacity factors as such higher-wind-speed sites are developed using turbines like the GEWE 1.5 (77-meter) and NM82 (1.65-MW).

Even at a 16-mph site (low-to-moderate Class 4) with 15% overall losses (including array losses), these machines would produce at .30 and .31 capacity factors, respectively, according to the manufacturer's power curve.

With the tower heights now available for MW-scale machines, Wisconsin has some 17-mph in-land sites and many potential 17-mph-or-higher offshore sites, and the number of both will grow as tower heights increase. These would have higher capacity factors, up to about .34 or .35. Offshore sites in some cases could reach .40.

Capacity factors would tend to increase by about .01 for individually-sited turbines distant from neighboring turbines due to an absence of significant array losses in such cases.

I believe Wisconsin has many hundreds, possibly more than 1000, sites suitable for individual wind turbines. Our land-use and topography patterns in some parts of the state favor individual turbines distant from others. This kind of distributed development can be extremely efficient, minimizing array losses, electrical losses, and grid-connection investment.

I would suggest that modeling use a capacity factor of .35 (including losses) for Class 5, .32 for Class 4, and .27 for Class 3 wind farm installations, limiting the last category to no more than 20% of all wind installations, with about 20% of inland installations in Class 5 by 2005. I would model offshore installations as 80% Class 5, the rest Class 4 initially, and all Class 5 by 2010. If individually-sited turbines are modeled, they should be modeled at .01 higher capacity factors to reflect the absence of array losses in such cases. With the new large rotor, tall tower, technology now starting to come on line, Wisconsin will very seldom develop less-than-15-mph sites in the future. Most new wind installations will have more than a 15.66 mph (Class 4) wind resource, and virtually all will use large-rotor technology which will out-produce the Vestas V-47 at Wisconsin wind sites. Capacity factors used in modeling should reflect current commercial and near-future wind realities relevant to Wisconsin, not obsolete technology or technology optimized for different wind regimes which wind developers will not use here.

Wind is an increasingly competitive technology because it has not stood still since 1991. PSCW wind economic analyses need to be updated to 21st Century realities. Due to larger rotors and taller towers developed over the last 12 years, wind is now the most economic technology available to produce electric energy in Wisconsin, but PSCW models and some of your colleagues appear to be stuck in an early 1990's time warp which has not quite caught up to the new reality.

Now is the time to catch up!

Wind could displace <u>every single kWh</u> proposed to be produced by ERGS, and Wisconsin's economy, Great Lakes fishery, and environment would be all big winners from the substitution of clean Wisconsin wind for unclean Pennsylvania coal.

Biomass

Biomass could also displace <u>every kWh and every kW</u> proposed to be produced by ERGS.

Biomass potential from on-farm digesters may be as much as an order of magnitude higher than the 30 MW you identify. While much of this potential is on large dairy farms, there may also be some potential at large poultry and hog operations, with the latter potential increasing as global warming progresses and Wisconsin grows more corn and soybeans. There does appear to be a strong trend toward increasing herd or animal waste unit size in all three industries. The 30 MW figure is probably about right for current potential, but current potential does not begin to capture the rapid trend toward increasing animal unit size and farm consolidation.

I suspect that your cost numbers are also too high for biogas technology. This is a relatively new technology (like wind 20 years ago). Costs will drop significantly. Biogas generation will be economical, certainly more economical than ERGS, before 2010. Also, it is worth noting that biogas generation is a base load resource.

I believe that your costs are too high for other biomass technologies as for biogas. If your costs were realistic, biomass would begin to significantly penetrate the generation mix by about 2010.

Like biogas technology, other biomass technologies are at a relatively primitive stage of development. They will be more economical after future technological development. The development of biomass gasification and liquid fuel technologies is particularly promising for future efficient use of biomass feed stocks. Current biomass combustion technologies are not very efficient, but future technologies could be much more so. This not only improves future economics but also increases the amount of the potential to supply kW from a given biomass feed stock or land base.

The retirement of aging coal and perhaps nuclear plants will give impetus to greater efforts to develop biomass technologies in this decade or soon thereafter. As a state importing more than 95 percent of its primary energy at an annual cost of billions of dollars, an economically inhibiting dependence WE proposes to increase with the construction of ERGS, Wisconsin stands to benefit economically from finding ways to efficiently use its biomass resources as local energy resources instead.

The economic benefits of biomass development to rural counties are especially significant. This realization will give impetus to greater efforts to develop local biomass energy sources as current budget crises ease in a few years.

Also, biomass, like wind, is an inflation-resistant alternative to high-priced natural gas.

I think the FEIS would be enhanced significantly if it incorporated an expanded discussion on how biomass could play an important role in a more energy-self-reliant Wisconsin economy. I would like to see some real vision of an alternative future in this area.

There are a lot of people in all counties of this state who would rather pay Wisconsin farmers than Pennsylvania coal miners and intervening railroads for their energy. I certainly would.

Photovoltaic Cells

I see solar too as working its way into the electric grid a decade or two hence.

Right now, p.v. power is very expensive compared to base load energy. But when p.v. installed costs get down somewhere near $1000 per kW, perhaps by around 2020, I think p.v. will begin to be integrated into the grid on a large scale as a summer-peak capacity resource, offsetting by-then-very-expensive-to-run-gas-fired CT's and substation and distribution line upgrades.

P.v. will be more valuable than its avoided energy cost, because it will also avoid distribution and transmission and summer peak generation capacity costs. In some places, p.v. may make inroads into the grid as a distributed generation resource much earlier than this.

If the EGEAS model does not allow you to factor the d.g. benefits of p.v. into your alternative analysis, you need to find a better method for doing the analysis. This is a substantial benefit of

this technology.

Eventually, roof-mounted p.v. cells will be major producers of grid electricity. This will happen well before the ERGS black elephant is mothballed. The FEIS should acknowledge this very broadly shared vision.

I suggest you figure out a way to estimate when p.v. will drop to $1000/kW and then figure out a method to work it into the generation mix. Solar is a future generation resource circa 2057. Coal is not. If you are going to entertain proposals to build 50-year-life coal-fired pollution factories, you need to think well past the next 12 months in terms of the cost and role of potential alternatives. Solar is an example of one that may take more than a decade to begin to assume its future major role, but it will drop in cost, and it will assume that role in a time frame relevant to the ERGS proposal. P.v. costs have been declining, albeit slowly, for decades.

You need to figure out a way to model solar reasonably so that it can compete in the capacity and energy mix in the relevant time frame. Using some MGE inflated capital cost for a historical p.v. project as a fixed cost for p.v. into the next several decades is unacceptable. Ignoring p.v.'s peak and d.g. benefits is also unacceptable.

You must treat p.v. as a real alternative to ERGS. You may not punt on this. Solar, like wind and biomass, is a higher priority energy resource than high-sulfur coal, and it will be very big in Wisconsin's electric energy mix some day.

Remember, 20 years ago, wind cost 30 or 40 cents per kWh too. Now, wind energy sells for less than 3 cents per kWh in some cases. Something similar will likely happen with solar in the next 15 years. Any realistic model must treat solar installed costs as dropping over time.

Fuel Cells and Hydrogen

Again, you must treat fuel cells as a real alternative, dropping in installed cost over time. Even if they are fueled with natural gas, due to their high efficiency, they may be preferable to ERGS. With the auto industry committed to developing fuel cells as auto power plants, the advent of affordable fuel cells right down to household scale is inevitable, probably by about 2010.

You should lay greater emphasis on the likelihood that fuel cells will ultimately be fueled with hydrogen derived from renewable energy sources like wind or solar which have a variable output determined by the natural flow of wind or light photons at the moment. This natural variability, so troublesome to some linear-thinking engineers of limited imagination, including a few authors of the DEIS, is actually an advantage if the wind or p.v. generation is allowed to supply either electrons to the grid or hydrogen to storage, depending on the relationship of the current natural energy stream to current electric demand.

Ultimately, wind generation is likely to produce hydrogen at lower cost than natural gas.

With fuel cells in the generation mix, wind, biomass, and solar p.v. could run the electric grid

without combustion of any fossil fuels or production of any net CO_2 or nuclear waste. The grid could utilize surplus wind (mostly) or solar energy to electrolise hydrogen from water, store it, and use the hydrogen in fuel cells later to meet grid needs when the wind and solar flows were insufficient. The entire electric system could be virtually pollution free. Indeed, it could produce surplus hydrogen to fuel transport, homes, industry and commerce too.

Fuel cells exist. They are getting cheaper. They will ultimately be major players in supplying electricity. They will be much cleaner and more efficient than most current generation systems burning fossil fuels. They may ultimately play a major role in our vehicles and homes. They may even ultimately give us a chance to get rid of significant parts of our electric/water grids.

Consider the possibilities. Perhaps one day we will have the option to replace We (Filthy) Energies at our houses with we ourselves, our clean home fuel cell, and our hydrogen purchased from Offshore Environmental Energies, our friendly Lake Michigan wind-hydrogen producer, a company which will not disgorge mercury to the lake, CO_2 to the atmosphere, and slush funds to every self-absorbed legislative leader in Madison in need of an extended term in a state institution with bars on the windows.

I would like to read much more about such visionary possibilities in the FEIS.

Staff Analysis of Renewables

I think the DEIS correctly appraises the prospects for the federal wind energy production tax credit.

However, in the wind capacity credit area, I believe 20 percent is too conservative. I would use a figure of about 80 percent of the expected wind capacity factor to represent its summer peak capacity value. For a mean future installation wind capacity factor of .32, I would expect wind summer peak capacity value to average about .25, with big year-to-year fluctuations.

Conclusion

An important difference between people who lead change and people who resist it is the ability of the former to visualize how the future can be different from the present. Be visionary as you make your key contribution to the ERGS FEIS.

The emerging story of progress in renewable energy technology is engaging and exciting. Let the reader share the vision of a brighter, cleaner, energy and economic future for Wisconsin!

Very truly yours,

Robert H. Owen, Jr.
cc: Kathleen Zuelsdorff

Comments on the Draft Environmental Impact Statement, submitted by S.C. Johnson & Son, Inc.

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June 12, 2003

VIA HAND-DELIVERY AND E-MAIL

Mr. Jeffrey Kitsembel
Public Service Commission
P.O. Box 7854
Madison, WI 53707-2854

Re: Comments on Draft Environmental Impact Statement
Elm Road Generating Station
Docket 05-CE-130

Dear Mr. Kitsembel:

Enclosed please find the Comments of S.C. Johnson & Son, Inc., on the Draft Environmental Impact Statement for the Elm Road Generating Station. We are also sending a copy of these comments by e-mail to Mr. Michael Thompson, DNR's EIS coordinator for the project.

Sincerely,

WICKWIRE GAVIN, P.C.

Carl A. Sinderbrand

Enclosure
cc: Mr. Michael Thompson
S.C. Johnson & Son, Inc.
Service List (via e-mail)

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COMMENTS OF S. C. JOHNSON & SON, INC. ON THE DRAFT ENVIRONMENTAL IMPACT STATEMENT FOR THE ELM ROAD GENERATING STATION PSC DOCKET NO. 05-CE-130

S. C. Johnson & Son, Inc. ("SC Johnson") respectfully submits these comments to the Public Service Commission of Wisconsin ("PSC") and the Department of Natural Resources ("DNR") on their draft environmental impact statement for the proposed Elm Road Generating Station ("ERGS") dated April 2003 (the "DEIS").

SC Johnson is a family-owned and managed Wisconsin corporation whose principal place of business is located at 1525 Howe Street, Racine, Wisconsin. The company has been a Racine-based business since it was founded in 1886 and has grown to be one of the world's leading manufacturers of household cleaning products and products for home storage, personal care and insect control. The company has made a substantial investment in the area that would be directly affected by the ERGS and has a demonstrated historical interest and commitment to the environmental, social and economic health of the affected area.

SUMMARY OF COMMENTS

Wisconsin Electric Power Company and its affiliates (collectively, "WEPCO") have proposed to burden electric ratepayers with a $4.1 billion capital project that will have significant adverse economic and environmental impacts. The DEIS discloses many of the adverse impacts of WEPCO's proposal but requires substantial revision as a result of its heavy reliance on WEPCO's permit applications, which fail to identify many additional adverse impacts of the ERGS proposal. SC Johnson believes that the revisions that need to be made to the document are so numerous and important, and the gaps in the information provided by WEPCO so material and substantial, that the agencies should allow for a new period of public comment on a revised DEIS prior to publishing the final document. It is also apparent from WEPCO's testimony in the PSC proceeding that WEPCO is changing, or at least considering

changing, particular aspects of its proposal that would affect the assessment of environmental impacts. Such changes provide an additional reason why the agencies should make a revised DEIS, reflecting WEPCO's changes, available for another round of public review and comment.

The chapters of the DEIS that discuss the economics of the proposal examine a number of supply-side and demand-side issues in addressing the need for baseload capacity in Southeastern Wisconsin, and more specifically the reasonableness of the ERGS proposal. While the DEIS analysis is sound in many respects, there are a number of issues that are not sufficiently addressed that could significantly affect the ultimate determination of the need for and reasonableness of the ERGS project. The analyses undertaken in these parts of the DEIS reflect serious efforts to initiate a hard look at the proposal, but still stop short in a number of critical respects from truly exposing the overly optimistic, and often unrealistic, approach taken by WEPCO. In particular, the DEIS base case EGEAS analysis of the ERGS project fails to adjust for a number of unreasonable assumptions developed by WEPCO that serve to bias the study results in favor of the ERGS proposal. In several instances, the DEIS even notes that WEPCO's assumptions are unreasonable, but continues to incorporate such assumptions in the base case analysis instead of substituting more realistic figures. It is important to note that, notwithstanding these deficiencies in the DEIS analysis, the DEIS concludes that the proposed ERGS project is more costly than other alternatives in virtually all of the cases considered.

At minimum, the DEIS base case EGEAS analysis should be updated to reflect more reasonable assumptions for the items that are identified below. When such changes are made, the DEIS-projected significant economic advantage of other supply alternatives over the ERGS proposal will increase and will further support the conclusion that ERGS is neither a least-cost nor cost-effective proposal.

The DEIS's discussion of the environmental impacts of the ERGS is fatally flawed because, like WEPCO's submissions, it fails to analyze the health impacts of the project's high levels of air pollutant emissions. Public health issues cannot be ignored. The DEIS erroneously concludes that the project will meet the National Ambient Air Quality Standard (NAAQS) for particulate matter (PM) because WEPCO's modeling shows no exceedance of the PM_{10} NAAQS. In 1997, however, the U.S. Environmental Protection Agency determined that the PM_{10} standard was inadequate to protect the public against the adverse health impacts of $PM_{2.5}$ and, accordingly, supplemented the PM_{10} standard with a $PM_{2.5}$ standard. The DEIS fails to consider whether the project will cause or contribute to a contravention of the $PM_{2.5}$ NAAQS. The DEIS should be amended to disclose whether and to what extent the project will result in $PM_{2.5}$ impacts in excess of this health-based standard. The DEIS also fails to evaluate the health impacts of the project's hazardous air pollutants, which should be analyzed in a risk assessment using standard EPA methodologies.

The Clean Water Act requires that WEPCO use the Best Technology Available to limit the adverse impacts of the project's non-contact cooling water on Lake Michigan. The ERGS design presumes that WEPCO can use once through cooling for the project and, as a result, intake, heat and discharge approximately 2 billion gallons of Lake Michigan water a day. There has been no comparative demonstration by WEPCO, however, that the largely abandoned technology of once through cooling is the Best Technology Available for this project. The DEIS also fails to evaluate this technology choice against other available, and increasingly preferred, technologies. No discussion is presented as to alternative cooling technologies or whether they would be available to serve the proposed project. The DEIS also fails to adequately assess the

environmental impacts of using and heating 2 billion gallons of lake water per day for the project.

Another adverse impact of the project proposal is the doubling of coal train traffic in Racine County. The DEIS identifies this issue but fails to take the necessary hard look at the adverse local impacts of the coal trains.

COMMENTS ON CHAPTER 2 – COSTS AND FINANCING MECHANISM

The DEIS correctly notes that the leasing arrangements that WEPCO has proposed are more costly to electric customers than a traditional rate-making approach. The DEIS concludes that a traditional rate-making approach would cost ratepayers about 14% less on a present value basis than the WEPCO-proposed leasing mechanism. DEIS at 27. Even this estimate, however, understates the burden that WEPCO's self-serving leasing arrangements would place on electric customers, because the DEIS assumes that, under a traditional rate-making approach, WEPCO should receive a 13.7% after-tax rate of return on its invested capital in the project. DEIS at 26. This is an exceptionally high figure, especially since, under traditional rate-making, the utility bears little financial risk, since all prudently incurred costs are passed along to ratepayers. Considering our economy today, or even over the last decade, it would be difficult to find other opportunities for low-risk investments with an expected after tax rate of return of 13.7%. Additionally, the DEIS recognizes, at page 25, that WEPCO currently receives 12.2% on rate-based recovery on its existing owned generating units, further demonstrating that the DEIS's assumed 13.7% return for the traditional rate-making alternative, against which the leasing arrangements are compared, is too high. Were a lower return-on-equity number used for the traditional rate-making alternative, the advantage to customers of

traditional ownership and rate-making treatment over the leasing arrangements that WEPCO has proposed would be even more apparent.

COMMENTS ON CHAPTER 3 – NEED FOR BASELOAD CAPACITY

The title of this chapter – "Need for Baseload Capacity" – inadvertently places the emphasis on the wrong issue. The question is not so much whether there will ever be a need for new baseload generating units in Wisconsin (at some point, there will be, under any forecasting scenario) but when it would be prudent to make such investments. If optimal planning calls for the construction of peaking units or wind turbines and the implementation of additional energy efficiency measures for the next decade, as the DEIS EGEAS-modeling runs plainly indicate, then the ERGS plan, which frontloads the construction of a $4.1 billion investment in coal-fired generating units, is imprudent and should not be certificated.

A key factor influencing the need, timing and economic benefits of WEPCO's proposed ERGS project is the projected growth in peak demand on the Company's system over the next ten years. While the DEIS notes that WEPCO's peak demand has increased at a rate of approximately 2.5% per year since 1997, and concludes that WEPCO's peak demand growth forecast of 2.8% to 3.0% per year over the 2002-2010 period "may be on the high side," DEIS at 51, the DEIS ultimately uses the Company's demand forecast for its base case EGEAS economic analysis of the ERGS project. The use of WEPCO's peak demand growth forecast, rather than a more reasonable forecast that reflects historical growth levels in the demands on WEPCO's system, unduly favors the ERGS project. The DEIS wisely considered a peak demand sensitivity case that evaluated the impact of using a peak demand growth rate of 2.3% to 2.5% per year over the 2002-2010 period. DEIS at 47. While the lower demand forecast used in the DEIS more closely resembles the recent historical demand growth on WEPCO's system and therefore

represents a more reasonable growth assumption for the base case analysis of the ERGS, it is important to note that WEPCO's 2002 SEC 10-K states that its system peak demand was lower in 2002 than it was in 2001. The 10-K also states that total energy sales from the WEPCO electric system were lower in 2002 than they were in 2001 and lower in 2001 than they were in 2000. WEPCO has not provided any rational basis for concluding that the demand and energy sales growth on its system over the next ten years will exceed the growth experienced during the economic boom of the late 1990's, particularly when it has experienced decreases in energy and demand growth more recently. The DEIS base case analysis should be modified to replace WEPCO's peak demand and energy growth forecasts with a forecast that more reasonably reflects the historical demand and energy growth of the system.

The discussion of projected increases in WEPCO's peak load (DEIS at 46-48) should be clarified. These projections, even if accurate, have little relevance to determining whether the ERGS is needed or would be cost-effective. Peak demand, which may occur on the one hundred hottest hours of the summer, can be met with relatively inexpensive alternatives such as demand-side management (DSM) or by installing off-the-shelf single cycle combustion turbines that may not be suitable for base load generation but can be a cost-effective way of producing electricity for a few hundred hours a year. The enormously capital-intensive coal-fired plants that have been proposed here can be justified only by secular increases in electricity demand within WEPCO's service territory that require more base load generation. They cannot be justified to meet projected increases in peak load that are highly questionable in light of recent experience and which may occur in only a few hours each year. The discussion of peak load in Chapter 3 should be rewritten to make this clear.

The PSC-certificated Badger Gen project is omitted from Table 3-3 on the theory that it, like certain other independent power product projects, has "been placed on hold because they have been unable to sign contracts with Wisconsin electricity providers and the widespread financial difficulties in the IPP markets." DEIS at 38 n.32. It should be noted, however, that WEPCO has purchased the land on which this project was to be sited and could seek to pursue it if it chose to do so.

Chapter 3 also suggests that more baseload generating units are needed because such units are prone to frequent and prolonged outages. DEIS at 50-51. We submit that a different inference should be drawn from this premise. First, since large baseload units are prone to frequent and prolonged outages due to the failure of their high pressure boiler components, the analysis of their costs should realistically reflect the lower reliability of such units and the cost of such replacement power when the units are out of service. More realistic consideration of this factor would greatly increase the costs of operating the type of large coal-fired units that comprise the ERGS, making them even less economic than they are portrayed in the DEIS. Second, the frequent outages at large coal-fired units illustrate the unrealistic reliability assumptions that WEPCO and the DEIS have used to analyze the ERGS units. While the DEIS accepts the Company's forecast that the annual forced outage rate for the ERGS units will be only 2%, history has shown that such units typically operate with forced outage rates of nearly 7% per year. The EGEAS runs should be redone using a more realistic 6% forced outage rate for the ERGS units rather than the unjustifiably low 2% forced outage rate that WEPCO and the DEIS have used to analyze the economics of these units. Using more realistic performance assumptions for the ERGS units in the EGEAS runs will show that these units are even less economic than the DEIS suggests that they would be.

COMMENTS ON CHAPTER 4 – ALTERNATIVES TO THE PROPOSED PROJECT

The DEIS notes that the EGEAS model does not pick a coal unit until 2022 if CO_2 costs are monetized. DEIS at 81. This conclusion illustrates the uneconomic nature of the ERGS proposal, particularly since CO_2 monetization falls well short of a full consideration of all of the social and economic costs resulting from coal-fired generation. On June 5, 2003, WEPCO publicly committed itself to monetizing CO_2 costs, endorsing an important proposal to that effect that CERES – a leading U.S. coalition of environmental, investor, and advocacy groups – has announced and is promoting. See CERES, Electric Power, Investors and Climate Change (June 2003) (www.ceres.org/pdf/ceres_electric_recs.pdf). Since WEPCO has itself endorsed the principle that utilities should be required to monetize CO_2 costs, these costs should be added to the EGEAS base case analysis. The data presented in the DEIS establish that doing so would result in a finding that the ERGS proposal is not cost-effective and cannot be certificated.

A. Energy Efficiency Alternatives

The DEIS recognizes that Wisconsin law requires that energy conservation is to be given the highest priority when evaluating options to supply future electricity needs. DEIS at 53. Although WEPCO's application claims that cost-effective energy efficiency measures cannot obviate the need for the ERGS, the DEIS correctly concludes that WEPCO has failed to substantiate its contention because: (i) there is no basis to verify WEPCO's claim that virtually all cost-effective energy measures are already included in WEPCO's future demand forecasts, and (ii) WEPCO limited its analysis exclusively to the residential sector. DEIS at 56-57. The DEIS concludes that "[a]s a result of these shortcomings, it is likely that the applicant underestimated the availability of additional cost-effective energy efficiency." DEIS at 57.

The DEIS also presents the PSC staff's analysis of energy efficiency alternatives. Significantly, the DEIS notes that – using the 85% market penetration rate that WEPCO itself assumed to be reasonable in its application, see DEIS at 56 – the staff's analysis identifies "an additional 1,000 MW of cost-effective savings by 2011." DEIS at 58. The DEIS characterizes this analysis as the "Staff's most aggressive scenario" but it does not seem overly aggressive since it merely uses the same market penetration rate that WEPCO itself assumes to be reasonable in its application. Moreover, the DEIS states that there are "several shortcomings" in the Staff's analysis that "likely underestimate the energy efficiency potential." DEIS at 58. The shortcomings include the failure to consider new technologies and the application of energy efficiency measures in the industrial sector. See DEIS at 58. Accordingly, it is reasonable to consider the 1,000 MW figure as a reasonable estimate of the minimum peak load reduction that could be achieved by 2011 through pursuit of cost-effective energy efficiency measures. This demand reduction must be incorporated in the demand forecast in Chapter 3.

Notwithstanding the DEIS's important finding that WEPCO did not fully consider the potential demand reduction impacts of energy conservation in its peak demand forecast, the DEIS does not include any energy efficiency peak reduction impacts in its base case analysis of the ERGS project. The DEIS base case analysis of the ERGS project should be updated to include a reasonable level of additional energy and demand reduction impacts available from cost-effective energy conservation and load management options.

B. Wind and Natural Gas Alternatives

The EGEAS model runs presented in the DEIS show that wind turbines and natural gas combustion turbines are complementary and, in combination, deliver reliable electricity at a lower economic cost than the coal-fired units that WEPCO has proposed. DEIS at

74. Even with the 250 MW and 1,250 MW wind power limitations placed on the EGEAS model runs, the DEIS concludes that "wind power could be a significant component of an integrated resource alternative that could substitute for all or a portion of the ERGS." DEIS at 61. This conclusion is highly significant, particularly in light of the statutory preference for the use of renewable resources over fossil fuels. Sec. 1.12, Stats.

Even the DEIS analysis, however, short-changes the advantages of the integrated wind and gas alternative to the ERGS because it (i) assumes that only 20% of the capacity of a wind turbine can be credited towards the reserve margin, see DEIS at 71; (ii) arbitrarily caps the wind turbines at 250 MW or 1,250 MW, see DEIS at 72, 76; (iii) fails to consider the social and economic costs of coal-powered generation, including the adverse land use impacts of the coal trains and the premature mortality and increased morbidity from the air pollution generated by this highly polluting fuel; and (iv) fails to consider hundreds of millions of dollars of costs specific to the ERGS proposal, including $266 million in electric transmission reinforcement costs, railroad line modifications, potential bluff removal, extension of the intake water structures, the potential capital and operating costs of an alternative to once through cooling, and payments to the local municipality.

The EGEAS model should be re-run relaxing the limitations that discourage wind power. Thus, the model should be run assuming a 25% or, alternatively, a 30% capacity credit for wind power and eliminating the artificial caps on wind power. Additionally, the DEIS assumes no water-based wind power generation on the basis of cost assumptions that are poorly documented and poorly explained. See DEIS at 60. No similar cost data are presented for competing technologies, making it difficult to evaluate the cost data presented on page 60, which also appear to be stated using inapplicable or misstated units of measurement. Water-based wind

power generation, using accurate and realistic cost assumptions, should be added to the options that the EGEAS model may consider, and the cost figures for this technology should be documented and explained. (As a precedent for a water-based wind farm, it should be noted that the Long Island Power Authority has proposed to construct such a facility in the Atlantic Ocean near Long Island. See www.lipower.org/papers/RFP/wind_rfp.html.)

To put the 250 MW and 1,250 MW ceilings on wind power in perspective, it should be noted that wind power has become a mainstream business. A record 6,868 MW of new wind power capacity was installed worldwide in 2002, increasing generating capacity by 28%. See American Wind Energy Association press release March 3, 2003 (available at www.awea.org). Global wind power capacity has quadrupled over the last five years, growing from 7,600 MW at the end of 1997 to more than 31,000 MW at the end of 2002. Id. Installed generating capacity has increased by an average of 32% annually for the last five years (1998-2002). Id. Were this rate of increase to be sustained, worldwide capacity would be 375,000 MW by 2011. The maturation of the industry is illustrated by General Electric Corporation's recent purchase of Enron's wind turbine business. GE expects the operation to generate more than $1 billion in revenue during 2003 and expand about 20% annually. See "GE's Wind-Power Play May Be Turning Point for Clean Energy," The Courier-Journal, Louisville, KY (May 15, 2003) (AP news story) (available at www.courier-journal.com). A significant increase in global reliance on wind power in the coming years is likely in light of the economics of this resource, which, as the EGEAS model runs presented in the DEIS indicate, is cheaper than coal-fired generation and, when combined with natural gas backup power, supplies a reliable, cleaner and lower cost alternative to coal-fired options.

C. Natural Gas Price Volatility

Electricity customers, such as SC Johnson, have an interest in the price that a utility pays for natural gas to run its generating units because that cost is passed through to the customer. One of the principal arguments marshaled in the DEIS against using natural gas as an alternative to coal is the variability in natural gas prices. See DEIS at 67. The DEIS makes this point by using a simplistic statistical model that purports to show that it is nearly impossible to predict future gas prices because of the historic variability in natural gas prices on the spot market. See id. What principally matters to electric customers, however, is not the extent to which gas prices vary from day-to-day or from season-to-season but the average dollar that the utility pays per Btu over the course of several years, because it is these long-term averages that are relevant to predicting whether fueling new units with natural gas rather than coal will be economically advantageous or disadvantageous over the several decades in which a new unit will be in service.

The DEIS discussion at pages 67-68 appears to exaggerate the importance of the statistical model that is used there. Natural gas prices can be forecasted into the future notwithstanding their season-to-season variability, because long-term trend lines establish a basis for such forecasting. Much of the variation from the general year-to-year trend of U.S. natural gas use (and the resulting variation in natural gas prices) can be attributed to variations in average winter temperatures. For example, the larger than average increase in gas use from 1999 to 2000 was primarily the result of a change from the particularly warm winter weather of 1999-2000 (3,351 heating degree-days or 457 fewer heating degree-days than normal) to the particularly cold winter of 2000-2001 (4,048 heating degree-days or 240 more heating degree-days than normal). The fact that natural gas prices change with the turning of the seasons and

annual variations in temperatures merely establishes that, in using historic price data to predict future prices, the forecaster must consider additional variables that the DEIS has omitted from its statistical model. Price variability per se does not establish, as the discussion in the DEIS would appear to indicate, that it is impossible to forecast long term natural gas price trends or that natural gas is an uneconomic fuel. Historic trends have shown that periods of rapid increases in natural gas prices have inevitably been followed by periods of similarly rapid decreases in prices as the market responds to short-term imbalances between supply and demand for natural gas.

D. Firm Power Purchases

The DEIS concludes that WEPCO has increased its firm power purchases to a level that is near the limit that can be reliably considered, thereby suggesting that additional power purchases are not a viable alternative to supply the capacity need that WEPCO plans to serve from its proposed ERGS units. DEIS at 50. In support of this conclusion, the DEIS provides information on the growth in the level of WEPCO's firm power purchases from approximately 400 MW in 1998 to a forecasted level of slightly over 1600 MW in 2004. DEIS, Figure 3-2, at 33. Yet a closer examination of WEPCO's supply-side plan shows that the Company is forecasting that its firm purchases will decrease sharply from approximately 1,600 MW in 2004 to less than 980 MW by 2008, the year after the first ERGS unit is planned to come on line. See WEPCO Original Application, Enclosure 1, Table 1-4. While there certainly may be reasonable limits on the level of purchased power that WEPCO should consider, the DEIS base case analysis should not simply adopt WEPCO's forecasted sharp decrease in firm purchases that coincidentally correspond with the timing of the forecasted need for the ERGS units. This sharp drop in firm purchase alternatives is particularly questionable given the Company's failure to seek competitive bids for purchased power as an alternative to the

proposed ERGS projects. The DEIS base case EGEAS analysis should be updated to maintain future firm purchases at the 2004 level for at least the first ten years of the analysis. This revision could significantly alter the forecasted base case analysis of the need for and benefits of the ERGS units.

In addition, the DEIS appears to adopt WEPCO's proposal to treat capacity supplied by firm purchases in the same manner as it treats capacity supplied from a generating unit. However, firm purchased power contracts are frequently backed by reserves provided by the seller. Accordingly, WEPCO's analysis of its system capacity requirements may be overstated by ignoring the capacity reserves that are supplied with such firm purchase contracts. The DEIS base case EGEAS analysis should be updated to specifically address this issue in order to ensure that WEPCO has not overstated its reserve requirements and thereby overstated its need for new capacity.

E. Projected Firm Power Sales

The DEIS base case EGEAS analysis incorporates without adjustment WEPCO's firm power sales forecast that includes approximately 500 MW of off-system sales that presently are not under contract. It is unreasonably speculative and improper to include such uncommitted off-system power sales in the base case analysis of the ERGS project, since no such contracts may come into existence and WEPCO's native system retail customers ultimately will be held responsible for the entire investment in the ERGS if such sales do not materialize. Moreover, it appears that WEPCO's firm sales forecast that is used for the DEIS base case analysis includes "options" that have been negotiated by WPPI and certain other publicly owned utilities to purchase firm capacity from the ERGS project. This treatment of unexercised purchase options as firm demand obligations of the WEPCO system is not only overly speculative, but it also

appears to overstate WEPCO's peak demand by including such capacity sales options as an increase in WEPCO's peak demand obligation and as a 100 MW per unit reduction in the generating capacity of the ERGS project. WEPCO's assumptions, as reflected in the DEIS analysis, appear to double count 100 MW per ERGS unit, because they add the additional 100 MW that would be generated by these units to WEPCO's peak load forecast but assume that 100 MW from each unit will not be available to meet that peak load, thereby necessitating construction of yet more reserve capacity on the WEPCO system. The DEIS base case EGEAS analysis should be modified to address this apparent double counting of ERGS capacity options, to remove the speculative off-system sales options included in WEPCO's peak demand forecast, and to remove reserves included for any existing capacity sales that do not provide for reserves.

F. Construction Cost Assumptions for ERGS and Gas-fired Alternatives

The DEIS recognizes that, under WEPCO's proposal, the risk of construction cost over-runs for the ERGS project would be placed on the ratepayers. The DEIS further notes that the Company admits that "because few coal-based facilities have been built recently, the risk that actual costs may deviate from estimated costs is greater for the ERGS facility . . . ." DEIS at 14. Notwithstanding these warnings of the risks of construction cost over-runs for the ERGS proposal, the DEIS base case EGEAS analysis uses the Company's base construction cost estimate for the ERGS project. Conversely, the DEIS base case analysis also uses WEPCO's construction cost estimate for natural gas-fired combustion turbine alternatives, even though there have been significant recent reductions in combustion turbine equipment prices due to the downturn in the merchant power industry.

The DEIS base case analysis should be modified to reflect a minimum 10% increase in WEPCO's base construction cost estimate for the ERGS project and to include lower

natural gas combustion turbine equipment costs that reflect current market conditions. A 10% increase in WEPCO's base construction cost estimates would be modest indeed since it is our understanding that WEPCO's contractor (Bechtel) will not even provide a firm cost estimate until the construction is 30% complete, and the proposed leases have WEPCO-drafted exceptions to the porous cost "cap" they incorporate as to make their 10% limit on cost escalation a meaningless façade.

G. ERGS Performance Assumptions

The DEIS base case EGEAS analysis incorporates WEPCO's unreasonably optimistic and unsupported assumptions regarding the operating availability and efficiency of the ERGS units. These optimistic assumptions bias the EGEAS results in favor of the ERGS project. For example, the DEIS does not address the reasonableness of WEPCO's forecasted equivalent availability factor (EAF) (over 90%) and forced outage factor (only 2%) for the ERGS project. These assumptions are extremely optimistic; in comparison the national average forced outage factor for similarly sized coal-fired units is more than 6%. Moreover, the DEIS adopts WEPCO's heat rate (efficiency) assumptions for the ERGS project that are also highly optimistic and unsupported. While the most recent heat rate information published by the Utility Data Institute for existing coal-fired units indicates that no units achieve a heat rate better than 9,035 Btu/kWh, the DEIS base case analysis has used WEPCO's heat rate forecast of 8,850 Btu/kWh for the ERGS project. It is not appropriate to justify $4.1 billion in investments based on highly optimistic, unrealistic performance assumptions that have not been achieved by any other similar generating unit. The DEIS base case analysis should be modified to incorporate more reasonable availability and efficiency assumptions for the ERGS based on demonstrated performance of similar coal-fired generating units.

H. ERGS Emissions Costs

While the DEIS recognizes that the proposed ERGS units will emit considerable amounts of SO_2, NO_x, mercury and other air pollutants, only the current cost of SO_2 allowances is monetized, and then not even in the base case analysis. Clean air legislation already proposed by both major political parties would impute a market value upon NO_x and mercury and increase the value (determined by anticipated compliance costs) of SO_2 allowances. Due to the fact that emissions from the ERGS would be much higher than gas-fired alternatives, and with the prospect that new legislation could soon be passed that would significantly increase future emissions allowance costs, the DEIS base case analysis of the ERGS should be updated to more reasonably reflect the costs of SO_2, NOx and mercury emissions.

Monetization of these additional allowance costs, although appropriate, would not fully reflect the social and economic costs of the coal-fired generating units that WEPCO has proposed to build. Even with the additional allowance costs factored into the analysis, the DEIS would continue to understate the true cost of the ERGS proposal, because the allowance costs do not include the social and economic cost of the morbidity and premature mortality associated with the ERGS emissions, the costs associated with the adverse aquatic impacts to Lake Michigan resulting from the ERGS' once through cooling water system, or the costs associated with the adverse land use impacts of the coal trains. These issues are addressed in further detail below.

I. EGEAS Runs

The EGEAS data presented in Table 4-7 of the DEIS demonstrate the uneconomic nature of the ERGS proposal. The PSC staff base case, which contains a number of unrealistic assumptions that, as explained above, appear to bias the analysis in favor of the ERGS, calls for

constructing only one ERGS unit through 2011. The EGEAS runs using the "high gas [price]" scenario, which favors coal-fired generation, also call for constructing only a single ERGS unit through 2011. An increase of coal capital costs by 20% results in the EGEAS model selecting no ERGS units through 2011. CO_2 monetization results in constructing no ERGS units through 2022. DEIS at 81. The final EIS should contain a similar table setting forth the results of the additional EGEAS runs that SC Johnson and other commentators have suggested. Specifically, based on the information that it has been provided to date, SC Johnson requests that the PSC staff include the results of the additional EGEAS runs identified below in the final EIS for the project.

The additional EGEAS scenarios are intended to be conducted as changes to WEPCO's base case EGEAS runs supporting WEPCO's direct testimony as filed on May 27, 2003. EGEAS should be run for two cases – (i) ERGS without IGCC and (ii) EGEAS Optimized (with timing and type of capacity additions selected by EGEAS) – for each of the following scenarios. For each scenario, except for modifications specified, all assumptions should reflect WEPCO's base case EGEAS analysis, as filed on May 27, 2003, in order to maintain comparability of results.

Scenario 1: Demand and Supply-Side Modifications

a. Peak Demand Obligation

- Demand Growth – midpoint between WEPCO's 5/27 base case and low case forecasts, per Table 1 below.

b. Supply Side Resources

- Assume wind generation tax credit eligibility extended through 2006
- Assign 20% capacity credit for wind generation
- Increase capital cost of SCPC units by 10%

- Increase forecasted heat rates for SCPC units by 3% at all load levels

- Increase forced outage rate for SCPC units to 6%

- Reduce forecasted heat rates for gas-fired combined cycle alternative to reflect 6,820 average heat rate and assumed values at all load levels as reflected in the original application

Scenario 2: Emissions Cost Sensitivity

a. Model SCPC Emissions at the following rates and based on allowance costs reflected in Table 2 below:

   SO_2 Emission Rate: 0.16 lb/MMBtu (1-SCJ-012)

   NOx Emission Rate: 0.07 lb/MMBtu (1-SCJ-14)

   Mercury Emission Rate: 2.3×10^{-6} lb/MMBtu (1-SCJ-023)

b. Model gas-fired combined cycle combustion turbine emissions at the following rates and based on allowance costs reflected in Table 2 below:

   SO_2 Emission Rate: 0.0006 lb/MMBtu (Original Table 1-8)

   NOx Emission Rate: 0.013 lb/MMBtu (Original Table 1-8)

   Mercury Emission Rate: 2.3×10^{-6} lb/MMBtu (1-SCJ-023)

c. Model gas-fired simple cycle combustion turbine emissions at the following rates and based on allowance costs reflected in Table 2 below:

   SO_2 Emission Rate: 0.0006 lb/MMBtu (Original Table 1-8)

   NOx Emission Rate: 0.037 lb/MMBtu (Original Table 1-8)

   Mercury Emission Rate: 2.3×10^{-6} lb/MMBtu (1-SCJ-023)

d. Incorporate all other changes and revised assumptions as reflected in Scenario 1.

Scenario 3: Sensitivity as to Changing Assumptions as to Retirements of Existing Units

a. Assume Oak Creek Units 5 and 6 retire after 60 years of operation (instead of in 2012) as reflected in original application.

b. Incorporate all other changes and revised assumptions as reflected in Scenario 2.

Scenario 4: Low Demand and Energy Growth Sensitivity

a. Use WEPCO's 5/27 low case peak demand and energy forecasts

b. Incorporate all other changes and revised assumptions as reflected in Scenario 1.

Scenario 5: Enhanced DSM, Energy Efficiency and Renewable Energy Sensitivity

a. Use WEPCO's low case peak demand and energy forecasts to reflect enhanced energy efficiency and DSM potential.

b. Increase capacity credit for Wind Generation to 20%, remove all caps on level of wind generation option and extend production tax credit for Wind Generation through study period.

c. Incorporate all other changes and revised assumptions as reflected in Scenario 1.

Scenario 6: Gas-fired Combustion Turbine Sensitivity

a. Reduce WEPCO's forecasts of installed capital costs for gas-fired combined cycle and simple cycle combustion turbines by $75/kW.

b. Decrease annual forced outage rate assumptions for gas-fired combined cycle and simple cycle combustion turbines to 3%.

c. Reduce Scenario 1's heat rate estimates for gas-fired combined cycle and simple cycle alternatives by 3%.

d. Incorporate all other changes and revised assumptions as reflected in Scenario 1.

Scenario 7: High Coal Price Sensitivity

a. Use WEPCO's high coal price sensitivity

b. Incorporate all other changes and revised assumptions as reflected in Scenario 1.

Table 1

Scenario 1 Peak Demand and Energy Forecast

Year	Peak Demand (MW)	Growth	Annual Energy (GWh)	Growth
2003	5,912		31,771	
2004	6,115	3.4%	32,694	2.9%
2005	6,232	1.9%	33,163	1.4%
2006	6,376	2.3%	33,782	1.9%
2007	6,567	3.0%	34,511	2.2%
2008	6,734	2.6%	35,438	2.7%
2009	6,970	3.5%	36,397	2.7%
2010	7,126	2.2%	37,284	2.4%
2011	7,299	2.4%	37,979	1.9%
2012	7,446	2.0%	38,825	2.2%
2013	7,602	2.1%	39,499	1.7%
2014	7,763	2.1%	40,187	1.7%
2015	7,928	2.1%	40,888	1.7%
2016	8,096	2.1%	41,604	1.7%
2017	8,268	2.1%	42,333	1.8%
2018	8,444	2.1%	43,078	1.8%
2019	8,624	2.1%	43,837	1.8%
2020	8,808	2.1%	44,612	1.8%
2021	8,976	1.9%	43,207	-3.1%
2022	9,168	2.1%	44,013	1.9%
2023	9,364	2.1%	44,836	1.9%
2024	9,564	2.1%	45,675	1.9%
2025	9,770	2.2%	46,530	1.9%
2026	9,980	2.1%	45,783	-1.6%
2027	9,894	-0.9%	46,673	1.9%
2028	10,113	2.2%	47,597	2.0%
2029	10,338	2.2%	48,508	1.9%
2030	10,567	2.2%	49,454	1.9%
2031	10,802	2.2%	50,419	2.0%
2003-2011		2.7%		2.3%
2003-2020		2.4%		2.0%
2003-2031		2.2%		1.7%

Table 2

Scenario 2 Emissions Allowance Cost Estimates
Source: http://www.epa.gov/air/clearskies/tech_sectionc.pdf

	SO2 $/ton	Nox $/ton	Mercury $/ounce
2002	$200		
2003	$200		
2004	$200		
2005	$200		
2006	$200		
2007	$200		
2008	$200		
2009	$200		
2010	$700	$1,425	$550
2011	$740	$1,417	$580
2012	$780	$1,409	$610
2013	$820	$1,400	$640
2014	$860	$1,388	$670
2015	$900	$1,375	$700
2016	$960	$1,488	$740
2017	$1,020	$1,600	$780
2018	$1,080	$1,658	$820
2019	$1,140	$1,716	$860
2020	$1,200	$1,775	$900
2021	$1,280	$1,820	$950
2022	$1,360	$1,865	$1,000
2023	$1,440	$1,910	$1,050
2024	$1,520	$1,955	$1,100
2025	$1,600	$2,000	$1,150
2026	$1,700	$2,045	$1,210
2027	$1,800	$2,090	$1,270
2028	$1,900	$2,135	$1,330
2029	$2,000	$2,180	$1,390
2030	$2,100	$2,225	$1,450
2031	$2,220	$2,270	$1,520
2032	$2,340	$2,315	$1,590
2033	$2,460	$2,360	$1,660
2034	$2,580	$2,405	$1,730
2035	$2,700	$2,450	$1,800

COMMENTS ON CHAPTER 5 – FUEL DIVERSITY PERSPECTIVES

The DEIS discloses that 69% of the energy consumed by WEPCO's electricity customers is produced by coal-fired generation. DEIS at 34, Figure 3-4. Nuclear energy supplies another 27.5%. Id. Natural gas is used to generate only 3.3% of the electricity that WEPCO sells, and renewable energy is used to generate only 0.1% of WEPCO's electricity. Id. It is these statistics that need to be kept in mind when considering whether the proposal to build more coal-fired power plants in Wisconsin would contribute to the "fuel diversity" that WEPCO has said that it wants to promote.

The first sentence in the section of the DEIS discussing the "reliability" of natural gas states that "Wisconsin has no indigenous supplies of natural gas." DEIS at 84. A similar comment could be made about coal, as well, since WEPCO has proposed to power the ERGS by burning out-of-state Pennsylvania coal. Although the DEIS focuses on the fact that natural gas must be imported to Wisconsin, the equally pertinent facts as to the extent to which the ERGS must rely upon out-of-state coal are omitted. There is potential for disruptions in the supply of coal due to transportation problems, strikes and other factors, just as there is potential for a reduction in the supply of natural gas. If reliance upon out-of-state fossil fuels is undesirable, as the DEIS implies, the logical conclusion is not to use coal instead of natural gas but to rely upon renewable energies such as wind and energy efficiency measures to reduce electricity demand.

The discussion on page 88 mixes data on new gas-fired electric generation nameplate capacity with statements about increased use of natural gas for electricity generation. The discussion could be improved by noting that coal-fired units typically have much higher annual capacity factors (i.e., utilization levels) than single cycle gas-fired combustion turbines, which are often used as peaking units. Moreoever, new gas-fired combined cycle generating units are approximately 30% more efficient than existing gas-fired generation that these units

displace and, therefore, consume less fuel per megawatt-hour produced. Accordingly, future energy consumption trends for coal and gas will not match the tend line that would be established simply by comparing the nameplate generating capacity data for 2000 and 2003 presented in Figures 5-3 and 5-4. For example, according to data published by the Energy Information Administration, less natural gas was consumed for electricity generation in the United States in 2001 than in 2000. See EIS Annual Energy Review 2001 Table 8.3a (www.eia.doe.gov/emeu/aer). Energy use data for 2002 are not yet available.

The discussion on pages 89-90 of the DEIS suggests that gas-fired electric generating units are less reliable than coal-fired units because gas-fired units must cease operating in the event of an interruption in gas availability, if the gas-fired unit is relying on interruptible interstate transmission capacity. No data are presented, however, as to how often gas-fired units are taken off-line as a result of an interruption in gas supply availability. Moreover, the DEIS provides no discussion of the reduction in supply curtailments that can be achieved for gas-fired power plants by adding fuel oil backup capability. Nor are any data presented as to forced outages at coal-fired power plants. Published historical outage data for coal-fired and combustion turbine gas-fired units indicate that combustion turbine gas-fired units are at least as reliable, if not more reliable, than coal-fired units. Historic forced outage data for gas-fired and coal-fired units should be presented in the final EIS before any conclusion is reached that gas-fired units are less reliable than their coal-fired counterparts.

COMMENTS ON CHAPTER 6 – OVERVIEW OF PROPOSED SITES AND TECHNOLOGIES

A. Alternatives Analysis

The DEIS – no doubt accurately – describes the site selection criteria that WEPCO used to arrive at a proposed site for the ERGS. DEIS at 97. According to the DEIS,

WEPCO's siting criteria required the site to have access to the massive amounts of cooling water needed for once through cooling and screened out sites that are not well suited for the delivery of coal. DEIS at 97-98.

Notably, WEPCO did not use siting criteria aimed at minimizing the adverse environmental impacts of the project. No sites suitable for natural gas units were considered. No sites suitable for cooling water technology that would have less adverse impacts on Lake Michigan were considered. No effort was made to seek to locate the new plant outside of Wisconsin's severe ozone nonattainment area. Nor was consideration given to the fact that the neighborhoods near the existing Oak Creek Power Plant are already burdened by the very high emissions of WEPCO's existing coal-fired generating units at that site. No thought was given to seeking to choose a site that might involve less earth moving or wetland filling than the Oak Creek site. WEPCO also did not consider any sites that might be suitable for two SCPC units without the IGCC.

The DEIS telescopes the site selection process so as to leave the reader with the impression that WEPCO's siting criteria led it to propose multiple locations for the proposed ERGS units on the grounds of the Oak Creek Power Plant site. The contrary is true. WEPCO's idea of proposing as "alternatives" different configurations of the coal-fired ERGS units at the Oak Creek Power Plant site was a mere afterthought on WEPCO's part as a result of the Commission's determination that WEPCO's initial application was incomplete due to its failure to comply with the legal requirement that it consider more than one site. Instead of coming up with a bona fide alternative to its preferred site for the project, WEPCO merely rearranged the location of the ERGS units within the existing Oak Creek Power Plant site and deemed these new configurations "alternatives."

The inadequate alternatives analysis in the DEIS falls short of the alternatives analysis that is required for the PSC to certificate the project. In order to grant a Certificate of Public Convenience and Necessity, the statute requires a determination that, among other things, "[t]he design and location [of the proposed facility] is in the public interest considering alternative sources [of fuel] supply, alternative locations . . . engineering, economic, safety, reliability and environmental factors . . . ." Sec. 196.491(3)(d)3, Stats. The PSC regulations provide that an application for a large electric generating facility cannot be deemed complete unless and until it contains detailed information about, among other things the "alternative sources of [fuel] supply considered, including . . . any alternative whose energy source has a higher priority ranking under the [State Energy Policy] than the fuel proposed to [be] used for the facility . . . [and] at least two proposed sites for the proposed facility . . . ." § PSC 111.53(1)(d) & (e), Wis. Admin. Code.

The alternatives analysis in the DEIS also falls short of the evaluation required by the Wisconsin Environmental Policy Act ("WEPA"). According to DNR's WEPA regulations, an EIS shall include "[a]n evaluation of the alternatives to the proposal, including a rigorous exploration and objective evaluation of the environmental impacts of <u>all reasonable alternatives</u>, particularly those that might avoid all of some of the adverse environmental effects of the proposed action." § NR 150.22(2)(e), Wis. Admin. Code (emphasis added). The term "alternatives" is defined as "other actions or activities which may be reasonably available to achieve the same or altered purpose of the proposed action including the alternative of no action." § NR 150.02(2), Wis. Admin. Code. The PSC's WEPA regulations similarly require that the EIS include an "evaluation of the reasonable alternatives to the proposed action and significant environmental consequences of the alternatives, including those alternatives that

could avoid some or all of the proposed action's adverse environmental effects and the alternative of taking no action." § PSC 4.30(3)(c), Wis. Admin. Code.

Here, instead of requiring WEPCO to submit detailed information on at least one additional location somewhere in its service area where it might meet its projected increased generation needs, the agencies have prepared a DEIS that limits its analysis of alternative locations to a single site. The various "alternative" locations within that site are no more than a fig leaf to hide the fact that WEPCO, and the DEIS, have only considered one site. Indeed, the caption of DEIS Figure 6-2, on page 100 of the DEIS, correctly demarcates the area that encompasses the alternative configurations of the project units as the "existing OCPP site."

The "alternatives" are all nearly identical to each other, since they would use the same rail line to transport coal to the site and the major coal pile required for both "alternatives" would be in the same location at the site. The "alternatives" would use the same transmission line interconnects, and would use either the same breakwater structures and expanded electrical switchyard facilities or simply move these to a different part of the site. The "alternatives" presented in the application would burden the same area with the same significant air emissions from the coal-fired units and would have the same adverse aquatic impacts on Lake Michigan, since each "alternative" would withdraw the same volume of water from the Lake and discharge the same volume of water from the site.

The rationale for the decision to limit the analysis to a single site is the agency's deference to WEPCO's siting criteria, which excluded all sites that are not suitable to coal or a technology other than once through cooling. WEPCO's self-serving siting criteria, however, are not the priorities that should govern the preparation of the DEIS for WEPCO's project. The State Energy Policy enacted by the Legislature and codified by statute into Wisconsin law

establishes "priorities" that place WEPCO's choice of fuel – high sulfur bituminous coal – dead last in the hierarchy of options for generating energy in Wisconsin. The Policy enjoins all state agencies to design all new energy projects in accordance with the Legislature's statutory priorities to the "greatest extent cost-effective and technically feasible." Sec. 1.12(5)(b), Stats. By allowing WEPCO to first select coal as the preferred fuel for its project (and allowing WEPCO to rule out sites that cannot accommodate each of the three coal-fired units, the last of which would not even be built for ten years) and then presenting in the DEIS only those "alternatives" that WEPCO believes to be appropriate for three coal-fired units, the PSC has erroneously allowed WEPCO's fuel preference – rather than the Legislature's fuel preference codified into law – to dictate the range of site alternatives that should be considered in the DEIS. The agencies have, in effect, delegated the choice of the location, size and fuel type of WEPCO's project to WEPCO itself, by allowing WEPCO to circumscribe the range of considered alternatives to different configurations of coal-fired units at the site of the existing Oak Creek Power Plant.

Even if the DEIS were to be limited only to sites that are suitable to coal-fired generation, the DEIS does not identify or analyze any other site other than the Oak Creek Power Plant site. The impacts at a different site could be substantially different, because there are particular characteristics of the Oak Creek Power Plant site that make it poorly suited to the ERGS project. The Oak Creek Power Plant site is located in a severe nonattainment area and adjacent to neighborhoods that are already burdened by the adverse air quality impacts of WEPCO's existing coal-fired generating units at the site. The Oak Creek Power Plant site also suffers from peculiarities of topography that have caused WEPCO to propose what may well be the largest earth moving project ever conceived of in the State. The site is on Lake Michigan,

resulting in adverse ecological impacts from the construction work that WEPCO has proposed and the use of lake water for the units' cooling water system. Alternative sites might suffer from fewer of these disadvantages, or use different rail lines, and thus have less adverse train-related impacts. Since the DEIS does not present information about any alternative sites, however, the data that should have been gathered to allow the agencies to determine whether the Oak Creek Power Plant site is the best location for the project simply are not available. This is a key deficiency in the DEIS.

An analysis of alternative sites is important for the additional reason that locating the ERGS at the Oak Creek Power Plant site burdens the project with more than $266 million in incremental transmission costs – costs that the DEIS has excluded from the EGEAS modeling runs altogether. DEIS at 18, 129-31. The DEIS is deficient in not presenting any information as to whether using an alternative site could have avoided these costs.

B. Synergy with the Oak Creek Power Plant

There is a suggestion in the DEIS that the ERGS would share the same "coal-handling equipment" as the Oak Creek Power Plant. DEIS at 98. This statement appears to be inaccurate. Since the ERGS is expected to use bituminous coal from Pennsylvania and the existing Oak Creek Power Plant units use Powder River Basin coal, the two plants are expected to have separate coal piles and use different coal-handling equipment. The site plan drawings that WEPCO has submitted with its application confirm that this is the case. Accordingly, locating the ERGS at the Oak Creek Power Plant site does not result in significant savings. This conclusion is consistent with the earlier discussion as to the significant ($266 million) incremental transmission costs associated with siting the ERGS units at Oak Creek.

C. Commercial Wallboard Plant

The DEIS mentions WEPCO's aspiration to bring a commercial wallboard plant to the Oak Creek Power Plant site. DEIS at 117. The DEIS neither analyzes the potential environmental impacts of such a plant or the commercial feasibility of the proposal. No credible evidence exists that the project will ever come to fruition. It appears to have been forwarded by WEPCO simply to divert attention from the massive amount of solid waste that the ERGS will produce as a result of the use of coal, which is a high ash fuel.

COMMENTS ON CHAPTER 7 – AIR EMISSIONS

The DEIS states that "the DNR must still conduct its own air quality modeling analysis in order to determine if the project is permittable, and if so, under what circumstances and conditions." DEIS at 133. SC Johnson strongly agrees with this statement. We nevertheless present below a number of criticisms of the air quality modeling, and other air-related issues, in the DEIS, and request that these issues be addressed in the final EIS and in the analysis that the DNR must complete to evaluate WEPCO's application for air permits. In virtually all cases, the deficiencies in the DEIS on air-related issues can be traced directly to the deficiencies in WEPCO's air permit and CPCN applications.

The WEPCO air permit application is flawed in a very fundamental way because it fails to analyze the health impacts of the air pollution from the new coal-fired units. To our knowledge, neither the PSC nor DNR has requested this extremely important information as part of the CPCN or other permit applications, or to assist in their preparation of the EIS. By failing to evaluate whether WEPCO's project would endanger public health, the DEIS does not provide the public and the agencies with essential information about the project's impacts that must be considered prior to issuing any project-related permits or approvals.

PSC and DNR should require WEPCO to provide the necessary additional data and information so that the DEIS can be supplemented with an analysis of the health impacts of the new coal-fired generating units that WEPCO proposes to build at the Oak Creek Power Plant site. The health analysis should consider both (i) the impacts of the new units on a stand alone basis and (ii) the cumulative health impacts of the new units and the air pollution from the existing coal-fired units at the Oak Creek Power Plant.

If WEPCO's project proposal were to be approved, the residential neighborhoods near the Power Plant would be subjected to the cumulative air pollution from the existing and new coal-fired units. If these cumulative impacts exceed health-based standards, WEPCO must be required to locate its proposed new units elsewhere, use a less polluting fuel, or implement substantially more effective pollution reduction and control measures.

WEPCO has failed to provide the necessary underlying information to allow the draft EIS to evaluate health impacts of the ERGS' air emissions. It is essential that the information be obtained and that the DEIS be revised and then subjected to another round of public comment after the supplemental analyses are performed and prior to finalization of the final EIS. This is necessary to give the public the opportunity, to which it is legally entitled, to comment on the agencies' full analysis of health impacts for the proposed project.

A. Fine Particulates ($PM_{2.5}$)

Of particular concern is the failure of WEPCO (and thus the DEIS) to even address the severe adverse health impacts of fine particulates – known as $PM_{2.5}$ – from the proposed new coal-fired units. EPA promulgated a NAAQS for $PM_{2.5}$ six years ago, in 1997. In setting the standard, EPA concluded that exposure to $PM_{2.5}$ at the ambient concentrations that presently exist in some areas of the country – including those in compliance with the NAAQS for

PM_{10} – can result in serious health consequences, including premature mortality, exacerbation of respiratory and cardiovascular disease, decreased lung function, increased respiratory symptoms from pre-existing pulmonary disease, and aggravation of symptoms associated with asthma. See EPA, National Ambient Air Quality Standards for Particulate Matter, 62 Fed. Reg. 38652, 38656 (July 18, 1997). More recent studies published in peer-reviewed scientific journals, including the Journal of the American Medical Association, confirm these findings and conclude that exposure to combustion-related $PM_{2.5}$ air pollution is also an important environmental risk factor for cardiopulmonary and lung cancer mortality. See Pope, *et al.*, "Lung Cancer, Cardiopulmonary Mortality, and Long-term Exposure to Fine Particulate Air Pollution," J. Am. Med. Assoc. 287:1132-41 (March 6, 2002). This pollutant cannot be ignored by either WEPCO or the draft EIS.

DNR's $PM_{2.5}$ monitoring network has been operating statewide since 1999. DEIS at 135. None of these data is presented in the DEIS. Nor is there any information as to whether the cumulative impact of the ERGS and the existing Oak Creek Power Plant generating units will result in exceedances of the $PM_{2.5}$ NAAQS in light of these background data. This is a critical flaw in the DEIS that must be corrected.

WEPCO has inexplicably failed to provide any analysis of the $PM_{2.5}$ emissions of the proposed new coal-fired units or the existing units at the Oak Creek Power Plant. Consequently, the DEIS does not address this major concern. The DEIS must be supplemented so that it will analyze (i) the local and regional impacts of the new coal-fired units on ambient $PM_{2.5}$ levels; (ii) whether these impacts will cause or contribute to a contravention of the National Ambient Air Quality Standard for $PM_{2.5}$; and (iii) the cumulative health impact of the

$PM_{2.5}$ emissions from the new coal-fired units and the existing units at the Oak Creek Power Plant.

Instead of considering $PM_{2.5}$ impacts, the DEIS addresses the only particulate matter analysis that WEPCO has provided to date and presents the ambient air quality impacts of the PM_{10} emissions from the new coal-fired units and compares them to the National Ambient Air Quality Standard for PM_{10}. This approach is inadequate because the reason that EPA set the more stringent standard for fine particulates six years ago was that it determined that the PM_{10} standard does not adequately protect human health from the mortality and morbidity impacts of $PM_{2.5}$. Since the EPA has concluded that the PM_{10} standard is inadequate to protect human health, the draft EIS will remain deficient if it perpetuates WEPCO's shortcoming by relying upon the PM_{10} standard as the only point of reference for analyzing the project's particulate matter impacts.

The DEIS also errs in implying that $PM_{2.5}$ is caused exclusively by the reaction of gaseous pollutants in the atmosphere. DEIS at 134. These types of reactions are indeed a significant source of ambient $PM_{2.5}$. In addition, however, coal-fired power plants such as the ERGS emit substantial quantities of $PM_{2.5}$ directly. Due to the filter fabric used to reduce the ERGS' particulate matter emissions, most of the ERGS' PM_{10} emissions are condensable particulates that fall within the $PM_{2.5}$ particle size. Accordingly, the ERGS is likely to directly emit more than 1000 tons of $PM_{2.5}$ per year into the local atmosphere, not including the type of additional atmospheric formation of $PM_{2.5}$ to which the DEIS alludes. See DEIS Table 7-9.

B. Hazardous Air Pollutants

The draft EIS, at page 173, reveals that the new coal-fired units will spew into the air, each year, more than 203 tons – more than 406,000 lbs – of a suite of metals and other

chemicals, including mercury, chromium and arsenic, that are regulated as Hazardous Air Pollutants. The draft EIS does not provide any assessment of the risks that emissions of these pollutants may present to the health of those who live in the neighborhoods surrounding the plant, or in the region. As with $PM_{2.5}$, it is critically important that the draft EIS be supplemented to assess the health risks of these pollutants and the cumulative impacts of the existing coal-fired generating units at the Oak Creek Power Plant.

The multi-pathway risk assessment that needs to be undertaken here should look at both cancer risks and non-cancer toxicity. In addition to examining the inhalation risks imposed on those who live near the power plant, the risk assessment should examine the health risks from the deposition of these pollutants on the ground and in Lake Michigan and other local water bodies.

The single largest source of human-made mercury pollution in America is coal-fired power plants. People are exposed to mercury primarily through eating fish that have been contaminated when mercury from power plants and other sources is deposited to water bodies. Once mercury enters water, biological processes can transform it into methylmercury, a highly toxic form of mercury that builds up in animal and human tissues. Additional exposure pathways include direct inhalation and the consumption of crops, milk and meat that have been contaminated by mercury that falls on farmland. Exposure to mercury has been associated with both neurological and developmental damage in humans. The developing fetus is highly sensitive to mercury's effects, which include damage to nervous system development.

The Oak Creek Power Plant is already one of the largest sources of mercury emissions in the State of Wisconsin. The ERGS would more than double the mercury emissions at Oak Creek, and the final EIS must carefully evaluate the ERGS' adverse mercury impacts.

The seriousness of the issue is illustrated by the EPA's finding, on December 14, 2000, that mercury emissions from coal-fired power plants pose significant hazards to public health and must be reduced. See 65 Fed. Reg. 79825 (Dec. 20, 2000). Instead of reducing mercury emissions in Wisconsin, the ERGS would increase them.

In addition to evaluating mercury impacts, the DEIS should also examine the project's other toxic air pollutants, including arsenic and chromium. Although the DEIS makes reference to the "virgin fossil fuel" exemption in the State's air toxics regulations, see DEIS at 150, the ERGS units will not be able to take advantage of this exemption because WEPCO plans to burn previously landfilled ash, as well as coal, and reclaimed ash is not a virgin fossil fuel. More fundamentally, the health issues created by the ERGS' emission of large quantities of hazardous air pollutants must be examined irrespective of whether the units fall under the cited exemption.

C. Coal Dust

Another significant gap in the information provided by WEPCO and a flaw perpetuated in the draft EIS is its failure to identify and evaluate the impacts of the coal dust that will be generated by the massive coal-handling operations associated with the new coal-fired units, which are expected to burn more than 10,000 tons of coal daily. It is unclear whether the DEIS includes any modeling of the adverse impact of the coal dust on local air quality or considers the impact of the dust on WEPCO's employees or local residents. These impacts could be very significant. The DEIS (at page 300) identifies this issue but fails to take the requisite hard look at it.

D. Nonattainment New Source Review Requirements

The very brief discussion of nonattainment new source review requirements on page 142 of the DEIS purports to summarize these requirements. The DEIS summary, however, is materially deficient in ways that illustrate the importance of the health issues that the DEIS fails to analyze.

Oak Creek is located in a severe nonattainment area for ozone that is comprised of six counties in southeastern Wisconsin (Kenosha, Milwaukee, Ozaukee, Racine, Washington and Waukesha). Exposure to ozone, one of the principal components of smog, can reduce lung function, cause asthma attacks, and, with frequent exposure, cause permanent lung damage. The proposed coal-fired units would emit volatile organic compounds (VOC) above the severe nonattainment area significance threshold of 25 tons per year. See § NR 408.02(21)(a)1.d, Wis. Admin. Code. Because WEPCO has proposed to locate a significant new source of VOC emissions in a nonattainment area, it is required to obtain a permit from the DNR under section 173 of the Clean Air Act.

Although the DEIS purports to summarize the requirements of a section 173 permit, it omits any mention of the three permit requirements outlined below.

1. WEPCO Must Present an Alternatives Analysis that Demonstrates That The Benefits of the ERGS "Significantly Outweigh" the Environmental and Social Costs Imposed as a Result of its Location.

Section 173(a)(5) of the Clean Air Act requires the permitting agency to determine that "an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source demonstrates that benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification." Although the Wisconsin air regulations contain the same

requirement, see § NR 408.08(2), Wis. Admin. Code, the DEIS omits any mention of the provision.

This permitting requirement mandates an assessment of the "environmental and social costs" of the ERGS proposal, including (i) the mortality and morbidity burden associated with WEPCO's proposed use of supercritical pulverized coal (SCPC) technology and resulting changes in ambient concentrations of $PM_{2.5}$ and other air pollutants and (ii) the traffic and other adverse impacts of the increase in the number of coal trains that will traverse Racine County to deliver coal to the new generating units. The DEIS – like WEPCO's air permit application – is deficient in not assessing these environmental and social costs.

This permitting requirement also mandates "an analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source." As explained above, there is no bona fide analysis of "alternative sites" in the DEIS, or in WEPCO's air permit application. Moving the three coal-fired units around the Oak Creek Power Plant site does not meet the requirement to consider "alternative sites" under the Clean Air Act. Nor does the DEIS consider in an adequate way alternative "sizes, production processes, . . . [or] environmental control techniques" to the ERGS proposal, as there is little in the way of an environmental assessment of the relative air quality advantages of the numerous feasible alternatives to the ERGS project.

Finally, this requirement mandates that WEPCO demonstrate through the foregoing (omitted) alternatives analysis that the benefits of the proposed project "significantly outweigh" its environmental and social costs. Since the air permit application and the DEIS contain neither an adequate alternatives analysis nor an assessment of the environmental and

social costs of the ERGS, there is no basis to make this finding on the information that WEPCO has provided to date.

2. To Obtain the Nonattainment Permit, WEPCO Is Also Required To Demonstrate That Its Wisconsin Facilities Are In Compliance, Or Are On a Schedule to Come Into Compliance, With All Applicable Clean Air Act Emission Limitations and Standards.

Section 173(a)(3) of the Clean Air Act states that "the owner or operator of the proposed new or modified source [must] . . . demonstrate[] that all major stationary sources owned or operated by such person (or by any entity controlling, controlled by, or under common control with such person) in such State are subject to emission limitations and are in compliance, or on a schedule for compliance with all applicable emission limitations and standards under [the Clean Air Act]." The Wisconsin regulations contain a similar requirement, but add that the applicant must also establish that all of its sources are in compliance with Wisconsin's air regulations. See § NR 408.08(1), Wis. Admin. Code. The DEIS discussion of nonattainment new source review permitting neglects to mention these requirements.

On April 29, 2003, the United States Attorney's Office, on behalf of EPA, commenced a civil action in the U.S. District Court for the Eastern District of Wisconsin alleging that the Oak Creek Power Plant and WEPCO's other major power plants in the State are operating in violation of numerous Clean Air Act requirements and, as a result, are unlawfully emitting tens of thousands of tons of pollutants each year into the air. In light of this civil action, WEPCO's unsubstantiated assertion that its power plants are in compliance, contained in a pro forma statement in its air permit application, cannot be credited. Indeed, WEPCO has not even attempted to demonstrate that its existing plants are in compliance with the Clean Air Act in any document that has been made available to the parties to this proceeding or the public.

It should be noted that WEPCO has negotiated a proposed consent decree with the EPA, and this document has been lodged with the federal court. The EPA, however, has reserved any final decision as to whether it will request the court to enter the proposed consent decree, pending its consideration of the public comments that it has solicited on the proposed settlement by notice published in the Federal Register on May 15, 2003. See 68 Fed. Reg. 26,354. Even if the EPA were to decide to request that the court approve and enter the propose consent decree, there is no guarantee that the court would do so. Accordingly, we believe that, at least at this time, there is no basis to conclude that WEPCO's in-State power plants are "on a schedule for compliance with all applicable emission limitations and standards" of the Clean Air Act as implemented in Wisconsin by the DNR, as no such enforceable schedule with DNR concurrence exists at this time to resolve the serious allegations made in the EPA's federal court action. Until this matter is fully resolved at all levels, WEPCO's air permit application cannot be considered complete.

3. To Obtain the Nonattainment New Source Review Permit, WEPCO Is Also Required To Demonstrate That The ERGS Will Comply With The Lowest Achievable Emission Rate (LAER) for VOC Emissions.

WEPCO must show that the proposed source will comply with the LAER requirement for the project's VOC emissions. The SCPC units do not meet LAER requirements because this technology for producing electricity from coal has higher VOC emissions than the IGCC technology that WEPCO has included in the ERGS proposal. See DEIS Table 7-9 at page 155. WEPCO cannot claim that the lower emissions associated with the IGCC technology are not "achievable" in light of WEPCO's determination to apply for a Certificate of Public Convenience and Necessity for the IGCC unit as part of this project.

E. State Air Permitting Regulations

The DEIS also summarizes the State's air permitting regulations. See DEIS at 168. The discussion is deficient because it omits applicable regulations that WEPCO also failed to address in its air permit application.

According to DNR's regulations, "[n]o person may cause, allow or permit particulate matter to be emitted into the ambient air which substantially contributes to exceeding of an air standard, or creates air pollution." § NR 415.03, Wis. Admin. Code. Similarly, "[n]o person may cause, allow or permit emission of sulfur or sulfur compounds into the ambient air which substantially contribute to the exceeding of an air standard or cause air pollution." § NR 417.03, Wis. Admin. Code. Identical language is used for NO_x (§ NR 428.03) and organic compounds (§ NR 419.03(1)). The regulations define "air pollution" as "the presence in the atmosphere of one or more air contaminants in such quantities and of such duration as is or tends to be injurious to human health or welfare, animal or plant life, or property, or would unreasonably interfere with the enjoyment of life or property." § NR 400.02(16), Wis. Admin. Code.

Accordingly, it is clear that Wisconsin's air permitting regulations prohibit "air pollution," a term that is defined by reference to adverse health impacts. As noted above, however, the DEIS, like WEPCO's air permit application, fails to address the mortality or morbidity impacts of the new coal-fired units. As previously noted, there is no discussion of the $PM_{2.5}$ impacts of the units and no risk assessment of the impacts of the units' hazardous air pollutants. These deficiencies in WEPCO's air permit application and the DEIS must be corrected before any approvals are given to the ERGS.

F. Modeling Results

The DEIS presents modeling results that are stated to be based on WEPCO's modeling work. These data are presented in DEIS Tables 7-23, 7-24, 7-25, 7-26, 7-27, and 7-28. Like the WEPCO documents from which the data are drawn, however, this modeling effort is inadequately documented, limiting its value for public comment on the modeling work. For example, no information is provided as to the emission rates used for the modeling, or how these rates were derived, either for the ERGS units or the existing units at the Oak Creek Power Plant. Nor is information presented as to the impacts at the specific locations of the residential neighborhoods that are nearest to the Plant. And, as noted above, the modeling fails to include either $PM_{2.5}$ or HAPs such as mercury, chromium or arsenic. No information is presented as to how the ambient background data were calculated from the State's network of monitoring sites. This type of undocumented presentation is conclusory and does not provide an adequate basis for public comment and analysis. An additional flaw in the modeling work is that it fails to consider impacts to local and regional $PM_{2.5}$ levels, including the secondary formation of $PM_{2.5}$ in the atmosphere as a result of the ERGS' gaseous emissions.

Finally, the impact of plant emissions on short-term air quality, in particular compliance with the 3-hour SO_2 air quality standard, during Lake Michigan inversion breakup fumigation events has not been assessed. This is an important issue because the modeling that WEPCO has done shows that the Oak Creek plant will, even without considering fumigation, be perilously close to the 3-hour SO_2 standard. It is our understanding that the modeling presented in the DEIS is based on the ISC-PRIME model. This model is appropriate for many applications but may underestimate impacts from the ERGS during certain local meteorological conditions. As stated in the December 2, 2002 letter of Mr. Robert B. Miller, Chief, USEPA Region 5

Permits and Grants Section, which was copied to DNR, fumigation may occur with pollutants near a shoreline that are emitted into a cool, stable layer of air coming off of the water. This stable layer can break down in the warmer boundary layer over the land, resulting in the pollutant being mixed down to the ground and causing higher concentrations than those shown in the ISC-PRIME model that WEPCO and the DEIS are relying upon for this project. The USEPA letter states that: "Given the location of the Wisconsin Energies Oak Creek power plant relative to Lake Michigan, fumigation of the power plant emissions should be examined." We agree with this recommendation, which appears to have been ignored in preparing the DEIS. This issue should be studied further, along the lines that the USEPA suggests in its December 2, 2002 letter.

Additionally, the modeling that WEPCO has done is sensitive to the number, height and location of the stacks. The recently filed direct testimony of WEPCO's witnesses suggests that the stacks for the SCPC may be combined, moved and reduced in height. These changes may be necessary to comply with federal aviation requirements as well, at least for the two southern configurations. DNR and PSC should require that WEPCO resubmit its modeling and the underlying data so that DNR can re-evaluate anticipated emission impacts. Since air emissions are among the most significant potential environmental, health and cost impacts from this project, DNR and PSC should reissue the DEIS, including the underlying emissions assumptions, calculations, and supporting data, for further public review and comment.

Notwithstanding the deficiencies in WEPCO's modeling, the results, as presented in the DEIS, indicate that the project will consume very large percentages of the available SO_2 and PM_{10} air resources in the vicinity of the plant. The additional projected emissions of NO_x will also exacerbate the existing severe ozone nonattainment problem, and the project will

require a large number of VOC emission offsets that would no longer be available to support future industrial growth in the region.

G. Construction-Related Air Emissions

The DEIS, very properly, discloses that the construction work required to build the ERGS project at the Oak Creek Power Plant site will result in a potential for "localized diesel emissions" that could be "very high." DEIS at 176. The DEIS is deficient, however, in not providing any modeling results for these emissions and thereby failing to provide the data needed to assess whether the emissions will result in a contravention of NAAQS (including the $PM_{2.5}$ NAAQS). Nor does the DEIS discuss or analyze the means by which such adverse impacts could be avoided. For example, potential mitigation measures include a requirement that the construction vehicles use low sulfur diesel fuel. More fundamentally, WEPCO should be required to select an alternative location for the project that would not require the massive earth moving that WEPCO has proposed.

COMMENTS ON CHAPTER 8 – WATER RESOURCES

A. Adverse Impacts of Once Through Cooling

WEPCO has proposed to use once through cooling for the ERGS units – a primitive technology that uses massive amounts of water and thereby results in maximum impacts to the aquatic environment. The new units are projected to use approximately two billion gallons of water per day, every day, for the next 50 years.

Cooling water intake structures cause adverse environmental impacts by pulling large numbers of fish and shellfish or their eggs into a power plant's cooling system, a phenomenon called "entrainment." There, the organisms are killed or injured by heat, physical stress, and by the chemicals used to clean the cooling system. Larger organisms are killed or

injured when they are trapped against screens at the front of an intake structure, a phenomenon called "impingement."

The magnitude of fish deaths is directly related to intake volume. The more water WEPCO uses, the more organisms they will kill. As a result of WEPCO's plans to use once through cooling, it can be expected that the new generating units will kill tens of millions of aquatic organisms – including adult and juvenile fish, shellfish, larvae, eggs and other organisms – annually. The draft EIS (at pages 206-07) identifies the problem but reflects WEPCO's failure to provide any comprehensive analysis or evaluation of the ecological significance of these impacts to our environment. The DEIS does not provide a basic description of the current baseline aquatic environment that will be impacted by the intake or a description of the anticipated impact on that aquatic environment. As a result, the DEIS can make no meaningful statements about the ecological significance of the impact of this massive intake volume.

There are a series of well-recognized steps required for the adequate assessment of the impingement and entrainment impacts caused by cooling water intakes. These can be summarized as follows:

1. Identify the species that are living in the area and which will be likely to be impacted.
2. Identify the presence of rare and important species and assess their vulnerability to direct and indirect impacts.
3. Quantify impingement and entrainment using relevant past data and ecological surveys.

4. Assess seasonal patterns of entrainment and impingement to determine if there are particular periods of the year when mortalities of fish and other organisms will be particularly great.
5. Assess the impact on the local populations using the quantitative estimates of the number of fish and other animals killed.
6. Assess the impact on other water users such as fishermen and potential long-term impacts over the 40-50 year lifetime of the plant.

The DEIS is substantially deficient because it does not undertake the above steps adequately. The agencies need to require WEPCO to provide all of the necessary data and information, and then take a closer look at these impacts and the mitigating measures that can be imposed to prevent them.

The DEIS does not discuss any alternatives to the once through cooling proposal. Nor does it discuss what can or will actually be done to minimize impacts. To our knowledge, WEPCO has not even begun a study of the distribution of fish eggs and larvae to determine the best locality of the intake; at any rate, the DEIS does not contain the information that is needed on this score. This information should have been included in WEPCO's initial CPCN application so that it could be considered in the DEIS. This is yet another unfortunate consequence of the PSC's hasty decision to certify WEPCO's CPCN application as complete last November.

The DEIS fails to provide any useful data on the number of organisms that will be killed by the project. Data collected in the 1970s indicates that large numbers of fish and crustaceans were being killed at that time by the existing coal-fired units at the Oak Creek Power Plant. DEIS at 188. No estimates are provided, however, as to the number of organisms that the

ERGS will kill in the current, very different Lake Michigan environment, and there is no assessment of the ecological significance of the killings.

There have been major changes in the aquatic life of the lake since the 1970s. The extent of these changes is such that using 1970s impingement and entrainment data for the ERGS is inadequate. Many species have declined as zebra mussel populations, which deprive the water of essential nutrients, have increased. A strong case can be made that the present situation is not healthy. To assume that all is well and WEPCO can kill even more fish and other organisms in Lake Michigan is inappropriate in the absence of a detailed assessment of the issue, which has not been undertaken.

The DEIS also fails to assess adequately the impacts of the construction of the intake and outfall structures. There are still considerable uncertainties about the construction methods and the impacts on the environment. Large scale dredging work will be undertaken that will have an impact on fish and invertebrates. Yet no benthic survey has been carried out to assess the communities that will be impacted.

The DEIS makes vague comments about the fact that best practices will be used but it does not explain what they will be. WEPCO has failed to demonstrate that the technology that it has proposed is the "best technology available," as section 316(b) of the Clean Water Act requires. The DEIS does not discuss in any detail the alternatives to the primitive technology that WEPCO has proposed or assess whether better technology is, in fact, available for this project.

The use of once-through cooling for such a large plant with an offshore intake will make it very difficult to minimize impingement and entrainment mortality and preclude a finding that WEPCO is proposing to use the best technology available. In an attempt to avoid an

analysis describing the cooling water intake impact, the DEIS states that cooling water intake structure rules require "that the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." DEIS at 201. The DEIS, however, contains not the slightest hint of what will actually be done to minimize impacts. Technologies for reducing impingement and entrainment mortality do exist and are most effective for smaller volumes of water than would be extracted by the proposal. Thus, they would be far more feasible if indirect cooling was proposed. It is essential that protective technologies are designed into the intake and outfall configuration from the outset, since it has frequently been found that post-commissioning alterations are both expensive and of reduced effectiveness.

Technologies that might be applied to reduce entrainment and impingement include fish deterrent systems, barrier nets, modified Ristroph screens with fish return systems, aquatic filter barriers, wedge wire screens and variable speed pumps. Most of these cannot be applied to an offshore intake of the size proposed. Even if they could be installed, in most cases their effectiveness in such an application is unknown.

Given the massive volume of cooling water that WEPCO has proposed, which would appear to preclude adequate measures to mitigate adverse environmental impacts, WEPCO should be required to use closed cycle cooling. Closed cycle cooling would reduce the volume of intake water, and the resulting impingement and entrainment of fish and other aquatic organisms, by 97% or more. WEPCO should be required to provide all of the necessary information and analyses so that the EIS can evaluate closed cycle cooling technology as an option or compare the impacts of closed cycle cooling to the once through cooling method. This

is a significant deficiency in WEPCO's analysis and in the draft EIS that must be corrected through a supplemental analysis.

B. Thermal Discharge Impacts

Thermal pollution refers to the discharge of heated water to lakes and streams. The sudden increase in water temperatures in the area of the discharge kills aquatic organisms that are unable to adjust to quickly changing water temperatures, reduces dissolved oxygen in the water, and has other adverse impacts on aquatic ecology. WEPCO's proposal to use once through cooling at the Oak Creek Power Plant would place a significant thermal load on the area of Lake Michigan adjacent to the Plant.

The DEIS mentions the issue of thermal discharges (at pages 208-10) and presents an analysis that purports to show – by using a mathematical mixing model (CORMIX) that is less conservative than the one that DNR generally recommends – that the discharges from the new coal-fired units will meet DNR's standards. It appears, however, that there are deficiencies in the CORMIX modeling upon which the DEIS relies.

The DEIS acknowledges that "using the proposed NR 106 default mixing zone formula for lakes, the thermal discharge is predicted to nearly meet the proposed chronic temperature criteria." DEIS at 208. In other words, using DNR's standard default assumptions, the ERGS does not meet these chronic temperature criteria.

The DEIS attempts to dismiss this major problem by introducing CORMIX model results that purport to show that there will be no problem. The CORMIX model, however, can only be used for temperatures above 4° C (39.2° F) because water at lower temperatures becomes buoyant and the model will not work. Since minimum Lake Michigan winter water temperatures

are 34° F, see DEIS at 209, the agencies are relying on a model that cannot be applied at these temperatures.

Contrary to what is stated in the DEIS, there are potential thermal pollution issues because the discharges may not meet chronic temperature criteria. Furthermore, all of the modeling appears to be for the new discharges alone. Since the existing coal-fired units will continue in operation, the thermal load of the existing units should have been included in the calculations, but the discussion in the DEIS suggests that they were not. Although the DEIS discussion is vague, it also appears that the calculations do not simultaneously consider the impact of the SCPC units and IGCC units together, since separate results are given for each and no mention is made of a cumulative impacts analysis. These are substantial deficiencies in the DEIS that must be corrected.

C. Harbor Construction Activities

If WEPCO were proposing only to construct the harbor expansions associated with the ERGS, that action alone would warrant a detailed environmental impact statement. Since this major harbor expansion is coupled with the ERGS, however, it appears to have been given short shrift in the DEIS. Again, this is due to the agencies' failure to require WEPCO to provide the necessary data in its application.

The harbor expansion will involve considerable dredging and construction work. Yet little ecological survey work is reported. Dredging can have a range of adverse effects including release of toxic chemicals from the sediments and reduction in lake oxygen levels. There is no evidence that these possibilities have been properly assessed.

D. Wetlands

The ERGS will destroy more than 15 acres of wetlands. See DEIS at Table 8-10. The DEIS notes that "[i]ncluded in the mix of wetland types are some high-quality wetlands in terms of their functional values" and that "many of these high-quality wetlands will be either partially filled in or directly adjacent to berms with a constructed height of 50 or more feet. Wetlands adjacent to these new topographic highs will most likely be impacted by sediment-laden stormwater runoff and erosion." DEIS at 222. Additional, unspecified acreage of wetlands would also be filled or destroyed in connection with railroad corridor modifications. DEIS at 223-24. The DEIS also acknowledges significant other secondary impacts.

The DEIS is deficient in not assessing alternatives to this fill activity or discussing other mitigating measures, such as changing WEPCO's proposed layout to avoid wetlands. It should also be noted that much of this wetlands destruction is a direct result of WEPCO's plan to fuel the new units with coal, which has a much larger footprint due to the need for coal piles, coal-handling equipment, and ash landfills. The DEIS also fails to discuss the permitting requirements that apply to the filling of these wetlands, or even to evaluate whether such filling would be permissible under State wetland water quality standards.

COMMENTS ON CHAPTER 9 – SOLID AND HAZARDOUS WASTE

The type of fuel that is used to produce electricity has a direct and significant impact on the amount of solid waste that is generated by the power plant. The benefits of natural gas over coal are enormous in this respect, since natural gas produces virtually no ash while coal generates tens of thousands of tons of ash per year. The two new SCPC units that WEPCO has proposed to construct at Oak Creek are expected to generate more than 200,000 tons of ash each and every year.

The DEIS (at page 232) acknowledges that WEPCO does not yet have sufficient data to show that it will be able to sell or use of any of this ash or determine how much will have to be dumped in a landfill. Although the draft EIS discusses the landfills that might be used to dispose of this ash in Southeastern Wisconsin, it fails to discuss the potential adverse environmental impacts of these disposal activities, such as the formation of toxic leachate and surface water runoff that could pollute groundwater and surface water in the vicinity of the landfills, or the engineering features of these landfills that are designed to prevent these problems.

According to the DEIS (at page 229), it is contemplated that the ash will be hauled to the landfill by truck. No analysis is presented, however, of the adverse impacts of this truck traffic – and other vehicular traffic that will be associated with the new units – on local air quality and traffic congestion. Instead, the draft EIS merely estimates the number of vehicular movements associated with the new plant without modeling or otherwise evaluating their impact on local air quality or the level of transportation services provided by the existing road network.

COMMENTS ON CHAPTER 11 – COMMUNITY IMPACTS

The DEIS discloses many of the adverse community impacts of the ERGS. These include noise, construction-related impacts, increased traffic, and the adverse impacts of the coal trains. The projected 100% increase in coal train traffic, see DEIS at 349, is of particular concern, since this is an impact that the community will need to live with for decades to come. Although of shorter duration and more localized in nature, the construction-related impacts are also very significant due to the massive earth moving activities that WEPCO has proposed.

The DEIS limits its rail impact analysis to potential blockages at three crossings. However, there are numerous impacts that arise from increased coal trains, including noise, train-

related pollution, land use decisions, and a variety of quality of life impacts. These are given scant or literally no attention.

More importantly, the DEIS artificially limits its evaluation to three discrete crossings. The coal trains necessarily will pass through Racine, a densely populated urban area with numerous crossings.

Rail-related adverse impacts in Racine will include traffic congestion at crossings, as well as interference with residential and business activities. Increased coal train traffic will discourage in-fill development and redevelopment of the inner city; it will also encourage residents and businesses to move further out of the city, thereby exacerbating urban sprawl. These are some of the most significant impacts of WEPCO's proposal, and the DEIS is deficient for its complete lack of any analysis or even acknowledgement of these impacts.

For those few impacts that are discussed, the discussion is incomplete and inaccurate. For example, DEIS Table 11-31 on page 353 presents data as to the amount of time that Four Mile Road would be blocked by coal trains, but there are errors in this table that need to be corrected. The DEIS discloses that, after the ERGS is constructed, an average of 11 coal trains will enter the Oak Creek Power Plant site weekly. See DEIS Table 11-29 & 11-31. Because each train must return south on the same track, it can be assumed that there will be an average of 22 train crossings per week across Four Mile Road. Rounding downward to 21 trips per week, instead of 22, the result is an average of 3 coal trains crossing Four Mile Road each day. The average time it takes a train to cross Four Mile Road is approximately 4 minutes. DEIS at 353. So, at Four Mile Road, that should work out to a daily average of 12 minutes per day of road blockage due to the coal trains (3 x 4 = 12). Since 12 minutes represents a daily

average, DEIS Table 11-31 should not identify 13 minutes as the "maximum average daily time blocked." The concept of "maximum average" is confusing and should not be used.

DEIS Table 11-31 also errs in stating that the "total maximum average weekly time blocked" will be 56 minutes. Since the daily average will be 12 minutes, it follows that the weekly average will be 84 minutes (12 x 7 = 84). The table's reference to 56 minutes as the "maximum average" is incorrect.

It is apparent that the "maximum" time the coal trains would block Four Mile Road on any given day – or even an "average" day where only 3 trains pass the road – is greater than 13 minutes, as Table 11-31 would suggest. In fact, about once in 30 times, a coal train takes 9 minutes to cross Four Mile Road. DEIS at 352. Thus, every 10 days, on average, one of the coal trains will block Four Mile Road for 9 minutes. If the other two trains on that day block Four Mile Road for the average time of 4 minutes each, that would result in a total blockage for that day of 17 minutes. Of course, it is possible that more than 3 trains might traverse Four Mile Road on that particular day, or that the two trains – other than the 9 minute train – would block the road for an above average time period. Thus, in the course of a month, it would appear to be likely that there will be one or more days when Four Mile Road will be blocked for 20 minutes or more by coal trains, although the data presented in the DEIS are insufficient to prepare a simple probabilistic analysis.

The DEIS does not adequately assess this impact. The vehicular traffic on Four Mile Road at the railroad track crossing averages 11,300 trips per day, see DEIS Table 11-22, or an average of 8 vehicular trips per minute, each minute of the day, 24 hours a day. (Traffic is likely to be much greater than 8 trips per minute during rush hour and other peak time periods during the day, and much less than 8 trips per minute in the late evenings and early mornings.) It

is apparent that the queueing and delay when a 9 minute blockage occurs every 10 days can be substantial, especially when the blockage occurs during the periods when traffic on Four Mile Road exceeds the hourly average of 8 vehicular trips per minute.

The intersection with Four Mile Road, although significant, is but one of the numerous at grade crossings affected by the increased coal train traffic. The DEIS is deficient in omitting any evaluation of the impacts at these other crossings. Significant adverse impacts will occur all along the rail corridor south of the Oak Creek Power Plant, since the entire corridor will suffer from the 100% increase in daily coal trains. The DEIS does not take the required hard look at these impacts.

The DEIS discloses, at page 357, that the diesel engines that pull the coal trains sometimes idle near the homes south of the plant for more than 24 hours at a time. It is highly likely that a simple modeling analysis would reveal that this practice of idling diesel train engines is resulting in exceedances of the 24-hour PM_{10} and 24-hour $PM_{2.5}$ NAAQS at these locations, and this modeling should be performed for the final EIS. This is an unacceptable threat to the health of these residents. The practice should be prohibited. The increase in localized adverse impacts from the coal trains represents yet another adverse impact of WEPCO's proposal to use coal to fuel this project.

CONCLUSION

SC Johnson appreciates and respects the very significant efforts that the PSC and DNR made to develop this draft EIS. Notwithstanding the deficiencies in WEPCO's permit applications, the agencies seek to present information about the economic and environmental impacts of WEPCO's proposal to spend $4.1 billion of ratepayer-backed money on another massive coal-fired power plant. The draft EIS is nevertheless deficient in a number of important

respects, as noted above. SC Johnson remains concerned that the project has not been subject to adequate analysis and, if constructed, would impose significant environmental, social and economic costs on the residents and businesses in Southeastern Wisconsin for decades to come. Accordingly, SC Johnson calls upon the PSC to: (i) determine that the WEPCO application in this proceeding is incomplete for failing to provide the necessary information to conduct a thorough and sufficient EIS; (ii) reverse its determination of completeness; and (iii) require WEPCO to resubmit its application to provide the missing information and analyses. At a minimum, a revised DEIS that corrects the existing deficiencies identified in these comments and the comments of others should be prepared and published for public review and comment before PSC and DNR proceed to the preparation and publication of the final EIS.

Dated: June 12, 2003

Comments on the Draft Environmental Impact Statement, submitted by the Sierra Club, Southeast Gateway Group

LAW OFFICE OF **DENNIS M. GRZEZINSKI** ENVIRONMENTAL LAW AND CIVIL LITIGATION

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Jeffery Kitsembel
Public Service Commission
P.O. Box 7854
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Public Service Commission Docket: 05-CE-130

Dear Mr. Kitsembel:

The following comments on the Draft Environmental Impact Statement (DEIS) for the Elm Road Generating Station (ERGS) are submitted on behalf of the Sierra Club, Southeast Gateway Group (SCSSG). SCSSG has 726 active members in Racine and Kenosha Counties; the Sierra Club's Great Waters Group, which includes Milwaukee and Waukesha Counties has 3,107 active members. These members are in the service area for WEEnergy (WE), and will bear the capital costs for construction and the rate-payer costs for operation of the proposed facilities, and they are in the emission plume shadow from WE facilities, meaning their families' health will be impacted from the emissions from the proposed facilities.

SCSSG's most basic comment on the DEIS is that it is inadequate and should be redone and published for public comment, before a FEIS is prepared. At the most fundamental level, the DEIS is inadequate because WE's application is deficient and fails to provide the data, information and analyses that are necessary to support what is legally required under the Wisconsin Environmental Policy Act (WEPA): a reasonably complete evaluation of the impacts of the proposed project on the environment, and of reasonable alternatives to the proposed project.

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SCSSG has reached the conclusion that the DEIS is inadequate and must be redone for the following reasons. The DEIS:

1. explicitly acknowledges that consideration of a number of important subjects are being deferred to the FEIS, or to other proceedings, or are incomplete and will need to be supplemented (e.g., the feasibility of moving the amount of soil required in the construction timeframe proposed and the impacts of soil excavation and hauling, p. xxviii, 175-176; leases for units subsequent to the first unit, p. 14; a number of specific items that could impact WE's original cost estimate, p. 15; air quality analysis and air modeling using actual stack heights, p. 133, 146, 163, 164, 167; estimated hazardous air pollutants, p. 172-175; analysis of an integrated resource alternative, p. 83; design of the offshore water intake structure, p. 203-206; design of the water discharge structure, p. 207),
2. fails to consider alternative sites, and
3. fails to reasonably consider alternative fuel sources.

INADEQUACY OF THE ALTERNATIVES ANALYSIS

FAILURE TO DISCUSS ALTERNATIVE SITES

Reflecting the fundamental inadequacy of WE's CPCN application, the DEIS fails to identify or discuss alternative sites. This contradicts the Commission's legal requirements for conducting siting reviews and violates WEPA as well. The Commission has long held that alternative sites or routes must be considered that differ significantly in the type of resources impacted and the degree of impact. That is necessary to properly balance the impacts on the human environment against economic considerations.

The significance of the agency's failure to comply with the legal requirement to consider alternatives sites is illustrated by the severe drawbacks of the Oak Creek Power Plant site. Among these drawbacks are:

X Wisconsin Energies already operates four large coal-fired generating units at this site. As a result, the neighborhoods surrounding the site are already burdened with poor air quality from the existing power plant. Locating new generating units at the site exacerbates this problem and will result in unacceptable air quality in the area.

Alternative sites not burdened with the adverse impacts of existing coal-fired generating units would not suffer this problem.

X The Oak Creek Site is located in a severe ozone nonattainment area that encompasses the major population centers in the State. Locating the new source in this area maximizes the number of people who will be exposed to project-related emissions and inappropriately concentrates emissions in an area of the State that already has poor air quality.

X The Oak Creek Site will require enormous transmission reinforcement costs. At this point, the most recent available information is that expanding the transmission system to connect the new generating units to the power grid will cost about a quarter of a billion dollars. Some or all of that cost may be avoided if the new generating units were sited elsewhere. It is appropriate and <u>necessary</u> to evaluate the full cost of WE's proposal, including the required transmission expansion, <u>and to compare that to alternatives, including alternative sites</u>. The DEIS does not present this analysis.

X The economics of any proposal for a new power plant vary with the site location and characteristics. The DEIS recognizes the environmental mitigation cost uncertainties in its bulleted list on page 15. The Oak Creek Site is burdened with the need – which may be entirely unnecessary at an alternative site – to remove a portion of the bluff, tunnel the water intake through as much as 9,000 feet of bedrock, and construct an underpass on a local road. It is also relatively remote from the nearest interstate natural gas pipeline.

These adverse environmental and cost impacts could be avoided at alternative sites, and the DEIS needs to undertake that analysis. To recognize the site-related uncertainties and that site related costs will vary with the site, but not consider alternatives to the proposed site is inconsistent and inappropriate from both an economic and environmental point of view.

Given the impact that site location has on the cost and feasibility of the facility (e.g., environmental mitigation), cost and feasibility of alternatives (e.g., wind farm wouldn't work at Elm Road site), cost and feasibility of the project (e.g., transmission requirements to interconnect), and the types and magnitude of environmental impacts, a DEIS that does not meaningfully address viable alternative sites is not adequate. It is also inconsistent with the long-ago established Commission principle that all sites must be equally viable – that is, sufficient data must have been developed on the alternative sites to allow any of them to be licensed and implemented within the date needed. This requirement arose when the Commission rightly became concerned that the utilities were preparing dummy alternatives to meet filing requirements, but that were not licensable. Staff's comment that the "cost estimates for any necessary transmission system expansion elsewhere in the state to accommodate specific projects other than ERGS are presently not available" (DEIS page 78) is evidence that the Commission has violated its own principle.

It is important to emphasize that the failure to include an alternative site analysis in the DEIS is not merely a technical violation of WEPA requirements. It is a fundamental defect that makes it impossible for the agencies to perform the careful environmental review that this project requires, because the agencies do not have the data they need to evaluate the relative environmental, social and economic costs of locating the new electric generation that is purportedly needed at the Oak Creek site rather than at

other sites in the State that are available for this facility. This gaping hole in the DEIS stems largely from WE's failure to include a proper alternatives analysis in its application for a Certificate of Public Convenience and Necessity. Accordingly, the Commission should reconsider its earlier decision to certify WE's application as complete and instruct the company to submit a new application that complies with the legal requirement to present a discussion of alternative sites. A new draft EIS should then be prepared that corrects the deficiencies in the current draft of that document.

On page 97 the DEIS indicated that "the ability to locate all three proposed units at one site" was an important consideration in WE's final site selection. Why should that be important, especially to the extent of eliminating potentially viable sites as indicated on page 98? Putting three large units on a single site concentrates the power generation making it more susceptible to terrorist activity and concentrates the environmental burden. Requiring all three units to be located on one site might allow facilities to be shared, thus reducing cost. According to the DEIS, shared facilities in the third unit cost $31 million (DEIS, page 14). However, the incremental cost of transmission system expansion required by adding the third unit 3 is $102 million (DEIS, page 18) or $151 million (DEIS, page 131). On the basis of transmission system expansion alone, the economics of adding the third unit are unfavorable relative to splitting up the units among two sites. The DEIS indicates that WE eliminated at least one site because of its criterion that the sites could accommodate three units. That criterion appears unjustified, and inappropriately rejects not only viable but likely less expensive and less environmentally damaging sites.

Similarly, on page 95, the DEIS indicates that WE rejected the Haven site because it cooling towers would be required due to its distance (0.25 miles) away from Lake Michigan cooling water. This is an inadequate basis for rejecting the site for two reasons. First, it has not yet been determined whether once through cooling will be

approved at the proposed ERGS site. Second, the distance of 0.25 miles is rather trivial compared to the "water intake being tunneled 3,500 to 9,000 feet into bedrock" at the ERGS (DEIS, page 15). The fact that ERGS might require a 1.7 mile water intake and still use once through cooling is inconsistent with rejecting the Haven site because it could not use once through cooling because it is a quarter mile inland. Again, it appears that arbitrary reasons were used to eliminate potentially viable and preferable sites. Is that in the public interest, and can the Commission make the statutory findings required to approve the project?

INADEQUATE ANALYSIS OF ENERGY EFFICIENCY ALTERNATIVES

The DEIS discusses conservation and energy efficiency as an alternative at pages 54-58. Review of this discussion demonstrates that the DEIS does not adequate address this important issue, which the Legislature has designated in Section 196.025 and Section 1.12(4), Stats., as the State's highest priority for achieving energy needs. All that can be learned from the DEIS is that the potential role of conservation and energy efficiency in meeting the energy needs identified in the DEIS is great, but that the analyses by both the applicant and staff are likely to underestimate the potential savings. The applicant considered only residential efficiency opportunities. Staff's analysis is outdated, and does not reflect changes in the market, in technologies, and in applicable laws since 1995; and it did not adequately address industrial energy efficiency potential. As a result, on its face, the DEIS fails to provide the Commission, the public, or other interested parties any reasonable basis on which to evaluate the extent to which conservation and energy efficiency can and should substitute for the proposed project.

INADEQUATE DISCUSSION OF RENEWABLES ALTERNATIVES

It is noteworthy that staff's EGEAS analyses demonstrate the cost-effectiveness of wind generation, even with an extremely conservative 20% credit to reserve margin. The analyses should be redone using more representative margins, such as those actually experienced in Minnesota (21-29%), as indicated on page 66.

NO ANALYSIS OF INTEGRATED RESOURCE ALTERNATIVE

On page 83, the DEIS promises that the FEIS will include an integrated resource alternative which includes renewables, energy efficiency, electric transmission improvements, and possibly other smaller fossil-fueled facilities. This analysis should have been presented in the DEIS, and subjected to public comment, prior to preparation of an FEIS. This is another reason the DEIS should be redone and republished for public comment, before an FEIS is issued. The analysis of integrated resource alternatives should consider the potential impact on natural gas availability and pricing of the proposed Alaska north slope gas pipeline.

MORE SPECIFIC COMMENTS ON THE DEIS

AIR EMISSIONS

The DEIS devotes some 43 pages to a discussion of the air emissions of the proposed project. The DEIS reports WEPCO's analysis and estimates of air emissions. It also indicates that the DNR has yet to do its own analysis. Thus the DEIS appears to merely reflect utility assertions, which may or may not prove to be consistent with the results of the yet-to-be-completed DNR analysis. As such, the DEIS does not provide an independent disclosure of the impacts of the ERGS on air quality.

Moreover, the DEIS fails to disclose the potential impacts of the plant on the public. It provides no way for the reader to correlate the air emissions to impacts on human health, mortality, materials damage, vegetation damage, and so on. A reader unfamiliar with the impacts of a pollutant (e.g., SO2 or beryllium) on humans, materials,

flora and fauna cannot determine from the DEIS the likely impacts of the proposed project. Discussions of the impacts of air pollutants (including HAPS) must be included in the EIS to satisfy the requirement that the EIS fully disclose the potential impacts to the human environment. We note, for example, that the U.S. EPA has done studies which estimate the health and mortality impacts of power plants. Advocacy groups have also done such studies. An Environmental Impact Study should not do less.

The DEIS should be redone and republished, including an evaluation and analysis of the health impacts of the air pollution from the proposed coal-fired plants (on a stand-alone basis, and on a cumulative basis in addition to emissions from the existing Oak Creek coal-fired units). If the cumulative impacts exceed health-based standards, WEPCO should be required to locate its proposed new units elsewhere, use a less polluting fuel, or implement considerably more effective pollution reduction and control measures. And, regardless of whether those standards are met, the Commission, the public, and other interested parties should be informed regarding these impacts in a new DEIS.

A new DEIS should include analysis on the significant impact area (SIA) of the proposed project, and should include modeling of an interactive source analysis with overlapping plants' SIAs, especially in the case of southerly winds, and northerly winds, when emission plumes from all of the plants sited on or near the Lake Michigan lakefront line up and overlap.

In addition, there is a complete failure in the DEIS to address the severe adverse health impacts of fine particulates ($PM_{2.5}$), for which National Ambient Air Quality Standards were set in 1997. $PM_{2.5}$ causes premature death, exacerbation of respiratory and cardiovascular disease, decreased lung function, increased respiratory symptoms from preexisting pulmonary disease, and aggravation of symptoms associated with asthma, and cardiopulmonary and lung cancer mortality. The DEIS analyzes only

compliance with the PM_{10} standard, which EPA concluded in 1997 was inadequate to protect human health. The DEIS ought to have modeled whether the proposed project, together with the existing coal-fired plants would comply with the $PM_{2.5}$ standards.

Nor does the DEIS contain any assessment of the adverse health impacts of the more than 203 tons of hazardous air pollutants per year that will be emitted from the proposed plants, according to page 173. What is the cumulative impact of these emissions, together with those emitted by the existing units, in terms of both cancer and noncancer impacts?

On page 170, the DEIS indicates that the emissions of hazardous air pollutants from the ERGS are exempt from DNR requirements because coal is a virgin fuel. This does not satisfy the requirement that an EIS fully disclose the environmental impacts of a proposed action. In fact, the emission rates of a number of hazardous air pollutants exceed the emission levels of significance specified in Chapter NR 445. Thus, while the quantities emitted are significant enough to be of concern to the environment, they are exempted from regulation because of a definition. That does not exempt the EIS from disclosing their potential impacts.

Table 7-29 on page 150 shows WEPCO's estimates of the HAP emissions. First, is the method of calculation of the HAP emissions acceptable to the air regulatory agencies? The method of estimation yields different results from the EPA AP-42 estimation method. In most cases, the application of AP-42 yields higher estimates of HAP emissions. Second, it would be useful to add Chapter 445 thresholds of significance information for each pollutant (assuming that it was not exempted as a virgin fuel). That would provide much-needed context as to how much the public should be concerned with emissions of a few to several thousand pounds of specific HAPS. Third, it should be clarified whether these HAP emission levels will be permit criteria, enforceable limits, or just expected emissions.

Mercury Removal Efficiency

Table 7-2 on page 140 is misleading. It discusses the differences in mercury removal efficiency between bituminous and sub-bituminous coals, but does not reflect the fact that bituminous coal starts out with significantly more mercury than sub-bituminous coals. On average, Pennsylvania bituminous coal contains approximately four times the mercury that Wyoming sub-bituminous coal does. In fact, this difference between bituminous and sub-bituminous coals is never mentioned in the DEIS. Since one of the reasons given for selecting bituminous coal is the higher mercury removal efficiency, it is misleading not to also include the additional facts of the comparative mercury content.

Also, Table 7-2 has some figures in it which do not seem to make sense in light of the text right below the table. The table shows a mercury collection efficiency for sub-bituminous coal of 72% for a fabric filter baghouse, but only 25% for a combination of dry FGD scrubber and fabric filter baghouse. Since the text states that FGD reduces the gas temperature and leads to better opportunities to collect mercury, it would seem that the FGD/baghouse combination should have better collection efficiency than the baghouse alone, not worse. The source of the information contained in Table 7-2 should be indicated. Are the mercury control efficiencies accepted by EPA and/or DNR?

Inconsistency in Expected Project Emissions

On page 155 Table 7-9 lists maximum emissions from the various parts of the Elm Road plant. A number of the potential emissions shown in this table are not consistent with other numbers which We Energies has released. For example, the SO2 emissions shown for the two SCPC units are not consistent with the SO2 emission rate and plant heat rate which the Company has been touting. Also, the potential emissions shown in Table 7-9 are significantly higher than what We Energies has been touting to

the public. If, in fact, the emissions shown in Table 7-9 are those which the plant will be legally held to, it would be informative to the public for the staff to make clear that the numbers being touted by the Company are not those for which they are asking permit approval.

Recent Consent Decree with US EPA

While we cannot expect the DEIS to reflect the recent Consent Decree between WE and the U.S. EPA (since it came out about the same time as the DEIS), we hope that the staff will compare the emissions from the proposed new Elm Road plants, touted by the company as the ultimate in emission control technologies, with the emission rates which the Company has agreed to meet at its existing units at Oak Creek and Pleasant Prairie. It would be useful to point out to the public that the emission rates at the new plants will be significantly higher than the emissions rates at the older plants.

Greenhouse Gases

On page 170, the DEIS discusses greenhouse gases. There seems to be a serious problem with the calculations of CO2 equivalent emissions from Elm Road. The DEIS says that the CO2 equivalent emissions of greenhouse gases from Elm Road will be 1,060,000 tons per year at maximum utilization. This seems too low by more than an order of magnitude. The Elm Road plant will be 1,830 MW. At full utilization it would generate (1830 MW) times (8760 hours per year) = 16 million MWH per year. Coal-fired power plants emit approximately 200 lbs of CO2 per million BTUs. With a heat rate of 8,800 BTUs per kWh, the CO2 emission rate is about 1,760 lbs per MWH, or 0.88 tons per MWH. At 0.88 tons per MWH and 16 million MWH per year, the CO2 emissions would be 14 million tons per year, over 13 times the amount given in the DEIS. This means that the increase in CO2, rather than being 1.9% of the existing utility CO2 emissions, would be a 26% increase.

Coal Dust

The DEIS contains no analysis or modeling of the impacts of coal dust on local air quality or on employees or local residents, resulting from the cumulative impact of the proposed units and the existing coal-fired plants. This should be done.

WATER RESOURCE IMPACTS

Once Through Cooling

Cooling water intake structures cause adverse environmental impacts by pulling large numbers of fish and shellfish or their eggs into a power plant's cooling system. There, the organisms are killed or injured by heat, physical stress, and by the chemicals used to clean the cooling system, a phenomenon called "entrainment." Larger organisms are killed or injured when they are trapped against screens at the front of an intake structure, a phenomenon called "impingement." WE proposes to use once through cooling for the three new electric generating units it is seeking to build at the Oak Creek Power Plant. The result is that the new units are projected to use approximately two billion gallons of water per day, every day, for the next 50 years.

It can be expected that, as a result, the new generating units will kill tens of millions of aquatic organisms – including adult and juvenile fish, shellfish, larvae, eggs and other organisms – annually. The DEIS identifies the problem [at pages 206-07] but reflects WE's failure to provide any comprehensive analysis or evaluation of the ecological significance of these impacts to our environment. Instead, the agencies need to go back to the drawing board, require WE to provide all of the necessary data and information, and then take a closer look in an EIS at these impacts and the mitigating measures that can be imposed to prevent them.

The magnitude of fish deaths is directly related to intake volume. The more water WE uses, the more organisms they will kill. WE has proposed to use once

through cooling for its new units – a primitive technology that uses massive amounts of water and thereby wreaks maximum devastation on the aquatic environment.

In contrast, all power plants built in the last twenty years in this area of the country have used closed cycle cooling. In fact, since the passage of the Clean Water Act Amendments of 1972 only one unit at one power plant was proposed (in the early 1980s) with once through cooling. If the new units are built with the primitive once through cooling technology that WE has proposed, Oak Creek would be the largest once through cooling plant in the region.

Instead of once through cooling, WE should be required to use closed cycle cooling. Closed cycle cooling would reduce the amount of intake water, and the resulting impingement and entrainment of fish and other aquatic organisms, by 97% or more. WE should be required to provide all of the necessary information and analyses so that the EIS can evaluate closed cycle cooling technology as an option or compare the impacts of closed cycle cooling to the primitive once through cooling method. This is a significant deficiency in WEPCO's analysis and in the draft EIS that must be corrected through a supplemental analysis. In addition, the DEIS has not addressed in any detail proposed standards for "existing plants".

The DEIS considers only the once through cooling system proposed by WE for the ERGS. It is not at all clear that a once through cooling system will be approved by EPA. On page 94-95 the DEIS states that a coal-fired power plant will have more water flowing through it than a natural gas-fired plant, but that consumptive water use is greater for the gas-fired plant. This is dependent on the coal-fired plant using once-through cooling. While We Energies has applied to build a once-through cooled plant, the decision on whether or not this will be allowed will come from the Wisconsin DNR <u>and</u> the U.S. EPA. Have the agency staffs estimated the likelihood of once-through cooling being approved?

The alternative of a cooling tower must be considered to allow decision makers to make an informed decision between cooling towers and once through cooling. The DEIS must contain information about the alternative of using cooling towers. The purpose of the DEIS, to fully disclose environmental impacts and inform the public regarding the proposal and its alternatives, cannot be achieved without an analysis of the alternative of cooling towers.

Inadequate detail on water intake design

Moreover, another deficiency in the DEIS is that it lacks detail on the design of the water intake system. The proper design of the intake system is a critical component of the proposed project in avoiding or minimizing entrainment and impingement of Lake Michigan adult, juvenile, and larval fish, and fish eggs. The DEIS includes minimal information about the intake system. As currently described, it would consist of a timber crib or velocity caps and an intake channel. As stated, the future intake configuration would be dependent on the applicability of existing or proposed federal regulations.

There are many factors that must be included in the design of a high water volume intake system to avoid or minimize adverse impacts to the fish community due to entrainment and impingement. Mitigating measures include, but are not limited to, a low intake velocity of about 0.5 feet per second, use of wedgewire screening to exclude fish eggs and adult, juvenile and larval fish from being drawn in (or willfully swimming into) the intake system, and appropriate mesh size of the screening. In addition, intake siting considerations are necessary to determine appropriate depth and lake bed location to avoid a sensitive fish spawning area or other biologically sensitive area. Currently, the DEIS only states that the offshore intake system is proposed to extend into the lake 3,500 to 9,000 feet and that the depth of water at this location varies between 30 and 40 feet.

The final site will not be selected until the results of a two year environmental monitoring study are completed (September 2004).

The specific intake design and intake channel proposed should be fully described in the DEIS such that it can be reviewed by the resource agencies, non-governmental organizations, and the general public. The public should not have to depend on interacting in the WPDES system to get a chance to review the intake system details to insure that impacts to Lake Michigan fish are minimized. Currently, there is not enough information included in the DEIS for a credible review and it appears that the draft was released prematurely. Since, as stated, further decisions on applicable federal and state regulations are necessary before intake design details can be developed and disclosed, then a **revised DEIS** should be released prior to completion of the final EIS. This is further supported by the well known fact that once a selected alternative is presented in the final EIS, it is very difficult for the public to effectuate reevaluation of the selected alternative or otherwise make changes in the plan.

Thermal Discharge Impacts

Thermal pollution refers to the discharge of heated water to lakes and streams. The sudden increase in water temperatures in the area of the discharge kills aquatic organisms that are unable to adjust to quickly changing water temperatures, reduces dissolved oxygen in the water, and has other adverse impacts on aquatic ecology. Due to WE's proposal to use once through cooling, the Oak Creek Power Plant would place a significant thermal load on the area of Lake Michigan adjacent to the Plant.

The DEIS mentions the issue of thermal discharges [at pages 208-10] and presents an analysis that purports to show – by using a mixing model that is less conservative than the one that DNR generally recommends – that the thermal discharges from the new coal-fired units will meet DNR's thermal discharge standards. The analysis in the DEIS, however, does not take into account the cumulative impact of the thermal

discharge from the three new generating units and the thermal discharge from the existing generating units at Oak Creek. Instead, the DEIS discusses the thermal discharge from the proposed new SPCC units and separately discusses the thermal discharge from the proposed new IGCC unit. The DEIS does not analyze the cumulative impact of all three new units and the existing coal-fired generating units that are presently operating at the Oak Creek Power Plant. Thus, the analysis reflected in the DEIS is not even minimally adequate because it does not look at the cumulative impact of all the units on the thermal load imposed on this area of Lake Michigan.

Nor does the DEIS address the fact that the Wisconsin DNR is currently working on draft thermal discharge standards which would be applicable to the proposed units. In the absence of final state standards, the DEIS ought to at least discuss compliance with federal Clean Water Act thermal discharge standards.

SOLID WASTE ISSUES

The type of fuel that is used to produce electricity has a direct and significant impact on the amount of solid waste that is generated by the power plant. The benefits of natural gas over coal are enormous in this respect, since natural gas produces virtually no ash while coal generates tens of thousands of tons of ash per year The two new SCPC units that WE has proposed to construct at Oak Creek are expected to generate more than 200,000 tons of ash each and every year.

The DEIS acknowledges [at page 232] that WE does not yet have sufficient data to show that it will be able to sell or use of any of this ash or determine whether, as is likely, it will all have to be dumped in a landfill. Although the DEIS discusses the landfills that might be used to dispose of this ash in Southeastern Wisconsin, it fails to discuss the adverse environmental impacts of these disposal activities, such as the formation of toxic leachate and surface water runoff that will pollute groundwater and surface water in the vicinity of the landfills.

According to the DEIS [at page 229], it is contemplated that the ash will be hauled to the landfill by truck. No analysis is presented, however, of the adverse impacts of this truck traffic – and other vehicular traffic that will be associated with the new units – on local air quality and traffic congestion. Instead, the DEIS merely estimates the number of vehicular movements associated with the new plant without modeling their impact on local air quality or the level of transportation services provided by the existing road network.

Reburning flyash

The DEIS on page 230 indicates that by reburning existing flyash landfills, WE has gained additional space in the landfills. Where did the excavated material go to create the additional space? Flyash typically contains only a small amount of burnable fuel, typically around 300 BTU per pound. If the flyash is reburned, the volume combusted would be quite small, meaning that regained volumes would be quite small. If there are noticeable gains in space, that suggests the volume returned after reburning is significantly less than the volume excavated to be reburned. Where did that additional material (flyash) that was not returned to the landfill go? Did it escape through the stack (because the ash content per BTU of heat input increases substantially when flyash is blended into the fuel stream for reburning, but the particulate removal efficiency is the same)? The DEIS makes reburning flyash sound like a good thing, but doesn't address the effect doing so may have on air emissions and air related impacts.

CONCLUSION

Largely as a result of gaps and deficiencies in WE's application, SCSGG believes for the reasons stated above that the DEIS prepared by agency staff is inadequate, and needs to be redone and republished for public comment. In addition,

SCSGG has presented a number of comments regarding inadequacies, inconsistencies, and questions raised by the DEIS, which need to be addressed.

Very truly yours,

/s/

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Comments on the Draft Environmental Impact Statement, submitted by the Wisconsin Electric Cooperative Association

05-CE-130

Comments of David Jenkins
Wisconsin Electric Cooperative Association
Draft EIS PTF-II Project
June 13, 2003

Wisconsin's electric cooperatives serve 216,000 rural electric consumers in the state, and operate one-third of the state's electric distribution lines. We strongly support the PTF-II project and urge the Commission to consider the following issues in its preparation of a final EIS on the project:

Long-term Rising Prices of Natural Gas

Our members have a very serious concern about the increasingly limited choices of fuel for generating electric power. Currently, some groups (including many that are opposed to this project) are committed to eliminating coal as a generating fuel for electric power.

This would be extremely costly for Wisconsin's consumers and would affect not only the price but the reliability of our state's electric supply.

Two days ago, on June 10, the Chairman of the Federal Reserve Board of Governors testified to the House of Representatives about the looming, serious threat to this nation's economy of long-term increases in the price of natural gas. (Dr. Greenspan's testimony is attached).

In his testimony, Chairman Greenspan indicated that "the long-term equilibrium price for natural gas in the United States has risen persistenly during the past six years from approximately $2/MM Btu to more than $4.50."

This week NYMEX gas futures hit $6.31.

If the Commission consults authorities such as the Federal Reserve, Cambridge Energy Research Associates, and publicly available data, it must conclude that the trend of rising natural gas prices exhibits the characteristics that resemble a long-term structural (not just temporary) upward ratcheting of prices.

Why do rural electric consumers care about whether a southeastern Wisconsin utility has high fuel costs, now and in the future?

MFC
CO-8
AWJ
OGC-2
ELE-10

Because the cost and resulting price of energy that WE Energies sends into the wholesale marketplace has (because of its sheer size in this market) impact on the price that all electric power provides must pay on the wholesale market. High gas prices will result in high energy costs and make it more expensive for every utility and cooperative seeking power in the wholesale market to purchase that power at a reasonable price.

Volatility of Natural Gas Prices

All fuels (except most renewables) fluctuate in price. However, a fair examination of the price fluctuations in natural gas indicate that it is a far more volatile commodity with respect to price than coal or uranium (the other major fuels used to power Wisconsin's utility boilers). This volatility requires that electric power providers, if they increase their dependence on gas as a fuel, would almost certainly be making more frequent fuel cost adjustments in their rates, causing more irritation for consumers, and more expense for electric power providers.

Consumers like stable, predictable electric bills. They DO NOT like frequent changes in rates. Especially if they are increases.

We believe increasing dependence on gas, as the opponents of this project advocate, will lead to higher and more frequently changing electric bills. Our members do not welcome that.

Competition for Fuel Supplies With Residential, Commercial and Industrial Customers

The Commission should be mindful of the long-term consequences of moving to a generating fuel decision which creates substantially more pressure on gas supplies to the detriment of ordinary citizens, business and industry. How is a consumer well-served by having to compete with electric utilities for natural gas? Shouldn't the Commission consider what is going to happen to a consumer's natural gas bill if and when more and more scare natural gas is consumed to make electricity? Coal is no longer a residential heating fuel. There is no substitution in this market. Thus there is no pressure on home heating fuel costs from a decision to use coal as a generating fuel.

Low-income and elderly consumers would be especially hard hit by such a move away from non-substitutable fuels. They would not be better off as a result of a decision to pay a little more for the capital costs of a coal plant, as measured against years and years of pressure on supplies (and resulting cost increases) of natural gas to heat their homes. The same is true of commercial and industrial users.

PTF-II Makes Historic Commitment to Renewables

PTF-II makes the largest commitment to the expansion of renewable generating resources ever made by a utility in this state. One that far surpasses that which is required of WE Energies.

We believe this commitment ought to be given some weight and credit in the EIS.

Adding 200 Mw of renewables is an enormously significant step. WE Energies actions in this regard have won the company praise from organizations like RENEW Wisconsin.

We ask the Commission to bear in mind the efforts of WE Energies in this EIS because these activities and the company's manure digester project in Wrightsown are all a part of a package of generation resources under the PTF-II undertaking.

It is saddening to us, that WE Energies is the subject of daily hostile television ads which completely ignore the company's efforts in the renewables area. Such a state of affairs clearly demonstrates the anti-coal (not pro-consumer) agenda of most opponents of the project.

The Commission Should Expand, Not Narrow, Fuel Options for Electric Generation

Having eliminated new nuclear resources as an option and, through DNR pressure, having made it very difficult to re-license existing hydro (and essentially banning new small hydro), the state of Wisconsin may be on its way to eliminating coal as a generating fuel option.

Such a long-term policy result will leave us with two options: gas and renewables.

We strongly caution against moving in this direction.

This EIS and this case is important because it will determine the direction the state intends to take in respect to what fuels electric generators are allowed to use to make electricity. Many opponents of this project want to end the use of coal today.

In terms of the price of electricity and reliability, this would be a disaster for Wisconsin consumers.

If anything, the electric power industry needs more--not fewer--options for generating power. More options will certainly lower the risk simply by virtue of the operation of portfolio theory principles.

More available **types** of fuels will also enhance competition between fuels. Narrowing fuel choices will give the remaining fuels much greater resistance or immunity against competitive pressure, resulting in higher than normal prices.

We thank the Commission for its consideration.

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The Federal Reserve Board

Testimony of Chairman Alan Greenspan

Natural gas supply and demand issues

Before the Committee on Energy and Commerce, U.S. House of Representatives
June 10, 2003

In recent months, in response to very tight supplies, prices of natural gas have increased sharply. Working gas in storage is currently at very low levels relative to its seasonal norm because of a colder than average winter and a seeming inability of increased gas well drilling to significantly augment net marketed production. Canada, our major source of imported natural gas, has had little room to expand shipments to the United States, and our limited capacity to import liquefied natural gas (LNG) effectively restricts our access to the world's abundant supplies of gas.

Our inability to increase imports to close a modest gap between North American demand and production (a gap we can almost always close in oil) is largely responsible for the marked rise in natural gas prices over the past year. Such price pressures are not evident elsewhere. Competitive crude oil prices, after wide gyrations related to the war in Iraq, are now only slightly elevated from a year ago, and where spot markets for natural gas exist, such as in Great Britain, prices exhibit little change from a year ago. In the United States, rising demand for natural gas, especially as a clean-burning source of electric power, is pressing against a supply essentially restricted to North American production.

Given the current infrastructure, the U.S. market for natural gas is mainly regional, is characterized by relatively longer term contracts, and is still regulated, but less so than in the past. As a result, residential and commercial prices of natural gas respond sluggishly to movements in the spot price. Thus, to the extent that natural gas consumption must adjust to limited supplies, most of the reduction must come from the industrial sector and, to a lesser extent, utilities.

Yesterday the price of gas for delivery in July closed at $6.31 per million Btu. That contract sold for as low as $2.55 in July 2000 and for $3.65 a year ago. Futures markets project further price increases through the summer cooling season to the peak of the heating season next January. Indeed, market expectations reflected in option prices imply a 25 percent probability that the peak price will exceed $7.50 per million Btu.

Today's tight natural gas markets have been a long time in coming, and futures prices suggest that we are not apt to return to earlier periods of relative abundance and low prices anytime soon. It was little more than a half-century ago that drillers seeking valuable crude oil bemoaned the discovery of natural gas. Given the lack of

adequate transportation, wells had to be capped or the gas flared. As the economy expanded after World War II, the development of a vast interstate transmission system facilitated widespread consumption of natural gas in our homes and business establishments. On a heat-equivalent basis, natural gas consumption by 1970 had risen to three-fourths of that of oil. But natural gas consumption lagged in the following decade because of competitive incursions from coal and nuclear power. Since 1985, natural gas has gradually increased its share of total energy use and is projected by the Energy Information Administration to gain share over the next quarter century, owing to its status as a clean-burning fuel.

* * * * *

Recent years' dramatic changes in technology are making existing energy reserves stretch further while keeping long-term energy costs lower than they otherwise would have been. Seismic techniques and satellite imaging, which are facilitating the discovery of promising new natural gas reservoirs, have nearly doubled the success rate of new-field wildcat wells in the United States during the past decade. New techniques allow far deeper drilling of promising fields, especially offshore. The newer recovery innovations reportedly have raised the average proportion of gas reserves eventually brought to the surface. Technologies are facilitating Rocky Mountain production of tight sands gas and coalbed methane. Marketed production in Wyoming, for example, has risen from 3.4 percent of total U.S. output in 1996 to 7.1 percent last year.

One might expect that the dramatic shift away from hit-or-miss methods toward more advanced technologies would have lowered the cost of developing new fields and, hence, the long-term marginal costs of new gas. Indeed, those costs have declined, but by less than might have been the case because much of the innovation in oil and gas development outside of OPEC has been directed at overcoming an increasingly inhospitable and costly exploratory physical environment.

Moreover, improving technologies have also increased the depletion rate of newly discovered gas reservoirs, placing a strain on supply that has required increasingly larger gross additions from drilling to maintain any given level of dry gas production. Depletion rates are estimated to have reached 27 percent last year, compared with 21 percent as recently as five years ago. The rise has been even more pronounced for conventionally produced gas because tight sands gas, which comprises an increasing share of new gas finds, exhibits a slower depletion rate than conventional wells.

Improved technologies, however, have been unable to prevent the underlying long-term price of natural gas in the United States from rising. This is most readily observed in markets for natural gas where contract delivery is sufficiently distant to allow new supply to be developed and brought to market. That price has risen gradually from $2 per million Btu in 1997 for delivery in 2000, and presumably well beyond, to more than $4.50 for delivery in 2009, the crude oil heating equivalent of rising from less than $12 per barrel to $26 per barrel. Over the same period, the distant futures price of light sweet crude oil has edged up only $4 per barrel and is selling at a historically rare discount to comparably dated natural gas.

Because gas is particularly challenging to transport in its cryogenic form as a liquid, imports of LNG have been negligible. Environmental and safety concerns and cost have limited the number of LNG terminals and imports of LNG. In 2001, LNG imports accounted for only 1 percent of U.S. gas supply. Canada, which has recently supplied a sixth of our consumption, has little capacity to significantly expand its exports, in part because of the role that Canadian gas plays in supporting growing oil production from tar sands.

Given notable cost reductions for both liquefaction and transportation of LNG, significant global trade is developing. And high gas prices projected in the American distant futures market have made us a potential very large importer. Worldwide imports of natural gas in 2000 were only 26 percent of world consumption, compared to 50 percent for oil.

Even with markedly less geopolitical instability confronting world gas than world oil in recent years, spot gas prices have been far more volatile than those for oil, doubtless reflecting, in part, less-developed global trade. The updrift and volatility of the spot price for gas have put significant segments of the North American gas-using industry in a weakened competitive position. Unless this competitive weakness is addressed, new investment in these technologies will flag.

Increased marginal supplies from abroad, while likely to notably damp the levels and volatility of American natural gas prices, would expose us to possibly insecure sources of foreign supply, as it has for oil. But natural gas reserves are somewhat more widely dispersed than those of oil, for which three-fifths of proved world reserves reside in the Middle East. Nearly two-fifths of world natural gas reserves are in Russia and its former satellites, and one-third are in the Middle East.

Creating a price-pressure safety valve through larger import capacity of LNG need not unduly expose us to potentially unstable sources of imports. There are still numerous unexploited sources of gas production in the United States. We have been struggling to reach an agreeable tradeoff between environmental and energy concerns for decades. I do not doubt we will continue to fine-tune our areas of consensus. But it is essential that our policies be consistent. For example, we cannot, on the one hand, encourage the use of environmentally desirable natural gas in this country while being conflicted on larger imports of LNG. Such contradictions are resolved only by debilitating spikes in price.

* * * * *

In summary, the long-term equilibrium price for natural gas in the United States has risen persistently during the past six years from approximately $2 per million Btu to more than $4.50. The perceived tightening of long-term demand-supply balances is beginning to price some industrial demand out of the market. It is not clear whether these losses are temporary, pending a fall in price, or permanent.

Such pressures do not arise in the U.S. market for crude oil. American refiners have unlimited access to world supplies, as was demonstrated most recently when Venezuelan oil production shut down. Refiners were able to replace lost oil with supplies from Europe, Asia, and the Middle East. If North American natural gas markets are to function with the flexibility exhibited by oil, unlimited access to the vast world reserves of gas is required. Markets need to be able to effectively adjust to unexpected shortfalls in domestic supply. Access to world natural gas supplies will require a major expansion of LNG terminal import capacity. Without the flexibility such facilities will impart, imbalances in supply and demand must inevitably engender price volatility.

As the technology of LNG liquefaction and shipping has improved, and as safety considerations have lessened, a major expansion of U.S. import capability appears to be under way. These movements bode well for widespread natural gas availability in North America in the years ahead.

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Comments on the Draft Environmental Impact Statement, submitted by Wisconsin Electric Power Company, W.E. Power, and Wisconsin Energy Corporation

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June 13, 2003

via MESSENGER

Jeffery Kitsembel
Public Service Commission
P.O. Box 7854
610 North Whitney Way
Madison, WI 53707-7854

RE: Power The Future – Phase II
PSC Docket No. 05-CE-130

Dear Mr. Kitsembel:

Attached are the comments of Wisconsin Electric Power Company, W.E. Power, LLC, and Wisconsin Energy Corporation (the companies) on the Draft Environmental Impact Statement in the above docket, issued by the Commission on April 28, 2003.

It is important to note that the companies are extremely cognizant of the tremendous amount of investigation and review required by the state agencies involved in this process, the Public Service Commission of Wisconsin and the Department of Natural Resources. Both agencies participated in public meetings to gather additional comments. The Public Service Commission staff had the responsibility of gathering, organizing and issuing the Draft Environmental Impact Statement ("DEIS"), incorporating the wide range of impacts of this significant and important project. We believe that the DEIS fully and comprehensively considers the environmental impacts of the proposed action consistent with the requirements of §1.11, Stats. The companies appreciate those efforts and believe the record in this case will be enhanced because of them.

The comments enclosed fall into several categories. First, some comments address facts or calculations which may have been misstated. Second, there are comments which address interpretations of data or information. Third, we have provided certain information related to the accommodations identified as a result of input from various stakeholder groups and detailed in the testimony filed on May 27, 2003. Finally, certain information has been provided regarding other planned projects, particularly at the Oak Creek Power Plant, which may have impacts over the entire system or at the Elm Road site.

Even though additional information has been provided regarding the impact on the aggregate emissions of Wisconsin Electric's fossil generation fleet from future pollution control efforts at its existing generation, the company is not requesting approval for any projects other than the 1800 MW proposal for Elm Road Generating Station. Further, our comments do not indicate any request for approval of a scope of work other than that identified in the Company's original request for the Elm Road project. These comments are provided for the Commission's convenience and information, not as a requirement for the DEIS. However, we believe the impacts of the emission reductions, which will be addressed at the hearing, are important to the Commission's decision-making in the proceeding.

Copies of these comments will be served on all parties in accordance with the procedures directed by the Law Judge.

Thank you for the opportunity to comment on this important document, and for your consideration of those comments.

Very truly yours,

R. A. Draba
Vice President-State Regulatory Affairs

encls.
/rmr

cc: Service List (w/encls)

ERGS DEIS Applicants' Comments – Enclosure A

Executive Summary (p xix)

Under the leased generation approach, WEPCO would enter into a long-term facility lease with its non-affiliate company known as WE Power. WE Power would construct and own the facilities, but lease the generating units to WEPCO and other interested utilities at economic terms and conditions reviewed, regulated, and approved by the PSC. WEPCO would operate the coal facilities at the ERGS. Operation would include staffing, maintenance, and fuel procurement.

Comment: It would be more accurate to state this as follows:.

Under the leased generation approach, WEPCO would enter into ~~a~~ long-term facility leases with wholly owned subsidiaries of its non-affiliate company ~~known as~~ WE Power. WE Power's subsidiaries (ERGS SC LLC and ERGS IGCC LLC) would construct and have the ownership interest in the facilities, but would lease the generating units to WEPCO ~~and other interested utilities~~ at economic terms and conditions reviewed, regulated, and approved by the PSC. Other interested utilities might have ownership interests in the facilities as well, but the WE Power companies will ultimately own no less than 83% of each of the new units. WEPCO would operate the coal facilities at the ERGS. Operation would include staffing, maintenance, and fuel procurement.

(p xx) Suggested change: IGCC cost estimates are less certain because coal-based IGCC plants in the 500+ MW range have not been built anywhere in the world.

Comment: This is only true for coal based IGCC plants. Two heavy oil IGCC plants in Italy (ISAB 520 MW, SARAS 550MW) entered commercial service in 2001. This information was included in 1-SUP-166.

(p xxii) **Executive Summary**

On March 25, 2003, the city of Oak Creek and WEPCO entered into an agreement by which WEPCO agrees to annually pay the city of Oak Creek $1.5 million at the start-up of ERGS unit 1…The first annual payment of $1.5 million would increase the cost of the facility lease for the first SCPC unit by about 1.5 percent based on an annual estimated lease payment of nearly $107 million.

Comment: $1.5 million divided by $106.9 million = 1.4 percent, not 1.5 percent. Further, the impact of $2.25 million divided by $214 million for the first two plants combined is less than 1.1 percent.

(pxxiii), first par., last sentence. Comment: WEPCO reserve margin 20.56% per MAIN audit.

(p xxvii) Comment: Please consider the following correction.

The primary soil stockpile locations described in the application include:

- an area east of STH 32 south of the existing transmission line corridor;
- an area north of Elm Road across the railroad tracks from the Barton Oaks subdivision that is currently old field, ~~and~~ wetlands, and the North Ash Landfill;
- a large area immediately south of Haas Park that currently supports the Oak Creek ~~North~~ South Landfill;

(p xxx) **Solid Waste**

Comment: Change quantities because of the updated bituminous coal characteristics (Washed Pittsburgh #8) as follows for the SCPC units:

165,200 tons per year of fly ash changes to 206,300 tons per year
38,600 tons per year of bottom ash changes to 51,600 tons per year
137,666 cubic yards per year of fly ash changes to 171,900 cubic yards per year
32,166 cubic yards per year of bottom ash changes to 43,000 cubic yards per year
169,832 cubic yards per year of total volume changes to 214,900 cubic yards per year

Change quantities for the IGCC units based on more detailed information as follows:
18,000 tons per year of elemental sulfur changes to 33,200 tons per year
60,000 tons per year of sulfuric acid changes to 109,200 tons per year
62,400 gallons per day of sulfuric acid changes to 50,700 gallons per day
200,000 gallons of on site storage remains the unchanged.

(p xxxviii) primary stockpile locations. Correction: The second bullet should read ...that is currently old field, wetlands, and the North Ash Landfill. Third bullet should read....supports the Oak Creek South Landfill.

(pp 1, 6 & 31) **Description of the Proposed Project.** Comment: Suggest correcting typo in last paragraph as follows.
In order to meet this need, plus an 18 percent reserve margin, it has proposed a package of generation capacity that includes 1,090 MW of natural gas-fired capacity at its existing Port Washington Power Plant site and ~~1,860~~1,830 MW of coal-based generation that is the subject of this application.

(p 2) Proposed sites Comment: Suggest clarifying first paragraph as follows.

The proposed sites for the ERGS are on a large parcel of land located along the shore of Lake Michigan near the OCPP. The parcel is approximately 1,000 acres in size, and is primarily owned by WEPCO. This land currently functions as buffer area around the existing OCPP. A ~~federally owned 7~~80-acre property within the WEPCO property is currently used as a shooting range, but is also being considered as a site for some of the facilities. The property consists of two parcels - a northerly parcel owned by the State of Wisconsin (28.92 acres) and a southerly parcel owned by the U.S.A. (51.08 acres).

(p 9) Table 1-2 Comment: CPCNs will be needed for transmission.

(p 13, par. 2 and Executive Summary, p xx) "WEPCO provided the costs for the ERGS as part of its overall PTF application. However, the costs provided for ERGS are not as certain as those provided for the Port Washington units. The costs provided for the SCPC units are somewhat uncertain and the cost for the IGCC unit is even less certain. Thus, the estimated costs for the ERGS are on a "cost-plus" basis, rather than a "firm" basis like the Port Washington costs."
Comment: Please use the more accurate term "Cost Reimbursable with Cap."

(p 14) Suggested change: In addition, IGCC cost estimates are less certain because coal-based IGCC plants in the 500+ MW range have not been built anywhere in the world.
Comment: This is only true for coal based IGCC plants. Two heavy oil IGCC plants in Italy (ISAB 520 MW, SARAS 550MW) entered commercial service in 2001.

(p 15) Suggest changing "Bechtel Engineering" to "Bechtel Power Corporation."

(p 15) "Items that could impact or increase the original estimate provided by WEPCO include:"

Comment: All capital costs items listed are included in WE Power's estimate provided in the direct Testimony of Mihm with the exception of transmission (ATC costs) and City of Oak Creek payments (not capital). Also coal shed estimate is $20 million not $5 million.

(p 16) The cost for one of those plants, the Wabash River Plant in Indiana, was $417 million for a 262-MW facility (in 1995 dollars) or $1,591/kW.
Comment: According to the response to 1-SUP-166, Wabash was $438 million for a 260 MW plant (in 1995 dollars) or $1,685/kW. However, this was a repowering of an existing coal fired unit. Because of re-use of existing plant equipment, it is not directly comparable to other projects. Allowing for new equipment, the estimated cost would be $29 million higher. This would result in a cost of $1,796/kW. Costs are higher because of the interpretation of capital costs versus capital costs.

A DOE report entitled "Wabash River Coal Gasification Repowering Project, Final Technical Report, August 2000" states "The installed cost of the overall IGCC facility including start-up was about $1590/kW (1994$). Allowing for new equipment that would have been required if this had been a greenfield project instead of repowering, the installed cost figure on this demonstration project was $1700/kW (1994$).

(p 18) Suggest the following change:
In Wisconsin, several generation projects that preceded the ERGS proposal in the ATC queue have been cancelled, or indefinitely delayed. At the time that the initial interconnection study for the ERGS was completed, there were other units in the Midwest queue ahead of Elm Road, including IC001 (Badger Gen – Kenosha~~Midwest Power – Germantown~~) and IC003 (~~Badger Gen – Kenosha~~ Midwest Power – ~~Germantown~~New Berlin) and four generating units in northern Illinois.

(p 22) Chapter 2, **Figure 2-4**
Comment:

The facility lease relationship shown as A between the ERGS SCPC 1 LLC and the Other Investors is included in the diagram in error. The description for that symbol also erroneously mentions "two secondary Lessees". There will not be a lease between ERGS and Other Investors; the facility lease will only be between ERGS (as Lessor) and WEPCO (as a single Lessee). There might be a facility lease between the "Other Investor SPE's" and the "Other Investors", but such a lease is not the subject of the Applicants' filings in either Docket No. 05-CE-130 or Docket No. 05-AE-118.

Further, the party labeled "W.E. Power SCPC1 LLC" should be renamed "ERGS SC LLC" and the subsidiary labeled "ERGS-SCPC 1 LLC" will not exist. The ERGS SC LLC will have an ownership interest somewhere between 83.34% and 100% in the Unit 1 facility. The lease agreements are between WEPCO and ERGS SC LLC, not between WEPCO and the Unit 1 facility.

(p 24) Chapter 2,
In a July 19, 2002, agreement with the Customers First Coalition, an intervener group representing a variety of consumer groups, WEPCO agreed to seek financing for the coal facilities using a 12.9 percent return on equity and 55 percent common equity in the capital structure.

Comment: The July 19, 2002 stipulated agreement covers the two proposed PTF gas units at Port Washington. It is silent as to the terms that would be proposed for the coal units at the Elm Road site.

Given the facility lease payment calculation shown above, it is possible to estimate the effect on ratepayers for the two SCPC plants. Together, the annual lease payments would equal about $214.million. Presently, the retail electric revenue requirement for WEPCO is $1.7 billion. By 2007, WEPCO's retail revenue requirement may equal $2 billion. This means that the additional lease payments for the first two SCPC plants at Elm Road would increase retail electric revenue requirement by about 10.7 percent.
Comment: In 2007, while WEPCO's retail revenue requirement may equal $2 billion, only one of the SCPC units will go into service and it will not go into service until mid-year. Thus, for 2007 the rate impact would be 2.7%, not 10.7% (($107 million/2)/$2 billion).

For 2008 the revenue requirement would increase (assuming a 2.32% inflation factor) but the lease payment would remain the same, for a net impact of ($107 million/($2 billion * 1.0232%)) = 5.2% compared to 2006 rates. The increase in rates from 2007 to 2008 is only 2.6%.

For 2009, the second SCPC unit would go into service mid-year. The net impact for that year would be ($107 million + 107 million/2))/($2 billion*1.0232^2) = 7.67% when compared to 2006 rates. The increase in rates from 2008 to 2009 is only 2.6%.

When both plants are in service, in 2010, the net impact would be ($107 million*2)/($2 billion*1.0232^3) = 9.99% when compared to 2006 rates. The increase in rates from 2009 to 2010 is only 2.5%.

Because the lease payment remains fixed, the rate impact thereafter declines as the overall revenue requirement increases.

The estimate does not include carrying costs or interest during construction.

Comment: One cannot include carrying costs or interest during construction to the estimated future rate impacts because those costs are being paid by the utility (and recovered in rates) during construction. This was intentionally established by the parties in the lease in order to mitigate future rate impacts.

(p 31) , 5th Par. Please consider the following changes.
The PSC has traditionally ~~required~~ recommends Eastern Wisconsin utilities ~~to~~ maintain a higher 18 percent planning reserve margin due to concerns with issues such as transmission limitations. The Mid-America Interconnected Network (MAIN) guidelines typically ~~require~~ recommend about 15 percent target reserves.

(p32) Note (2 places): MAIN audit results show 20.56% reserve margin.

(p 37) Comment: Suggest the following changes to Table 3-2.

Table 3-2 Generating units installed by or under contract to WEPCO since 1985

1997	Whitewater combined-cycle (purchase)	235	~~288~~247
2000	Neenah combustion turbines (purchase)	300	350
2003~~4~~	Zion combustion turbines (Illinois purchase)	450	

(p 37) Comment: Suggest the following change to the 2nd par.
In addition to the generating units it built, WEPCO arranged a 235 MW power purchase from the Whitewater combined-cycle generating unit and it expects to use up to 450 MW of capacity from Calpine's Zion Energy Center in Illinois by ~~2004~~2003.

(p 38) Comment: Consider the following title revision.
Table 3-3 Other generating units greater than 50 MW installed ~~in Wisconsin~~ since 1998 (or under construction)

(p 38) Comment: Consider the following changes.
During the summer of 2000, SEI Wisconsin, ~~an affiliate~~the predecessor of Mirant, placed a 300 MW natural gas facility in Neenah into commercial operation (the plant subsequently purchased by ~~WP&L~~Alliant Generation). During 2001, the 450 MW RockGen combustion turbine project located in the town of Christiana in Dane County began full operation. All of these facilities are under contract to various state utilities. The sale of some of the merchant power plants to Wisconsin utilities reduces the amount of generation that merchant plants were predicted to supply toward the state's generation needs.

By the end of 2004, nearly 2,050 MW of electric generating supply being used by electricity providers for Wisconsin customers may come from merchant plants under contract to the states utilities. Some of this power will come from merchant facilities located outside the state; such capacity plays an important part in maintaining electric reliability in the state. For instance, by ~~2004~~June 2003, WEPCO expects to use up to 450 MW of capacity from Calpine's Zion Energy Center in Illinois.

(p 43) Suggest the following change:

Planned capacity retirements and nuclear relicensing

WEPCO has indicated that no existing baseload capacity would be retired in the near future. Commission staff recommended considering retirement of a generating unit at 60 years and this assumption was incorporated into the EGEAS modeling. This would allow retirement of Oak Creek Unit 5~~4~~ in 2019.

(p 48) Comment: Suggest revising the last paragraph as follows.
An alternative way to depict the information in Figure 3-14 is to examine the expected planning reserve margin for WEPCO if the capacity represented by the Port Washington and ERGS units is added to the existing system. Figure 3-15 portrays expected planning reserve margins with or without the Port Washington and ERGS units. Presently, the PSC ~~requires~~ recommends the state's utilities to maintain an 18 percent planning reserve margin.

(p 59) **Renewable Resources as an Alternative**

In Wisconsin, the noncombustible renewable resources in use for electric generation are wind, solar and hydro. Combustible renewable resources include fuel cells fueled by hydrogen that is produced by a renewable resource and biomass energy derived from wood or plant residue, biological waste, crops grown for use as a resource, or landfill gas. The main renewable energy resources for Wisconsin electric generation appear to be wind power and biomass fuels, including waste-to-energy. At this time, solar power appears too costly to install on a utility scale and there is very little additional hydroelectric power potential available in Wisconsin.
Comment: Please change the third sentence in the above paragraph as follows:
The main new renewable energy resources for Wisconsin electric generation appear to be wind power and biomass fuels, including waste-to-energy.

(p 59 last paragraph)Comment: Suggest revising as follows:
Blades are shaped and positioned to take advantage of different wind velocities so that, depending on design, one wind machine may produce power in a different range of wind velocities than another. Power output is ~~directly~~ proportional to the square of the length of the blades. Cold air is denser, which means it ~~has more force, or ability to turn the blades~~is heavier, than warm air. A wind machine in Wisconsin's cold, dense winter air can produce up to 20 percent more than the same machine with the same wind speed but in ~~warmer~~ hot summer air.

(p 60) Clarifying Comment:
Table 4-1 shows potential capacity and electrical generation based on the land area exhibiting each class of wind speed and assuming 12 MW per square mile.41 The numbers in 4-1 do not include potential offshore wind development in the Great Lakes because the greater projected cost per MW and greater O&M cost ($1671 per MWh and $33 per kW-yr.). Wind power imports from neighboring states with superior wind regimes are also not included due to severe transmission constraints.

(p 61 first paragraph)Comment: Suggest revising as follows:
Factors affecting property values ~~including~~ include the general condition of the local and national economy, taxes, the reputation of the school system, and the availability and condition of infrastructure (i.e. roads, police and fire protection).

(p 61) Comment: Please consider the following revision to include pertinent factual information.
From a social and economic standpoint, wind power has several advantages. Wind energy generally requires a larger workforce than typical gas fueled combustion turbine technologies but less than typical coal fueled facilities. From an economic standpoint, wind power does not have any associated fuel-price risks. Because wind power requires no fuel, the cost of wind generated electricity would not be affected by volatility in fuel prices.

(p 62 Table 4-2)Comment: Suggest using "lb." instead of "#".

(p 62 Sentence following Table 4-2)Comment: Suggest revising as follows:
At an 85 percent capacity factor, ~~22,547,000 MWh~~ 3028 MW would yield ~~3028 MW~~ 22,547,000 MWh of energy per year.

(p 63)Comment: Suggest revising as follows:

3. Woody or herbaceous energy crops—grown ~~sustainable~~sustainably on cropland or in plantations and dedicated for conversion to electricity.

(p 66) Comment: Suggest revising as follows:
Another important assumption in the EGEAS runs is the 20 percent credit to reserve margin. This means that for every 100 MW of wind power generated, only 20 MW would be credited toward WEPCO's reserve margin. This is somewhat conservative in light of the Mid-Continent Area Power Pool (MAPP's) wind accreditation reporting for 2000 through 2001, indicating that five wind farms in Minnesota had accredited capacities ranging from 21 to 29 percent. However, those wind farms are located in stronger wind regimes than Wisconsin has.

(p 69) Comment: Please consider the following qualifications to the last paragraph.
The Calpine proposal submitted to the PSC does contain a ~~completed~~ sample power purchase agreement (PPA) with relevant economic and engineering terms and conditions determined solely by Calpine. Such terms and conditions, due to their trade secret nature, have been filed confidentially at the PSC and are available only from Calpine after entering into an appropriate trade secret protection legal framework.

(p 83) Chapter 5 - Fuel Diversity Perspectives Comment: Suggest adding to the second paragraph as follows.
Some of these considerations include: the age and condition of WEPCO's existing generating units; the source and availability of the fuels; fuel prices and the expected stability or volatility of fuel price over time; overall energy balance in the State of energy use in all applications; and the environmental effects and safety issues associated with the use of different fuels.

(p 85) Comment: Suggest adding to the 3rd paragraph, last sentence as follows.
This suggests that even though large volumes of natural gas continue to be consumed, the available resource base may be expanding, not declining, as gas prices move higher. Over the long term, existing production areas will not be able to supply the increases in demand. Gas will need to be brought to market from areas that currently have little or no production because of cost, technology or regulatory reasons. Examples include importing LNG, offshore eastern Canada, the Mackenzie Delta, Alaska and the Rocky Mountains.

(p 87) Comment: Suggest citing the demand forecast that shows a slowing as stated in the following.
With the generally slow growth rate in natural gas demand and the apparent slowing in the pace of natural-gas- fired electrical generation, technological advance and technological innovation could allow for the development of additional supplies to keep pace with the demand for natural gas.

(p 89) Comment: Suggest adding to the 3rd par., the following.

When the number of operating rigs is not sufficient to keep up with demand, ~~two~~ three things happen: (1) interruptible customers do not receive natural gas ~~and~~ , (2) natural gas prices rise and (3) demand

destruction occurs. So during these situations for the generator using natural gas, supplies might be available at high cost, or under certain conditions might not be available at all.

(p 91) The recently-constructed Guardian Pipeline is such an example. It brings an additional 750 dekatherms per day of capacity to the state, some of which could be used to serve natural-gas-fired electric generators.
Comment: Instead of dekatherms, the unit of measure is million cubic feet. The same error is repeated in footnote 67.

(p 93) Coal mining and transport, 3rd par. Comment: Please consider the following change:
To grasp the impact coal mining has had on the environment, one can examine the statistics for Pennsylvania, the ~~second~~ fourth largest coal-producing state in the U.S. and the source of the coal to be used in the ERGS facilities.

(p 95) **Chapter 5 - Solid Waste**
Comment: Change quantities because of the updated bituminous coal characteristics (Washed Pittsburgh #8) as follows for the SCPC units:
165,200 tons per year of fly ash changes to 206,300 tons per year
38,600 tons per year of bottom ash changes to 51,600 tons per year

In the fourth line the word "acid" should be deleted or changed to "ash". Leachate from coal ash is typically basic rather than acidic.

(p 101) Comment: par. 5 refers to an existing rail loop. There is currently no "loop." The existing track curves onto the property, but terminates rather than reconnecting with the UPRR tracks.

p 101 par. 6. Comment: There are two existing storage piles, one on the dock as mentioned, and one east of the car dumper.

p 102 Comment: par. 3 States generating station equipment would occupy about half of the site. If this is referring to the 1000 acre site, then it is incorrect. Also included with balance of the site would be existing landfill areas, which cover a large portion of the 1000 acres.

(p 102) Note: par. 7 Comment: Outdoor piles will occupy 22 acres of land. Apparently, the Staff's calculation did not consider the irregular shape of the coal piles. Please consider the following revision.

The new coal piles would occupy approximately ~~55~~ 22 acres of land ~~with a footprint of approximately 1,425 by 1,650 feet~~, exclusive of the various conveyors.

(p 102, par. 8) Comment - semantics: A *harbor* is required for ship delivery of coal only. The *expansion* is used for limestone and gypsum loading, unloading, and processing, even if ship delivery of coal is not the chosen fuel delivery method.

(p 109) Comment: Please revise the first sentence and associated footnote as follows.
The SCPC units are being designed to burn an ~~un~~washed fuel.[70]

[70]DR-032 says coal washing will not occur at the ERGS site.

(p 109, Table 6-2) Comment: Please substituting the washed bituminous coal column from Table 9-1.

(p 110, par. 5) Clarification: Conveyors handling crushed coal will be installed inside enclosed galleries. Conveyors handling uncrushed coal would be covered conveyors.

(p114) **Solid waste production, storage, and beneficial use**
Comment: Please change quantities because of the updated bituminous coal characteristics (Washed Pittsburgh #8) as follows for the SCPC units:
165,200 tons per year of fly ash changes to 206,300 tons per year
38,600 tons per year of bottom ash changes to 51,600 tons per year
248,800 tons per year of gypsum changes to 543,600 tons per year

(p114, par. 3) **Water use, storage and discharge**
Comment: Delete first sentence and replace with the following: A new pump house will be installed on the southwest side of the proposed SCPC site plan. OCPP units 5-8 will utilize the existing south plant pump house that will withdraw water from the planned forebay area that will enclose the western end of the intake channel. Both the forebay and new SCPC pump house locations will be connected to the proposed intake tunnel by means of a vertical dropshaft.

(p116) **Fly ash**
Comment: Change "industrial" use to "commercial" use.

(p116) **Bottom ash**
Comment: Change "industrial" use to "commercial" use.

(p 116, par. 6) Plans for gypsum may also include conveyance to a wall board plant if one is constructed in nearby vicinity, or barging off site.

(p 122) HAPs, including mercury, would be controlled in the gasification process. Information from currently operating IGCC facilities suggests that at least 50 percent of the mercury is removed in this gasification process
Comment: We have committed to at least 90 percent mercury removal. This information is included in the revised air permit application.

(p 122, par. 4) Comment: typo. Consider revising as follows.

"The rated heat load input is estimated to be 5,035 million British thermal units (MMBTU/hr) as shown in Figure 6-9. The IGCC unit ~~heat rate~~efficiency would be 37 percent, which currently is slightly less than a SCPC unit under the same conditions."

(p126) **Solid waste generation and use**
Comment: Change quantities for the IGCC units based on more detailed information as follows:
18,000 tons per year of elemental sulfur changes to 33,200 tons per year
60,000 tons per year of sulfuric acid changes to 109,200 tons per year
Change 12,000 Btu/pound bituminous coal to 13,100 Btu/pound bituminous coal
Change 3.2 percent coal sulfur to 2.69 percent coal sulfur

(p 127) Interconnection on the plant site, 2nd paragraph. Suggest the following changes:
The interconnection would consist of three circuits. Two circuits from the plant area to the expanded 345 kV substation area and one circuit from the plant area to the 138 kV substation area. Each circuit would be approximately 4,000 feet in length. For the North Site, the line route from the generators to the substation would travel southwest over the coal handling area, then south to the new expanded 345 kV substation(see Figure Vol. 2-1). For the South Site ~~(see Figure Vol. 2-1)~~, the transmission interconnection lines from the SCPC units would head west northwest across the proposed rail loop track toward the expanded substation which would be located inside of the loop.

(p 128) Stability issues, 3rd paragraph. Suggest the following changes:
ATC issued a 10-Year Assessment Update February 2003. The update indicates the conceptual plan for a number of 345 kV lines in southern Wisconsin connecting to Illinois and Iowa. The Big Bend to Paddock 345 kV line is illustrated as one of several 345 kV lines that could meet future needs. The line is not being proposed at this time. With the recent removal of the interconnections for IC001 (Badger Gen – Kenosha~~Midwest Power – Germantown~~) and IC003 (Midwest Power – Germantown~~Badger Gen – Kenosha~~), a different stability solution may be available.

(p157, **Table 7-11, NO_x row, BACT column)** Comment: typo.
Low NOx burners and selective catalytic reduction

(p 181) Fall Turnover
"The annual temperature cycle can generally be broken down into three stages."
Comment: typo. This sentence is carried over from the previous paragraph, is redundant, and should be removed.

(p 193) Existing impingement and entrainment levels
"In 1985, units 1-4 were retired."
Comment: North Oak Creek Units 3&4 were retired in April 1988; Units 1&2 were retired in December 1989.

(p 194) Existing impingement and entrainment levels
"This system releases dissolved copper and aluminum into the intake water,....."

Comment: The Copper Ion Generator discharges into the House Service Water system that subsequently discharges to Lake Michigan via the condenser cooling water outfalls (WPDES outfalls 003, 004, 005 and 006).

(p200, par. 3) **IGCC unit**
Comment: typos – first sentence (power block,…)

(p200, footnote) **IGCC unit**
Comment: typos – date reference should be 2-01-02 (not 2-10-02)

(p201, par. 3) **IGCC unit**
Comment: Flow rate in last sentence should be 2,948,900 gpm

(p201, par. 3) **Cumulative use** Comment: typos – IGCC (not OGCC) and 485,000 gpm (not gmp)

Comment: Delete first sentence of the final paragraph and replace it with the following: A new pump houses will be installed on the southwest side of the proposed SCPC site plan. OCPP units 5-8 will utilize the existing south plant pump house that will withdraw water from the planned forebay area that will enclose the western end of the intake channel. Both the forebay and new SCPC pump house locations will be connected to the proposed intake tunnel by means of a vertical dropshaft.

(p203, par. 3) **Description and location of proposed water intake system**
Comment: third sentence – delete the words "includes an on-shore pumping station". Also, for this paragraph the reference to a 3,500 feet intake can be deleted. Depth proposed for the intake cribs is about 43 feet.

(pp. 203-204) **Construction methods for the water intake transport system**
Comment: Delete the first paragraph of this section. Delete the first sentence of the first full paragraph on page 204. Alter the second sentence to state: "The proposed tunnel would be 32 feet in diameter and approximately 200 feet below the bed of the lake." Forth sentence – delete 30 foot reference. Fifth and sentences replace with – "The proposed design is to install four intake cribs at the lake bottom that will each connected to a 14 foot diameter tunnel that leads to a drop shaft that is 32 feet in diameter." Delete the sixth sentence.

(p 207) Comment: typo
ERGS ~~1,060,000~~10,600,000 tpy

(p 212) 1st paragraph
Comment: In discussing the dredging, it should be made clear that WE can already dredge a sizeable portion of the proposed navigational channel. This would be done as maintenance dredging of an existing channel.

Rooted Aquatic plants and algae (p218)
Lakebed surveys within the project area were undertaken in 2002 by the Great Lakes WATER Institute. Those studies show no aquatic macrophytes within the project area. Most of the project area is in water depths deeper than (typo) the maximum rooting depth of…

(p 225) Because the plant would use once-through cooling technology which returns water to Lake Michigan and the make-up water for the boilers would come from the municipal water supply, no water filtration or treatment would occur.
Comment: But in fact water treatment will occur, probably demineralization. In particular, the zero discharge facility for the IGCC unit will have a salt cake which will require disposal. At this time it is not known whether this will be a hazardous waste. Other wastes may be generated from the gasification process, including spent catalysts, carbon beds, and other assorted materials.

(p 229) **Early ash disposal areas** Comment: Typos
In addition to the two closed landfills and one open landfill, four early ash disposal areas (EADAs) were identified on the OCPP property. These are ~~five~~ four places on-site where OCPP ash was buried in the early years of plant operation.

Isolated Natural Resource Areas and ~~Primaray~~Primary ~~Environental~~Environmental Corridors are also described in Chapter 10.

(p 230) **Present methods of re-use** Comment: Please consider the following changes:
WEPCO's existing plant currently creates two main by-products: fly ash (class C and F) and bottom ash. Class C fly ash is produced by newer boilers and has more calcium. It is used as a cementitious material and is very good for making concrete. Class F fly ash comes from older boilers and has less or no calcium and a high carbon content. It has little to no economic value at this time.

At this time, over ~~90~~ 96 percent of these by-products are recycled. Class C fly ash is used as admixtures in concrete and soil stabilization beneath paved surfaces. Bottom ash is primarily used in construction, as sub-base below paved surfaces and beneath commercial buildings. Most of the high carbon Class F fly ash is utilized as a supplemental fuel at Pleasant Prairie Power Plant or utilized for manufacturing portland cement~~Most of Class F fly ash is landfilled~~.

(p230) **Fly ash and bottom ash** Comment: Please consider the following changes:
Table 9-1 illustrates the potential components of the ash by-products from the proposed ERGS SCPC units.

Based on the characteristics reported in Table 9-1, and an 85 percent capacity factor for the new SCPC units, WEPCO estimates that the amount of coal combustion by-products materials produced by each unit would be:

Fly ash ~~82,600 tons/year~~ 103,100 tons/year per unit
Bottom ash ~~19,300 tons/year~~ 25,800 tons/year per unit

Thus, a total of ~~165,200 tons per year of fly ash and 38,600 tons of bottom ash~~206,300 tons per year of fly ash and 61,600 tons of bottom ash would be produced each year by the two SCPC units. Using the standards in Wis. Admin. Code § NR 520.15 (20) and a field capacity conversion factor of 1.2 tons/cubic yard, the respective volumes of the fly ash and bottom ash would be calculated 171,899 cubic yards and 42,975~~at 137,666 cubic yards and 32,166~~ cubic yards. The total volume of fly ash and bottom ash together would be 214,874 ~~169,832~~ cubic yards per year.

(p231) **Synthetic gypsum** Comment: Please consider the following changes:

As discussed in Chapters 6 and 7, the ERGS SCPC units would utilize limestone or organic-acid promoted limestone to control and reduce SO2 emissions. The use of limestone versus organic-acid-promoted limestone would depend upon the fuel sulfur content. Synthetic gypsum by-product would be generated in this operation regardless. WEPCO estimates that about ~~124,400 tons/year~~ 271,800 tons/year per unit would be generated by each unit. The two proposed SCPC units would then create a total of ~~248,800 tons~~543,600 tons of gypsum per year.

(p232) **Elemental sulfur and sulfuric acid** Comment: Please consider the following changes:

In the sulfur recovery plant, the sulfur-containing gases from the Acid Gas Removal (AGR) system would be converted to either elemental sulfur or sulfuric acid. Elemental sulfur and sulfuric acid production would be directly related to the sulfur content of the coal. Based on the proposed fuel, the sulfur content of the coal would yield about ~~18,000 tons/year~~ 33,200 tons/year of elemental sulfur. The quantity of sulfuric acid produced would amount to approximately 60,000 tons/year, or 62,400 gallons per day. ~~This material may be considered hazardous waste.~~

(p 233) **Storage and Handling of Construction and Operation By-Products Fly ash**
Comment: Please consider the following change:
Fly ash collected in the fabric filter hoppers and the air heater hoppers (see Figures Vol. 2-1-to 2-3) would be conveyed to the fly ash storage silo via a pneumatic transport system using low-pressure air from a blower. The fly ash would be discharged through a wet or dry unloader and conveyed through a telescopic unloading chute into a truck for disposal or utilization.

(p233) **Bottom ash**
Comment: Please consider the following addition:
Bottom ash from the boiler would be collected and transported on a submerged scraper conveyor and dewatered. The ash would then be collected in a dump truck and hauled to a storage pad on site (see Figures Vol. 2-1 to 2-3). The ash collected on the storage pad could be loaded into a truck using a front-end loader. It could then be taken to a landfill or recycled as permit allows by NR 538 rules for beneficial utilization of industrial by-products.

(p233) **Gypsum**

par. 2 Comment: typo. Should say "Secondary dewatering....."

par. 3 WEPCO has not proposed the size of the storage shed at this time.
Comment: Please note that the storage shed is to be sized for 3 day storage (refer to air model).

par. 4 Comment: Please consider the following addition.
WEPCO must contract with commercial landfills for gypsum disposal until a wallboard plant is available to accept it or modify the license for the WEPCO landfills.

(p234) Elemental sulfur or sulfuric acid Comment: Please consider the following changes.
Either elemental sulfur or liquid sulfuric acid would be produced as part of the AGR process for the IGCC unit. WEPCO proposes an on-site, three-day storage for liquid sulfuric acid. Based on production of ~~62,400~~50,700 gallons of sulfuric acid per day; a bulk liquid storage of 200,000 gallons would be needed.

WEPCO has stated its intention to haul 30 truckloads (at 3,000 gallons per truckload) per day from the power plant on a Monday through Friday basis. Rail cars hold a capacity of 10,000 to 11,000 gallons and could be considered for longer distance shipments. This material may be classified as hazardous material. The storage and transportation will be regulated as a hazardous material like conventionally manufactured sulfuric acid~~waste. If determined to be hazardous waste, the storage and transportation will be regulated as hazardous waste~~.

(p 235) **Changes in hauling methods and timing** Comment: Please consider the following addition. WEPCO does not anticipate any substantial changes in the hauling methods or routes for solid waste from the new facilities. There would be an increase in truck traffic for transportation of ashes and other by-products from the ERGS to other WEPCO-owned landfills if the Caledonia landfill capacity is exhausted.

(p236) **Disposal in local landfills** Comment: Please consider the following changes.
As discussed at the beginning of this chapter, WEPCO operates three licensed landfills in the southeast region. The three active landfills are not near capacity and are expected to remain operational for many years. As noted above, the SCPC units are expected to generate ~~165,200 tons/year (82,600 tons per unit per year)~~257800 tons/year (128,900 tons per unit per year).

(p236) **Need for changes in landfill operating plans or licenses** Comment: Please consider the following change.
WEPCO is required to submit plan modifications to the DNR for any of the landfills they plan to use for disposal of newly generated by-products. WEPCO ~~would~~ may also be required to update the design of these landfills to provide better protection for the groundwater.

(p237) **Oak Creek North (OCN)** Comment: Please consider the following change.
Phase II -- Fill would be placed and temporary parking facilities would be constructed. These actions would also result in changes in surface drainage off of the landfill. See the discussion in Chapter 8 on stormwater discharge. The landfill reconfiguration will improve cover impermeability, drainage characteristics and minimize the production of leachate. Long term plans for the OCN site include source removal for use as a supplemental fuel in the proposed generating units. The site will eventually be reclaimed and become available for other uses.

(p237) **Oak Creek South (OCS)** Comment: Please consider the following correction.

Coal combustion by-products generated by the OCPP were disposed of at the OCS beginning in 1974 when it was licensed until it reached its capacity in May 1992 and was covered. The OCS landfill covers 80 acres and contains 3,760,000 cubic yards of ash.

(p237) Comment: Please consider adding an additional bullet.
As discussed in Chapters 10 and 11, construction of the ERGS would require excavation of a significant amount of native soil for construction of the new power plant units and other features. The proposed modifications to the OCS landfill involve:
• Placement of soil on the top. Fill would be placed at a minimum thickness of eight feet over the cover of the OCS.

• Compaction and grading of the newly placed soil to prepare a construction laydown area. Following the relocation of soil, predominantly clay in composition, from the ERGS excavation areas to the top of the OCS, a construction laydown area would be placed as the final surface.
• Construction of access roads and development of short- and long-term stormwater management facilities.
• Proposed cover upgrades from the ERGS project will reduce the production of leachate at the OCS landfill.

(p237) **Beneficial Re-use Ash** Comment: Please consider the following correction.
WEPCO has a beneficial ash re-use program in place. Companies have been working with WEPCO since 1980 to market fly ash and bottom ash from WEPCO's existing coal-fired plants. Since 1980, re-use of the ash has increased until about ~~90~~96 percent of the by-products from its power plants are now beneficially used.

(p 237) Comment: Please consider the following addition.
Bottom ash is now being utilized as base or sub-base material for building floors and foundations, paved roads, and parking lots. Fly ash is now being utilized in cements as a raw feed material for portland cement production, soil stabilization, cold in-place recycling of asphalt pavements, in controlled low-strength materials, and as a supplemental fuel.

(p 237) Comment: Please consider the following change.
WEPCO has approached marketers for their projections on reaching full utilization of the fly ash and bottom ash and has received optimistic replies (these are filed at the PSC as part of WEPCO's CPCN application.) A.W. Oakes & Son of Racine, Wisconsin has indicated that it could utilize 100 percent of the bottom ash within two years of the commissioning of each unit. Mineral Solutions, Incorporated has indicated that it could utilize 100 percent of the fly ash within three years of the commissioning of each unit. This would require working to expand the market for Class F fly ash. Class F fly ash can be used to produce high performance concrete if it meets ASTM C-618 and has consistent quality from a base loaded power plant. WEPCO's current sources of Class F fly ash have high carbon content and thus are not suitable for use in concrete.~~Class F fly ash is not a good ash for making concrete because it contains less than 10 percent calcium oxide (CaO). However, if water is added to it, it somewhat hydrates and solidifies. It has been marketable as "controlled low strength material" (CLSM) or as "flowable fill" (concrete that flows). Basically, it can make a weak concrete for nonstructural use. For instance, it has been used for abandonment of utility tunnels. This market is very limited.~~

(p239) **Table 9-2** Comment: Table 9.2 below is an update to reflect Pittsburgh #8 washed bituminous coal and shows quantities of coal combustion products projected for storage at the Caledonia landfill based on the 10 year straight line utilization growth assumption.

Table 9-2 WEPCO's Projected Annual Coal Combustion Products Landfill Quantities for Fly Ash, Bottom Ash, and Slag

Year	SCPC FA	SCPC BA	SCPC FA	SCPC BA	IGCC Slag	Total
2007	103,100	25,800	0	0	0	128,900
2008	92,790	23,220	0	0	0	116,010
2009	82,480	20,640	103,100	25,800	0	232,020
2010	72,170	18,060	92,790	23,220	0	206,240

2011	61,860	15,480	82,460	20,640	100,000	280,460
2012	51,550	12,900	72,170	18,060	90,000	244,680
2013	41,240	10,320	61,860	15,480	80,000	208,900
2014	30,930	7,740	51,550	12,900	70,000	173,120
2015	20,620	5,160	41,240	10,320	60,000	137,340
2016	10,310	2,580	30,930	7,740	50,000	101,560
2017	0	0	20,620	5,160	40,000	65,780
2018	0	0	10,310	2,580	30,000	42,860
2019	0	0	0	0	20,000	20,000
2020	0	0	0	0	10,000	10,000
2021	0	0	0	0	0	0
TOTAL	567,050	141,900	567,050	141,900	550,000	1,967,870

(p 260) In summary, the topography of the present OCPP property would be altered with a large amount of soil excavation, transport, and deposition to accommodate the two SCPC units at the lakeshore for once-through cooling access and the IGCC combined-cycle and AGR units to handle their water needs as well.
Comment: AGR should be ASU (Air Separation Unit).

(p 275) 2nd par.
Comment: The OCPP currently has two stacks.

(p 277) Communities close to the power plant site
Comment: typo
Communities closest to the site may experience increased noise, dust, traffic problems, and visual impacts. Communities more than one-half mile away are usually too far from a power plant site to experience most of these impacts, but there exceptions, especially with respect ~~top~~ to visual impacts along the lakeshore.

(p 279) **Table 11-1.**
Comment: The column labeled in operation appears to have the wrong dates for OC U-2 & 3 (others are close). The following information was obtained from NERC.

Unit Name	Commercial Operation Date
Oak Creek 1	9/30/1953
Oak Creek 2	10/21/1954
Oak Creek 3	12/3/1955
Oak Creek 4	10/22/1957
Oak Creek 5	12/31/1959
Oak Creek 6	11/25/1961
Oak Creek 7	3/16/1965
Oak Creek 8	10/31/1967
Oak Creek 9	2/10/1969

(p 299) **Jobs and Employment**

Expected changes in on-site employment

During construction (temporary)

Comment: typo

The electric utility industry has one of the lowest workers per dollar investment ratio. SCPC Units 1 and 2 would each take four years to construct using an average work force of 500 employees for each unit. The maximum number of employees ~~world~~ would be 600 people per unit....

(p306) Causes of increased traffic

Comment: Please consider the following correction.

The sources of increased traffic during construction are: (1) truck delivery of equipment and supplies, (2) additional employee vehicles, and (3) possible hauling of soil offsite by truck. Increased traffic during operation could be due to: (1) truck delivery of supplies, (2) additional employee vehicles, (3) vehicles used in routine maintenance, (4) ash shipment to market, (5) vehicles needed for mining of landfill ash, and disposal of byproducts, and (6) gypsum shipments to market if there is not a wallboard plant onsite or if not barged off site.

(p 309) Ash shipments Comment: Please consider the following clarification.

The number of vehicle trips for shipment of ash to off-site beneficial-use markets or waste disposal sites is not included in Table 11-14. At first, the applicants plan to store ash at the on-site Caledonia Landfill. Off-site ash shipments would start ~~only after all three units are operational,~~following startup of the first unit, ramping up to 100 percent utilization ~~and~~ after markets for the ash are fully developed. Table 11-15 shows the ultimate amount of off-site ash shipment, although shipments are likely to start at a lower number and increase as markets develop.

(p 330) Proposed changes to lands adjacent to Haas Park Comment: Please consider the following correction (typo).

The existing power plant chimneys are currently visible from Haas Park. Three new stacks or chimneys would be added if the entire ERGS facility is built. The new stacks for the SCPC units ~~and the IGCC~~ would be higher and larger in diameter than the OCPP stacks. Refer to the Visual Impacts section of this chapter for more information.

(p 330) **Table 11-15** Comment: typo in footnote **

(p 339) **Figure 11-14** Comment: Please consider revising the Figure title for accuracy as follows.

New residential area near existing ~~T~~transmission lines ~~passing through new residential areas~~

(p335) Shore access and fishing

Concerns about the effect of the ERGS facility on local fish populations are addressed in Chapter 8. Based on interested generated by the public, the applicants have developed some initial ideas for fishing access on the north end of the property as close to the proposed warm water discharge (for the North Site) as possible. They have also sponsored meeting with ~~local~~local (typo) fishing groups to get feedback.

(p 349) Splitting coal delivery between rail and ship options
Table 11-29 'Average number of trains per week entering the Oak Creek/ERGS site under a range of coal delivery options (compared to a current five trains of 125 cars per week)

(p 350) Process for altering railroads and ownership
"WE Power would also pay for any other changes to town or country roads due to the proposed power project."
Comment: "Any" is too broad. Suggest using the word "specific" instead.

(p 352) Comment: Please consider the following clarification to the 6th bullet for accuracy.
The summary included the following:
• 30 coal trains passed Four Mile Road traveling to and from the Oak Creek site
• The number of vehicles stopped at the crossing (for coal trains) averaged 24, with a maximum of over 50
• Coal train crossing times averaged 3 minutes 48 seconds
• The maximum coal train crossing time was 8 minutes 50 seconds
• The minimum coal train crossing time was 2 minutes 17 seconds
• There were 61 other (non-coal) trains or gate closings

(p361) Wetlands Comment: typo
An overpass (rather than an underpass as proposed) at Six Mile Road, would have greater land disturbance and wetland impacts than other alternatives. It would also be more expensive than the ~~Benisch~~ Benesch recommendation

(p 365) Table 11-38, footnote 2. Comment: I-93 should be I-43.

(p 365) Effect of a proposed new 4-mile transmission line Comment: Please consider the following clarification.
The proposed new transmission line is a 345 kV line that would extend from the substation on the OCPP/ERGS site to the Chicago and Northwest (C&NW) railroad track (It is listed as reinforcement 2a on Table 6-4). This new line would be one transmission circuit, (a set of three ~~lines~~conductors) with three insulator strings. Some transmission structures carry two circuits (six ~~lines~~conductors) on two sets of arms. At the C&NW railroad track, the circuit from this new line would continue on existing, two-circuit structures which are only carrying one operating circuit now.

ERGS DEIS Applicants' Comments – Enclosure D

Comment: Please consider the following clarifications to the DEIS Executive summary:

Air quality impacts

WE is proposing to install best available control technologies for nitrogen oxides (NO_x), carbon monoxide (CO), sulfur dioxide (SO_2), particulate matter less than 10 microns in diameter (PM_{10}), lead, mercury, fluorides, and sulfuric acid mist (H_2SO_4). In addition, Lowest Achievable Emissions Rate (LAER) controls are proposed for volatile organic compounds (VOCs).

In addition, best available control technologies and operating practices are proposed to control fugitive particulate emissions from the various material handling and storage processes.

The air modeling and PSD increment results demonstrates that ERGS meets the NAAQS and PSD increment. However, local air quality would be expected to be impacted as a result of constructing and operating the facility. Results of air modeling analysis indicate that the resultant concentration of total suspended particulates (TSP 24-hr) including the regional background would be nearly 100 percent of the Wisconsin secondary (welfare based) air quality standard. Concentrations of PM_{10} including the regional background are expected to be about 80 percent of the health-based National Ambient Air Quality Standard (NAAQS). The ambient air impacts of TSP and PM_{10} are very localized at specific locations around the plant site or along the railroad track that runs through the site and are not regional in nature.

PM_{10} (24-hour) would also consume nearly 100 percent of the PSD increment. However, increment impacts are also very localized at specific locations around the plant site and are not regional in nature. The probability that a new PM_{10} source would impact the same specific locations at the Elm Road site is very remote. The PSD increment modeling results show that a new source located in Racine County would not have a measurable impact on the specific high increment locations around the Elm Road site. Therefore, the Elm Road Generating Station should not affect this new source or any other major source of PM_{10} from being able to obtain an air permit

If constructed on the North Site with accommodations, the concentration of TSP would be a slightly lower percentage of the standard compared to the North Site without accommodations, and less of the expected increment for the 24-hour PM_{10} and 24-hour SO2 increments would be consumed.

An air quality modeling assessment of the potential impacts of the proposed Elm Road Generating Station as well as the multi-emission reduction agreements on regional ozone (1-hr and 8-hr) and fine particulate (24-hr $PM_{2.5}$ and PM_{10}) standards indicate that there would be minimal impacts on the regional 1 hour and 8 hour ozone and on the 24-hr $PM_{2.5}$ concentrations.

An air quality modeling assessment of the potential impact of the proposed Elm Road Generating Station and existing Oak Creek units on local mercury deposition in Wisconsin indicates that the existing Oak Creek Power Plant contributes about 2% to the total background Hg deposition. The corresponding ratio of incremental local Hg deposition to background deposition is about 1% for the new ERGS units

The air modeling and PSD increment results demonstrates that ERGS meets the NAAQS and PSD increment. The information provided in the air permit application and in the environmental impact statement demonstrate that the ERGS project is permittable. A final determination will made after the requirements of Wis. Admin. Code ch. NR 150, the DNR WEPA rule, are satisfied

Comments on the Draft Environmental Impact Statement, submitted by the Wisconsin Legislature

05-CE-130

WISCONSIN LEGISLATURE

P.O. BOX 8952 · MADISON, WI 53708

June 11, 2003

RECEIVED
2003 JUN 13 P 3:30
WISCONSIN PUBLIC SERVICE COMMISSION

Jeffery Kitsembel
Public Service Commission of Wisconsin
610 North Whitney Way
Madison, WI 53705

Re: Elm Road Generating Station, docket no. 05-CE-130

Dear Mr. Kitsembel:

In the next five months, the Wisconsin Public Service Commission (PSC) will face several major decisions related to ensuring that the state will have adequate power supplies to meet its future needs in an environmentally safe and affordable manner. How your agency decides on the alternatives before it will have dramatic impacts on Wisconsin's energy and environmental profile for decades to come.

Specifically, your decisions on these matters will have various long-term ramifications to Wisconsin. These include:

- How much state residents will pay for electricity and transmission, both now and under potentially higher regulatory costs stemming from stricter rules on mercury or new limits on greenhouse gas emissions.
- How strongly the state is committed to viable wholesale competition in the power sector, which in turn, impacts the state's future ability to attract new investments in power generation.
- Finally, how new generation will either stifle or bolster economic development in many Wisconsin counties that already face or are poised to face challenges due to nonattainment of federal air quality standards.

We believe that Calpine's proposed power plants in Fond du Lac and Kaukauna should be included in the final mix of new sources of electricity that will be approved in this proceeding. The Draft Environmental Impact Statement indicates that the Calpine proposal is environmentally responsible and lower cost than proposed alternatives.

The plants would not create risks to ratepayers or the environment from new mercury emissions or high emissions of greenhouse gasses. NOx emissions would also be lower than under alternatives – a major benefit as many Wisconsin counties face possible new ozone nonattainment regulations.

MFC
CO-8
ALJ
OCC-2
Elec-10

We appreciate the opportunity to comment on this important public policy decision. We are confident that both agencies will continue to review these alternatives in a fair, unbiased manner.

Sincerely,

Terri McCormick

Alvin R. Ott Jr.

Carol Roessler

Karl Van Roy

Judy Krawczyk

Frank Lassee

Gregg Underheim

Garey Bies

Carol Owens

Steve Kestell

John Lehman

Dave Hansen

Signed by:

Representative Terri McCormick

Representative Alvin Ott

Senator Carol Roessler

Representative Karl Van Roy

Representative Judy Krawczyk

Representative Frank Lassee

Representative Gregg Underheim

Representative Garey Bies

Representative Carol Owens

Representative Steve Kestell

Representative John Lehman

Senator Dave Hansen

Cc: Burnie Bridge, Chairperson
Public Service Commission of
Wisconsin

P. Scott Hassert, Secretary
Wisconsin Department of Natural
Resources

Comments on the Draft Environmental Impact Statement, submitted by Wisconsin Public Power Inc.

BEFORE THE
PUBLIC SERVICE COMMISION OF WISCONSIN

Application of Wisconsin Electric Power Company; Wisconsin Energy Corporation; and W.E. Power, LLC; For a Certificate of Public Convenience and Necessity For Construction of Three Large Electric Generation Facilities, the Elm Road Generating Station, and Associated High Voltage Transmission Interconnection Facilities to be Located in Milwaukee and Racine Counties	Docket No. 05-CE-130

COMMENT OF WISCONSIN PUBLIC POWER, INC.

Wisconsin Public Power Inc. (WPPI) submits this comment on the draft Environmental Impact Statement (EIS) for the Elm Road Generating Station (ERGS). The draft EIS provides an assessment of the relative economics of the ERGS project and its environmental impacts. In these comments, WPPI suggests certain revisions to the report that would put into better focus the need for the project and the economic and environmental impacts of the project.

SUMMARY OF KEY COMMENTS

- **Wisconsin Energy's proactive mitigation of potential adverse impacts on wholesale electric competition should be commended and recognized as a significant benefit of the project.** The draft EIS recognizes that the PSC's regulation of the economic terms of the Facility Lease provides protection to retail ratepayers. However, the draft EIS should also recognize the wholesale market mitigation measures that are a key ingredient of the proposal. The wholesale market problem addressed by these measures is the inability of smaller Wisconsin utilities that need new baseload capacity, like WPPI and Madison Gas and

Electric ("MGE"), to construct economic coal-fired capacity on their own. At the same time, their options for purchasing such capacity are very limited because the market in Wisconsin for long-term wholesale baseload power is very tight, in part because of the serious transmission constraints that prevent additional long term firm imports. Without the ability to participate as owners in large baseload projects like the ERGS units, or to buy additional long term wholesale power at average embedded cost rates, the future viability of Wisconsin's smaller utilities will be threatened and their customers could be faced with significantly higher rates. By offering ownership rights in the ERGS units to WPPI and MGE and offering blocks of average embedded cost power from its system to other small utilities that depend on the wholesale market, WEPCO has affirmatively addressed potential adverse competitive impacts of the ERGS project on the wholesale market.

- **The state needs significant new baseload generating capacity, and if there is an error in timing, it should be on the side of adding new baseload resources sooner rather than later.** There should be no dispute that Wisconsin desperately needs additional baseload generation. The existing baseload fleet in the state is aging; Wisconsin has not added any new coal-fired generation in almost 20 years. New generation is required to meet continued load growth and offset inevitable unit retirements in the future. Further, Wisconsin's overtaxed and highly constrained transmission system cannot be relied on to import additional capacity and energy to satisfy Wisconsin's baseload requirements,

which means additional baseload generating capacity must be built within the state.

The ERGS should not be delayed just because a large plant addition may result in a slightly higher than optimal reserve margin for a year or two. The permitting and construction of new coal baseload facilities requires a long lead time. By necessity, new baseload capacity must be installed in large blocks. Given load forecast uncertainty and the long lead time needed to construct baseload generation projects, projects such as the ERGS can not be timed precisely to meet the capacity needs of WEPCO in each year. This is inevitable and must be expected. It should be recognized in the EIS that the impact to ratepayers of any temporary excess baseload capacity can be mitigated through wholesale sales and reduced fuel costs. A much more significant concern is not having sufficient baseload resources available to meet the state's needs, particularly given the risks of an LMP market, high natural gas prices, or an otherwise volatile wholesale market. Simply put, it is much riskier to be a little short than a little long on capacity.

- **WPPI cautions against placing too much reliance on the EGEAS computer model results.** The EGEAS model, while a useful planning tool, does not account for a number of important considerations in determining an optimal resource expansion plan, such as the economic risks associated with delaying the ERGS units and the operational difficulty of combining wind turbines and conventional generation to provide reliable generation output. Such factors were apparently not considered in interpreting the EGEAS results. A broad perspective

needs to be applied when interpreting the EGEAS results, rather than simply accepting a plan produced by the model as the "optimal" plan.

- **The current economic environment is extremely favorable for developing high capital cost baseload projects.** Given the current economic conditions – low interest rates and low inflation – this is an excellent time to proceed with the development of a high capital cost project such as the ERGS units. The risk that significant cost overruns will be experienced is substantially lower in this environment. Conversely, delay risks pushing construction into a less favorable economic environment and would increase project cost risk substantially. For example, based on the lease calculation used in the draft EIS on page 26, the annual lease payment would increase by approximately 3.1% for each 100 basis point increase in the interest rate on 30-year corporate A rated bonds. An increase of 300 basis points would increase the annual lease payment by approximately 9.4%. Higher interest rates would likely also be accompanied by higher inflation rates, resulting in a double whammy on the base cost of construction of the project. Thus, the risks of delay overwhelm any perceived benefits of such delay in an "all else being equal" analysis.

- **While wind generation is definitely a promising renewable technology, at this time, it is not a dependable substitute for coal-fired baseload generation.** Wisconsin utilities should be encouraged to develop significant wind generation in the state. This will give the state experience with an increasingly viable technology. However, wind technology is still developing and its capability to function as a cost-effective baseload power source in Wisconsin has yet to be

demonstrated. It is not an alternative to proven baseload technology at this time. There are a number of uncertainties related to annual energy production, availability at time of peak demand, the economics of using combustion turbines to back up wind generation and the long-term reliability of wind generation compared to mature technologies such as the SCPC units proposed for use at ERGS. In addition, there are uncertainties about the interaction of large-scale wind farms with the bulk power system and the ability to site such farms in Wisconsin.

- **The ERGS facilities provide a hedge against early retirement of Wisconsin's nuclear power plants.** Wisconsin's nuclear power plant operating licenses all expire early next decade. While the NRC has recently been granting license extensions, there is no guarantee this trend will continue. Wisconsin could face a significant need for baseload resources if problems develop with these older units or the licenses are not extended. Waiting to decide on any new clean-coal baseload additions until the uncertainties with respect to our aging nuclear plants are fully resolved is a very risky strategy given inflation and interest rate risks, among others. Having baseload capacity in place by the end of the decade would substantially increase Wisconsin's flexibility in dealing with the complex issues that relicensing may raise.

- **The ERGS site is a brownfield site that is well suited for coal-fired generation.** Sites for major new generating facilities are difficult to find. The ERGS site is an existing plant site and use of the site avoids the need to construct at a greenfield site with much greater environmental impacts.

- **The risks of high natural gas prices and supply interruptions are not fully captured in EGEAS sensitivities reported in the draft EIS.** The draft EIS provides a good discussion of the historical relationship between natural gas and coal prices on pages 66 through 68. However, the high natural gas price sensitivity analyzed in the draft EIS is based on WEPCO's high natural gas price forecast, which assumed a 15% increase over the base natural gas price forecast. It is reasonable for WEPCO to use a conservative high natural gas price scenario when presenting their analysis supporting the ERGS proposal. To do otherwise would clearly invite criticism. However, in our view a 15% increase over the base natural gas price forecast does not adequately capture the significant risk that natural gas prices will be much higher than the base natural gas price forecast or that the supply of gas could be interrupted. Today natural gas prices are double what they were a year ago. WPPI suggests that a high natural gas price sensitivity should use a natural gas price forecast that is at least 50% over the base natural gas price forecast in order to capture the significant price and availability risks associated with natural gas.

In addition, WPPI questions whether the CO_2 monetization sensitivity analyzed in the draft EIS incorporated a higher natural gas price forecast to account for the impact of a CO_2 tax. If a CO_2 tax were implemented generators could be expected to switch from coal to natural gas where feasible to avoid this tax. The result would be to increase the demand for natural gas and, in turn the price of natural gas. The effect of incorporating the potential impacts of a CO_2 tax on natural gas

prices would be to lower the relative cost penalty on coal-fired generation in the CO_2 tax monetization analysis.

- **The description air quality impacts of the proposed ERGS units in the Executive Summary is not complete.** In the discussion of air quality impacts on pages x and xxxi, the draft EIS concludes that the concentrations of SO_2 would increase dramatically, approaching 93% and 87% of NAAQS, respectively, as a result of the ERGS units. This discussion of air quality impacts is incomplete. It does not recognize, for example, that the air emissions from the proposed ERGS units will be far lower than the air emissions from any existing Wisconsin coal fired power plant or that the development of these facilities in conjunction with the future retirement of some existing coal plants will over time result in a substantial reduction in SO_2 and other pollutants from Wisconsin coal plants.

WPPI'S INTEREST IN PTF

WPPI is a municipal electric company serving 37 member municipalities that operate electric distribution utilities. WPPI's members purchase all of their electricity requirements from WPPI and serve approximately 140,000 customers. WPPI was formed by its members in 1980 pursuant to (now) Section 66.0825, Wisconsin Statutes, to achieve economies of scale in the acquisition of generation facilities, transmission service and in the purchase of electric power needed to provide their customers with safe, reliable and economic electric power and energy. WPPI initially supplied the power requirements of its members through power purchased at wholesale from the Wisconsin investor-owned utilities that previously supplied its members. Over the years, WPPI acquired some of its own power resources and blended those resources into a portfolio

that continues to include substantial wholesale purchases. At the present time, approximately 25% of WPPI's capacity requirements are satisfied from its owned resources. WPPI's projected 2003 system peak demand is 858 MW with energy requirements of 4,798 GWh.

Achieving greater supply independence is part of WPPI's long-term power supply strategy. This objective is particularly important given the uncertainties that exist as to the availability of long term wholesale power in the future. A key part of this strategy is to obtain additional baseload resources that allow WPPI more control of future costs. WPPI currently owns only one baseload resource - a 20% interest (107 MW) in Boswell Unit No. 4, a 535 MW coal-fired generating unit operated by Minnesota Power and located near Grand Rapids, Minnesota. Given the volatility of natural gas prices, WPPI believes coal-fired baseload generation is significantly more likely than other baseload options to provide a dependable supply of electricity at relatively stable prices. For this reason, WPPI negotiated with Wisconsin Energy Corporation ("WEC") and its affiliates to obtain an option to participate as an 8.33% owner in each of the three proposed ERGS units (approximately 50 MW in each unit), with a further option to increase WPPI's ownership to 10% (to approximately 60 MW in each unit) in the event that MGE elects not to exercise a similar option for ownership in the ERGS units.[1] This option will either be exercised or expire for a unit shortly after a CPCN is issued for that unit.

This option is very important to WPPI. WPPI is not large enough to obtain on its own the economies of scale that WEC will realize through the ERGS project. To obtain

[1] WEC seeks a CPCN for the entire PTF project and plans to proceed with the entire PTF project even if MGE and WPPI decline to exercise their options.

such economies of scale, WPPI must find partnership opportunities with other entities to pursue the development of large baseload generation.

In addition to the interest in potential ownership, WPPI is WEPCO's largest long term wholesale electric customer, with a contract that extends through April 25, 2025. WPPI's current purchase under this agreement is 210 MW, which is purchased on a take or pay basis pursuant to demand nominations made two years in advance. Under this arrangement, WPPI has agreed that the costs of the PTF coal units will be reflected in WEPCO's wholesale rates at the same lease cost that the PSC approves for recovery of PTF plant costs in retail rates. This agreement will treat wholesale and retail customers equitably and prevent any discrimination in either direction due to potentially different FERC and PSC rate treatments of the units. As a long term firm customer, WPPI is vitally interested in WEPCO's long term power costs. While construction of the PTF units will increase rates, WPPI is convinced that the projects offer better long term price stability than alternatives and therefore supports construction of the ERGS units.

COMMENTS ON EIS

For the reasons given below, WPPI believes its members and the state as a whole will benefit from the development of the proposed ERGS facilities.

- **Wisconsin Energy's proactive mitigation of potential adverse impacts on the competitiveness of the wholesale market should be commended and recognized as a significant benefit of the project.** The draft EIS correctly notes that by statute the Commission must determine prior to issuing a CPCN that a facility will not have a material adverse impact on competition in the relevant

wholesale electric service market. See Section 196.491(3)(d)7. In this case, WPPI believes that the "relevant" wholesale market is the long-term wholesale market for baseload capacity. The draft EIS, however, primarily analyzes the impact of the Facility Lease, and the rates at which capacity and energy from ERGS would be sold to WEPCO, on WEPCO's retail rates. The lease is not really a bona fide wholesale transaction; it is a financing structure.

While WPPI agrees that PSC regulation of the economic terms and conditions of the Facility Lease provides protection to retail ratepayers, WPPI believes that the draft EIS should also address the project's impact on the relevant wholesale market – the market for long term baseload capacity. An analysis of WEPCO's actions as they relate to the long-term wholesale capacity market discloses that WEPCO has addressed what otherwise would be significant adverse impacts of the ERGS proposal by offering ownership rights in the ERGS units to WPPI and MGE and offering average embedded cost pricing from its system to other small participants in the Wisconsin wholesale market.

WEPCO's affirmative mitigation efforts should be recognized in the EIS as a key element of the proposal. As a smaller load serving entity, WPPI's ability to provide price stability and reliable service to its customers over the long term is dependent upon a diversified resource portfolio. Although WPPI and other small load serving entities (LSEs) are able to compete with larger suppliers in many contexts, the barriers to entry into baseload capacity ownership are very steep. Small LSEs cannot achieve the economies of scale inherent in the ERGS units without joining larger entities, such as WEPCO, as partners. WPPI has sought

cost effective joint ownership opportunities in large baseload plants since its inception in 1980. WEPCO is only the second party to agree to WPPI's participation as an owner in a large scale project. The first such project – WPPI's 20% (107 megawatts) ownership share in Boswell No. 4 – is the backbone of our power supply. Without this resource, WPPI would not have become a viable power supplier. WPPI cannot predict when, if ever, an opportunity similar to WPPI's PTF option will materialize in the future.

Without the ability to participate as owners in large baseload projects like the ERGS units or to buy power at average embedded cost rates, the future viability of Wisconsin smaller utilities will be threatened and their consumers could be faced with significantly higher rates. By offering ownership rights in the ERGS units to WPPI and MGE and offering blocks of average embedded cost power from its system to other small participants that depend on the wholesale market, WEPCO has affirmatively addressed potential adverse competitive impacts on the wholesale market of the PTF proposal. The EIS should recognize WEPCO's initiative as a very positive step. WEPCO's agreements in this regard should be held by the Commission to be sufficient to meet WEPCO's obligation under the CPCN statute and further should be held up as an example to other large entities constructing baseload units as a desirable means to meet their statutory obligations to mitigate adverse impacts on the wholesale market.

- **The state needs significant new baseload generating capacity, and if there is an error in timing, it should be on the side of adding new baseload resources sooner rather than later.** There should be no dispute that Wisconsin

desperately needs additional baseload generation. The existing baseload fleet in the state is aging; Wisconsin has not added any new coal-fired generation in almost 20 years. New generation is required to meet continued load growth and offset inevitable unit retirements in the future. Further, Wisconsin's overtaxed and highly constrained transmission system cannot be relied on to import additional capacity and energy to satisfy Wisconsin's baseload requirements, which means additional baseload generating capacity must be built within the state.

On pages xxiv and xxv, the draft EIS compares WEPCO's forecast to the EIA MAIN forecast. From a planning perspective, the EIS should recognize there is really not much difference in the forecasts. The projected growth rates for the period 2002 to 2005 are 2.6% for energy use in the WEPCO forecast and 2.5% in the MAIN forecast. For the period 2005-2010, the WEPCO forecast is 2.6% and the MAIN forecast is 2.3%. These forecasts are sufficiently close that one can conclude that either forecast is reasonable to use for planning purposes. Certainly there is no basis to conclude WEPCO's proposal is unreasonable or that the difference in forecasts is material enough to change the outcome of the CPCN application. In any event, these load forecasts should not be the critical issue in this resource decision. The load in Wisconsin is growing, and substantial additional generating resources will be needed in the future. We will not know which load forecast is correct (or off by one or two percent per year) until the end of the decade, and by that time it may be too late to undertake this project in a way that will benefit consumers. The EIS should recognize it is important to

proceed now with the construction of new baseload facilities when interest rates are low and inflation is in check.

- **WPPI believes the draft EIS significantly overstates the impact of adding baseload capacity before it is actually needed.** On page 79, the draft EIS states, "If WEPCO were to pay WE Power for a coal plant that was constructed but not needed, WEPCO under the facility lease would have to pay an annual rent of $106.9 million. Using the job-loss-to-sales-tax-increase estimate from above would translate into a loss of about 3,700 jobs per year per unit." This calculation substantially overstates the impact of adding more coal capacity sooner than needed (if it ultimately proves that the capacity is brought on-line slightly earlier than a "just-in-time" in service date) for several reasons and does not take into account the long term economic benefits the ERGS would provide.

  First, because the ERGS units will be very efficient and produce energy at lower cost than most existing generating units, WEPCO's energy costs (fuel costs) will decrease due to the addition of an ERGS unit even if the capacity is not needed to meet WEPCO's planning reserve requirement. Second, even if all the capacity from an ERGS unit is not needed the year the unit goes in-service, WEPCO's power requirements will continue to grow. Based on WEPCO's current load growth rate of approximately 150 MW per year, there is little risk of overbuilding. While WEPCO might end up with a higher than optimal reserve margin for a short time, this result is inevitable when adding a new block of generation. This is no reason not to proceed. Given the size of WEPCO's system, WEPCO would grow into its entire share of an ERGS unit in a very short time. Finally, if there is

a short term surplus, WEPCO should be able to make additional wholesale sales to mitigate the impact on ratepayers. Clearly, some offsetting value can be achieved through short term off-system sales. In this regard, it is important to recognize that Wisconsin's transmission system is constrained for imports but not for exports. Thus, the impact on jobs from adding too much baseload capacity is likely to be considerably lower than the 3,700 jobs per year reported in the draft EIS and will be a temporary not a permanent phenomenon.

- **WPPI cautions against placing too much reliance on the EGEAS computer model results.** The EGEAS model, while a useful planning tool, does not account for a number of considerations important in determining an optimal resource expansion plan, such as the economic risks associated with delaying the ERGS units and the operational interaction of wind turbines and conventional generation. Such factors were apparently not considered in interpreting the EGEAS results. Ultimately, a broad perspective needs to be applied in interpreting the EGEAS results, not adherence to an optimal scenario from any particular model.

In the draft EIS the EGEAS results (with wind potential limited to 250 MW) indicate that the optimal least cost plan would require 250 MW of wind for 2004, 300 MW of combustion turbines in 2007, and a 550 MW SCPC coal plant in 2009. These EGEAS results should not be accepted at face value. Rather, they should be interpreted with recognition of the limitations of the EGEAS model and the assumptions used in the model.

The EGEAS model is only one of a number of useful tools available to generation planners. It has strengths and limitations. One limitation of the model is its simulation of the system based solely upon the use of load duration curves. The model is not a detailed operational simulation of a power system. It does not present an hour-by-hour or real-time simulation of power system dispatch. As a consequence, it does not consider factors such as start-up time, ramp rates, and operating reserve requirements associated with the real-time operation of power systems. Second, the model is only as good as the input data. In the draft EIS, the input data does not differentiate between the relative dependability and technological maturity of the various supply alternatives considered. Thus, no distinction is made in the draft EIS between wind generation, which is a relatively unproven power source in Wisconsin, and mature technologies such as the SCPC units proposed for use at ERGS.

Based upon the EGEAS analysis results, the draft EIS concludes that WEPCO's proposed timing of the SCPC units in 2007 and 2009 is not least-cost under any scenario. Although this conclusion may follow from a strict adherence to the EGEAS model analysis result as presented in the draft EIS, this conclusion should be reconsidered based upon other factors, particularly risk factors, not analyzed by EGEAS. Given the clear need for Wisconsin to develop additional baseload coal-fired capacity and the current environment of low interest rates and low inflation, the state is presented with a historically exceptional opportunity to construct these units. There is a very substantial risk, not factored into the EGEAS analysis, that delaying these units by even one or two years could cause

their costs to increase substantially if the rate of inflation and/or interest rates increase. The risk of these rates rising from present levels is clearly much greater than the potential for decreases.

- **The materiality threshold should be $50 million not $10 million.** With respect to the interpretation of the EGEAS results, on page xxviii, the draft EIS states that the results of the analyses are based on a materiality threshold of $10 million. WPPI wonders why a $10 million threshold was selected. WPPI understands that a $50 million materiality threshold was used by Commission staff in the analysis of the Port Washington plants. Given the much greater capital investment associated with development of the proposed ERGS facilities, it is unreasonable to use a much narrower $10 million materiality threshold for the ERGS units. If the $50 million threshold is used here, under most sensitivities examined in the draft EIS there would be no material economic difference between the ERGS without the IGCC or the Calpine projects.

- **The current economic environment is extremely favorable for developing high capital cost baseload projects.** The capital costs of a large baseload coal plant are greater than many alternative technologies. If Wisconsin is to maintain fuel diversity into the future, it must build new clean coal plants at some point in the relatively near term. Given the current economic conditions – low interest rates and low inflation – now is an excellent time to proceed with the development of a high capital cost project in Wisconsin such as the ERGS units. Any significant delay in proceeding with the ERGS units significantly increases the risk that higher interest rates or inflation could affect the cost of the project to

the substantial detriment of Wisconsin consumers. The risk that significant cost overruns will be experienced is substantially lower in this environment. For example, based on the lease calculation used in the draft EIS on page 26, the annual lease payment would increase approximately 3.1% for each 100 basis point increase in the interest rate on 30-year corporate A rated bonds. An increase of 300 basis points would increase the annual lease payment by approximately 9.4% or for each unit add $10 million to the annual lease payment as calculated in the draft EIS.

In the draft EIS, a sensitivity is examined where the ERGS experiences a 20% capital cost overrun based (purportedly) on the significant cost overruns experienced during construction of WEPCO's Pleasant Prairie plant. The reasons for the cost overruns at the Pleasant Prairie plant are summarized on page 21 of the draft EIS. These reasons include higher-than-anticipated inflation, a high demand for labor and materials for power plant construction and a delay in the plant's start-up construction. The experience with the Pleasant Prairie plant in the early 1980's demonstrates the significance of these risks for what has turned out to be an excellent system addition despite the overrun. Rather than penalizing the ERGS alternative with 20% cost overrun sensitivity because of the Pleasant Prairie experience, the experience should be seen as strong support for proceeding with the ERGS proposal without delay.

In contrast, the draft EIS concludes that if coal plants were to have cost overruns of 20%, then the optimal expansion plan does not include a coal plant until 2014. While this analysis apparently is intended to provide a risk analysis, WPPI

believes that the risk of such an overrun is unlikely in the current environment of relatively low interest rates and low inflation, especially if construction proceeds under a fixed-price EPC contract as contemplated by WEPCO. The real risk of cost overruns will occur if construction of these plants is delayed, in which case delaying the in-service date until 2014 likely will result in a self-fulfilling prophecy compared to the current cost estimates for the project.

- **While wind generation is definitely a promising renewable technology, at this time, it is not a dependable substitute for coal-fired baseload generation.** Wisconsin utilities should be encouraged to develop significant wind generation in the state. We understand that WEPCO is already committed to 200 MW of wind. Other utilities are likely to follow suit without new legislation or regulatory mandates. However, wind is not yet a substitute for baseload generation. Wind technology is relatively untested in Wisconsin. There are a number of uncertainties related to annual energy production, availability at time of peak demand, the economics of using gas-fired generation to back up wind generation and the long-term reliability of wind generation compared to mature technologies such as the SCPC units proposed for use at ERGS. In addition, there are uncertainties about the interaction of large-scale wind farms with the bulk power system and the ability to site such farms in Wisconsin.

The discussion on pages 59 and 60 of the draft EIS assumes wind turbines will achieve a 32.4% capacity factor in Wisconsin. WPPI believes this capacity factor exceeds what has been achieved at the best Wisconsin sites to date. The ability to achieve the capacity factors assumed in the draft EIS study have not been proven,

and the long-term reliability of Class IV wind machines in Wisconsin has also not been established.

On page 72, the EGEAS results conclude that Class IV wind competes favorably with SCPC units, assuming a wind tax credit. The prospects for future tax credits and the ability to site Class IV wind turbines in significant numbers and to achieve the assumed capacity factors are all uncertain. Thus, the long-term reliability, dependability and costs associated with Class IV wind turbines in Wisconsin, not to mention the ability to site units on this scale, are all uncertain. We need more experience with wind before depending on it as a substantial baseload capacity resource. We should first get that experience before relying on wind to supply our baseload power needs.

- **The ERGS facilities provide a hedge against early retirement of Wisconsin's nuclear power plants.** Wisconsin's nuclear power plant operating licenses all expire early next decade. Wisconsin faces risk in that all three nuclear units share the same design. If the NRC uncovers a problem with one unit, the (re)licensing of all three units may be in jeopardy. While the NRC has recently been granting license extensions, there is no guarantee this trend will continue. Very strong intervenor opposition to relicensing is likely. The loss of two out of three nuclear units today would have a devastating impact on Wisconsin's reliability. One only has to look back to 1997 to see the impact Wisconsin's nuclear power plants have on the state's reliability.

Given the long lead time to construct coal-fired baseload units, now is the time to proceed with the first two ERGS units. Wisconsin cannot replace the nuclear units and also meet all of the PTF requirements with gas and wind. Since replacements of nuclear may have to be installed quickly (i.e. with gas), doing the coal now makes great sense. The ERGS facility will provide an important hedge, helping to protect consumers from the potential adverse economic consequences of the retirement of existing baseload plants and providing the state with more flexibility to deal with what may be hard decisions in the future.

- **The ERGS site is a brownfield site that is well suited for coal-fired generation.** Sites for major new generating facilities are difficult to find. The ERGS site is an existing plant site and use of the site avoids the need to construct at a greenfield site with much greater environmental impacts. This site has the advantage of utilizing a significant amount of existing infrastructure and, given its location, provides the opportunity for substantial energy cost savings and emissions reductions through the ability to utilize once-thru cooling using the cold waters of Lake Michigan to increase the efficiency of the energy production at the plant.

- **The risks of high natural gas prices and supply interruptions are not fully captured in EGEAS sensitivities reported in the draft EIS.** The draft EIS provides a good discussion of the historical relationship between natural gas and coal prices on pages 66 through 68. However, the high natural gas price sensitivity analyzed in the draft EIS is based on WEPCO's high natural gas price

forecast, which assumed a 15% increase over the base natural gas price forecast. It is reasonable for WEPCO to use a conservative high natural gas price scenario when presenting their analysis supporting the ERGS proposal. To do otherwise would clearly invite criticism. However, in our view a 15% increase over the base natural gas price forecast does not adequately capture the significant risk that natural gas prices could be much higher than the base natural gas price forecast or that the supply of gas could be interrupted. Today natural gas prices are double what they were a year ago. WPPI suggests that a high natural gas price sensitivity should use a natural gas price forecast that is at least 50% over the base natural gas price forecast in order to capture the significant price and availability risks associated with natural gas.

In addition, WPPI questions whether the CO_2 monetization sensitivity analyzed in the draft EIS incorporated a higher natural gas price forecast to account for the impact of a CO_2 tax. If a CO_2 tax were implemented generators could be expected to switch from coal to natural gas where feasible to avoid this tax. The result would be to increase the demand for natural gas and, in turn the price of natural gas. The effect of incorporating the potential impacts of a CO_2 tax on natural gas prices would be to lower the relative cost penalty on coal-fired generation in the CO_2 tax monetization analysis.

- **The description of air quality impacts of the proposed ERGS units in the Executive Summary is not complete.** In the discussion of air quality impacts on pages x and xxxi, the draft EIS concludes that the concentrations of SO2 would increase dramatically, approaching 93% and 87% of NAAQS, respectively, as a

result of the ERGS units. The discussion of air quality impacts is incomplete. It does not recognize, for example, that the air emissions from the proposed ERGS units will be far lower than the air emissions from any existing Wisconsin coal fired power plant or that the development of these facilities in conjunction with the future retirement of existing coal plants will over time result in substantial reduction in SO2 and other pollutants from Wisconsin coal plant.

Dated this 13th day of June, 2003.

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