UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)))	Docket No. EL21-91-000, -003

COMMENTS OF THE INDEPENDENT MARKET MONITOR FOR PJM IN OPPOSITION TO OFFER OF SETTLEMENT

Pursuant to Rule 602(f) of the Commission's Rules and Regulations,[1] Monitoring Analytics, LLC, acting in its capacity as the Independent Market Monitor ("Market Monitor") for PJM Interconnection, L.L.C.[2] ("PJM"), submits this reply in opposition to the offer of settlement and Settlement Agreement filed January 31, 2024, by PJM ("Offer"). The Settlement Agreement is by and among: PJM; American Municipal Power, Inc.; Dynegy Marketing and Trade, LLC; Hazelton Generation, LLC; J-POWER USA Development Co., Ltd.; LS Power Development, LLC; Old Dominion Electric Cooperative; PJM Industrial Customer Coalition; and Vistra Corp" ("Settling Parties").

The Offer does not serve the public interest and should be rejected. This case presents a straightforward issue. Should resources receiving a special formula rate tied to the recovery of investment receive, based on a known faulty input, costs based on taxes that they do not pay. Despite the simple issue presented by this case, redress has been delayed by slow administration of the tariff revision process by PJM, and by the unnecessarily lengthy procedures before the Office of Administrative Law Judges. A consequence of this delay is that for years generators have been collecting from customer revenues to pay taxes that they do not pay. As of November 17, 2022, refund protection in this Section 206 proceeding expired.[3]

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1 18 CFR § 385.602(f) (2023).

2 Capitalized terms used herein and not otherwise defined have the meaning used in the PJM Open Access Transmission Tariff ("OATT").

3 *See PJM Interconnection, L.L.C.; Notice of Institution of Section 206 Proceeding and Refund Effective Date*, Docket No. EL21-19-000, 86 Fed. Reg. 45980 (August 17, 2021); 16 U.S.C. § 824e(b).

The Offer would provide an unjustified windfall to affected black start unit owners of at least $74.1 million.

Action by the Commission is needed to ensure that the black start unit Capital Cost Recovery Rate operates as it was intended, allows unit owners recovery of specific investment costs, sets just and reasonable rates for PJM customers, and serves the public interest.

Based on the record of this proceeding, including the Affidavit attached to this pleading, PJM should be required to provide accurate CRF values for units selected for black start service prior to June 6, 2021. There is no reason why this proceeding cannot be immediately resolved with the just and reasonable, accurate, implementation of the formula rates for black start service in PJM.

I. ARGUMENT

A contested offer of settlement may only be approved based on its merits.[4] A contested settlement may be approved on its merits under one of the four approaches set forth in *Trailblazer Pipeline Company*.[5] None of the approaches under *Trailblazer Pipeline Company* can be relied on for approval of the Offer. The Offer does not and cannot resolve the single issue, an issue of material fact, identified in the order setting this matter for hearing.[6] There is no

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4 18 CFR § 385.602(h)(1) ("If the Commission determines that any offer of settlement is contested in whole or in part, by any party, the Commission may decide the merits of the contested settlement issues, if the record contains substantial evidence upon which to base a reasoned decision or the Commission determines there is no genuine issue of material fact.").

5 The four approaches for approving a settlement under *Trailblazer Pipeline Company* include: (i) addressing the contentions of the contesting party on the merits when there is any adequate record; (ii) approving a contested settlement as a package on the ground that the overall result of the settlement is just and reasonable; (iii) determining that the contesting party's interest is sufficiently attenuated such that the settlement can be analyzed under the fair and reasonable standard applicable to uncontested settlements when the settlement benefits the directly affected settling parties; or (iv) preserving the settlement for the consenting parties while allowing contesting parties to obtain a litigated result on the merits. *See Trailblazer Pipeline Company*, 85 FERC ¶ 61,345 (1998).

6 *See PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,194 at P 32 ("[W]hether, as a result of changes from the TCJA, the existing CRF values result in a Capital Cost Recovery Rate for generating units that were selected to provide Black Start Service prior to June 6, 2021 that is unjust and unreasonable. While the record does not contain conclusive evidence that the existing CRF values include a 35% tax rate,

record supporting the Offer's CRF values as just and reasonable, including as a "package." The Market Monitor represents the public interest in efficient and competitive markets. The settlement cannot be analyzed under the fair and reasonable standard applicable to uncontested settlements because the Offer allows unjust and unreasonable overrecovery of investment costs, contrary to efficient and competitive markets. There is no possibility of severing the issues in the manner contemplated under the *Trailblazer Pipeline Company* approaches.

Although the Commission encourages settlements, that policy is not a license to resolve cases at all costs.[7] An offer of settlement, as in this case, that is unfair, unreasonable, or against the public interest must be rejected.[8]

The matter could continue to proceed to hearing. However, this is unnecessary. In the attached affidavit of Dr. Joseph E. Bowring ("Affidavit"), included pursuant to Rule 602(f)(4), Dr. Bowring provides sufficient evidence for the Commission to resolve the issues of material fact set for hearing and to determine just and reasonable CRF values to apply to units selected for service prior to June 6, 2021.[9]

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the Market Monitor has introduced sufficient evidence that those values may include a 35% tax rate, raising a disputed issue of material fact as to whether changes to the tax rate render the existing CRF values unjust and unreasonable. The import of the tax rate in the determination of the CRF value is a material fact that cannot be determined based on the existing record, which warrants setting the justness and reasonableness of the existing CRF values for hearing and settlement judge procedures.").

7 *See, e.g.*, *Arkla Energy Resources*, 49 FERC ¶ 61,051, 61,217 (1989); *Transwestern Pipeline Co.*, 9 FERC ¶ 61,075, at 61,166 (1979).

8 *See* Petal Gas Storage, L.L.C. v. FERC, 496 F.3d 695, 701 (2007) ("[T]he Commission has a duty to disapprove uncontested settlements that are unfair, unreasonable, or against the public interest"); citing Mobil Oil Corp. v. FPC, 417 U.S. 283, 314 ("If a [settlement] proposal enjoys unanimous support . . ., it could certainly be adopted . . . if approved in the general interest of the public." (emphasis added) (internal quotation marks omitted)); NorAm Gas Transmission Co. v. FERC, 148 F.3d 1158, 1165 (D.C. Cir. 1998) ("Even if . . . customers had unanimously supported the proposed settlement, the Commission would still have the responsibility to make an independent judgment as to whether the settlement is 'fair and reasonable and in the public interest.'"); Tejas Power Corp. v. FERC, 908 F.2d 998, 1003 (D.C. Cir. 1990) ("Commission may approve uncontested settlement only upon a finding that the settlement appears to be fair and reasonable and in the public interest." (internal quotation marks omitted)).

9 *See* 18 CFR § 385.602(h)(1).

II. CONCLUSION

The Market Monitor opposes the Offer. The Offer should be rejected. Rather than reinstitute the hearing process, the matter should be resolved expeditiously based on the record, including the facts established in the attached affidavit.

Respectfully submitted,

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Dated: February 20, 2024

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Eagleville, Pennsylvania,
this 20th day of February, 2024.

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Attachment
Exhibit Nos. IMM-0001–-IMM-0014

Bowring Affidavit
and Supporting Exhibits

Exhibit IMM-0001

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket No. EL21-91-000, -003
	)	

AFFIDAVIT OF JOSEPH E. BOWRING ON BEHALF OF THE INDEPENDENT MARKET MONITOR FOR PJM

Q 1. PLEASE STATE YOUR NAME AND POSITION.

A. My name is Joseph E. Bowring. I am the Market Monitor for PJM. I am the President of Monitoring Analytics, LLC. My business address is 2621 Van Buren Avenue, Suite 160, Eagleville, Pennsylvania. Monitoring Analytics serves as the Independent Market Monitor (IMM) for PJM, also known as the Market Monitoring Unit (MMU or Market Monitor). Since March 8, 1999, I have been responsible for all the market monitoring activities of PJM, first as the head of the internal PJM Market Monitoring Unit and, since August 1, 2008, as President of Monitoring Analytics. The market monitoring activities of PJM are defined in the PJM Market Monitoring Plan, Attachment M and Attachment M-Appendix to PJM Open Access Transmission Tariff (OATT).[1]

Q 2. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to explain: (1) the nature and purpose of the formula rate at issue in this proceeding; (2) how the existing Capital Recovery Factor (CRF) values for generating units that were selected to provide Black Start Service prior to June 6, 2021 were calculated;[2] (3) why, as a result of changes resulting from the Tax Cuts and Jobs Act (TCJA),[3] the existing CRF values that result in a Capital Cost Recovery Rate for generating units that were selected to provide Black Start Service prior to June 6, 2021, are unjust, unreasonable, and unduly discriminatory or preferential; (4) how the inputs to the existing formula rate should be adjusted to

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1 *See PJM Interconnection, L.L.C.*, 86 FERC ¶ 61,247; 18 CFR § 35.34(k)(6).

2 *See* PJM OATT Schedule 6A Para. 18.

3 Tax Cuts and Jobs Act of 2017, Pub. L. No. 115-97, 131 Stat. 2054 (2017).

produce a correct Capital Cost Recovery Rate for such units; and (5) why the settlement proposed January 31, 2024, has not been shown to be just and reasonable and should not be approved.

Q 3. PLEASE PROVIDE A SUMMARY OF THE CENTRAL ISSUE IN THIS CASE.

A. The inputs to the formula rate for black start capital cost recovery changed as a result of tax law changes that became effective on January 1, 2018. The result was that the correctly calculated CRF rates decreased significantly. PJM failed to reflect those changed inputs in the rates paid to black start owners. PJM failed to change the CRF rates after being notified of the issue by the Market Monitor. PJM finally changed the CRF rates in a filing approved by order issued August 10, 2021, but those rates failed to address the ongoing overpayments to black start resources which had been selected to enter service prior to June 6, 2021.[4] PJM's approach and the approach of the proposed settlement in this case both misunderstand the fundamental purpose of the CRF provision. That purpose is to ensure the payment of 100 percent of the defined return to investors. PJM's approach and the settlement approach would both result in substantial overpayment to all affected black start units. This is a factual matter.

Q 4. WHAT ISSUE(S) DID THE COMMISSION SET FOR HEARING?

A. The Commission's March 24, 2023 order set the following issue of fact for hearing:

> [W]hether, as a result of changes from the TCJA, the existing CRF values result in a Capital Cost Recovery Rate for generating units that were selected to provide Black Start Service prior to June 6, 2021 that is unjust and unreasonable. While the record does not contain conclusive evidence that the existing CRF values include a 35% tax rate, the Market Monitor has introduced sufficient evidence that those values may include a 35% tax rate, raising a disputed issue of material fact as to whether changes to the tax rate render the existing CRF values unjust and unreasonable. The import of the tax rate in the determination of the CRF

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[4] *See PJM Interconnection, L.L.C.*, 176 FERC ¶ 61,080.

> value is a material fact that cannot be determined based on the existing record, which warrants setting the justness and reasonableness of the existing CRF values for hearing and settlement judge procedures.[5]

Q 5. HOW DO YOU RESPOND TO THE ISSUES SET FOR HEARING?

A. The Commission noted that the Market Monitor had provided sufficient evidence to raise the issue but did not find that there was conclusive evidence as to the tax rate included in the CRF calculations. This testimony provides dispositive evidence that the existing CRF rates were based on a 36 percent tax rate, including 2005 affidavits from Market Monitor witnesses and public PJM reports. [6] [7] AMP and ODEC cited the same PJM report.[8] This testimony provides dispositive evidence that the existing CRF rates were based on the use of MACRS depreciation, including 2005 affidavits from Market Monitor witnesses and public PJM reports. As a result, this testimony demonstrates that the existing CRF rates that PJM continues to apply to black start resources selected prior to June 6, 2021, are simply wrong and therefore unjust and unreasonable because the CRF rates do not include the actual tax rate and depreciation provisions that became effective on January 1, 2018.

Once the factual issue is resolved, the issue of how to determine the appropriate going forward CRF rates for units selected prior to June 6, 2021, must be resolved, in order to ensure just and reasonable recovery of their discrete investment under the applicable formula rate.

The offer of settlement does not address the only issue explicitly set for hearing. The offer of settlement includes, without justification, CRF rates that are calculated incorrectly even on their own terms and are inconsistent with the Commission approved CRF rates that account for the TCJA changes in the tax code. In addition, the settlement fails, without explanation, to address the fact that the CRF rate is

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5 *See PJM Interconnection, L.L.C.*, 182 FERC ¶ 61,194 at P 32.

6 *Comments of the Independent Market Monitor for PJM* at 6, Docket No. ER21-1635-000 (April 28, 2021).

7 *Id*. at footnote 15.

8 *Protest of American Municipal Power, Inc. and Old Dominion Electric Cooperative* at 3, Docket No. ER21-1635-000 (April 28, 2021).

designed to ensure full recovery of a return on and of capital over the defined term of the CRF, no more and no less.

Q 6. IS YOUR APPROACH RETROACTIVE RATEMAKING?

A. No. The CRF is a formula rate that defines total payments over a defined term. If the CRF is overstated in the early years, regardless of the reason, it can be reduced in the later years in order to produce the intended result over the entire term. That is not retroactive ratemaking as it does not require the repayment of payments made under a stated or filed rate. The proposed going forward adjustment to the formula produces an outcome that is the only outcome consistent with the purpose of this specific formula rate for CRFs, to provide 100 percent of the defined return to both debt and equity investors over the defined term of the CRF.

Note that this is very different from standard cost of service ratemaking that sets a stated rate that remains in place until it is changed by a subsequent decision of the Commission. That is the essential difference between a stated rate and a formula rate designed to recover capital costs over a defined term.

Q 7. PLEASE DESCRIBE THE NATURE AND PURPOSE OF THE RATE AT ISSUE IN THIS PROCEEDING.

A. The specific rate at issue in this proceeding is a formula rate included in Paragraph 18 of Schedule 6A of the OATT (Schedule 6A). The formula rate in Schedule 6A compensates black start service units included in PJM's system restoration plan. PJM relies on the black start system restoration plan to restore service if there is a system wide black out event, a shut down of the PJM transmission system.

The formula rate included in Schedule 6A is:

$$\text{(Fixed BSSC)} + \text{(Variable BSSC)} + \text{(Training Costs)}$$
$$+ \text{(Fuel Storage Costs)}\} * (1 + Z)$$

Only the Fixed BSSC term of the formula is at issue in this proceeding and even more specifically only the CRF component of the Fixed BSCC as it applies to black start units selected to enter service before June 6, 2021, is at issue in this proceeding. Selected to enter service means that PJM selected the black start resource pursuant to a PJM RFP process prior to June 6, 2021, and does not refer to the date that the resource actually began providing service.

There are three options for calculating the Fixed BSSC term: the Base Formula Rate; the Capital Cost Recovery NERC-CIP Specific Recovery; and the Capital Cost Recovery Rate.

The first option is the Base Formula Rate for Fixed BSSC:

(Net CONE * Black Start Unit Capacity * X.)

The Base Formula Rate formula calculates a rate based on the net cost of new entry (Net CONE) for a new unit in the PJM capacity market in $/MW-day, multiplied by the Black Start Unit Capacity in MW, multiplied by an allocation factor X which is defined to be .02 for CTs (combustion turbine generators). The Net CONE value is a parameter of the PJM Capacity Market and has nothing directly to do with the cost of units providing black start service.

The Base Formula Rate for Fixed BSSC does not provide for the recovery of a specific capital investment in black start capability. The default Fixed BSSC is not based on the cost of the black start resource. The Base Formula Rate in Paragraph 18 is not a cost of service rate.

The second option is the Capital Cost Recovery NERC-CIP Specific Recovery, a special purpose Fixed BSCC that allows existing black start units to recover incremental costs associated with compliance with NERC reliability standards.[9] The formula for Capital Cost Recovery NERC-CIP Specific Recovery is:

(Net Cone * Black Start NERC-CIP Unit Capacity * X) + (Incremental Black Start NERC-CIP Capital Costs * CRF) + (Fuel Assurance Capital Costs * CRF)

The third option, the Capital Cost Recovery Rate, is at issue in this proceeding. [10] The Fixed BSCC formula is:

(FERC-approved rate) + (Incremental Black Start Capital Costs * CRF) + (Fuel Assurance Capital Costs * CRF)

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9 *See PJM Interconnection, L.L.C.*, 127 FERC ¶ 61,197, at P 39; order on compliance filing 1, 128 FERC ¶ 61,249 (September 17, 2009); delegated order on compliance filing 2 (November 17, 2009).

10 This option was established by the Commission in 2011. *See PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,020; PJM Filing, Docket No. ER11-1440 (August 30, 2011) at 9.

The issue in this case is the correct CRF values for black start resources that are paid under the Capital Cost Recovery Rate.

As there is no “FERC-approved rate” component of the rates for the units at issue in this proceeding, the “FERC approved rate” component is effectively zero dollars.

None of the black start resources at issue have any Fuel Assurance Capital Costs to date.

Therefore, the effective Fixed BSCC formula for purposes of this proceeding is:

(Incremental Black Start Capital Costs * CRF)

The CRF provides for the recovery of a discrete, defined investment in black start capability over a defined period, after which the payment for black start transitions to the default fee for the remainder of the black start service provided.

Q 8. WHAT IS A CRF?

A. CRF means capital recovery factor. A CRF is a rate which when multiplied by the investment in an asset results in an equal annual revenue requirement over the defined term of the CRF. That annual revenue requirement provides for full recovery of the investment costs and a return on that investment over the defined term of the CRF. CRF is a general financial concept broadly applicable across investments and industries.

Q 9. WHAT IS THE PURPOSE OF THE CRF RATE FOR BLACK START REVENUE REQUIREMENTS?

A. The CRF calculations in the PJM OATT were originally developed for use in defining market seller offer caps in PJM capacity market auctions.[11] The purpose of the CRF values in the capacity market was to explicitly match the return of and on capital to the expected life of the incremental investment in capacity resources, defined as APIR in the OATT, Attachment DD. [12] At the time of the establishment of the RPM capacity market rules, coal units with relatively short expected remaining lives were required to make large investments in environmental controls.

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[11] *See PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,331 (2006); OATT Attachment DD § 6.8(a).

[12] *See* OATT Attachment DD § 6.8(a).

As a result, it was necessary to provide for different time periods over which the opportunity for full recovery of capital costs could occur. The CRF table defined CRF levels for a range of expected asset lives with a defined set of input variables and values.

Q 10. HOW WERE THE EXISTING CRF VALUES CALCULATED FOR GENERATING UNITS THAT WERE SELECTED TO PROVIDE BLACK START SERVICE PRIOR TO JUNE 6, 2021?

A. The CRF values were included in the initial RPM filing in 2005.[13] The Market Monitor calculated the CRF values and affidavits attached to the RPM filing by Joseph Bowring and Raymond Pasteris provide a description of the CRF calculation and the model assumptions.[14] [15] The CRF values were added to Schedule 6A in 2009 to allow for the recovery of new or additional fixed black start capital costs.[16] It was explicit at the time of the filing that the CRF rate was a specifically defined formula rate and not a stated rate.[17]

Q 11. WERE THE CRF VALUES ALWAYS BASED ON EXPLICTLY STATED INPUT VALUES, INCLUDING THE APPLICABLE FEDERAL INCOME TAX RATE?

A. Yes. There are six defined inputs to the CRF formula: debt to equity ratio, rate of return on equity, interest rate on debt, federal income tax rate, state income tax rate and depreciation factors. These inputs were stated explicitly the very first time that PJM filed the CRF rates in the capacity market filing. The Market Monitor developed the CRF method that was incorporated in the CRF tables in the PJM OATT.

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13 PJM Filing, ER05-1410 (August 31, 2005) Tab C (Revised Original Sheet No. 590).

14 *Id.*, Tab G (Affidavit of Joseph E. Bowring) at 23.

15 *Id.*, Tab I ("Independent Study to Determine Cost of New Entry Combustion Turbine Power Plan Revenue Requirement," Attachment to the Affidavit of Raymond M. Pasteris on Behalf of PJM Interconnection, L.L.C.) at 3–4.

16 PJM Filing, Docket No. ER09-730 (February 19, 2009) at 7.

17 *Id. passim.*

Q 12. IS THE CRF CALCULATION A BLACK BOX CALCULATION?

A. No. The CRF calculation is not and has never been a black box calculation. The CRF calculation is based on a limited set of known inputs that result in the defined CRF values that were first listed in a table in Attachment DD to the PJM OATT.

Q 13. IS THE FEDERAL INCOME TAX ONE OF THE INPUTS TO THE CRF CALCULATION?

A. Yes. The federal income tax rate is one of the explicitly state inputs to the CRF calculation. The original CRF calculations explicitly include a federal income tax rate of 36 percent that was stated repeatedly publicly by both PJM and the Market Monitor.[18]

Q 14. HAS THE MARKET MONITOR USED DIFFERENT APPROACHES TO DEFINING THE CRF FORMULA?

A. Yes. The Market Monitor has used different approaches but all of them are substantively identical. The Market Monitor used a multiyear financial model to calculate the CRF values that were included in Attachment DD to the PJM OATT. That financial model included repayment of debt on a fixed mortgage style schedule and recognized that all net revenue in excess of costs including debt costs and tax obligations flow to the equity owner of the asset. This approach is called the flow to equity (FTE) approach.

In 2021, the Market Monitor developed a formula that is the equivalent of the multiyear financial model for calculating CRF values.[19] However, the formula used the weighted average cost of capital (WACC) approach to defining returns to debt holders and equity owners. The WACC approach maintains a constant debt to equity ratio by attributing net revenue in excess of costs to both debt holders and equity owners in proportion to the debt to equity ratio. That formula was filed by PJM and approved by the Commission and is now both in Attachment DD and Schedule 6A of the PJM OATT.

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18 *See* Exhibits Nos. IMM-0001}, -0002, -0003, -0004, -0005, -0006, 0007, -0008, -0009, -0010, -0011, -0012, -0013, attached.

19 *Comments of the Independent Market Monitor for PJM* at 16, ER21-1635-000 (April 28, 2021).

As part of the Market Monitor's responses to Commission Staff discovery in this case, the Market Monitor clarified that the FTE approach correctly reflects the ownership interests in net revenue in excess of costs.[20] The FTE approach is the correct way to calculate CRF values.

The Market Monitor developed and provided the CRF formula based on the FTE approach as part of the responses to Staff discovery.

Q 15. WHAT IS THE RELATIONSHIP BETWEEN THE CRF TABLE IN ATTACHMENT DD AND THE CRF TABLE IN SCHEDULE 6A?

A. The table of CRF values based on the CRF table in Attachment DD was included in Schedule 6A for black start because the issue was the same issue addressed in the capacity market. The issue was how to match the expected or intended life of the asset (black start investment) to the recovery of the capital costs using equal annual payments for a range of different recovery periods. The financial calculation is the same for any asset if the inputs are the same. The inputs were the same for the capacity market and the black start cost recovery. One important difference between the two applications of CRF is that the CRF is intended to pay black start owners the exact amount of the CRF revenue requirement while in the capacity market, the CRF/APIR calculation changes the market seller offer cap and provides the opportunity to receive the full annual revenue requirement in the capacity market.

Q 16. DOES SCHEDULE 6A PROVIDE FOR FULL RECOVERY OF CAPACITY COSTS OVER A DEFINED PERIOD?

A. Yes. Schedule 6A provides that at the conclusion of the recovery of the specific and discrete investment cost over the defined term of the recovery period, recovery of the investment cost using the Capital Cost Recovery Rate is complete. The Capital Cost Recovery Rate is specifically designed for the recovery of a discrete fixed capital investment. When the Capital Cost Recovery Rate has served its purpose, continued black start service is then compensated under the default rate.

Q 17. WHAT IS THE DIFFERENCE BETWEEN A STATED RATE AND A FORMULA RATE?

A. A stated rate is a fixed value approved by the Commission. A formula rate is a formula approved by the Commission with defined inputs. As input values change,

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[20] *See* Exhibit No. IMM-0014, attached.

the new values are used in the formula to calculate the applicable rate. The Capital Cost Recovery Rate is a formula rate. The CRF, a component of the Capital Cost Recovery Rate, is a specific formula rate with clearly defined characteristics that distinguish it from other formula rates.

Q 18. WHY DO THE EXISTING CRF VALUES RESULT IN AN OVERRECOVERY OF CAPITAL COSTS FOR BLACK START UNITS SELECTED PRIOR TO JUNE 6, 2021?

A. The CRFs, when multiplied by the capital investment amount, result in an annual revenue payment that is sufficient to provide for the return on and return of the capital investment and to provide for the income taxes associated with the annual revenue payment over the term of the CRF.

The original CRF formula, that resulted in values calculated by the Market Monitor and proposed by PJM for inclusion in the OATT in 2005, and included in Schedule 6A of the PJM OATT in 2009, was based on a federal income tax rate of 36 percent and depreciation using the 15 year Modified Accelerated Cost Recovery System (MACRS).

The TCJA reduced the income tax rate for existing and new investments, including black start investments, effective January 1, 2018. The TCJA reduced the federal corporate income tax rate to 21 percent. The TCJA also included a provision that allows for 100 percent bonus depreciation for property placed in service after September 27, 2017, and before January 1, 2023.[21] [22]

The result was a significant reduction in the CRF for black start investments. The continued application of the CRF rates that include higher than actual tax obligations has resulted in customers paying black start owners a windfall equal to the impact of the reduction in tax obligations under the TCJA. Customers paid and are paying for the capital costs of black start resources as if those resources were obligated to pay taxes at the prior high rate when those resources were actually paying taxes at a much lower rate.

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[21] Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017) at Subtitle C, Part I, SEC. 13001.

[22] *Id*. at Subtitle C, Part III, SEC. 13201.

PJM should have reduced CRF rates immediately, effective January 1, 2018, for all existing and new black start resources. The result would have been to ensure that all black start owners received what they reasonably expected when PJM selected them to provide black start service and to ensure that all customers paid what they reasonably expected. Those reasonable expectations included a return on and of the capital invested to provide black start service, over the defined recovery period.

PJM was notified of the CRF errors in 2019. Eighteen months later, in April 2021, PJM filed to update the CRF and at that time argued the original CRFs were black box values that could not be updated for existing black start providers. PJM recognized in 2020 that the federal income tax rate in the CRF values needed to be corrected from 36 percent to 21 percent.[23]

Q 19. WHAT HAS BEEN THE RESULT OF THE FAILURE TO CORRECTLY CALCULATE THE CRF VALUES?

A. There are 49 black start generators that have received payments based on the outdated CRFs that reflect federal income tax rates and depreciation schedules corresponding to the tax laws in effect prior to the passage of the TCJA. The 49 generators include 29 black start generators that began providing black start service prior to September 27, 2017, and would not have been eligible for bonus depreciation under the TCJA. Of those 29 black start generators, 11 completed their capital recovery terms between January 1, 2018, and June 2021. The 11 generators that completed their capital recovery terms are not part of the settlement. The excess payments to these 29 generators were due to the change in the federal income tax rate alone and were not affected by the changes to depreciation rules. Of the 49 black start generators, 20 began black start service after September 27, 2017, and before January 1, 2023, and received excess payments as a combined result of the change in the federal income tax rate and the change in depreciation rules included in the TCJA. Of the 38 black start generators that have not completed their capital recovery terms, 24 generators will complete their capital recovery terms in 2024 and 2025. An additional 8 generators will complete their capital recovery terms in 2026. The last 6 generators will complete their capital recovery terms from 2035 through 2040.

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[23] *See* Exhibit IMM-0013 at 9, attached, Black Start Education, PJM Interconnection, L.L.C., PJM Operating Committee Meeting (May 14, 2020).

Q 20. HOW SHOULD THE EXISTING CAPITAL COST RECOVERY RATE FOR THE PRE JUNE 6, 2021 UNITS BE ADJUSTED?

A. The CRF rates going forward should be recalculated, using the formula and the correct inputs, in order to ensure that the purpose of the CRF is met, and that black start units are correctly compensated over the defined term of the CRF for each such unit. That recalculation should reflect the return of capital already received by existing black start units under the applied CRF values to date, and, as a result, eliminate the over recovery that would result under the settlement proposal CRF values. The CRF values should be set at a level that pays for the full tax liability and the full return on the black start capital investment (rate of return or cost of capital) and the full return of the black start capital investment (depreciation) over the full term of the CRF. The weighted average cost of capital paid to black start owners over the full term of the CRF should be exactly as explicitly included in the original CRF values. A description of this proposal and a formula for calculating the updated CRF are included in the Market Monitor's Comments in this docket.[24]

Q 21. CAN YOU EXPLAIN WHY THE PROPOSED SETTLEMENT SHOULD NOT BE APPROVED?

A. For the black start resources placed in service after September 27, 2017, the proposed settlement recalculates the annual revenue requirement for black start units by multiplying the original capital investment by an updated, but incorrectly calculated, CRF corresponding to the original cost recovery term. The settlement, for unexplained reasons, fails to use the going forward rate already approved by the Commission. The settlement substitutes unsupported and demonstrably incorrect CRF rates for the Commission approved rates. Even if the settling parties do not agree that the CRF should correctly account for capital recovery over the entire term of the CRF and should only be corrected going forward, the CRF rates are wrong. The settlement CRF rates with zero bonus depreciation are correct for resources placed in service before September 27, 2017. However, none of the settlement rates account for the capital recovery calculated over the full term of the CRF rates.

The updated CRFs were incorrectly calculated using the correct components of the CRF formula in Schedule 6A, section 18 of the PJM OATT, but with the incorrect input values. The financial parameter assumptions for the settlement CRFs are

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[24] *See* Comments of the Independent Market Monitor for PJM, Docket No. EL21-91-000 (November 11, 2021), corrected (November 18, 2021), at 19–26.

shown in Table 1. The federal income tax rate is the only parameter that was updated to calculate the proposed settlement CRFs. If a resource that began black start service in 2020 had an initial investment of $1 million with the five year recovery option, the original capital recovery payment would be $363,000, and the updated capital recovery payment would be $309,700. Table 2 compares the original and proposed settlement CRFs.

Table 1 Parameter Assumptions

Parameter Description	Parameter Value
Percent funding equity	50.0%
Percent funding debt	50.0%
Return on equity	12.0%
Debt interest rate	7.0%
Federal income tax rate	21.0%
State income tax rate	9.0%
Bonus depreciation percent	0.0%
Depreciation rate	MACRS15

Table 2 Original CRFs and Proposed Settlement CRFs

Capital Recovery Period (Years)	Original CRF	Proposed Settlement CRF
5	0.3630	0.3097
10	0.1980	0.1767
15	0.1460	0.1348
20	0.1250	0.1180

The proposed settlement values are incorrect for the following reasons:

1. The depreciation assumption of 0.0 percent bonus depreciation is not correct for 20 of the 38 resources seeking settlement. These 20 resources were eligible for 100 percent bonus depreciation. Bonus depreciation allows 100 percent of the capital investment to be depreciated in the first year of operation. The proposed settlement CRFs assume 15 year MACRS depreciation rates. Bonus depreciation significantly reduces the income tax liability compared to MACRS. The proposed settlement CRFs are 14 to 25 percent higher than the correctly calculated rates using the actual bonus depreciation rules in the tax code as a result of the use of the 15 year MACRS rates. Table 3 shows the CRFs with both zero percent and 100 percent bonus depreciation, and all other parameter values as listed in Table 1.

Table 3 Proposed Settlement CRFs with bonus depreciation

Capital Recovery Period (Years)	Settlement Proposal CRF	Settlement Proposal CRF with 100 percent bonus depreciation	Percent Difference
5	0.3097	0.2475	(20%)
10	0.1767	0.1487	(16%)
15	0.1348	0.1175	(13%)
20	0.1180	0.1031	(13%)

2. The proposed settlement CRFs will result in a wide disparity in the actual achieved returns on equity by unit. The CRF is designed to provide a 12 percent return on equity. The realized returns on equity for the 38 generators under the proposed settlement would range from 12.8 percent to 59.8 percent. The average realized return on equity would be 33.9 percent. The returns vary due to the length of the capital recovery period, the service start date and whether the resources are eligible for bonus depreciation. Table 4 provides a breakdown of the return levels based on bonus depreciation eligibility. The Market Monitor's proposal would provide a 12 percent return on equity to all generators except those for which the over recovery is already too high to reach that result.

Table 4 Realized returns under the proposed settlement agreement

		Realized return on equity under the proposed settlement		
	Number of generators	Minimum	Maximum	Average
Started black start service before September 27, 2017 and currently receiving capital cost recovery payments	18	12.8%	15.1%	14.7%
Started black start service after September 27, 2017 and currently receiving capital cost recovery payments	20	21.6%	59.8%	51.2%
All generators that are part of settlement	38	12.8%	59.8%	33.9%

3. The capital recovery period is not correct. The settlement CRF calculations should reflect the remaining capital recovery period, which in some cases, is less than one year.
4. The capital investment amount is not correct. The capital investment amount should reflect capital already recovered under the existing CRF rates. Each of the resources has received capital recovery payments for several years as defined by the CRF applied. That CRF included an incorrect definition of the income tax liability. In some cases, the equity capital has been completely returned to the equity investors plus the defined return on equity. The only reason to continue any CRF payments when the equity has been fully recovered plus the defined return on equity is to repay any debt obligations that have not been fully repaid.
5. The settlement CRF values are calculated using the weighted average cost of capital (WACC) model which assumes a constant debt to equity ratio during the capital recovery period. The original CRF values were calculated using a flow to equity (FTE) model. The FTE model recognizes that the debt is repaid according to a predetermined payment schedule with all revenue in excess of taxes and debt payments going to the equity investor. The FTE model accurately reflects the cash flows that occur during capital recovery. The FTE model should be used to revise the CRF values.[25]

Q 22. HOW DOES THE SETTLEMENT COMPARE TO A CORRECT CALCULATION OF THE CRF VALUES?

A. Under the proposed settlement, customers would pay $15.6 million less in capital recovery payments than if the incorrect CRF values were not changed. But the proposed settlement still requires the transmission customers to overpay by $74.1 million. See Table 5. The total overpayment if the incorrect CRF values were not changed would be $89.7 million. The settlement reduces the overpayment by 17.4 percent.

[25] See the Market Monitor's response to the discovery request S-IMM-1.3 in Exhibit IMM-0004.

Table 5 Capital recovery payments by customers

	Capital Recovery Payments 2018 - 2040 ($ millions)	Overpayment ($ millions)
Had CRFs been updated on January 1, 2018	$428.7	
Current CRFs remain in place	$518.4	$89.7
Proposed Settlement	$502.8	$74.1

Q 23. HOW DOES TIMING AFFECT THE POSSIBLE OUTCOMES IN THIS MATTER?

A. The Commission has indicated that retroactive application of revised CRFs to black start resources that have completed their capital cost recovery is not a viable option.[26] Twenty four black start resources will complete their capital recovery terms in 2024 and 2025. Eight black start resources will complete their capital recovery terms in 2026. Six generators will complete their capital recovery terms from 2035 through 2040. In the absence of a Commission decision, these black start resources will continue to be paid based on the incorrect and overstated CRFs through the full term of their CRFs.

Q 24. WHAT ARE THE ALTERNATIVES TO THE PROPOSED SETTLEMENT?

A. The Commission can determine that the original federal income tax rate assumption is 36 percent. There is ample evidence of this fact.[27] In addition, the actual federal income tax rate incorporated in the existing CRF values is irrelevant. The correct CRF values can be and have been calculated with the current tax rates. The correct CRF values are significantly lower than the existing CRF values.

The Commission could accept the Market Monitor's proposed resolution. If the Market Monitor's proposal were implemented effective January 1, 2025, the overpayment for capital cost recovery would be reduced from $89.7 million to $23.6 million. Table 5 shows the capital recovery payments that would result if the CRFs

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[26] 176 FERC ¶ 61,080 ("August 10th, 2021 Order") at 50.

[27] See Attachments A, B and C to *Answer and Motion for Leave to Answer of the Independent Market Monitor for PJM*, EL21-91-000 (May 10, 2023).

were corrected effective January 1, 2025. The reduction would be larger if the CRFs were corrected before an effective date of January 1, 2025.

Under the Market Monitor's proposal, an updated CRF is calculated for each unit. The unit specific updated CRF reflects the remaining unrecovered capital investment and the remaining years of capital recovery as of the date of implementing the updated CRF. The updated CRF values reflect the actual capital recovery to date based on the overstated CRF values and the correspondingly reduced requirement for the balance of the period. The capital recovery payment totals in Table 5 do not include separate refunds or disgorgement of previous payments to the black start generators.

To reduce the overpayment below $23.6 million it would be necessary to require refunds from black start resources that have completed their CRF terms using the overstated CRFs or that have already received 100 percent or more of their full capital recovery. The Commission established a 15 month refund period that began in August 2021.[28] The 15 month refund period has expired.

Table 6 Market Monitor resolution compared to settlement proposal

	Capital Recovery Payments 2018 - 2040 ($ millions)	Overpayment ($ millions)
Had CRFs been updated on January 1, 2018	$428.7	
Current CRFs remain in place	$518.4	$89.7
Proposed Settlement	$502.8	$74.1
Market Monitor - Updated CRFs beginning January 1, 2025	$452.3	$23.6

Q 25. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[28] August 10th, 2021 Order at 54.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket No. EL21-91-000, -003
	)	

DECLARATION

JOSEPH E. BOWRING states that I prepared the affidavit to which this declaration is attached with the assistance of the staff of Monitoring Analytics, LLC, and that the statements contained therein are true and correct to the best of my knowledge and belief. Monitoring Analytics, LLC, is acting in its capacity as the Independent Market Monitor for PJM.

Pursuant to Rule 2005(b)(3) (18 CFR § 385.2005(b)(3), citing 28 U.S.C. § 1746), I further state under penalty of perjury that the foregoing is true and correct.

Executed on February 20, 2024.

Joseph E. Bowring

Exhibit IMM-0002

Capital Recovery Factors (CRF) for the Flow to Equity Approach Technical Reference

Monitoring Analytics, LLC

December 10, 2021

Table of Contents

1 The Basics of CRF

A capital recovery factor (CRF) is used to convert a principal amount of capital into an equivalent stream of uniform payments. A typical CRF formula found in engineering economics textbooks is given in equation (1.1).[1]

(1.1)

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1}$$

Variable r is an interest rate, N is the number of uniform annual payments and payments are assumed to occur at the end of year. To derive equation (1.1) the CRF is first denoted by c, allowing the annual payment to be stated as $A = cK$, where K is the capital investment. Then c is the value that solves the following present value equation,

$$\begin{aligned} K &= \sum_{j=1}^{N} \frac{cK}{(1+r)^j} \\ &= cK \sum_{j=1}^{N} \left(\frac{1}{1+r}\right)^j \end{aligned}$$

The summation in the equation above is a finite geometric series. A general formula for the sum of a finite geometric series is given by

(1.2)

$$\sum_{j=H}^{W} v^j = \frac{v^H}{1-v}\left(1 - v^{W-H+1}\right).$$

H and W are positive integers and v is any number except one ($v \neq 1$). It is straightforward exercise to show that equation (1.2) is valid. If S is the sum on the left hand side of equation (1.2), then $S - vS = v^H - v^{W+1}$ and solving for S gives the right hand side of (1.2).

Using equation (1.2) with $H = 1$, $W = N$ and $v = 1/(1+r)$ yields

$$\sum_{j=1}^{N} \left(\frac{1}{1+r}\right)^j = \frac{(1+r)^N - 1}{r(1+r)^N}.$$

Replacing the summation in the present value equation yields

$$K = cK\left(\frac{(1+r)^N - 1}{r(1+r)^N}\right)$$

and solving for c produces equation (1.1).

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1 For example, see pages 21-22 in "Economic Evaluation and Investment Decision Methods," Stermole, F.J. and Stermole, J.M. (1993).

1.1 CRF That Reflect Taxable Income

The revenue that results from a capital investment is taxable income. The revenue payment A, obtained by multiplying the capital investment amount K by the CRF in equation (1.1), would be too low in cases where the revenue is taxable. The goal, in the presence of taxes, is to have a CRF for which the product $CRF \cdot K$ yields an annual payment A that will provide the necessary and sufficient level of revenue to cover the investors' annual tax payments, and the return on and return of the capital investment. In other words, over the life of the project, the revenue in excess of the tax payments and investment return should equal the original capital investment. The annual revenue payment can be determined by solving an equation where the present value of the after tax cash flows resulting from annual revenue payment is equal to the initial capital investment.

The composition of the after tax cash flow is dependent upon capital budgeting model. The flow to equity (FTE) model was used to develop the original CRF for PJM Black Start Service.[2] The FTE approach discounts the after tax cash flow to the equity investor at the return on equity. The CRF must satisfy the following present value equation,

$$E \cdot K = \sum_{j=1}^{N} \frac{CF_j}{(1+r_e)^j} \ .$$

$E \cdot K$ is the equity portion of the capital investment, CF_j is the after tax cash flow to the equity investor for year j, r_e is the rate of return on equity and the revenue, tax and debt payments are assumed to occur at the end of the year. The model variables are defined in Table 1. In the FTE model, the after tax cash flow is revenue net of taxes and the debt payment, and the tax calculation includes an offset for both depreciation and interest on the debt. The after tax cash flow for year j is

$$\begin{aligned} CF_j &= cK - \left(cK - \delta_j K - I_j\right)s - P \\ &= cK(1-s) + \delta_j Ks + I_j s - P \end{aligned}$$

where c is the CRF, K is the total capital investment including debt and equity, I_j is the interest portion of the debt payment P and s is the effective tax rate. Upon replacing CF_j in the present value equation

$$E \cdot K = cK(1-s)\sum_{j=1}^{N}\frac{1}{(1+r_e)^j} + Ks\sum_{j=1}^{N}\frac{\delta_j}{(1+r_e)^j} + s\sum_{j=1}^{N}\frac{I_j}{(1+r_e)^j} - P\sum_{j=1}^{N}\frac{1}{(1+r_e)^j} \,.$$

Equation (1.2) with $H = 1$, $W = N$ and $v = 1/(1+r_e)$ gives

2 Additional details on the flow to equity approach can be found in Section 17.2 in "Corporate Finance," Ross, Westerfield, Jaffe, 4th Edition, 1996.

$$\sum_{j=1}^{N} \frac{1}{(1+r_e)^j} = \frac{(1+r_e)^N - 1}{r_e(1+r_e)^N}$$

and substituting into the previous equation results in

$$E \cdot K = cK(1-s)\left(\frac{(1+r_e)^N - 1}{r_e(1+r_e)^N}\right) + Ks\sum_{j=1}^{N} \frac{\delta_j}{(1+r_e)^j} + s\sum_{j=1}^{N} \frac{I_j}{(1+r_e)^j} - P\left(\frac{(1+r_e)^N - 1}{r_e(1+r_e)^N}\right).$$

Solving for c yields

(1.3)

$$c = \frac{r_e(1+r_e)^N}{(1-s)[(1+r_e)^N - 1]}\left\{E - s\sum_{j=1}^{N} \frac{\delta_j}{(1+r_e)^j} - \frac{s}{K}\sum_{j=1}^{N} \frac{I_j}{(1+r_e)^j} + \frac{P}{K}\frac{(1+r_e)^N - 1}{r_e(1+r_e)^N}\right\}.$$

Table 1 Variable descriptions for the FTE capital budgeting model

Variable	Description
K	Capital investment (included debt and equity)
E	Equity funding percent
r_e	Return on equity
r_d	Debt interest rate
P	Debt payment
I_j	Interest portion of debt payment in year j
s	Effective tax rate
N	Cost recovery period
δ_j	Depreciation factor for year j

Formulas for the debt payment and interest portion of the debt payment, for debt with a term of N years and assuming end of year debt payments, are given in equation (1.4).

(1.4)

$$P = (1-E)K\frac{r_d(1+r_d)^N}{(1+r_d)^N - 1}$$

$$I_j = (1-E)Kr_d(1+r_d)^{j-1}\left(\frac{(1+r_d)^{N-j+1} - 1}{(1+r_d)^N - 1}\right), \quad j = 1, \cdots, N$$

Using the (1.4)

$$\sum_{j=1}^{N} \frac{I_j}{(1+r_e)^j} = \sum_{j=1}^{N}(1-E)Kr_d(1+r_d)^{j-1}\left(\frac{(1+r_d)^{N-j+1} - 1}{(1+r_d)^N - 1}\right)\frac{1}{(1+r_e)^j}$$

$$= (1-E)K\left(\frac{r_d}{(1+r_d)^N-1}\right)\left[(1+r_d)^N\sum_{\mathrm{j}=1}^{\mathrm{N}}\left(\frac{1}{1+\mathrm{r_e}}\right)^j-(1+r_d)^{-1}\sum_{\mathrm{j}=1}^{\mathrm{N}}\left(\frac{1+r_d}{1+\mathrm{r_e}}\right)^j\right]$$

As previously noted

$$\sum_{j=1}^{N}\frac{1}{(1+\mathrm{r_e})^{\mathrm{j}}}=\frac{(1+\mathrm{r_e})^N-1}{r_e(1+\mathrm{r_e})^N}$$

and equation (1.2) with $H = 1$, $W = N$ and $v = (1 + r_d)/(1 + r_e)$ gives

$$\sum_{j=1}^{N}\left(\frac{1+r_d}{1+r_e}\right)^j=\left(\frac{1+r_d}{r_e-r_d}\right)\left(\frac{(1+\mathrm{r_e})^N-(1+\mathrm{r_d})^N}{(1+\mathrm{r_e})^N}\right).$$

Upon replacing the finite geometric series with the expressions above

$$\sum_{\mathrm{j}=1}^{\mathrm{N}}\frac{\mathrm{I_j}}{(1+\mathrm{r_e})^{\mathrm{j}}}=(1-E)K\left(\frac{r_d}{(1+r_d)^N-1}\right)\left[(1+r_d)^N\left(\frac{(1+\mathrm{r_e})^N-1}{r_e(1+\mathrm{r_e})^N}\right)-\frac{(1+\mathrm{r_e})^N-(1+\mathrm{r_d})^N}{(r_e-r_d)(1+\mathrm{r_e})^N}\right].$$

Replacing the sum of discounted interest payments in equation (1.3) and using (1.4) to replace P yields the CRF formula in equation (1.5).

(1.5)

$$\mathrm{CRF}=\frac{\mathrm{r_e}(1+\mathrm{r_e})^{\mathrm{N}}}{(1-\mathrm{s})[(1+\mathrm{r_e})^{\mathrm{N}}-1]}\Bigg\{\mathrm{E}-\mathrm{s}\sum_{\mathrm{j}=1}^{\mathrm{N}}\frac{\delta_{\mathrm{j}}}{(1+\mathrm{r_e})^{\mathrm{j}}}$$
$$-(1-E)s\frac{r_d}{(1+r_d)^N-1}\left[(1+r_d)^N\left(\frac{(1+\mathrm{r_e})^N-1}{r_e(1+\mathrm{r_e})^N}\right)-\left(\frac{(1+\mathrm{r_e})^N-(1+\mathrm{r_d})^N}{(r_e-r_d)(1+\mathrm{r_e})^N}\right)\right]$$
$$+(1-E)\left(\frac{r_d(1+r_d)^N}{(1+r_d)^N-1}\right)\left(\frac{(1+\mathrm{r_e})^{\mathrm{N}}-1}{\mathrm{r_e}(1+\mathrm{r_e})^{\mathrm{N}}}\right)\Bigg\}$$

Substituting the parameter values shown in Table 2 into the CRF formula, assuming a five year capital recovery period and straight line depreciation yields a CRF of 0.275362. With a capital investment of $1 million, the annual payment is $275,362.

Table 3 provides a cash flow summary for a $1 million capital investment with a five year cost recovery period that uses straight line depreciation. The revenue for each year, equal to the product of the CRF and the capital investment amount, is $275,362. The tax payment for each year is equal to the effective tax rate times the revenue net of depreciation and the interest portion of the debt payment. The interest payment in year 1 is equal to the product of the debt interest rate and the initial debt of $500,000, and the return on equity in year 1 is equal to the product of the rate of return on equity and the initial equity investment of $500,000.

Table 2 Financial parameter and tax assumptions[3]

Parameter	Parameter Value
Equity Funding Percent	50.0000%
Debt Funding Percent	50.0000%
Equity Rate	12.0000%
Debt Interest Rate	7.0000%
Federal Tax Rate	21.0000%
State Tax Rate	9.3000%
Effective Tax Rate	28.3470%
Depreciation (δ_i , i = 1,2,3,4,5)	20.0000%

After accounting for the tax payment, the debt payment and return on equity in year 1, $81,975 is available as payback to the equity investors. The remaining equity investment is $418,025 at the end of year 1. The year 2 interest on debt is the product of the debt interest rate and the remaining debt at the end of year 1. The year 2 return on equity is the product of the rate of return on equity and the remaining equity investment at the end of year 1. Payback to equity investors is $90,087 in year 2. The cash flows for years 3 through 5 are analogous to the year 2 cash flow.

Table 3 Cash flow summary for 5 year, $1 million investment with straight line depreciation[4]

Service Year	1	2	3	4	5
Revenue	$275,362	$275,362	$275,362	$275,362	$275,362
Depreciation	$200,000	$200,000	$200,000	$200,000	$200,000
Interest on debt	$35,000	$28,914	$22,402	$15,434	$7,978
Tax payment	$11,441	$13,167	$15,013	$16,988	$19,101
Debt payment	$121,945	$121,945	$121,945	$121,945	$121,945
Return on equity	$60,000	$50,163	$39,353	$27,466	$14,391
Payback of debt	$86,945	$93,032	$99,544	$106,512	$113,968
Payback of equity	$81,975	$90,087	$99,051	$108,962	$119,924
Remaining debt	$413,055	$320,023	$220,479	$113,968	$0.000
Remaining equity	$418,025	$327,938	$228,887	$119,924	$0.000

3 The effective tax rate (parameter s in the formula) is equal to *State Tax Rate + Federal Tax Rate x (1-State Tax Rate).*

4 FTE model with end of year revenue and tax payments.

After the final revenue payment in year 5, the remaining equity investment, and the remaining debt are reduced to $0. Summing horizontally across the debt payback row and the equity payback row produces $500,000 for each, reflecting the 1:1 debt to equity ratio in Table 2. This example illustrates that the revenue payment determined by the CRF provides the necessary and sufficient annual revenue to pay the taxes associated with the revenue payment as well as the required return on and return of the capital investment. This important point is established as a general result in the following proposition.

Proposition 1.1. The CRF given by equation (1.5) is the unique value, assuming a FTE model with end of year payments, for which the resulting annual revenue payment is necessary and sufficient, over the term of the investment, to provide for the annual tax liability and the return on and return of the capital investment.

1.2 Half Year Convention

The revenue and tax payments would likely be made on a monthly or quarterly basis rather than occurring at the end of the year. A better model with respect to the timing of the revenue and tax payments is obtained by assuming the revenue and tax payments occur at the midpoint of each year. To derive a CRF corresponding to midyear revenue and tax payments, the present value equation from the previous section is modified to reflect the new timing assumption. Each after tax cash flow amount is assumed to occur a half year earlier than in the previous model. The revised present value equation is

$$K = \sum_{j=1}^{N} \frac{CF_j}{(1+r)^{j-0.5}} \ ,$$

or equivalently,

$$\mathrm{K} = \sqrt{1+r_e} \sum_{\mathrm{j}=1}^{\mathrm{N}} \frac{CF_j}{(1+r_e)^{\mathrm{j}}} \ .$$

Making the substitution,

$$CF_j = cK - \left(cK - \delta_j K - I_j\right)s - P$$

and solving for c yields equation (1.6).

(1.6)

$$c = \frac{r_e(1+r_e)^N}{(1-s)[(1+r_e)^N - 1]} \left\{ \frac{E}{\sqrt{1+r_e}} - s\sum_{j=1}^{N} \frac{\delta_j}{(1+r_e)^j} - \frac{s}{K}\sum_{j=1}^{N} \frac{I_j}{(1+r_e)^j} + \frac{P}{K}\frac{(1+r_e)^N - 1}{r_e(1+r_e)^N} \right\}.$$

Formulas for the debt payment and interest portion of the debt payment, for debt with a term of N years and assuming the half year convention are given in equation (1.7).

(1.7)

$$P = (1-E)K\frac{r_d(1+r_d)^{N-1/2}}{(1+r_d)^N-1}$$
$$I_1 = (1-E)K\left(\sqrt{1+r_d}-1\right)$$
$$I_j = (1-E)Kr_d(1+r_d)^{j-3/2}\left(\frac{(1+r_d)^{N-j+1}-1}{(1+r_d)^N-1}\right), \quad j=2,\cdots,N$$

Substituting the formulas for the interest payment into the sum of discounted interest payments from (1.6) results in

$$\begin{aligned}\sum_{j=1}^{N}\frac{I_j}{(1+r_e)^j} &= (1-E)K\left(\frac{\sqrt{1+r_d}-1}{1+r_e}+\sum_{j=2}^{N}\left(r_d(1+r_d)^{j-3/2}\left(\frac{(1+r_d)^{N-j+1}-1}{(1+r_d)^N-1}\right)\frac{1}{(1+r_e)^j}\right)\right)\\ &= (1-E)K\frac{\sqrt{1+r_d}-1}{1+r_e}\\ &\quad+\frac{(1-E)Kr_d}{\sqrt{1+r_d}[(1+r_d)^N-1]}\left[(1+r_d)^N\sum_{j=2}^{N}\left(\frac{1}{1+r_e}\right)^j-(1+r_d)^{-1}\sum_{j=2}^{N}\left(\frac{1+r_d}{1+r_e}\right)^j\right].\end{aligned}$$

Both summations in the previous expression are finite geometric series that can be simplified by using equation (1.2). Taking $H=2$, $W=N$ and $v=1/(1+r_e)$ gives

$$\sum_{j=2}^{N}\frac{1}{(1+\mathrm{r_e})^{\mathrm{j}}}=\frac{(1+\mathrm{r_e})^{N-1}-1}{r_e(1+\mathrm{r_e})^N}$$

and with $H=2$, $W=N$ and $v=(1+r_d)/(1+r_e)$

$$\sum_{j=2}^{N}\left(\frac{1+r_d}{1+r_e}\right)^j=(1+r_d)^2\left(\frac{(1+\mathrm{r_e})^{N-1}-(1+\mathrm{r_d})^{N-1}}{(r_e-r_d)(1+\mathrm{r_e})^N}\right).$$

Replacing the summations yields equation (1.8).

(1.8)

$$\begin{aligned}\sum_{j=1}^{N}\frac{I_j}{(1+r_e)^j} &= (1-E)K\frac{\sqrt{1+r_d}-1}{1+r_e}\\ &\quad+\frac{(1-E)Kr_d\sqrt{1+r_d}}{(1+r_d)^N-1}\left[(1+r_d)^{N-1}\left(\frac{(1+\mathrm{r_e})^{N-1}-1}{r_e(1+\mathrm{r_e})^N}\right)\right.\\ &\quad\left.-\left(\frac{(1+\mathrm{r_e})^{N-1}-(1+\mathrm{r_d})^{N-1}}{(r_e-r_d)(1+\mathrm{r_e})^N}\right)\right]\end{aligned}$$

Using (1.8) to replacing the sum of discounted interest payments in equation (1.6) and using (1.7) to replace P yields the CRF formula in equation (1.9).

(1.9)

$$CRF = \frac{r_e(1+r_e)^N}{(1-s)[(1+r_e)^N-1]}\left\{\frac{E}{\sqrt{1+r_e}} - s\sum_{j=1}^{N}\frac{\delta_j}{(1+r_e)^j} - s(1-E)\frac{\sqrt{1+r_d}-1}{1+r_e}\right.$$
$$- s(1-E)\frac{r_d\sqrt{1+r_d}}{(1+r_d)^N-1}\left[(1+r_d)^{N-1}\left(\frac{(1+\mathrm{r_e})^{N-1}-1}{r_e(1+\mathrm{r_e})^N}\right)\right.$$
$$\left.\left. - \left(\frac{(1+\mathrm{r_e})^{N-1}-(1+\mathrm{r_d})^{N-1}}{(r_e-r_d)(1+\mathrm{r_e})^N}\right)\right] + (1-E)\left(\frac{r_d(1+r_d)^{N-1/2}}{(1+r_d)^N-1}\right)\left(\frac{(1+r_e)^N-1}{r_e(1+r_e)^N}\right)\right\}$$

Using the parameter values in Table 2, with a five year capital cost recovery period and straight line depreciation, equation (1.9) yields a CRF of 0.260975. With an initial capital investment of $1 million, the annual payment is $260,975. Table 4 shows the corresponding cash flow summary.

Table 4 Cash flow summary for 5 year, $1 million investment with half year convention

Service Year	1	2	3	4	5
Revenue	$260,975	$260,975	$260,975	$260,975	$260,975
Depreciation	$200,000	$200,000	$200,000	$200,000	$200,000
Interest on debt	$17,204	$27,952	$21,656	$14,920	$7,712
Tax payment	$12,408	$9,361	$11,146	$13,055	$15,098
Debt payment	$117,889	$117,889	$117,889	$117,889	$117,889
Return on equity	$29,150	$47,817	$37,508	$26,176	$13,713
Payback of debt	$100,685	$89,937	$96,233	$102,969	$110,177
Payback of equity	$101,528	$85,909	$94,433	$103,855	$114,275
Remaining debt	$399,315	$309,378	$213,145	$110,177	$0
Remaining equity	$398,472	$312,563	$218,130	$114,275	$0

The calculation of the values in Table 4 is identical to the corresponding values in Table 3 except that the year 1 interest on the debt and the year 1 return on equity reflect a half year period. The interest on debt in year 1 is equal to the product of the initial debt and the half year interest rate $\sqrt{1+\mathrm{r}_d}-1$. The return on equity in year 1 is equal to the product of the equity investment and the half year rate of return $\sqrt{1+\mathrm{r}_e}-1$. The cash flow summary shows that the revenue payment determined by the CRF is necessary and sufficient to pay the taxes associated with the revenue payment as well as the required return on and return of the capital investment.

Changing the depreciation assumption to 3 year MACRS produces a CRF of 0.251812. The MACRS depreciation factors are shown in Table 7. The lower CRF relative to the straight line depreciation example reflects the lower tax payment under MACRS due to the accelerated depreciation schedule. In years 1 and 2, the tax payment in Table 5 is negative due to the accelerated depreciation assumption.[5] The cash flow summary in Table 5 shows that the revenue payment determined by the CRF, using 3 year MACRS depreciation, is at the necessary and sufficient level to provide for the taxes associated with the revenue payment as well as the required return on and return of the capital investment.

Table 5 Cash flow summary for 5 year, $1 million investment with 3 year MACRS

Service Year	1	2	3	4	5
Revenue	$251,812	$251,812	$251,812	$251,812	$251,812
Depreciation	$333,300	$444,500	$148,100	$74,100	$0
Interest on debt	$17,204	$27,952	$21,656	$14,920	$7,712
Tax payment	($27,976)	($62,545)	$23,260	$46,147	$69,195
Debt payment	$117,889	$117,889	$117,889	$117,889	$117,889
Return on equity	$29,150	$44,070	$25,782	$15,597	$6,935
Payback of debt	$100,685	$89,937	$96,233	$102,969	$110,177
Payback of equity	$132,749	$152,398	$84,880	$72,180	$57,793
Remaining debt	$399,315	$309,378	$213,145	$110,177	$0
Remaining equity	$367,251	$214,853	$129,973	$57,793	$0

Assuming 100 percent bonus depreciation results in a CRF of 0.242110. The corresponding cash flow summary is given in Table 6.

Table 6 Cash flow summary for 5 year, $1 million investment with bonus depreciation

Service Year	1	2	3	4	5
Revenue	$242,110	$242,110	$242,110	$242,110	$242,110
Depreciation	$1,000,000	$0	$0	$0	$0
Interest on debt	$17,204	$27,952	$21,656	$14,920	$7,712
Tax payment	($219,716)	$60,707	$62,492	$64,401	$66,445
Debt payment	$117,889	$117,889	$117,889	$117,889	$117,889
Return on equity	$29,150	$22,226	$17,271	$11,936	$6,190
Payback of debt	$100,685	$89,937	$96,233	$102,969	$110,177
Payback of equity	$314,786	$41,288	$44,458	$47,883	$51,586
Remaining debt	$399,315	$309,378	$213,145	$110,177	$0
Remaining equity	$185,214	$143,926	$99,469	$51,586	$0

In each example, the annual revenue payment, equal to the product of the capital investment and the CRF obtained from equation (1.9) is the necessary and sufficient revenue amount to cover the

[5] It is assumed that the capital investor would use the negative tax liability from this project as an offset against the tax liability resulting from other revenue.

tax liability and the return on and return of the investment capital. This observation is generalized in the following proposition.

Proposition 1.2. The CRF given by equation (1.9) is the unique value, assuming a FTE model with the half year convention, for which the resulting annual revenue payment is necessary and sufficient, over the term of the investment, to pay the annual tax liability and the return on and return of the capital investment.

Table 7 Modified Accelerated Cost Recovery System (MACRS) with half year convention[6]

Year	3 year Depreciation Factors	5 year Depreciation Factors	10 year Depreciation Factors	15 year Depreciation Factors	20 year Depreciation Factors
1	33.33%	20.00%	10.00%	5.00%	3.750%
2	44.45%	32.00%	18.00%	9.50%	7.219%
3	14.81%	19.20%	14.40%	8.55%	6.677%
4	7.41%	11.52%	11.52%	7.70%	6.177%
5		11.52%	9.22%	6.93%	5.713%
6		5.76%	7.37%	6.23%	5.285%
7			6.55%	5.90%	4.888%
8			6.55%	5.90%	4.522%
9			6.56%	5.91%	4.462%
10			6.55%	5.90%	4.461%
11			3.28%	5.91%	4.462%
12				5.90%	4.461%
13				5.91%	4.462%
14				5.90%	4.461%
15				5.91%	4.462%
16				2.95%	4.461%
17					4.462%
18					4.461%
19					4.462%
20					4.461%
21					2.231%

Proposition 1.2 Proof. K_0 is the initial capital invested and, $j \geq 1$, represents the equity investment remaining at the midpoint of cost recovery year j. $K_1^{(e)}$ is the remaining equity investment at the midpoint of year 1 after using the year 1 revenue net of taxes, the debt payment and return on equity, as a payback to the equity investors. The proposition states that the CRF in equation (1.9)

6 See Appendix A, Table A-1, IRS Publication 946, United States Department of Treasury (2020).

is the unique value that will result in $K_N^{(e)} = 0$. Representing the CRF in equation (1.9) as c, the year 1 revenue net of taxes and return is

$$cK_0(1-s) + \delta_1 K_0 s + I_1 s - P - EK_0\left(\sqrt{1+r_e} - 1\right).$$

The rate of return on equity reflects a half year of return due to the half year convention. The equity investment that remains at the midpoint of year 1 is

$$K_1^{(e)} = EK_0 - \left(cK_0(1-s) + \delta_1 K_0 s + I_1 s - P - EK_0\left(\sqrt{1+r_e} - 1\right)\right)$$

$$= EK_0\sqrt{1+r_e} - cK_0(1-s) - \delta_1 K_0 s - I_1 s + P.$$

The year 2 revenue net of taxes, the debt payment and return on equity is

$$cK_0(1-s) + \delta_2 K_0 s + I_2 s - P - r_e K_1^{(e)}$$

and the equity investment that remains at the midpoint of year 2 is

$$K_2^{(e)} = K_1^{(e)}(1+r_e) - cK_0(1-s) - \delta_2 K_0 s - I_2 s + P.$$

Substitution for $K_1^{(e)}$ yields

$$K_2^{(e)} = EK_0(1+r_e)^{3/2} - cK_0(1-s)[(1+r_e)+1] - [\delta_1(1+r_e)+\delta_2]K_0 s - [I_1(1+r_e)+I_2]s + P[(1+r_e)+1].$$

Repeating this process through the end of the capital recovery period yields

(1.10)

$$K_N^{(e)} = EK_0(1+r_e)^{N-1/2} - cK_0(1-s)\sum_{j=1}^{N}(1+r_e)^{j-1} - K_0 s\sum_{j=1}^{N}\delta_j(1+r_e)^{N-j} - s\sum_{j=1}^{N}I_j(1+r_e)^{N-j} + P\sum_{j=1}^{N}(1+r_e)^{j-1}.$$

Equation (1.2) with $H = 1$, $W = N$ and $v = 1 + r$ gives

$$\sum_{j=1}^{N}(1+r_e)^{j-1} = \frac{1}{1+r_e}\sum_{j=1}^{N}(1+r_e)^{j} = \frac{(1+r_e)^N - 1}{r_e}.$$

Using the formulas for I_j in equation (1.7) yields

$$
\begin{aligned}
&\sum_{j=1}^{N} I_j(1+r_e)^{N-j} \\
&\qquad = (1-E)K_0\left(\sqrt{1+r_d}-1\right)(1+r_e)^{N-1} \\
&\qquad + \sum_{j=2}^{N}(1-E)K_0 r_d(1+r_d)^{j-3/2}\left(\frac{(1+r_d)^{N-j+1}-1}{(1+r_d)^N-1}\right)(1+r_e)^{N-j} \\
&\qquad = (1-E)K_0\left(\sqrt{1+r_d}-1\right)(1+r_e)^{N-1} \\
&\qquad + \frac{(1-E)K_0 r_d(1+r_e)^N}{\sqrt{1+r_d}(1+r_d)^N-1}\left[(1+r_d)^N\sum_{j=2}^{N}\left(\frac{1}{1+r_e}\right)^j-(1+r_d)^{-1}\sum_{j=2}^{N}\left(\frac{1+r_d}{1+r_e}\right)^j\right]
\end{aligned}
$$

Equation (1.2) with $H = 2$, $W = N$ and $v = 1/(1 + r_e)$ gives

$$
\sum_{j=2}^{N}\left(\frac{1}{1+r_e}\right)^j = \frac{(1+r_e)^{N-1}-1}{r_e(1+r_e)^N}
$$

and $H = 2$, $W = N$ and $v = (1 + r_d)/(1 + r_e)$ gives

$$
\sum_{j=2}^{N}\left(\frac{1+r_d}{1+r_e}\right)^j = (1+r_d)^2\left[\frac{(1+r_e)^{N-1}-(1+r_d)^{N-1}}{(r_e-r_d)(1+r_e)^N}\right].
$$

Upon making these substitutions

$$
\begin{aligned}
&\sum_{j=1}^{N} I_j(1+r_e)^{N-j} \\
&\qquad = (1-E)K_0\left(\sqrt{1+r_d}-1\right)(1+r_e)^{N-1} \\
&\qquad + \frac{(1-E)K_0 r_d(1+r_d)}{\sqrt{1+r_d}(1+r_d)^N-1}\left[(1+r_d)^{N-1}\left(\frac{(1+r_e)^{N-1}-1}{r_e}\right)\right. \\
&\qquad \left. - \left(\frac{(1+r_e)^{N-1}-(1+r_d)^{N-1}}{(r_e-r_d)}\right)\right].
\end{aligned}
$$

Replacing the summations in equation (1.10) and replacing P using (1.7) yields

$$K_N^{(e)} = EK_0(1+r_e)^{N-1/2} - cK_0(1-s)\left(\frac{(1+r_e)^N-1}{r_e}\right) - K_0 s\sum_{j=1}^{N}\delta_j(1+r_e)^{N-j}$$
$$- s(1-E)K_0\left(\sqrt{1+r_d}-1\right)(1+r_e)^{N-1}$$
$$- s(1-E)K_0\frac{r_d(1+r_d)}{\sqrt{1+r_d}(1+r_d)^N-1}\left[(1+r_d)^{N-1}\left(\frac{(1+r_e)^{N-1}-1}{r_e}\right)\right.$$
$$\left.-\left(\frac{(1+r_e)^{N-1}-(1+r_d)^{N-1}}{(r_e-r_d)}\right)\right] + (1-E)K_0\left(\frac{\mathrm{r_d}(1+\mathrm{r_d})^{\mathrm{N}-1/2}}{(1+\mathrm{r_d})^{\mathrm{N}}-1}\right)\left(\frac{(1+r_e)^N-1}{r_e}\right).$$

Replacing c with the CRF formula in (1.9) results in $K_N^{(e)} = 0$. The equation for K_N also establishes the uniqueness of the CRF. If there are two CRF values, for instance c_1 and c_2, satisfying the proposition, then each will produce $K_N = 0$ and one can quickly deduce from the equation for K_N that $c_1 = c_2$.

Exhibit IMM-0003

Capital Recovery Factors (CRF) Technical Reference

Monitoring Analytics, LLC

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Table of Contents

1 The Basics of CRF

A capital recovery factor (CRF) is used to convert the principal amount of a capital investment into an equivalent stream of uniform payments. A typical CRF formula found in engineering economics textbooks is given in equation (1.1).[1]

(1.1)

$$CRF = \frac{r(1+r)^N}{(1+r)^N - 1}$$

Variable r is an interest rate, N is the number of uniform annual payments and the payments are assumed to occur at the end of year. To derive equation (1.1) the CRF is first denoted by c, allowing the annual payment to be stated as $A = cK$ where K is the capital investment. Then c is the value that solves the following present value equation,

$$\begin{aligned} K &= \sum_{j=1}^{N} \frac{cK}{(1+r)^j} \\ &= cK \sum_{j=1}^{N} \left(\frac{1}{1+r}\right)^j \end{aligned}$$

The summation in the equation above is a finite geometric series. A general formula for the sum of a finite geometric series is given by

(1.2)

$$\sum_{j=H}^{W} v^j = \frac{v^H}{1-v}\left(1 - v^{W-H+1}\right).$$

H and W are positive integers and v is any number except one ($v \neq 1$). It is a straightforward exercise to show that equation (1.2) is valid.[2]

Using equation (1.2) with $H = 1$, $W = N$ and $v = 1/(1+r)$ yields

$$\sum_{j=1}^{N} \left(\frac{1}{1+r}\right)^j = \frac{(1+r)^N - 1}{r(1+r)^N}.$$

Replacing the summation in the present value equation yields

$$K = cK\left(\frac{(1+r)^N - 1}{r(1+r)^N}\right)$$

[1] For example, see pages 21-22 in "Economic Evaluation and Investment Decision Methods," Stermole, F.J. and Stermole, J.M. (1993).

[2] If S is the sum on the left hand side of equation (1.2), then $S - vS = v^H - v^{W+1}$ and solving for S gives the right hand side of (1.2).

and solving for c produces equation (1.1).

1.1 CRF That Reflect Taxable Income

The revenue that results from a capital investment is taxable income. The revenue payment A, obtained by multiplying the capital investment amount K by the CRF in equation (1.1), would be too low in cases where the revenue is taxable. The goal, in the presence of taxes, is to have a CRF for which the product $CRF \cdot K$ yields an annual payment A that will provide the necessary and sufficient level of revenue to cover the investors' annual tax payments, and the return on and return of the capital investment. In other words, over the life of the project, the revenue in excess of the tax payments and investment return should equal the original capital investment. The annual revenue payment can be determined by solving an equation where the present value of the after tax cash flows resulting from the annual revenue payment is equal to the initial capital investment.

The composition of the after tax cash flow is dependent upon the capital budgeting model. The weighted average cost of capital (WACC) approach was used to develop the CRF for PJM Black Start Service which was accepted by FERC in August 2021.[3] [4] The WACC approach to capital budgeting discounts the after tax cash flow at the after tax weighted average cost of capital rate and payback of the investment in each recovery year reflects the assumed debt and equity financing structure.[5] The CRF must satisfy the following present value equation,

$$K = \sum_{j=1}^{N} \frac{CF_j}{(1+r)^j} \ .$$

K is the capital investment, CF_j is the after tax cash flow for year j, r is the WACC rate, and the revenue, tax and debt payments are assumed to occur at the end of the year. The model variables are defined in Table 1-1. In the WACC model, the after tax cash flow is revenue net of taxes, and the tax calculation includes an offset for depreciation. The after tax cash flow for year j is

$$\begin{aligned} CF_j &= cK - \left(cK - \delta_j K\right)s \\ &= cK(1-s) + \delta_j Ks \end{aligned}$$

[3] 176 FERC ¶ 61,080 (August 10, 2021) at 43-44.

[4] Additional details on the weighted average cost of capital approach to capital budgeting can be found in Section 17.3 in "Corporate Finance," Ross, Westerfield, Jaffe, 4th Edition, 1996.

[5] The after tax weighted average cost of capital rate is equal to *Equity Funding Percent* x *Equity Rate* + *Debt Funding Percent* x *Debt Interest Rate* x (1- *Effective Tax Rate*).

where c is the CRF, K is the total capital investment including debt and equity, cK is the annual revenue payment, s is the effective tax rate and δ_j is the depreciation factor for year j. Upon replacing CF_j in the present value equation

$$K = cK(1-s)\sum_{j=1}^{N}\frac{1}{(1+r)^j} + Ks\sum_{j=1}^{N}\frac{\delta_j}{(1+r)^j}.$$

Equation (1.2) with $H = 1$, $W = N$ and $v = 1/(1+r)$ gives

$$\sum_{j=1}^{N}\frac{1}{(1+r)^j} = \frac{(1+r)^N - 1}{r(1+r)^N}$$

and substituting into the previous equation results in

$$K = cK(1-s)\left(\frac{(1+r)^N - 1}{r(1+r)^N}\right) + Ks\sum_{j=1}^{N}\frac{\delta_j}{(1+r)^j}.$$

Solving for c yields the CRF formula in equation (1.3).

(1.3)

$$CRF = \frac{r(1+r)^N}{(1-s)[(1+r)^N - 1]}\left\{1 - s\sum_{j=1}^{N}\frac{\delta_j}{(1+r)^j}\right\}$$

Table 1-1 Variable descriptions for the WACC capital budgeting model

Variable	Description
r	After tax weighted average cost of capital
s	Effective tax rate
N	Cost recovery period
δ_j	Depreciation factor for recovery year *j*

Substituting the parameter values shown in Table 1-2 into the CRF formula, assuming a five year capital recovery period and straight line depreciation yields a CRF of 0.274938. With a capital investment of $1 million, the annual payment is $274,938.

Table 1-3 provides a cash flow summary for a $1 million capital investment with a five year cost recovery period that uses straight line depreciation. The revenue for each year, equal to the product of the CRF and the capital investment amount, is $274,938. The tax payment for each year is equal to the effective tax rate times the revenue net of depreciation. The return on the capital investment in year 1 is equal to the product of the WACC rate and the initial capital investment of $1,000,000.

Table 1-2 Financial parameter and tax assumptions[6]

Parameter	Parameter Value
Equity Funding Percent	50.0000%
Debt Funding Percent	50.0000%
Equity Rate	12.0000%
Debt Interest Rate	7.0000%
Federal Tax Rate	21.0000%
State Tax Rate	9.0000%
Effective Tax Rate (s)	28.1100%
After tax Weighted Average Cost of Capital (r)	8.5162%

After accounting for the tax payment and return on investment in year 1, $168,711 is available as payback to the investors. The remaining capital investment is $831,289 at the end of year 1. The year 2 return on investment is the product of the WACC rate and the remaining capital investment at the end of year 1. Payback to investors is $183,079 in year 2. The cash flows for years 3 through 5 are analogous to the year 2 cash flow.

Table 1-3 Cash flow summary for 5 year, $1 million investment with straight line depreciation[7]

Recovery Year	1	2	3	4	5
Revenue	$274,938	$274,938	$274,938	$274,938	$274,938
Depreciation	$200,000	$200,000	$200,000	$200,000	$200,000
Tax Payment	$21,065	$21,065	$21,065	$21,065	$21,065
Return on capital investment	$85,162	$70,794	$55,202	$38,283	$19,923
Capital investment payback	$168,711	$183,079	$198,670	$215,590	$233,949
Remaining capital investment	$831,289	$648,209	$449,539	$233,949	$0

After the final revenue payment in year 5, the remaining capital investment is reduced to $0. Summing horizontally across the capital investment payback row in Table 1-3 produces $1,000,000. This example illustrates that the revenue payment determined by the CRF provides the necessary and sufficient annual revenue to pay the taxes associated with the revenue payment as well as the required return on and return of the capital investment. This important point is established as a general result in the following proposition.

Proposition 1.1. The CRF given by equation (1.3) is the unique value, assuming a WACC capital budgeting model with end of year payments, for which the resulting annual revenue payment is

[6] The effective tax rate (parameter s in the formula) is equal to *State Tax Rate + Federal Tax Rate x (1-State Tax Rate).*

[7] WACC model with end of year revenue and tax payments.

necessary and sufficient, over the term of the investment, to provide for the annual tax liability and the return on and return of the capital investment.

1.2 Half Year Convention

The revenue and tax payments would likely be made on a monthly or quarterly basis rather than occurring at the end of the year. A better model with respect to the timing of the revenue and tax payments is obtained by assuming the revenue and tax payments occur at the midpoint of each year. To derive a CRF corresponding to midyear revenue and tax payments, the present value equation from the previous section is modified to reflect the new timing assumption. Each after tax cash flow amount is assumed to occur a half year earlier than in the previous model. The revised present value equation is

$$K = \sum_{j=1}^{N} \frac{CF_j}{(1+r)^{j-0.5}} ,$$

or equivalently,

$$\mathrm{K} = \sqrt{1+r} \sum_{\mathrm{j}=1}^{\mathrm{N}} \frac{CF_j}{(1+r)^{\mathrm{j}}} .$$

Making the substitution,

$$CF_j = cK(1-s) + \delta_j Ks$$

and solving for c yields equation (1.4).

(1.4)

$$CRF = \frac{r(1+r)^N}{(1-s)[(1+r)^N - 1]} \left\{ \frac{1}{\sqrt{1+r}} - s \sum_{j=1}^{N} \frac{\delta_j}{(1+r)^j} \right\}$$

Using the parameter values in Table 1-2, with a five year capital cost recovery period and straight line depreciation, equation (1.4) yields a CRF of 0.260798. With an initial capital investment of $1 million, the annual payment is $260,798. Table 1-4 shows the corresponding cash flow summary.

Table 1-4 Cash flow summary for 5 year, $1 million investment with half year convention

Service Year	1	2	3	4	5
Revenue	$260,798	$260,798	$260,798	$260,798	$260,798
Depreciation	$200,000	$200,000	$200,000	$200,000	$200,000
Tax Payment	$17,090	$17,090	$17,090	$17,090	$17,090
Return on Capital Investment	$41,711	$67,959	$52,992	$36,751	$19,126
Payback of Capital Investment	$201,997	$175,749	$190,716	$206,957	$224,582
Remaining Capital Investment	$798,003	$622,255	$431,539	$224,582	$0

The calculation of the values in Table 1-4 is identical to the corresponding values in Table 1-3 except that the year 1 return on investment reflects a half year period. The return on investment in year 1 is equal to the product of the capital investment and the half year rate of return $\sqrt{1+\mathrm{r}}-1$. The cash flow summary shows that the revenue payment determined by the CRF is necessary and sufficient to pay the taxes associated with the revenue payment as well as the required return on and return of the capital investment.

Changing the depreciation assumption to 3 year MACRS produces a CRF of 0.254231. The MACRS depreciation factors are shown in Table 1-8. The lower CRF relative to the straight line depreciation example reflects the lower tax payment under MACRS due to the accelerated depreciation schedule. In years 1 and 2, the tax payment in Table 1-5 is negative due to the accelerated depreciation assumption.[8] The cash flow summary in Table 1-5 shows that the revenue payment determined by the CRF, using 3 year MACRS depreciation, is at the necessary and sufficient level to provide for the taxes associated with the revenue payment as well as the required return on and return of the capital investment.

Table 1-5 Cash flow summary for 5 year, $1 million investment with 3 year MACRS

Service Year	1	2	3	4	5
Revenue	$254,231	$254,231	$254,231	$254,231	$254,231
Depreciation	$333,300	$444,500	$148,100	$74,100	$0
Tax Payment	($22,226)	($53,485)	$29,833	$50,635	$71,464
Return on Capital Investment	$41,711	$65,170	$44,515	$29,195	$14,343
Payback of Capital Investment	$234,747	$242,546	$179,883	$174,401	$168,424
Remaining Capital Investment	$765,253	$522,708	$342,825	$168,424	$0

The depreciation assumption has a significant impact on the CRF level. Generally, the faster the capital is depreciated for tax purposes, the lower the CRF. The Tax Cuts and Jobs Act (TCJA), signed into law on December 22, 2017 included bonus depreciation rates applicable to capital investments placed in service after September 27, 2017.[9] [10] Capital investments placed into service after September 27, 2017 and before January 1, 2023, are eligible for 100 percent bonus depreciation.[11]

8 It is assumed that the capital investor would use the negative tax liability from this project as an offset against the tax liability resulting from other revenue.

9 Tax Cuts and Jobs Act, Pub. L. No. 115-97, 131 Stat. 2096, Stat. 2105 (2017).

10 26 U.S. Code §11(b)

11 Bonus depreciation is 100 percent for capital investments placed in service after September 27, 2017 and before January 1, 2023. Bonus depreciation is 80 percent for capital investments placed in service after December 31, 2022 and before January 1, 2024, and the bonus depreciation level is reduced by 20

Assuming 100 percent bonus depreciation results in a CRF of 0.247523. The corresponding cash flow summary is given in Table 1-6. The CRF for straight line depreciation for a five year cost recovery period is 5.3 percent higher than the CRF corresponding to 100 percent bonus depreciation.

Table 1-6 Cash flow summary for 5 year, $1 million investment with bonus depreciation

Service Year	1	2	3	4	5
Revenue	$247,523	$247,523	$247,523	$247,523	$247,523
Depreciation	$1,000,000	$0	$0	$0	$0
Tax Payment	($211,521)	$69,579	$69,579	$69,579	$69,579
Return on Capital Investment	$41,711	$49,621	$38,692	$26,834	$13,965
Payback of Capital Investment	$417,334	$128,324	$139,252	$151,111	$163,980
Remaining Capital Investment	$582,666	$454,343	$315,091	$163,980	$0

The CRF for a capital investment with a 20 year recovery period is 0.103149 and the corresponding cash flow summary is given in Table 1-7 for a capital investment totaling $10,000,000.

percent for each subsequent year through 2026. Capital investments placed in service after December 31, 2026 are not eligible for bonus depreciation. See 26 U.S. Code §168(k)(6)(A).

Table 1-7 Cash flow summary for 20 year, $10 million investment with bonus depreciation

Service Year	Revenue	Depreciation	Tax Payment	Return on Capital Investment	Payback of Capital Investment	Remaining Capital Investment
1	$1,031,492	$10,000,000	($2,521,048)	$417,109	$3,135,431	$6,864,569
2	$1,031,492	$0	$289,952	$584,597	$156,943	$6,707,626
3	$1,031,492	$0	$289,952	$571,231	$170,308	$6,537,318
4	$1,031,492	$0	$289,952	$556,728	$184,812	$6,352,506
5	$1,031,492	$0	$289,952	$540,989	$200,551	$6,151,955
6	$1,031,492	$0	$289,952	$523,910	$217,630	$5,934,325
7	$1,031,492	$0	$289,952	$505,376	$236,164	$5,698,161
8	$1,031,492	$0	$289,952	$485,264	$256,276	$5,441,886
9	$1,031,492	$0	$289,952	$463,439	$278,101	$5,163,785
10	$1,031,492	$0	$289,952	$439,756	$301,784	$4,862,001
11	$1,031,492	$0	$289,952	$414,055	$327,484	$4,534,517
12	$1,031,492	$0	$289,952	$386,166	$355,373	$4,179,143
13	$1,031,492	$0	$289,952	$355,902	$385,638	$3,793,505
14	$1,031,492	$0	$289,952	$323,061	$418,479	$3,375,026
15	$1,031,492	$0	$289,952	$287,422	$454,117	$2,920,909
16	$1,031,492	$0	$289,952	$248,749	$492,791	$2,428,118
17	$1,031,492	$0	$289,952	$206,782	$534,758	$1,893,361
18	$1,031,492	$0	$289,952	$161,241	$580,298	$1,313,062
19	$1,031,492	$0	$289,952	$111,822	$629,717	$683,345
20	$1,031,492	$0	$289,952	$58,195	$683,345	$0

In each example, the annual revenue payment, equal to the product of the capital investment and the CRF obtained from equation (1.4) is the necessary and sufficient revenue amount to cover the tax liability and the return on and return of the investment capital. This observation is generalized in the following proposition.

Proposition 1.2. The CRF given by equation (1.4) is the unique value, assuming a WACC capital budgeting model with the half year convention, for which the resulting annual revenue payment is necessary and sufficient, over the term of the investment, to pay the annual tax liability and the return on and return of the capital investment.

Table 1-8 Modified Accelerated Cost Recovery System (MACRS) with half year convention[12]

Year	3 year Depreciation Factors	5 year Depreciation Factors	10 year Depreciation Factors	15 year Depreciation Factors	20 year Depreciation Factors
1	33.33%	20.00%	10.00%	5.00%	3.750%
2	44.45%	32.00%	18.00%	9.50%	7.219%
3	14.81%	19.20%	14.40%	8.55%	6.677%
4	7.41%	11.52%	11.52%	7.70%	6.177%
5		11.52%	9.22%	6.93%	5.713%
6		5.76%	7.37%	6.23%	5.285%
7			6.55%	5.90%	4.888%
8			6.55%	5.90%	4.522%
9			6.56%	5.91%	4.462%
10			6.55%	5.90%	4.461%
11			3.28%	5.91%	4.462%
12				5.90%	4.461%
13				5.91%	4.462%
14				5.90%	4.461%
15				5.91%	4.462%
16				2.95%	4.461%
17					4.462%
18					4.461%
19					4.462%
20					4.461%
21					2.231%

1.3 Proof of Proposition 1.2

Proposition 1.2. The CRF given by equation (1.4) is the unique value, assuming a WACC capital budgeting model with the half year convention, for which the resulting annual revenue payment is necessary and sufficient, over the term of the investment, to pay the annual tax liability and the return on and return of the capital investment.

Proof. K_0 is the initial capital invested and K_j, $j \geq 1$, represents the capital investment remaining at the midpoint of cost recovery year j. K_1 is the remaining capital investment at the midpoint of year 1 after using the year 1 revenue net of taxes and return on investment, as a payback to investors. The proposition states that the CRF in equation (1.4) is the unique value that will result in $K_N = 0$. Representing the CRF in equation (1.4) as c, the year 1 revenue net of taxes and return on investment is

12 See Appendix A, Table A-1, IRS Publication 946, United States Department of Treasury (2020).

$$cK_0(1-s)+\delta_1 K_0 s - K_0\left(\sqrt{1+r}-1\right).$$

The rate of return on the investment reflects a half year of return due to the half year convention. The equity investment that remains at the midpoint of year 1 is

$$K_1 = K_0 - \left(cK_0(1-s)+\delta_1 K_0 s - K_0\left(\sqrt{1+r}-1\right)\right)$$

$$= K_0\sqrt{1+r} - cK_0(1-s) - \delta_1 K_0 s.$$

The year 2 revenue net of taxes and return on investment is

$$cK_0(1-s)+\delta_2 K_0 s - rK_1$$

and the capital investment that remains at the midpoint of year 2 is

$$K_2 = K_1(1+r) - cK_0(1-s) - \delta_2 K_0 s.$$

Substitution for K_1 yields

$$K_2 = K_0(1+r)^{3/2} - cK_0(1-s)[(1+r)+1] - [\delta_1(1+r)+\delta_2]K_0 s.$$

Repeating this process through the end of the cost recovery period yields

(1.5)

$$K_N = K_0(1+r)^{N-1/2} - cK_0(1-s)\sum_{j=1}^{N}(1+r)^{j-1} - K_0 s\sum_{j=1}^{N}\delta_j(1+r)^{N-j}.$$

Equation (1.2) with $H = 1$, $W = N$ and $v = 1+r$ gives

$$\sum_{j=1}^{N}(1+r)^{j-1} = \frac{1}{1+r}\sum_{j=1}^{N}(1+r)^{j} = \frac{(1+r)^N-1}{r}.$$

Replacing the first summation in equation (1.5) yields

(1.6)

$$K_N = K_0(1+r)^{N-1/2} - cK_0(1-s)\left(\frac{(1+r)^N-1}{r}\right) - K_0 s\sum_{j=1}^{N}\delta_j(1+r)^{N-j}.$$

Replacing c in (1.6) with the CRF formula in (1.4) results in $K_N = 0$. Equation (1.6) also establishes the uniqueness of the CRF. If there are two CRF values, for instance c_1 and c_2, satisfying the proposition, then each will produce $K_N = 0$ and one can quickly deduce from the equation (1.6) that $c_1 = c_2$.

Exhibit IMM-0004

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket No. EL21-91-003
	)	

RESPONSE OF THE INDEPENDENT MARKET MONITOR FOR PJM TO FERC TRIAL STAFF'S FIRST SET OF DATA REQUESTS

S-IMM-1.1. Please provide all available workpapers and/or formulas used to derive the Levelized Capital Recovery Factor (CRF) for Black Start facilities selected to provide service prior to June 6, 2021 (pre-June 6, 2021 CRFs). Define all terms and where applicable provide as live excel spreadsheets.

RESPONSE

Documents responsive to this request are attached. The attached spreadsheet contains a simulation model that was used to calculate the pre-June 6, 2021, CRF values.[1] There is a separate tab for calculating the CRFs corresponding to the four capital recovery periods (5 years, 10 years, 15 years and 20 years). The annual revenue payment is equal to the product of the CRF and capital investment amount. The after tax cash flow to the equity investor is equal to the revenue net of income tax payments and debt payments.[2] The model uses the solver function to iterate through possible values for the CRF, stopping when the internal rate of return (IRR) corresponding to the after tax cash flow is equal to the required return on equity (12.0 percent).

There is an assumption in the simulation model that has an effect on the calculated CRF value, increasing the CRF value slightly. In the simulation model, the debt payments are treated as occurring at mid year. The mid year convention can be used to better align the

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1 2023-09-15 S-IMM DR 1-1 Response-Attachment.

2 Generally the fixed O&M expense would also be subtracted from the revenue but the fixed O&M is set to $0 for the capital recovery calculation.

timing of the revenue, income tax and debt payments which would likely be made on a monthly or quarterly basis.[3]

Three presentations from 2006 on the CRF approach are attached to the response to Data Request S-IMM-1.2.

Sponsor: Prepared under the supervision of Dr. Joseph E. Bowring.

Dated: September 15, 2023

[3] The Market Monitor noted this issue in a previous filing but described it as a rounding error. See pages 8-9 and footnote 20 in *Errata Filing of the Independent Market Monitor for PJM,* Attachment B, EL21-91 (November 18, 2021).

S-IMM-1.2. Please provide any Market Monitor records of the stakeholder process in which these CRF factors were developed.

RESPONSE

Please see the following attached documents:

- Attachment A: Black Start Tariff Section 6.4 Proposed Changes, MIC (September 18, 2006).
- Attachment B: Black Start Tariff Section 6.4 Issues, MRC (October 25, 2006).
- Attachment C: Black Start Tariff Section 6.4 Proposed Changes, MIC (October 31, 2006).

Sponsor: Prepared under the supervision of Dr. Joseph E. Bowring.

Dated: September 15, 2023

S-IMM-1.3. Was the formula used to derive the pre-June 6, 2021 CRFs equivalent to the formula for the CRF for facilities selected to provide service after June 6, 2021 (post-June 6, 2021 CRFs)? If not, please explain your understanding of the differences between the two formulas.

RESPONSE

No. The pre-June 6, 2021, CRFs were calculated using a flow to equity (FTE) financial model that incorporates a mortgage payment approach for the loan repayment. Under this approach, the debt to equity ratio is not constant during the cost recovery period. The formula for the post-June 6, 2021, CRF was derived from a weighted average cost of capital (WACC) financial model. When the revenue is equal to the level required to meet all the payment obligations, without excess payments, the results of the two models are quite close.

But when there are payments in excess of the level required to meet all the payment obligations, as has occurred in this case, the difference between the models is significant. In the WACC model, the revenue in excess of income taxes, required interest payments and return on equity is split between accelerated loan repayment and payment to equity according to the debt to equity ratio, and the debt to equity ratio is maintained at a constant level during the cost recovery period. In the FTE model, revenue in excess of income taxes, required debt payments and return on equity flows to the equity investor.

In this case, payments to black start resources used CRF calculations based on taxes higher than actual required tax payments. As a result, there were payments in excess of the level required to meet all the payment obligations. In cases where there are excess payments, the FTE model accurately captures the excess returns to equity while the WACC model does not.

The attached spreadsheet includes a side by side comparison of the approaches.[4] Model A is an FTE model and Model B is a WACC model. Both models use the mid year convention where revenue, tax and debt payments are assumed to occur at the midpoint of the year rather than at the end of the year. Model A uses a mortgage type loan repayment and model B splits the return of the investment between repayments of loan principal and payments to equity according to the debt to equity ratio. Model A results in a debt to equity ratio based on repaying the debt principal following the mortgage payment structure and all excess revenues flowing to equity. Model B maintains a constant debt to equity ratio throughout the cost recovery period. Model A is the model

4 2023-09-15 S-IMM DR 1-3 Response-Attachment.

used to determine the pre-June 6, 2021 CRFs. Model B is the model used to determine the post-June 6, 2021 CRFs.

The spreadsheet illustrates how each model reflects the impacts of using the incorrect federal income tax law to calculate the CRF.[5] Table 1 shows the revenue and payment streams associated with the FTE model that uses a mortgage style loan repayment (Model A in the attached spreadsheet). The revenue payment reflects the five year CRF value, 0.363, used to determine the revenue payments to pre-June 6, 2021, black start units based on tax laws in place prior to the Tax Cuts and Jobs Act of 2017 (TCJA).[6] The income tax payment in the model reflects the 100 percent bonus depreciation and 21 percent federal income tax rate included in the current tax laws. The interest on the debt and the repayment of the debt principal are not affected by the excess revenue which results from the incorrect income tax assumptions. All of the excess is paid to equity investors. In year 1, revenue in excess of income taxes, interest payments and return on equity is $500,542 of which $100,685 goes toward repayment of the debt principal and the remaining $399,857 goes to the equity investors. In year 2, the remaining equity investment is paid off and there is an additional $38,769 paid to the equity investors. Over the five year recovery period the repayment of the debt principal totals $500,000 as does the repayment of the equity investment. The excess revenue to equity investors in the table is the money left over in each year after meeting all other obligations. The after tax cash flow to equity investors is the sum of the ROE, repayment of the equity investment and the excess revenue to equity investors. The internal rate of return corresponding to the after tax cash flow is 61.7 percent. This 61.7 percent rate of return is more than five times higher than the target return. The intent of the CRF payment is to provide the equity investors with a 12 percent return on investment.

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5 On the Parameters Assumptions tab of the spreadsheet, set the federal income tax rate to 21 percent, the depreciation type to 100 percent bonus deprecation (by inputting 'B100') and set the CRF override flag to 1 (this forces the model to use a CRF value of 0.363 which is the original five year CRF).

6 Public Law 115-97.

Table 1 FTE model with five year cost recovery period and $1 million investment

Flow to Equity Approach - Non Constant D/E with Mid Year Payments					
Capital Recovery Year	1	2	3	4	5
Revenue	$363,000	$363,000	$363,000	$363,000	$363,000
Depreciation	$1,000,000	$0	$0	$0	$0
Interest on debt	$17,204	$27,952	$21,656	$14,920	$7,712
Income Tax	($183,897)	$94,182	$95,952	$97,845	$99,871
Return on equity (ROE)	$29,150	$12,017	$0	$0	$0
Revenue in excess of taxes, interest and ROE	$500,542	$228,849	$245,392	$250,235	$255,416
Repayment of debt principal	$100,685	$89,937	$96,233	$102,969	$110,177
Repayment of equity investment	$399,857	$100,143	$0	$0	$0
Debt Remaining	$399,315	$309,378	$213,145	$110,177	$0
Equity Remaining	$100,143	$0	$0	$0	$0
Excess Revenue to equity investors	$0	$38,769	$149,159	$147,266	$145,240
After tax cash flow to equity investors	$429,008	$150,929	$149,159	$147,266	$145,240
Internal Rate of Return (IRR) to equity investors	61.7%				

Table 2 shows the revenue and payment streams for the WACC model with a constant debt to equity ratio (Model B in the attached spreadsheet). Revenue in excess of income taxes, interest payments and return on equity is split between repayments of loan principal and repayments of equity investment according to the debt to equity ratio which is 50/50 in this case. In year 1, revenue in excess of income taxes, interest payments and return on equity is $500,350 with $250,175 going to accelerated debt repayment and $250,175 going to the equity investors.[7] Under this approach, the debt and equity are repaid in year 4. The excess revenue to equity investors in years 4 and 5 is the money left over in each year after meeting all other obligations. The after tax cash flow to equity investors is the sum of the ROE, repayment of the equity investment and the excess revenue to equity investors. The internal rate of return corresponding to the after tax

[7] The year 1 revenue net income taxes, interest and ROE is slightly lower (by $192) under the WACC approach. This results from the return on investment calculation when using the mid year convention. In the WACC model (Model B), the year 1 investment return net the income tax shield is equal to $\left(\sqrt{1+E\cdot r_e+D\cdot(1-s)\cdot r_d}-1\right)\cdot K$ where E is the equity funding percent, D is the debt funding percent, r_e is the return on equity, r_d is the interest rate on debt, s is the effective income tax rate and K is the capital investment. Under the FTE approach with the mid year convention (Model A), the year 1 return on equity is $\left(\sqrt{1+r_e}-1\right)\cdot E\cdot K$, the year 1 interest on the debt is $\left(\sqrt{1+r_d}-1\right)\cdot D\cdot K$ and the tax shield can be explicitly stated as $s\cdot\left(\sqrt{1+r_d}-1\right)\cdot D\cdot K$. Since $\left(\sqrt{1+E\cdot r_e+D\cdot(1-s)\cdot r_d}-1\right)\neq\left(\sqrt{1+r_e}-1\right)\cdot E+(1-s)\cdot\left(\sqrt{1+r_d}-1\right)\cdot D$, models A and B give different values for revenue net of income taxes, interest and ROE.[8] For a few resources, a portion of the payments received during the 15 month refund period will have to be returned in order to achieve a 12 percent return on investment.

cash flow is 41.5 percent. This 41.5 percent rate of return is more than three times higher than the target return. The intent of the CRF payment is to provide the equity investors with a 12 percent return on investment. The internal rate of return to equity investors in the WACC model is lower than in the FTE Model A because Model B is based on the incorrect assumption that equity holders would repay debt holders early despite the fact that it reduces the return to equity holders.

Table 2 WACC model with a five year cost recovery period and $1 million investment

WACC Approach - Constant D/E with Mid Year Payments					
Capital Recovery Year	1	2	3	4	5
Revenue	$363,000	$363,000	$363,000	$363,000	$363,000
Depreciation	$1,000,000	$0	$0	$0	$0
Gross Income Tax	($179,061)	$102,039	$102,039	$102,039	$102,039
Income Tax Shield[1 2]	$4,643	$4,916	$2,767	$435	$0
Interest on debt[1 2]	$17,204	$17,488	$9,843	$1,548	$0
Return on Equity (ROE)[1 2]	$29,150	$29,979.01	$16,874.42	$2,653.83	$0.00
Revenue in excess of taxes, interest and ROE	$500,350	$218,410	$237,010	$257,194	$260,961
Repayment of debt principal	$250,175	$109,205	$118,505	$22,115	$0
Repayment of equity investment	$250,175	$109,205	$118,505	$22,115	$0
Debt Remaining	$249,825	$140,620	$22,115	$0	$0
Equity Remaining	$249,825	$140,620	$22,115	$0	$0
Excess Revenue to equity investors	$0	$0	$0	$212,963	$260,961
After tax cash flow to equity investors	$279,325	$139,184	$135,379	$237,733	$260,961
Internal Rate of Return (IRR) to equity investors	41.5%				

The reduction in the income tax liability introduced with the TCJA significantly reduced the income tax payments and the windfall savings that resulted from continuing to pay black start resources under the outdated tax laws went to the equity investors. The FTE model correctly reflects the accelerated repayment of the equity investment and the flow of excess revenues to the equity investor. The WACC model with a constant debt to equity ratio understates the cash flow to the equity investor. The Market Monitor's proposal to calculate a revised CRF is based on the FTE model that reflects the windfall income tax savings accruing to the equity investors. Under the Market Monitor's proposal, a date is selected, for example January 1, 2024, and a revised CRF that accounts for the repayment of the investment as of January 1, 2024, is calculated. Under this approach, the revised revenue will be set at a level for which the return on investment for equity investors, over the entire black start service period, is 12 percent, as originally intended.[8] The revised CRF will result in a lower payment for black start units for the remainder of the capital recovery period but at the end of the recovery period the owner of the black start units will have received revenue sufficient to provide for the repayment of debt at 7 percent interest, federal and state income tax liabilities, a 12 percent return on equity and the return of the equity portion of the capital investment, all as intended in the CRF calculations.[9]

Sponsor: Prepared under the supervision of Dr. Joseph E. Bowring.

Dated: September 15, 2023

[8] For a few resources, a portion of the payments received during the 15 month refund period will have to be returned in order to achieve a 12 percent return on investment.

[9] The Market Monitor described the proposed resolution in a previous filing. See Section H in *Errata Filing of the Independent Market Monitor for PJM*, Attachment B, EL21-91 (November 18, 2021).

S-IMM-1.4. Does the CRF increase with the age of the Black Start Unit under the pre-June 6, 2021 CRFs, as well as the post-June 6, 2021 CRFs? If there is a difference in how age affects CRF between the two, please explain that difference and why that difference exists.

RESPONSE

The CRF value, holding the other parameters constant, is a function of the recovery period. The longer the recovery period, the lower the CRF. The logic is that the recovery of the investment is over a longer period and that the longer the recovery period, the smaller the required annual recovery. In Attachment DD, the recovery period is an inverse function of the life of the underlying capacity resource. The older the underlying capacity resource, the shorter the recovery period. In Attachment DD, the CRF is applied to incremental capital investment in existing capacity resources, termed APIR. The logic was that older units had a shorter remaining life and therefore needed a shorter recovery period for incremental investment.

In the case of black start resources, the same logic applied only if an existing resource added black start capability. If an older resource with a shorter remaining life added black start capability, the recovery period for the black start investment would be shorter. For a new resource with black start capability, the recovery period should be 20 years and include a commitment to provide black start for the entire life of the resource.

Sponsor: Prepared under the supervision of Dr. Joseph E. Bowring.

Dated: September 15, 2023

S-IMM-1.5.	Please provide any materials in your control relating to engagement between the Market Monitor and PJM relating to the use of tax rates in the development of existing or past CRFs, to include presentations, emails and other communications between PJM and the Market Monitor.

RESPONSE

The Market Monitor continues to review its files, and it expects that it can provide the requested materials on or before Friday, September 22, 2023.

Sponsor: Prepared under the supervision of Dr. Joseph E. Bowring.

Dated: September 15, 2023

S-IMM-1.6. Please provide any materials in your control relating to engagement between the Market Monitor and stakeholders, to include customers, Black Start Service providers and any other participants, relating to the use of tax rates in the development of existing or past CRFs, to include presentations, emails and other communications. Please note which if any of these are or were available to Black Start Service providers and/or to the public.

RESPONSE

The Market Monitor continues to review its files, and it expects that it can provide the requested materials on or before Friday, September 22, 2023.

Sponsor: Prepared under the supervision of Dr. Joseph E. Bowring.

Dated: September 15, 2023

S-IMM-1.7. Did the Market Monitor prepare the initial workpapers used to develop pre-June 6, 2021 CRF rates, including the use of a 36% corporate federal income tax rate in those calculations? If yes:

a. Please explain in detail any changes made to these calculations between the preparation of any initial workpapers and the final setting of the CRF rates at issue.
b. Please identify who at the Market Monitor would have the most knowledge of such calculations and any subsequent changes.

RESPONSE

Yes, the Market Monitor prepared the initial workpapers.

a. NA

b. Any questions about the calculations and any subsequent changes should be directed to Dr. Joseph E. Bowring.

Sponsor: Prepared under the supervision of Dr. Joseph E. Bowring.

Dated: September 15, 2023

Exhibit IMM-0005

Black Start Tariff Section 6.4 Proposed Changes

MIC

October 31, 2006

Joseph Bowring

Frank Racioppi

Black Start Tariff Issues

- BSS tariff initially designed to address existing black start units
- Tariff treatment of new black start investments is unclear
- Goal is to clarify tariff treatment of new black start investments
- Process requirements:
  - Members agreement and/or
  - FERC decision
- Owners retain option to file directly with FERC

Black Start Tariff Issues

- Capital recovery typically over investment life
- Capital recovery under recent black start filings is two to five years with request for existing tariff treatment thereafter
- Over recovery of capital costs when accelerated recovery combined with current tariff rate for balance of investment life
- Accelerated recovery results in higher rates of return without an explicit FERC decision

Basis for Required Changes

- Tariff treatment of new black start units is unclear
- Ensure appropriate incentives for new black start units
- Ensure appropriate agreement term for new black start units
  - Ensure appropriate cost recovery term for new black start units
  - Ensure that commitment by seller to provide black start service is consistent with life of black start investment
  - Ensure that commitment by buyers to purchase black start service is consistent with life of black start investment
  - Ensure that commitment by sellers and buyers is consistent

Basis for Required Changes

- Ensure that FERC has responsibility for regulatory decisions:
  - Rate of return in CRF factors
  - Rate of return for incentive payments

Framework for BSS Tariff Changes

- Treatment of existing black start units
- Treatment of new black start investments made in recent years
  - Payments over remaining investment life after accelerated full capital recovery
- Treatment of new entry black start investments in the future
  - Payments over investment life
  - Payments after investment life

Framework for BSS Tariff Changes

- New entry black start service generation revenue requirements
  - Actual fixed costs recovered over the remaining life of the associated generator up to a maximum of 20 years, as an example. (FERC decision)
    - Apply appropriate CRF (capital recovery factor)
  - Fixed costs include all fixed costs including return on and of capital and fixed O&M costs.
  - Actual variable costs recovered on an annual basis.
  - Tariff provisions will provide for such cost recovery. (FERC decision)
  - After the term of the agreement, such units eligible to receive tariff rate, as an example. (FERC decision)
  - Owners retain option to file with the FERC.

Framework for BSS Tariff Changes

- Owners recovering black start service generation revenue requirements for existing units under tariff rate
  - Continue to recover costs under that structure.
- Owners recovering black start service generation revenue requirements under FERC approved agreements
  - Continue to collect under those agreements until expiration of the contract term.
  - After the agreement expires, as an example, one half of the current tariff rate will apply until expiration of the contract term. (FERC decision)
  - After the agreement expires, as an example, the current tariff terms apply. (FERC decision)

Determinants of CRF

- Capital Recovery Factor (CRF)
  - Function of rate of return
  - Effects on CRF for 12%, 18% and 24%
  - Rate of return is a FERC decision
  - Capital will be recovered based on the remaining life of the associated generator.
  - Based on 15 year MACRS tax depreciation schedule.

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF @ 12% IRR	Levelized CRF @ 18% IRR	Levelized CRF @ 24% IRR
1 to 5	20	0.125	0.160	0.198
6 to 10	15	0.146	0.180	0.216
11 to 15	10	0.198	0.230	0.262
16 Plus	5	0.363	0.391	0.419

CRF Example

- CRF Example
  - A generator owner invests $1 million to enable a seven year old unit to provide black start service.
    - Life of the black start investment is 20 years.
    - From the CRF table, the default remaining age is 15 years.
    - Therefore assumed life of black start investment is 15 years.
    - With a 12% IRR, the resulting CRF is 0.146.
    - With a 24% IRR, the resulting CRF is 0.216
    - The annual levelized revenue requirement for the investment in the black start unit
      - With a 12% IRR is: $1M * 0.146 = $146,000 per year.
      - With a 24% IRR is: $1M * 0.216 = $216,000 per year

Issues

- Capital recovery
  - Capital recovery typically over investment life
  - Capital recovery under recent black start filings is two to five years
  - No match between payments and obligation
  - Double recovery of capital costs when combined with current tariff rate for balance of investment life
  - Resultant rates of return not explicitly considered

NPV Definition

- Net Present Value (NPV)
  - NPV is the discounted annual revenue received under each option for all the relevant years.
  - Discount rate used in example NPV calculations is 8.55 percent. (Based on a recent black start filing.)
  - NPV provides a method for comparing revenue streams that vary over time.

IRR Definition

- Internal Rate Of Return (IRR)
  - IRR is the rate of return the owner will receive on the equity investment in the project.
  - IRR is defined as the discount rate that results in the NPV of the after tax cash flow to equity being equal to the equity investment.
  - IRR provides a method for comparing the profitability of different investments.

Examples of Payment Alternatives - 1

- Col 1. Apply CRF factors (12% IRR) for 20 years
  – NPV =$925,293; IRR =12%
- Col 2. Apply CRF factors (18% IRR) for 20 years
  – NPV =$1,148,399; IRR =18%
- Col 3. Apply CRF factors (24% IRR) for 20 years
  – NPV =$1,384,050; IRR =24%

Illustration of Impacts - 1

Year	PJM Cost Based Method 12.0 % IRR	PJM Cost Based Method 18.0 % IRR	PJM Cost Based Method 24.0 % IRR
2007	$98,133	$121,795	$146,787
2008	$98,133	$121,795	$146,787
2009	$98,133	$121,795	$146,787
2010	$98,133	$121,795	$146,787
2011	$98,133	$121,795	$146,787
2012	$98,133	$121,795	$146,787
2013	$98,133	$121,795	$146,787
2014	$98,133	$121,795	$146,787
2015	$98,133	$121,795	$146,787
2016	$98,133	$121,795	$146,787
2017	$98,133	$121,795	$146,787
2018	$98,133	$121,795	$146,787
2019	$98,133	$121,795	$146,787
2020	$98,133	$121,795	$146,787
2021	$98,133	$121,795	$146,787
2022	$98,133	$121,795	$146,787
2023	$98,133	$121,795	$146,787
2024	$98,133	$121,795	$146,787
2025	$98,133	$121,795	$146,787
2026	$98,133	$121,795	$146,787
NPV	$925,293	$1,148,399	$1,384,050
IRR %	12.1%	18.0%	24.0%

Examples of Payment Alternatives - 2

- Col 1. Full capital cost recovery in 2 years
  – Tariff rate for 18 years
  – NPV =$3,044,040; IRR =117.5%
- Col 2. Full capital cost recovery in 2 years
  – One half tariff X-factor rate for 18 years
  – NPV =$2,060,003; IRR =104.6%
- Col 3. Full capital cost recovery in 5 years
  – Tariff rate for 15 years
  – NPV =$2,550,384; IRR =54.6%

Examples of Payment Alternatives - 2

- Col 4. Full capital cost recovery in 5 years
  - One half tariff X-factor rate for 15 years
  - NPV =$1,844,581 ; IRR =50.2%
- Col 5. PJM tariff rate for 20 years
  - Full PJM Tariff Formulaic Rate for 20 Years
  - NPV =$2,614,444 ; IRR =56.4%

Illustration of Impacts - 2

Year	2 Yr Offer then PJM Tariff	2 Yr Offer then One Half PJM Tariff	5 Yr Offer then PJM Tariff	5 Yr Offer then One Half PJM Tariff	Full PJM Tariff All Years
2007	$520,000	$520,000	$261,000	$261,000	$277,277
2008	$520,000	$520,000	$261,000	$261,000	$277,277
2009	$277,277	$148,797	$261,000	$261,000	$277,277
2010	$277,277	$148,797	$261,000	$261,000	$277,277
2011	$277,277	$148,797	$261,000	$261,000	$277,277
2012	$277,277	$148,797	$277,277	$148,797	$277,277
2013	$277,277	$148,797	$277,277	$148,797	$277,277
2014	$277,277	$148,797	$277,277	$148,797	$277,277
2015	$277,277	$148,797	$277,277	$148,797	$277,277
2016	$277,277	$148,797	$277,277	$148,797	$277,277
2017	$277,277	$148,797	$277,277	$148,797	$277,277
2018	$277,277	$148,797	$277,277	$148,797	$277,277
2019	$277,277	$148,797	$277,277	$148,797	$277,277
2020	$277,277	$148,797	$277,277	$148,797	$277,277
2021	$277,277	$148,797	$277,277	$148,797	$277,277
2022	$277,277	$148,797	$277,277	$148,797	$277,277
2023	$277,277	$148,797	$277,277	$148,797	$277,277
2024	$277,277	$148,797	$277,277	$148,797	$277,277
2025	$277,277	$148,797	$277,277	$148,797	$277,277
2026	$277,277	$148,797	$277,277	$148,797	$277,277
NPV	$3,044,040	$2,060,003	$2,550,384	$1,844,581	$2,614,444
IRR %	117.5%	104.6%	54.6%	50.2%	56.4%

Conclusions

- IRR for cost-based method is less than IRR for accelerated recovery options
- NPV for cost-based method is less than NPV for accelerated recovery options
- Need FERC decision as to appropriate returns for new black start investment
- Need FERC decision on double recovery of capital costs
- Need to clarify tariff to cover rates for new black start investment

Exhibit IMM-0006

Black Start Tariff Section 6.4 Proposed Changes

MIC

September 18, 2006

Market Monitoring Unit

Proposed Changes

- Ensure appropriate incentives for new black start units
- Ensure appropriate agreement term for new black start units
- Ensure appropriate cost recovery term for new black start units
- Goal is to match reasonable expected life of black start investment with cost recovery and commitment to purchase black start service

Proposed Changes

- Ensure that commitment by seller to provide black start service is consistent with life of black start investment
- Ensure that commitment by buyers to purchase black start service is consistent with life of black start investment

Proposed Changes

- New entry black start service generation revenue requirements
  - Actual fixed costs will be recovered over the remaining life of the associated generator up to a maximum of 20 years.
    - Apply CRF factors
  - Fixed costs include all fixed costs including return on and of capital.
  - Actual variable costs will be recovered on an annual basis.
  - Tariff provisions will provide for such cost recovery.
  - Owners retain option to file with the FERC.

Proposed Changes

- Owners recovering black start service generation revenue requirements for existing units under tariff rate
  - Will continue to recover costs under that structure.
- Owners recovering black start service generation revenue requirements under FERC approved agreements
  - Will continue to collect under those agreements until expiration of the contract term.
  - After the agreement expires, only variable costs will be collected.
  - After the agreement expires, there will be no additional collection of fixed costs unless new capital

Capital Recovery Methodology

- Capital Recovery Factor (CRF)
  - Capital will be recovered based on the remaining life of the associated generator.
  - Based on 15 year MACRS tax depreciation schedule.

Age of Existing Unit	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16 to 20	5	0.363

- CRF Example
  - A generator owner invests $1 million to enable a seven year old unit to provide black start service.
    - Life of the black start investment is 20 years.
    - From the CRF table, the default remaining age is 15 years.
    - Therefore assumed life of black start investment is 15 years.
    - The resulting CRF is 0.146.
    - The annual levelized revenue requirement for the investment in the black start unit is:

      $1 million * 0.146 = $146,000 per year.

Exhibit IMM-0007

Review of Black Start Formula and Cost Components

Laura Walter, PJM

June 2011

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Black Start: Executive Summary

Black Start Service is the ability of generating units to start without an outside electrical supply or the demonstrated ability of a generating unit with a high operating factor (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid.

PJM's Open Access Transmission Tariff, relating to Black Start Service, requires PJM to review the formula and cost components utilized to compensate Black Start Service providers at least every two years. Specifically, Schedule 6A: Section 18 states:

> ***At least every two years, PJM shall review the formula and its costs components set forth in this section, and report on the results of that review to stakeholders.*** [i]

This paper is the report required by the tariff, a review of the components and formulas in the current approved version of Schedule 6A: Section 18. **This report is not a review of the annual revenue requirements calculated by the tariff and whether the compensation black start units receive is adequate to keep the unit in black start service and maintain it reliably.**

Areas that require further consideration in this report include; possible update to the CRF table, the Fixed Black Start Service Cost (FBSSC) for units not requesting capital recovery costs under Section 5, more specific definitions to clarify and provide guidance when calculating cost for units requesting capital recovery costs under section 6 and the clarification of fuel storage cost to remove any interpretation from the tariff.

Black Start: Total Revenue Requirements

Black start service supplies electricity for system restoration in the unlikely event that the entire PJM Interconnection grid would lose power. In the event that power would be lost across the entire grid, black start service is be used to supply electricity to help restore the system. Black start service is provided by generating units that have the ability to start up and deliver power to the grid without an outside source of power – or units that can remain in operation at reduced output levels when disconnected from the grid. Such units must be able to reconnect to the grid within 90 minutes after a request from PJM. They also must be able to maintain frequency and voltage under varying loads. To be designated as a black start resource, a generating facility must pass a series of performance tests every 13 months. In a system-restoration situation, black start units can be used to reestablish the regional electric system. Once connected, they supply power to other generating units and help restore load. This must be a careful, deliberate process that keeps generation in balance with load in order to avoid the possibility of another loss of service.

The owners of black start units receive cost-based payments for providing the service to the grid. Schedule 6A section 18 outlines the formulas used to calculate the revenue requirements. The primary formula is as follows:

$$\text{Generator's Annual Black Start Service Revenue Requirement} = \\ \{\text{Fixed BSSC} + \text{Variable BSSC} + \text{Training Costs} + \text{Fuel Storage Costs}\} * (1 + \text{Z})$$

Where:

- Fixed BSSC = Fixed Black Start Service Cost
- Variable BSSC = Variable Black Start Service Costs
- Training Costs = $3,750 per plant per delivery year (50 staff hours per plant per year *$75 per staff hour)
- Fuel Storage Cost is the cost defined in the tariff for oil units with onsite storage (discussed below)
- Z= the incentive factor of 10%

The total revenue requirements are the amount of compensation a black start unit receives per delivery year if it fulfills all the black start requirements under the tariff. This amount is allotted monthly, and may change every delivery year (June 1 – May 31). PJM records the tests of all black start units receiving compensation through the PJM tariff and alerts PJM Settlements to stop payment if requirements are not met.

Automatic Load Rejection Units (ALR) or Units with a High Operating Factor

Automatic Load Rejection Units are generating units with a high operating factor that have demonstrated the ability (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid. These units can be considered black start where appropriate, but they do not receive the same black start payments as black start units that start without an outside electrical supply. The revenue requirements for ALR units are as follows[ii]:

$$\text{ALR Generator's Annual Black Start Service Revenue Requirement} = \\ \text{Training Costs} * (1 + \text{Z})$$

- Where Z is a 10% incentive factor
- Training costs are calculated as 50 staff hours per plant per year *$75 per staff hour = $3,750 per plan per delivery year

For ALR units, the total annual compensation from black start is $4,125 per plant per delivery year.

Fixed Black Start Service Cost (FBSSC)

Fixed Black Start Service Cost are calculated in two possible ways depending on whether the unit is recovering costs under section 5[iii] or Section 6[iv] of Schedule 6A with the central difference being whether the black start unit owner seeks to recover new or additional capital costs through application of the Schedule 6A formula rate. The following figure shows the 2 methods for recovery of Fixed BSSC.

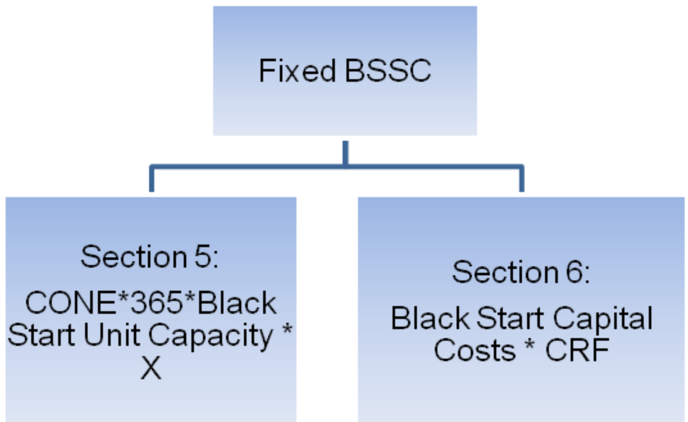

Figure 1: Two methods to recover fixed black start costs per Schedule 6A

If units recover Fixed BSSC through Schedule 6A, section 5, they are electing to forgo any recovery of black start capital costs and fall into the lower left-hand box above. If units prefer to recover through Schedule 6A, Section 6, then they do submit capital costs for recovery and fall into the lower right-hand box above.

<u>Section 5 Fixed Black Start Service Cost for Units not requesting Capital Cost Recovery</u>

For units recovering costs under Section 5 and not recovering black start capital costs, Fixed Black Start Service Costs are defined below:

Where CONE is equal to "then current net Cost of New Entry for the CONE Area where the Black Start Unit is located as set forth in Section 5.10 of Attachment DD". These are the CONE areas set forth in Attachment DD:

Geographic Location Within the PJM Region Encompassing These Zones	Cost of New Entry in $/MW-Year
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	122,040
BGE, PEPCO ("CONE Area 2")	112,868
AEP, Dayton, ComEd, APS, DQL ("CONE Area 3")	115,479
PPL, MetEd, Penelec ("CONE Area 4")	112,868
Dominion ("CONE Area 5")	112,868

The formula refers to a table with gross CONE in $-MW-year, but is referring only to the five CONE areas in the 2013-2014 delivery year. The use of UCAP CONE or ICAP CONE is not specified. Cost of New Entry is a Reliability Pricing Model (RPM) parameter and is related to the cost to build a GE Frame 7F in an area specified above. As CONE values used in planning parameters are calculated before Base Residual Auctions (BRA), the CONE values are three years old during the "current" delivery year in which the black start units are paid. The five CONE areas listed here are not applicable to every delivery year.

The net CONE is then multiplied by 365 so as to convert the $/MW-day net CONE value to a $/MW-year value. It is PJM staff opinion that units of measurements should be explicit in this formula to avoid confusion.

The Black start unit capacity is defined, as the installed capacity (ICAP).

The term X is:

> *the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For Black Start Units with a commitment established under section 5, X shall be .01 for Hydro units, .02 for Diesel or CT units.*

PJM staff would recommend changing "Hydro" to include "Storage Units".

Section 6 Fixed Black Start Service Cost for Units requesting Capital Cost Recovery

$$\text{Black Start Capital Cost Recovery} =$$

$$\text{Capital Costs for incremental equipment solely necessary for Black Start} * \text{CRF}$$

For units recovering black start capital costs under Section 6, Fixed Black Start Service Costs are defined below:

> *"Black Start Capital Costs" is the capital cost documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit.*

This section (Black Start Capital Costs) should be well defined to clarify what is meant by the statement, "for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide".

This statement could be interpreted in different ways – for example it could refer to s to only the equipment required to allow the unit to be black start capable, such as a diesel generator, air starter, batteries, or specific control functions. This section could also imply that the entire generating unit could be replaced or repaired through Schedule 6A. This ambiguity needs to be clarified.

"CRF" or "Capital Recovery Factor" includes age and years of remaining life, but the tariff specifies that the CRF is based on "the age of the unit."

Age of Black Start Unit	Years of Remaining Life of Black Start Unit	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

The CRF table has several different assumptions such as: the Capital Recovery Factor based on a levelized proforma for a 100MW Combustion Turbine for $1M, 2.5% inflation, 36% federal tax rate, 9% state tax rate, income tax rate 41%, 50% equity and 50% debt with a 7% interest rate, and a 12% internal rate of return on equity.

This CRF table was originally taken from the capacity market, and the capacity market CRF table has since been updated to the following:

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	30	0.107
6 to 10	25	0.114
11 to 15	20	0.125
16 to 20	15	0.146
21 to 25	10	0.198
25 Plus	5	0.363
Mandatory CapEx	4	0.450
40 Plus Alternative	1	1.100

[v]

Whether this is a more appropriate fit for the CRF table for Black Start should be explored.

Variable Black Start Service Cost (VBSSC)

$$\text{Variable Black Start Service Cost} = \text{Black Start Unit O\&M} * \text{Y}$$

O&M is the Operating and Maintenance Cost that is calculated for all cost offers through following Manual 15: Cost Development Guidelines. Y is 1% of the total annual O&M.

Training Cost

$$\text{Training Costs} = 50 \text{ staff hours/year/plant} * \$75/\text{hour}$$

$75 is a fixed rate written into the tariff that does not change with inflation or other economic indicators. This currently does not seem to be an inadequate amount. This cost is independent of the number of people trained, how many do restoration drills, and the cost of training to determine the true cost for training.

Fuel Storage Cost

$$\text{Fuel Storage Costs} =$$

$$(\text{Minimum Tank Suction Level} + (\text{\# of Run Hours Required} * \text{Fuel Burn Rate})) * (\text{12 month forward strip} + \text{basis}) * \text{Bond Rate}$$

PJM staff believes units of measure in this component should be explicit. For the 12 month forward strip and bond rate, the value from May 1 every year should be used to keep recovery consistent across resources. Determination of basis should also be defined.

Conclusion

The areas that require further consideration include; possible update to CRF table, the Fixed Black Start Service Cost (FBSSC) for units not requesting capital recovery costs under Section 5, more specific definitions to clarify and provide guidance when calculating cost for units requesting capital recovery costs under Section 6 and the clarification of fuel storage cost definitions should be clarified to remove any interpretation from the tariff.

Potential Parking Lot Items

- Fixed Black Start Service Cost (FBSSC) Formula Clarifications
- Evaluation of CRF table
- Fuel Storage Cost Clarifications

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[i] http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx page 512

[ii] http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx page 509

[iii] Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to forego any recovery of new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for an initial term of no less than two years and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. The term commitment shall continue to extend until the Black Start Unit owner, or the Transmission Owner, with the consent of the Transmission Provider, or the Transmission Provider, with the consent of the Transmission Owner, provides written, one-year advance notice of its intention to terminate the commitment.

[iv] Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to recover new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for a term based upon a reasonable estimate of the expected life of the Black Start Unit, as set forth in the CRF Factor Table in section 18, and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. Either the Transmission Provider, with the consent of the Transmission Owner, or the Transmission Owner, with the consent of the Transmission Provider, may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Transmission Owner shall reimburse the Black Start Unit owner for any amount of unrecovered Fixed Black Start Service Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice (or its commitment period may be involuntarily terminated pursuant to the section 15 below). Such Black Start Unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i)) in excess of the amount that would have been recovered pursuant to section 18 during the same period. At the conclusion of the term of commitment established under this section 6, a Black Start Unit shall commence a new term of commitment under either section 5 or 6, as applicable.

[v] http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx Page 2267

Exhibit IMM-0008

Review of Black Start Formula and Cost Components

Thomas Hauske, PJM

December 2014

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Black Start: Executive Summary

Black Start Service is used to restart the grid after a loss of electrical service and is needed because most generators require electricity to start. Traditional black start is the ability of generating units to start without an outside electrical supply. Another type of black start unit is an Automated Load Rejection (ALR) unit that is a generator with a high operating factor and the demonstrated ability [1]to automatically remain operating at reduced levels when disconnected from the grid.

The PJM Open Access Transmission Tariff (tariff) [2] requires PJM to review the formula and cost components utilized to compensate Black Start Service providers at least every two years. Specifically, Schedule 6A: Section 18 states:

> *At least every two years, PJM shall review the formula and its costs components set forth in this section, and report on the results of that review to stakeholders.*[3]

This paper describes in document form the report given on Black Start Compensation at the May 7, 2013 System Restoration Strategy Senior Task Force[4] that is required by the tariff with a review of the components and formulas for black start compensation. This report also documents the System Restoration Strategy Task Force's (SRSTF) review of black start compensation modifications that were discussed from February 2013 to September 2014, with submittals of minor compensation changes to the Federal Energy Regulatory Commission (FERC) for approval. The FERC approved the recommended compensation changes on November 14, 2014.

[1] Subject to Transmission Provider concurrence
[2] http://www.pjm.com/~/media/documents/agreements/tariff.ashx
[3] The most recent Tariff changes approved by FERC on November 14,2014 changed the review cycle to five (5) years.
[4] http://www.pjm.com/~/media/committees-groups/task-forces/srstf/20140522/20140522-item-02-bs-compensation-changes.ashx

Black Start: Current Total Revenue Requirements

Black start service supplies electricity for system restoration in the unlikely event that the entire PJM Interconnection grid would lose power. In the event that power would be lost across the entire grid, black start service is be used to supply electricity to help restore the system. Black start service is provided by generating units that have the ability to start up and deliver power to the grid without an outside source of power – or units that can remain in operation at reduced output levels when disconnected from the grid. Such units must be able to reconnect to the grid within 180 minutes after a request from PJM. They also must be able to maintain frequency and voltage under varying loads. To be designated as a black start resource, a generating facility must pass a series of performance tests every 13 months. In a system-restoration situation, black start units can be used to reestablish the regional electric system. Once connected, they supply power to other generating units and help restore load. This must be a careful, deliberate process that keeps generation in balance with load in order to avoid the possibility of another loss of service.

The owners of black start units receive cost-based payments for providing the service to the grid. A generator's Annual Black Start Service Revenue Requirement is the amount of compensation a black start unit receives per delivery year if it fulfills all the black start requirements under the tariff. The PJM tariff outlines the formulas used to calculate the revenue requirements.

Traditional Black Start Units

The primary formula to calculate a traditional black start generator's Annual Black Start Service Revenue Requirement can be found in the tariff, Section 18 of Schedule 6A is as follows:

$$\text{Generator's Annual Black Start Service Revenue Requirement} = \\ \{\text{Fixed BSSC} + \text{Variable BSSC} + \text{Training Costs} + \text{Fuel Storage Costs}\} * (1 + \text{Z})$$

Where:

- Fixed BSSC = Fixed Black Start Service Cost
- Variable BSSC = Variable Black Start Service Costs
- Training Costs = $3,750 per plant per delivery year (50 staff hours per plant per year multiplied by $75 per staff hour)
- Fuel Storage Cost is the cost defined in the tariff for oil units with onsite storage (discussed below)
- Z= the incentive factor of 10 percent

The Annual Black Start Service Revenue Requirements is allotted monthly, and may change every delivery year (June 1 – May 31). PJM records the tests of all black start units receiving compensation through the PJM tariff and alerts PJM Settlements to stop payment if requirements are not met.

Automatic Load Rejection Units (ALR) or Units with a High Operating Factor

Automatic Load Rejection Units are generating units with a high operating factor that have demonstrated the ability (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid. These units can be considered black start where appropriate, but they do not receive the same black start payments as black start units that start without an outside electrical supply. The revenue requirements for ALR units are as follows[5]:

$$\text{ALR Generator's Annual Black Start Service Revenue Requirement} = \text{Training Costs} * (1 + \text{Z})$$

- Where Z is a 10 percent incentive factor
- Training costs are calculated as 50 staff hours per plant per year multiplied by $75 per staff hour = $3,750 per plan per delivery year

For ALR units, the total annual compensation from black start is $4,125 per plant per delivery year.

Fixed Black Start Service Cost (FBSSC)

Fixed Black Start Service Cost can be recovered through the PJM tariff or through a FERC approved rate. Fixed Black Start Service Costs recovered through the tariff are calculated in three possible ways depending on whether the unit is recovering costs under Paragraph 5[6] or Paragraph 6[7] of Schedule 6A with the central difference being whether the black start unit owner seeks to recover new or additional capital costs. The following figure shows the three methods for recovery of Fixed BSSC.

[5] http://www.pjm.com/documents/~/media/documents/agreements/tariff.ashx page 509

[6] Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to forego any recovery of new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for an initial term of no less than two years and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. The term commitment shall continue to extend until the Black Start Unit owner, or the Transmission Owner, with the consent of the Transmission Provider, or the Transmission Provider, with the consent of the Transmission Owner, provides written, one-year advance notice of its intention to terminate the commitment.

[7] Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 and electing to recover new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for a term based upon a reasonable estimate of the expected life of the Black Start Unit, as set forth in the CRF Factor Table in section 18, and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. Either the Transmission Provider, with the consent of the Transmission Owner, or the Transmission Owner, with the consent of the Transmission Provider, may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Transmission Owner shall reimburse the Black Start Unit owner for any amount of unrecovered Fixed Black Start Service Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice (or its commitment period may be involuntarily terminated pursuant to the section 15 below). Such Black Start Unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i)) in excess of the amount that would have been recovered pursuant to section 18 during the same period. At the conclusion of the term of commitment established under this section 6, a Black Start Unit shall commence a new term of commitment under either section 5 or 6, as applicable.

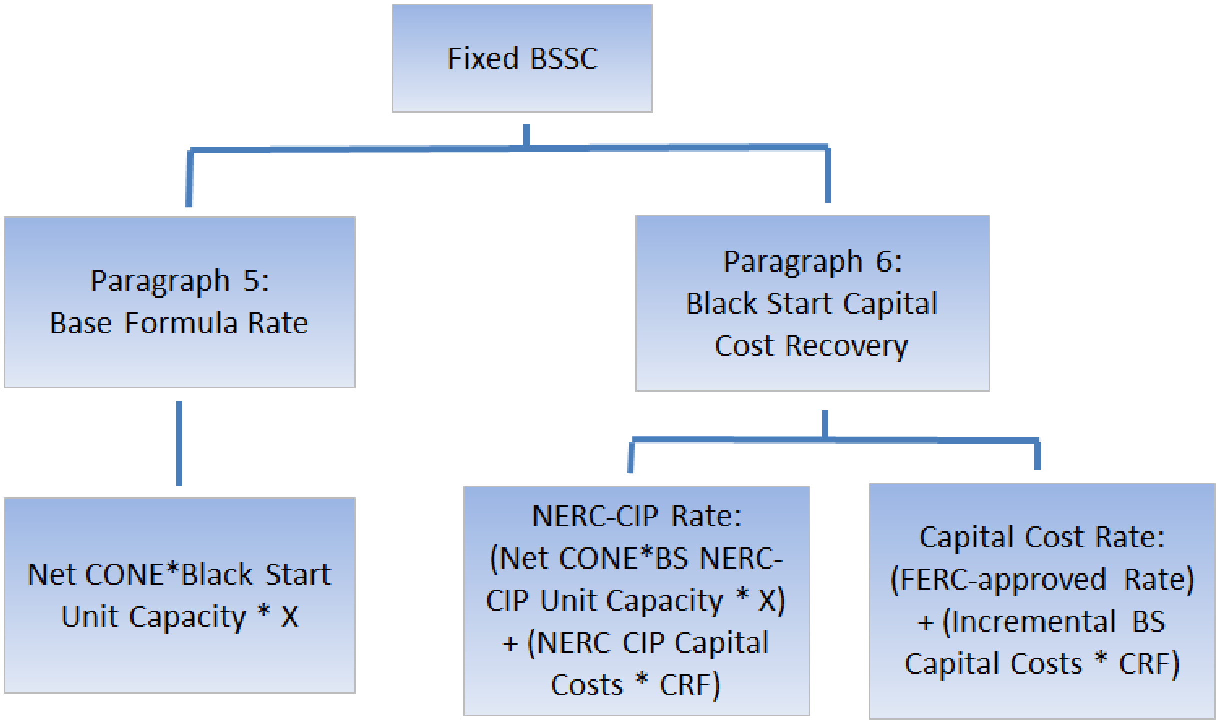

Figure 1: Three methods to recover fixed black start costs per Schedule 6A

If units recover Fixed BSSC through Paragraph 5, they are electing to forgo any recovery of black start capital costs and fall into the lower left-hand box above. If units prefer to recover through Paragraph 6, then they do submit capital costs for recovery and fall into the lower two right-hand boxes above. Units recovering costs under a FERC approved rate can also recover new or additional black start capital costs through the PJM tariff and fall into the lower right hand box.

<u>Paragraph 5 Fixed Black Start Service Cost for Units not requesting Capital Cost Recovery</u>

For units recovering costs under Paragraph 5, Fixed Black Start Service Costs are calculated using the Base Formula Rate below:

$$\text{Fixed BSSC} = \text{Net CONE} * \text{Black Start Unit Capacity} * X$$

Where Net CONE is "*the then current installed capacity ("ICAP") net Cost of New Entry (expressed in \$/MW year) for the CONE Area where the Black Start Unit is located*". The CONE areas and values for the 2014-2015 delivery year are:

	TO Zones within Cone Area	2014-2015 Cost of New Entry in $/MW - Year
CONE Area 1	PS, JCP&L, AE. PECO, DPL, RECO	94,108
CONE Area 2	BGE, PEPCO	82,778
CONE Area 3	AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC	123,655
CONE Area 4	PPL, MetEd, Penelec	97,455
CONE Area 5	Dominion	90,487

Black Start Unit Capacity is defined, as "*the Black Start Unit's installed capacity, expressed in MW*."

The term X is defined as *"the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For Black Start Units with a commitment established under paragraph 5, X shall be .01 for Hydro units, .02 for Diesel or CT units."*

Paragraph 6 Fixed Black Start Service Cost for Units requesting Capital Cost Recovery

For units recovering NERC-CIP black start capital costs under Paragraph 6, Fixed Black Start Service Costs are calculated using the following equation:

Fixed BSSC = (Net CONE * Black Start NERC-CIP Unit Capacity * X)
+ (Incremental Black Start NERC-CIP Capital Costs * CRF)

Where Net CONE is "*the then current installed capacity ("ICAP") net Cost of New Entry (expressed in $/MW year) for the CONE Area where the Black Start Unit is located*".

Black Start NERC-CIP Unit Capacity is *"the Black Start Unit's installed capacity, expressed in MW, but, for the purposes of this calculation, capped at 100 MW for Hydro units, or 50 MW for CT units."*

The term X is defined as *"the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For Black Start Units with a commitment established under paragraph 5, X shall be .01 for Hydro units, .02 for Diesel or CT units."*

Incremental Black Start NERC-CIP Capital Costs are defined as *" those capital cost documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a Black Start Unit to maintain* *compliance with mandatory Critical Infrastructure Protection Reliability Standards (as approved by the Commission and administered by the applicable Electric Reliability Organization ".*

"CRF" or "Capital Recovery Factor" is equal to the levelized CRF as set forth in the applicable CRF Table set forth below.

For units recovering incremental black start capital costs under Paragraph 6, Fixed Black Start Service Costs are calculated using the following equation;

Fixed BSSC = (FERC-approved rate) + (Incremental Black Start Capital Costs * CRF)

"FERC-approved rate" is "*the Black Start Unit's current FERC-approved recovery of costs to provide Black Start Service, if applicable. To the extent that a Black Start unit owner is currently recovering black start costs pursuant to a FERC-approved rate, which cost recovery will be included as a formulaic component for calculating the Black Start Unit's annual revenue requirement pursuant to this paragraph 18. However, under no circumstances will PJM or the Black Start Unit owner restructure or modify that existing FERC-approved rate without FERC approval."*

Incremental Black Start Capital Costs are defined as *the new or additional capital cost documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit. However, incremental Black Start Capital Costs shall not include any capital costs that the Black Start unit owner is recovering for that unit pursuant to a FERC-approved recovery rate."*

"CRF" or "Capital Recovery Factor" is "*equal to the Levelized CRF based on the age of the Black Start Unit, which is modified to provide Black Start Service, as present in the CRF Table below:"*

Age of Black Start Unit	Years of Remaining Life of Black Start Unit	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

The CRF table has several different assumptions such as: the Capital Recovery Factor based on a levelized proforma for a 100MW Combustion Turbine for $1M, 2.5 percent inflation, 36 percent federal tax rate, 9 percent state tax rate, income tax rate 41 percent, 50 percent equity and 50 percent debt with a 7 percent interest rate, and a 12percent internal rate of return on equity.

Optionally, a Black Start unit owner may elect to apply an alternative Capital Recovery Factor (CRF), in lieu of the age-based CRF table listed above, which is based upon the expected capital Improvement Lifespan of the new or additional capital improvements (as determined by the applicable depreciation period of the capital improvement, as published from time to time by the US Internal Revenue Service).The Applicable Recovery Period and the term of

Black Start Service Commitment shall be the same and determined by the expected Capital Improvement Lifespan. In the event that the Black Start unit seeks recovery of capital improvements that are included in more than one category of Capital Improvement Lifespan (as set forth below), its Applicable Recovery period and term of commitment to provide black start service for such Black Start unit shall be the longest expected life of those new or additional capital improvements.

Capital Improvement Lifespan (years)	Applicable Recovery Period/Term of Commitment (years)	Levelized CRF
16-20	20	0.125
11-15	15	0.146
6-10	10	0.198
1-5	5	0.363

In those circumstances where a Black Start Unit owner has elected to recover incremental Black Start Capital Costs, in addition to a FERC-approved recovery rate, its applicable term of commitment shall be the greater of: (i) the FERC-approved recovery period, or (ii) the applicable term of commitment as established by the CRF Tables above.

After a Black Start Unit has recovered its allowable Incremental Black Start Capital Costs or Incremental Black Start NERC-CIP Capital Costs, as provided by the applicable Capital Cost Recovery Rate, and has satisfied its applicable commitment period required under Schedule 6A: Paragraph 6, the Black Start Unit shall be committed to providing black start in accordance with Paragraph 5 of Schedule 6A and calculate its Fixed BSSC in accordance with the Base Formula rate.

Variable Black Start Service Cost (VBSSC)

$$\text{Variable Black Start Service Cost} = \text{Black Start Unit O\&M} * \text{Y}$$

Where Black Start Unit O&M is*" the operations and maintenance cost attributable to supporting Black Start Service and must equal the annual variable O&M outlined in the PJM Cost development Guidelines set forth in the PJM Manuals. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to a Black Start unit solely on the basis of the provision of Black Start Service by the unit."*

Y is "*unless a higher or lower value is supported by documentation of costs. If a value of Y is submitted for this cost, a (1-Y) factor must be applied to the Black Start unit's O&M costs on the unit's cost-based energy schedule, calculated based on the Cost Development Guidelines in the PJM Manuals"*

For unit qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid (ALR), there are no variable costs associated with providing Black Start Service and the value for Variable BSSC shall be zero.

Training Cost

$$\text{Training Costs} = 50 \text{ staff hours/year/plant} * \$75/\text{hour}$$

Fuel Storage Cost

Black Start Units that do not use oil as their fuel must set their Fuel Storage Costs to zero. Black Start units that can use oil for fuel shall calculate Fuel Storage Costs as:

$$\text{Fuel Storage Costs} =$$

$$(\text{Minimum Tank Suction Level} + (\text{\# of Run Hours Required} * \text{Fuel Burn Rate})) * (\text{12 month forward strip} + \text{basis}) * \text{Bond Rate}$$

Where Minimum Tank Suction Level is *"and shall apply where no direct current pumps are available for the black Start Unit"*.

Number of Run Hours are *"the actual number of hours a transmission provider requires a Black Start Unit to run. Run Hours shall be at least 16 hours or as defined by the Transmission Owner restoration plan, whichever is less".*

Fuel Burn rate is *"actual fuel burn rate for the Black Start Unit"*.

12 Month Forward Strip is *"the average of forward prices for the fuel burned in the Black Start unit traded the first business day on or following May 1"*.

Basis is *"the transportation costs from the location referenced in the forward price data to the Black Start unit plus any variable taxes".*

Bond rate is *"the value determined with reference to the Moody's Utility Index for bonds rated BAA1 reported the first business day on or following May 1".*

Z Factor

The Z factor shall be an incentive factor solely for Black Start Units with a commitment established under Schedule 6A Paragraph 5 and shall be ten percent. For those Black Start units that elect to recover new or additional Black Start Capital Costs under Paragraph 6, the incentive factor (Z), shall be equal to zero.

SRSTF Black Start Proposed Revenue Requirements Changes

Black Start: System Restoration Strategy Task Force (SRSTF)

The PJM System Restoration Strategy Task Force was created to analyze and evaluate PJM's System Restoration plan and utilization of Black Start generation during a System Restoration as directed by the Markets and Reliability Committee.[8]

The SRSTF reviewed the existing black start compensation methods contained in PJM's tariff on May 7, 2013[9] and considered four different black start compensation proposals:[10]

A. Modified Status Quo + Revised Incentives
B. Proxy for Formula Replacement
C. Cost Allocation
D. Minimum Incentive

The Minimum Incentive (D) became the primary and the Proxy for Formula Replacement (B) became the secondary. Both proposals were forwarded to the Markets and Reliability Committee (MRC) and proposals failed a sector weighted vote at the February 27, 2014 meeting.[11]

The SRSTF then considered several minor changes to Black Start unit compensation. These changes impact a small number of Black Start units and are seen more as "clean-up" or "equity" issues as opposed to any major changes to the method of compensation for Black Start units. The task force also looked at potential changes to cost allocation, but is not recommending any changes to the existing Black Start cost allocation methodology. The Minor Compensation Proposal was forward to the MRC and approved July 31, 2014[12] and submitted to FERC for approval

[8] The System Restoration Strategy Senior Task force (SRSTF) charge:

Due to industry developments such as new environmental regulations, NERC CIP (Critical Infrastructure Protection) standards and increasing cost of Black Start generation, PJM foresees a potential future reliability issue with the current method of System Restoration Planning. This Task Force will examine the current System Restoration Planning process to determine its viability and efficiency moving forward and recommend any changes to the System Restoration strategy and associated procurement, cost allocation, and compensation methods, inclusive of back stop options to the MRC for approval. - http://www.pjm.com/~/media/committees-groups/task-forces/srstf/postings/charter.ashx

[9] http://www.pjm.com/~/media/committees-groups/task-forces/srstf/20130507/20130507-black-start-compensation.ashx

[10] http://www.pjm.com/~/media/committees-groups/task-forces/srstf/20131122/20131122-compensation-back-stop-matrix.ashx

[11] http://www.pjm.com/~/media/committees-groups/committees/mrc/20140327/20140327-item-01-draft-20140227-meeting-minutes.ashx

[12] http://www.pjm.com/~/media/committees-groups/committees/mrc/20140821/20140821-item-01-draft-minutes-mrc-20140731.ashx

on September 15, 2014[13]. One of the changes included in the proposal extended the Schedule 6A review period from two years to five years to align with the RTO Wide Black Start RFP.

Main Proposal – Minimum Incentive Compensation Proposal

This proposal received 66 percent support from the SRSTF. The significant change in this proposal would be to change the incentive factor in the Black Start Base Formula Rate from 10 percent to the greater of 10 percent or $25,000. The existing Capital Recovery Rate and NERC CIP Capital Recovery Rates would not change. Other more minor changes included in this proposal include:

- The Black Start Capacity MW amount would be based on the offered Black Start MW for energy only units and the ICAP for capacity units
- ALR units would be permitted to recover NERC Compliance costs as documented to the Independent Market Monitor
- Would allow compensation for fuel storage to include fuels other than oil
- Would provide for a five year PJM internal review of revenue formulas

Alternate Proposal – Proxy for Formula Replacement

This proposal received 63 percent support from the SRSTF. The significant change in this proposal would be to replace the Black Start Base Formula Rate and components with a Proxy formulation. This proxy was developed based on the average of the responses received from the RTO-wide and Incremental Request for Proposal (RFP) submittals. The Proxy rate would replace the Base Formula Rate, Variable Operating and Maintenance (VOM) Costs, Fuel Storage and Training Costs. The existing Capital Recovery Rate and NERC CIP Capital Recovery Rates would not change. The Proxy rates are shown in the table below:

Black Start Resource Size	Initial Capital Payment to add Black Start (from RFP Responses)	Additional Black Start Resource Capital Payment (From RFP Responses)	Annual Black Start Capital Payment (using 0.125 CRF)	Additional Resource Annual Black Start Capital Payment	Annual Black Start O&M Payment (from RFP Responses)	Annual Black Start Fuel Storage Payment (from RFP Responses)	Unit Total Annual Black Start Payment (including Training)
MW <= 10*	$275,798	$105,871	$34,475	$13,234	$3,351	$6,280	$47,855
10 > MW <= 60	$1,930,588	$741,097	$241,323	$92,637	$23,456	$43,957	$312,486
60 > MW <= 90	$5,069,227	$1,258,927	$633,653	$157,366	$37,572	$64,152	$739,127
90 > MW <=300 Small Starting requirement	$6,861,848	$1,953,800	$857,731	$244,225	$182,896	$87,700	$1,132,077
90 > MW <=300 Medium Starting Requirement	$16,918,852	$1,953,800	$2,114,856	$244,225	$182,896	$87,700	$2,389,202
90 > MW <=300 Large Starting Requirement	$24,552,399	$1,953,800	$3,069,050	$244,225	$182,896	$87,700	$3,343,395

* No Data from RFP Responses. Assumed 5/35 of 10 > MW<= 60 MW Values

The proposal would also provide for a five year PJM internal review of this formulation.

Comparative Summary

The objective of both proposals is to provide more incentive for the existing Black Start resources (which are currently on the Base Formula Rate) to continue to provide this service. This provides for continuity and flexibility in Restoration Planning and provides more assurance of an adequate supply of Black Start generation to meet critical load needs.

[13] http://www.pjm.com/~/media/documents/ferc/2014-filings/20140915-er14-2883-000.ashx

Neither proposal changes the Capital Recovery Factors which are used for new capital investments for Black Start units as there was general agreement on the task force that the Capital Recovery Factors provides sufficient incentive to attract new Black Start resources.

Both proposals would increase the cost of Black Start Service in the RTO. The Proxy for Formula Replacement would increase costs more significantly than the Minimum Incentive proposal. Estimated cost impact for each proposal over existing rates is shown below:

Transmission Zone	Revenue Requirement 9/1/2011	Revenue Requirement 9/1/2012	Revenue Requirement 9/1/2013	Minimum Incentive	RTO & Incremental RFP Proxy Cost
AECO	$587,375.76	$612,749.80	$659,039.18	$849,126.54	$2,210,244.00
AEP	$641,304.41	$1,065,072.31	$713,841.68	$1,100,196.98	$1,955,964.00
APS	$163,108.11	$263,640.01	$293,618.98	$391,926.34	$885,337.00
ATSI	$110,933.66	$170,352.21	$121,530.86	$160,482.60	$624,972.00
BGE	$3,258,715.57	$8,220,357.01	$5,212,388.17	$5,299,327.26	$6,894,242.76
COMED	$3,607,130.48	$5,175,988.79	$4,394,846.18	$4,558,736.61	$5,233,355.84
DAY	$166,374.93	$245,123.31	$259,735.15	$436,122.86	$1,061,523.00
DEOK		$331,699.42	$1,211,017.72	$1,216,925.45	$1,674,002.69
DOM			$1,069,397.17	$1,069,397.17	$1,069,397.17
DPL	$534,124.05	$543,207.62	$587,724.57	$1,009,295.07	$2,938,570.00
DUQ	$40,729.08	$53,404.09	$61,788.81	$61,788.81	$61,788.81
EKPC			$387,247.88	$402,043.52	$869,913.00
JCPL	$541,191.23	$328,467.96	$608,508.56	$626,403.28	$1,726,848.68
METED	$541,937.33	$478,493.70	$897,429.93	$897,617.32	$897,617.32
PECO	$1,266,963.40	$1,379,460.78	$1,548,942.76	$2,108,129.78	$7,316,155.00
PENELEC	$367,061.09	$573,457.48	$525,051.98	$535,152.14	$1,557,651.75
PEPCO	$462,700.00	$212,074.47	$325,972.27	$325,972.27	$325,972.27
PPL	$157,515.64	$152,847.12	$251,989.60	$569,078.44	$1,814,081.00
PSEG	$3,858,641.94	$2,673,261.66	$1,867,588.19	$2,806,728.73	$3,533,143.00
PJM TOTAL	**$16,305,806.68**	**$22,479,657.74**	**$20,997,659.64**	**$24,424,451.18**	**$42,650,779.31**

Note – Values in the table above applied the two proposals to the existing Black Start costs as September 1, 2013. These costs will vary in the future as some existing Black Start units retire and new Black Start units are selected through the RTO-wide Black Start RFP process.

Markets and Reliability Committee Actions

Both proposals failed a sector weighted vote at the Markets and Reliability Committee (MRC) meeting on February 27, 2014[14]. The SRSTF continued to work on abridged compensation proposal and forwarded the Minor Compensation Changes with Limited Fuel Storage to the MRC for approval. This proposal was endorsed in the July 31, 2014 MRC meeting[15].

Minor Compensation Changes with Limited Fuel Storage Proposal

The SRSTF looked at several minor changes to Black Start unit compensation. The Minor Compensation Changes with Limited Fuel Storage Proposal impacts a small number of Black Start units and are seen more as "clean-up" or "equity" issues as opposed to any major changes to the method of compensation for Black Start units. The task force also looked at potential changes to cost allocation, but did not recommend any changes to the existing Black Start cost allocation methodology.

[14] http://www.pjm.com/~/media/committees-groups/committees/mrc/20140327/20140327-item-01-draft-20140227-meeting-minutes.ashx
[15] http://www.pjm.com/~/media/committees-groups/committees/mrc/20140821/20140821-item-01-draft-minutes-mrc-20140731.ashx

The Compensation proposal described below received 58 percent support at the SRSTF. No other compensation proposal received the required 50 percent approval at the SRSTF to move it forward to the MRC for consideration.

The changes include:

- Allowing Energy Only Black Start units to be compensated using the offered Black Start MW.
    - Justification: Currently Black Start units on the base formula rate are compensated based on ICAP values. There is no mechanism to compensate Energy Only Black Start units on the base formula rate for providing this service.
- Allow Automatic Load Rejection (ALR) units to recover NERC Compliance costs as documented to the IMM.
    - Justification: This would allow ALR units to recover NERC Compliance costs and be comparable with traditional Black Start units in the ability to recover these costs.
- Allow for fuel storage compensation for liquefied natural gas (LNG), propane and oil per the existing formula for fuel storage.
    - Justification: Currently only oil storage is specified in the tariff. This would allow units that use LNG or propane to comparably recover fuel storage costs associated with providing Black Start.
- In the case where Black Start units share a common fuel tank, only one Black Start unit will be eligible for recovery of Minimum Tank Suction Level (MTSL).
    - Justification: This is to close a loophole in the current fuel storage compensation which allows for multiple Black Start units using the same fuel tank to recover the fuel storage costs related to the minimum tank suction level.
- Provide for a five year PJM internal review of compensation formula.
    - Justification: This would align the formula review with the RTO-wide RFP process and reduce PJM staff administrative burden. Currently this review is performed every 2 years. Results of the review will be reviewed with PJM Stakeholders (either MRC or MC Webinar).

Conclusion

The SRSTF performed a thorough review of the current black start compensation in Schedule 6A of the PJM Open Access Transmission Tariff starting in February 2013. Only the minor compensation changes proposal was approved by the MRC in July 2014 and forwarded to the FERC for approval on September 15, 2014[16]. The FERC approved the minor compensation proposal on November 14, 2015.

[16] http://www.pjm.com/~/media/documents/ferc/2014-filings/20140915-er14-2883-000.ashx

Exhibit IMM-0009

Exhibit IMM-0009
Docket No. EL21-91-000, -003

Review of Black Start Formula and Cost Components

PJM Operation Analysis & Compliance Department

PJM Interconnection

October 2019

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Black Start: Executive Summary

Black Start Service is used to restart the grid after a loss of electrical service and is needed because most generators require electricity to start. Traditional black start is the ability of generating units to start without an outside electrical supply. Another type of black start unit is an Automated Load Rejection (ALR) unit that is a generator with a high operating factor and the demonstrated ability[1] to automatically remain operating at reduced levels when disconnected from the grid.

The PJM Open Access Transmission Tariff (tariff) [2] requires PJM to review the formula and cost components utilized to compensate Black Start Service providers at least every five years. Specifically, Schedule 6A: Section 18 states:

Every five years, PJM shall review the formula and its costs components set forth in this section 18, and report on the results of that review to stakeholders. [3]

This paper is intended to document the review as required by Schedule 6A, and is not intended to provide information and updates regarding the current PJM Operating Committee Special Sessions for Fuel Requirements for Black Start Resources. Current and future updates of the PJM Operating Committee Special Session for Fuel Requirements for Black Start Resources may be found via PJM's website for the PJM Operating Committee.[4]

Since the 2014 prior review of Schedule 6A, Section 18, a revision to the tariff language took effect on November 16, 2017 to clearly define the initial annual black start revenue requirement review process for new black start units. The initial review process for new black start units includes an initial annual black start revenue estimate to be collected during the document and compensation review period. This change has resulted in minimizing the potential for large after the fact black start rebilling charges to network service customers and point-to-point reservations.

During the past five years, PJM has held an RTO Wide Black Start Request for Proposal and four Black Start Incremental Request for Proposals with three completed and one currently under review. Generator Owner interest and black start service bidding remains active with multiple RFP responses. As a result, PJM is not recommending modifications to the current version of Schedule 6A, Section 18.

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[1] Subject to Transmission Provider concurrence
[2] https://agreements.pjm.com/oatt/3897
[3] Schedule 6A Black Start Service Section 18 Effective Date: 9/1/2018
[4] https://www.pjm.com/committees-and-groups/committees/oc.aspx

Schedule 6A Changes since 2014 Review

Initial Review for New Black Start Units

On September 22, 2017, Docket No. ER17-2332-000, the Commission issued an Order accepting revisions to PJM Tariff, Schedule 6A setting forth a process for establishing the initial revenue requirement for a new Black Start Unit entering service in PJM (effective date November 16, 2017). The new process can be found in the tariff, Section 17B which allows for the submittal of new Black Start Service revenue requirements (including supporting data and documentation) to PJM and the Market Monitoring Unit for review and analysis by no later than 90 days after entering Black Start Service. The Market Monitoring Unit has a 90-day period to review the submittals and calculate the new Black Start Unit's annual revenue requirement and submit to PJM and the Black Start Unit owner. More time is allotted in the event of more than three new Black Start owner submittals. In this case, the Marketing Monitoring Unit has an additional 90 days to review the next set of three submittals and so on until complete. The Black Start Owner has 7 days to notify PJM and the Marketing Monitoring Unit if it disagrees with the Market Monitoring Unit's determination. PJM shall determine within 30 days if the values submitted by the Black Start Unit owner meet the requirements of the Tariff and PJM Manuals. If PJM does not accept the values submitted by the Black Start Unit owner, the owner may file its proposed values with the Commission for approval. If PJM accepts the Black Start Unit owner's Black Start revenue requirements, the Market Monitoring Unit may petition the Commission for an order that would require the Black Start Unit owner to utilize the values determined by the Market Monitoring Unit or PJM or such other values determined by the Commission.

During this initial period, PJM will hold the new Black Start Unit owner's monthly credits in a non-interest bearing account. Following acceptance of the new Black Start Unit owner's annual revenue requirement (per Section 17B), the Black Start owner will begin to receive monthly credits, including any monthly credits held by PJM back to the date the unit enters Black Start Service (Section 22). Zonal rates will be based on Black Start Service capability or share of generation units designated by the Transmission Provider and allocated to network service customers and point-to-point reservations. Zonal rates will include estimated annual revenue requirements as estimated by the unit entering Black Start Service. Any estimated annual revenue requirement true up will be included in the monthly bill following the acceptance of the new Black Start unit's annual revenue requirement (Section 25)

Black Start: Current Total Revenue Requirements

Black start service supplies electricity for system restoration in the unlikely event that the entire PJM Interconnection grid would lose power. In the event that power would be lost across the entire grid, black start service is to be used to supply electricity to help restore the system. Black start service is provided by generating units that have the ability to start up and deliver power to the grid without an outside source of power – or units that can remain in operation at reduced output levels when disconnected from the grid. Such units must be able to reconnect to the grid within 180 minutes after a request from the Transmission Owner (specific to the Transmission Owner's System Restoration Plan). They also must be able to maintain frequency and voltage under varying loads. To be designated as a black start resource, a generating facility must pass a series of performance tests every 13 months. In a system-restoration situation, black start units can be used to reestablish the regional electric system. Once connected, they supply power to other generating units and help restore load. This must be a careful, deliberate process that keeps generation in balance with load in order to avoid the possibility of another loss of service.

The owners of black start units receive payments for providing the service to the grid. A generator's Annual Black Start Service Revenue Requirement is the amount of compensation a black start unit receives per delivery year if it fulfills all the black start requirements under the tariff. The PJM tariff Schedule 6A outlines the formulas used to calculate the revenue requirements.

Traditional Black Start Units

The primary formula to calculate a traditional black start generator's Annual Black Start Service Revenue Requirement can be found in the tariff, Section 18 of Schedule 6A is as follows:

$$\text{Generator's Annual Black Start Service Revenue Requirement} = \{\text{Fixed BSSC} + \text{Variable BSSC} + \text{Training Costs} + \text{Fuel Storage Costs}\} * (1 + \text{Z})$$

Where:

- Fixed BSSC = Fixed Black Start Service Cost
- Variable BSSC = Variable Black Start Service Costs
- Training Costs = $3,750 per plant per delivery year (50 staff hours per plant per year multiplied by $75 per staff hour)
- Fuel Storage Cost is the cost defined in the tariff for oil units with onsite storage (discussed below)
- Z = the incentive factor of 10 percent

The Annual Black Start Service Revenue Requirements is allotted monthly, and may change every delivery year (June 1 – May 31). PJM records the tests of all black start units receiving compensation through the PJM tariff and alerts PJM Settlements to stop payment if requirements are not met.

Automatic Load Rejection Units (ALR) or Units with a High Operating Factor

Automatic Load Rejection Units are generating units with a high operating factor that have demonstrated the ability (subject to Transmission Provider concurrence) to automatically remain operating at reduced levels when disconnected from the grid. These units can be considered black start where appropriate, but they do not receive the same black start payments as black start units that start without an outside electrical supply. The revenue requirements for ALR units are as follows[5]:

$$\text{ALR Generator's Annual Black Start Service Revenue Requirement} = \text{Training Costs} * (1 + \text{Z})$$

- Where Z is a 10 percent incentive factor
- Training costs are calculated as 50 staff hours per plant per year multiplied by $75 per staff hour = $3,750 per plan per delivery year

  For ALR units, the total annual compensation from black start is $4,125 per plant per delivery year.

[5] https://agreements.pjm.com/oatt/3897

Fixed Black Start Service Cost (FBSSC)

Fixed Black Start Service Cost can be recovered through the PJM tariff or through a FERC approved rate. Fixed Black Start Service Costs recovered through the tariff are calculated in three possible ways depending on whether the unit is recovering costs under Paragraph 5[6] or Paragraph 6[7] of Schedule 6A with the central difference being whether the black start unit owner seeks to recover new or additional capital costs. The following figure shows the three methods for recovery of Fixed BSSC.

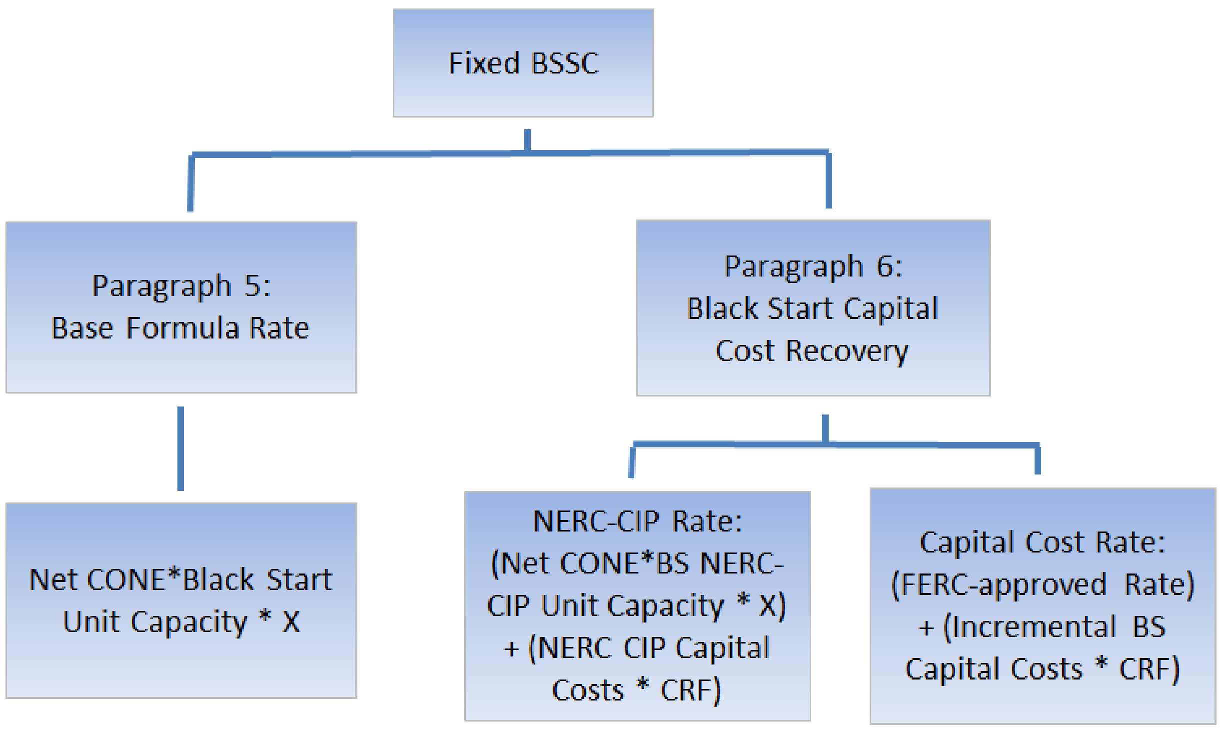

Figure 1: Three methods to recover fixed black start costs per Schedule 6A

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[6] Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 of this Schedule 6A and electing to forego any recovery of new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for an initial term of no less than two years and authorize the Transmission Provider to resell Black Start Service from its Black Start Units. The term commitment shall continue to extend until the Black Start Unit owner, or the Transmission Provider provides written, one-year advance notice of its intention to terminate the commitment or the commitment is involuntarily terminated pursuant to section 15 of this Schedule 6A.

[7] Owners of Black Start Units selected to provide Black Start Service in accordance with section 4 of this Schedule 6A and electing to recover new or additional Black Start Capital Costs shall commit to provide Black Start Service from such Black Start Units for a term based upon the age of the Black Start Unit or the longest expected life of the Incremental Black Start Capital Cost, as set forth in the applicable CRF Tables in section 18 of this Schedule 6A. For those Black Start Units that elect to recover new or additional Black Start Capital Costs in addition to a prior, FERC-approved cost recovery rate, the applicable commitment period shall be the longer of the FERC-approved recovery period or the applicable term of commitment as set forth in the CRF Tables in section 18 of this Schedule 6A. The Transmission Provider may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Black Start Unit owner shall be eligible to recover any amount of unrecovered Fixed Black Start Service Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice and consent of the Transmission Provider (or its commitment period may be involuntarily terminated pursuant to the section 15 below). Such Black Start Unit shall forego any otherwise existing entitlement to future revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate (recovered on an accelerated basis pursuant to the provisions of section 17(i) of this Schedule 6A) in excess of the amount that would have been recovered pursuant to section 18 of this Schedule 6A during the same period. At the conclusion of the term of commitment established under this section 6 of this Schedule 6A, a Black Start Unit shall commence a new term of commitment under either section 5 or 6 of this Schedule 6A, as applicable.

If units recover Fixed BSSC through Paragraph 5, they are electing to forgo any recovery of black start capital costs and fall into the lower left-hand box in Figure 1. If units prefer to recover through Paragraph 6, then they do submit capital costs for recovery and fall into the lower two right-hand boxes in Figure 1. Units recovering costs under a FERC approved rate can also recover new or additional black start capital costs through the PJM tariff and fall into the lower right hand box in Figure 1.

<u>Paragraph 5 Fixed Black Start Service Cost for Units not requesting Capital Cost Recovery</u>

For units recovering costs under Paragraph 5, Fixed Black Start Service Costs are calculated using the Base Formula Rate below:

$$\text{Fixed BSSC} = \text{Net CONE} * \text{Black Start Unit Capacity} * X$$

Where Net CONE is "*the then current installed capacity ("ICAP") net Cost of New Entry (expressed in $/MW year) for the CONE Area where the Black Start Unit is located*". The CONE areas are:

CONE Area 1: AE, DPL, JCPL, PECO, PS, RECO
CONE Area 2: BGE, PEPCO
CONE Area 3: AEP, APS, ATSI, ComEd, Dayton, DEOK, Dominion, Duquesne (DLCo), EKPC, OVEC
CONE Area 4: MetEd, Penelec, PPL

Net Cone Area $/MW day may be found by delivery year via PJM's website: https://www.pjm.com/markets-and-operations/rpm.aspx
Each delivery year contains a workbook titled "Planning Period Parameters for Base Residual Auction" with the values listed in the Net CONE worksheet.

Black Start Unit Capacity is defined, as "*the Black Start Unit's installed capacity, expressed in MW*."

The term X is defined as *"the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For Black Start Units with a commitment established under paragraph 5, X shall be .01 for Hydro units, .02 for Diesel or CT units."*

<u>Paragraph 6 Fixed Black Start Service Cost for Units requesting Capital Cost Recovery</u>

For units recovering NERC-CIP black start capital costs under Paragraph 6, Fixed Black Start Service Costs are calculated using the following equation:

$$\begin{aligned}\text{Fixed BSSC} = {} & (\text{ Net CONE} * \text{Black Start NERC-CIP Unit Capacity} * X) \\ & + (\text{ Incremental Black Start NERC-CIP Capital Costs} * \text{CRF})\end{aligned}$$

Where Net CONE is "*the then current installed capacity ("ICAP") net Cost of New Entry (expressed in $/MW year) for the CONE Area where the Black Start Unit is located*".

Black Start NERC-CIP Unit Capacity is *"the Black Start Unit's installed capacity, expressed in MW, but, for the purposes of this calculation, capped at 100 MW for Hydro units, or 50 MW for CT units."*

The term X is defined as *"the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For Black Start Units with a commitment established under paragraph 5, X shall be .01 for Hydro units, .02 for Diesel or CT units."*

Incremental Black Start NERC-CIP Capital Costs are defined as *" those capital cost documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a Black Start Unit to maintain compliance with mandatory Critical Infrastructure Protection Reliability Standards (as approved by the Commission and administered by the applicable Electric Reliability Organization ".*

"CRF" or "Capital Recovery Factor" is equal to the levelized CRF as set forth in the applicable CRF Table set forth below.

For units recovering incremental black start capital costs under Paragraph 6, Fixed Black Start Service Costs are calculated using the following equation;

Fixed BSSC = (FERC-approved rate) + (Incremental Black Start Capital Costs * CRF)

"FERC-approved rate" is "*the Black Start Unit's current FERC-approved recovery of costs to provide Black Start Service, if applicable. To the extent that a Black Start unit owner is currently recovering black start costs pursuant to a FERC-approved rate, which cost recovery will be included as a formulaic component for calculating the Black Start Unit's annual revenue requirement pursuant to this paragraph 18. However, under no circumstances will PJM or the Black Start Unit owner restructure or modify that existing FERC-approved rate without FERC approval."*

Incremental Black Start Capital Costs are defined as *the new or additional capital cost documented by the owner or accepted by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit. However, incremental Black Start Capital Costs shall not include any capital costs that the Black Start unit owner is recovering for that unit pursuant to a FERC-approved recovery rate."*

"CRF" or "Capital Recovery Factor" is "*equal to the Levelized CRF based on the age of the Black Start Unit, which is modified to provide Black Start Service, as present in the CRF Table below:"*

Age of Black Start Unit	Years of Remaining Life of Black Start Unit	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

The CRF table has several different assumptions such as: the Capital Recovery Factor based on a levelized proforma for a 100MW Combustion Turbine for $1M, 2.5 percent inflation, 36 percent federal tax rate, 9 percent state tax rate, income tax rate 41 percent, 50 percent equity and 50 percent debt with a 7 percent interest rate, and a 12percent internal rate of return on equity.

Optionally, a Black Start unit owner may elect to apply an alternative Capital Recovery Factor (CRF), in lieu of the age-based CRF table listed on page 7, which is based upon the expected capital Improvement Lifespan of the new or additional capital improvements (as determined by the applicable depreciation period of the capital improvement, as published from time to time by the US Internal Revenue Service).The Applicable Recovery Period and the term of Black Start Service Commitment shall be the same and determined by the expected Capital Improvement Lifespan. In the event that the Black Start unit seeks recovery of capital improvements that are included in more than one category of Capital Improvement Lifespan (as set forth below), its Applicable Recovery period and term of commitment to provide black start service for such Black Start unit shall be the longest expected life of those new or additional capital improvements.

Capital Improvement Lifespan (years)	Applicable Recovery Period/Term of Commitment (years)	Levelized CRF
16-20	20	0.125
11-15	15	0.146
6-10	10	0.198
1-5	5	0.363

In those circumstances where a Black Start Unit owner has elected to recover incremental Black Start Capital Costs, in addition to a FERC-approved recovery rate, its applicable term of commitment shall be the greater of: (i) the FERC-approved recovery period, or (ii) the applicable term of commitment as established by the CRF Tables above. After a Black Start Unit has recovered its allowable Incremental Black Start Capital Costs or Incremental Black Start NERC-CIP Capital Costs, as provided by the applicable Capital Cost Recovery Rate, and has satisfied its applicable commitment period required under Schedule 6A: Paragraph 6, the Black Start Unit shall be committed to providing black start in accordance with Paragraph 5 of Schedule 6A and calculate its Fixed BSSC in accordance with the Base Formula rate.

A. Variable Black Start Service Cost (VBSSC)

$$\text{Variable Black Start Service Cost} = \text{Black Start Unit O\&M} * \text{Y}$$

Where Black Start Unit O&M is *"the operations and maintenance cost attributable to supporting Black Start Service and must equal the annual variable O&M outlined in the PJM Cost development Guidelines set forth in the PJM Manuals. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to a Black Start unit solely on the basis of the provision of Black Start Service by the unit."*
Y is 0.01, "*unless a higher or lower value is supported by documentation of costs. If a value of Y is submitted for this cost, a (1-Y) factor must be applied to the Black Start unit's O&M costs on the unit's cost-based energy schedule, calculated based on the Cost Development Guidelines in the PJM Manuals"*

For unit qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid (ALR), there are no variable costs associated with providing Black Start Service and the value for Variable BSSC shall be zero.

B. Training Cost

$$\text{Training Costs} = 50 \text{ staff hours/year/plant} * \$75/\text{hour}$$

C. Fuel Storage Cost

Black Start Units that do not use oil as their fuel must set their Fuel Storage Costs to zero. Black Start units that can use oil for fuel shall calculate Fuel Storage Costs as:

$$\text{Fuel Storage Costs} = (\text{Minimum Tank Suction Level} + (\#\text{ of Run Hours Required} * \text{Fuel Burn Rate})) * (12 \text{ month forward strip} + \text{basis}) * \text{Bond Rate}$$

Where Minimum Tank Suction Level is *"and shall apply where no direct current pumps are available for the black Start Unit"*.

Number of Run Hours are *"the actual number of hours a transmission provider requires a Black Start Unit to run. Run Hours shall be at least 16 hours or as defined by the Transmission Owner restoration plan, whichever is less".*
Fuel Burn rate is *"actual fuel burn rate for the Black Start Unit"*.

12 Month Forward Strip is *"the average of forward prices for the fuel burned in the Black Start unit traded the first business day on or following May 1"*.

Basis is *"the transportation costs from the location referenced in the forward price data to the Black Start unit plus any variable taxes".*

Bond rate is *"the value determined with reference to the Moody's Utility Index for bonds rated BAA1 reported the first business day on or following May 1".*

D. Z Factor

The Z factor shall be an incentive factor solely for Black Start Units with a commitment established under Schedule 6A Paragraph 5 and shall be ten percent. For those Black Start units that elect to recover new or additional Black Start Capital Costs under Paragraph 6, the incentive factor (Z), shall be equal to zero.

Request for Proposal (RFP) since 2014

April 11, 2014: Black Start Incremental Request for Proposal for AEP Zone. PJM requested bids for additional black start capability within the AEP transmission zone.

November 24, 2014: Black Start Incremental Request for Proposal for Northeast Ohio and Western Pennsylvania. PJM requested additional black start capability within Northeastern Ohio and Western Pennsylvania.

July 28, 2015: Second Incremental Request for Proposal for Northeast Ohio and Western Pennsylvania. PJM determined the need for additional black start capability within Northeastern Ohio and Western Pennsylvania.

February 01, 2018: PJM 2018 RTO Wide Black Start Request for Proposal. This was the second PJM RTO-wide black start Request for Proposal process and requested bids for new black start capability in accordance with the Five-Year Black Start Selection Process as documented in PJM Manual 14D.

February 01, 2019: Black Start Incremental Request for Proposal for BGE/PEPCO Zones. PJM requested bids for additional black start capability within the BGE transmission zone.

Conclusion

PJM Manual 14D: Generator Operational Requirements; Section 10: Black Start Generation Procurement outlines the PJM black start selection process and includes the RTO wide black start RFPs, PJM incremental black start RFPs and PJM Reliability Backstop processes. Resources that are awarded black start service are compensated under Schedule 6A of the Tariff, with the associated formula and its cost components documented in this paper. PJM has received, reviewed, and approved several resources during the multiple RFPs listed above. As a result, no additional changes are needed due to the response following the above mentioned RTO Wide and Incremental RFPs.

Exhibit IMM-00010

Gerard Cerchio

From: Joseph Bowring
Sent: Thursday, October 3, 2019 6:07 PM
To: 'David.schweizer@pjm.com'; Glen D. Boyle (Glen.Boyle@pjm.com)
Cc: Gerard Cerchio
Subject: Black Start CRF tables

David/Glen:
Three CRF tables:

- First is the current tariff table
- Second is the current tariff table recalculated to reflect recent changes in tax law that reduce CRF values
- Third is our proposed CRF table for black start. This table uses a 20 year CRF for all black start units. We would be ok providing for a return of a pro rata share of the payments to the generation owner if the unit failed before 20 years, and with a guarantee to continue providing black start service for the balance of the useful life of the unit at the tariff rate.

Let us know if you want to discuss.
Thanks
Joe

Black Start CRF - Current Tariff

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF @ 12% IRR
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16 +	5	0.363

Black Start CRF - Current Tariff-New Tax Law

Age of Existing Units (Years)	Remaining Life of Plant (Years)	Levelized CRF @ 12% IRR
1 to 5	20	0.096
6 to 10	15	0.111
11 to 15	10	0.144
16 +	5	0.246

Black Start CRF - IMM Proposed New Tariff

Age of Existing Unit Where BS Located (Years)	Life of BS Unit (Years)	Levelized CRF @ 12% IRR
1 to 60 Plus	20	0.096

Financial Assumptions

	Current	2019
Percent Equity	50%	50%
Percent Debt	50%	50%
Loan Term	Remaining Plant Life	Remaining Plant Life
Loan Rate (%)	7.0%	7.0%
Federal Tax Rate (%)	35.0%	21.0%
Sate Tax Rate (%)	9.0%	9.0%
Depreciation	15 Yr. MACRS	First Year 100% Bonus (1)
Target IRR	At End of Plant Life	At End of Plant Life

(1) For property placed in service after September 27, 2017

Exhibit IMM-00011

Filed Date
Aug 31, 2005

PJM Interconnection, L.L.C.
Docket Nos. ER05-1410-000
and EL05-148-000

Reliability Pricing Model Filing

August 31, 2005

Volume 2 ORIGINAL

TAB E

Affidavit of Andrew L. Ott

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM INTERCONNECTION, L.L.C.) **Docket Nos. ER05-____-000
and EL05-____-000**

**AFFIDAVIT OF
ANDREW L. OTT
ON BEHALF OF
PJM INTERCONNECTION, L.L.C.**

I, Andrew L. Ott, being duly sworn, depose and state as follows:

My name is Andrew L. Ott, and my business address is 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania, 19403-2497. As Vice President of Market Services at PJM, I am responsible for day-to-day operation of all PJM markets including the energy markets, ancillary services markets, financial transmission rights market, and the capacity markets. I am also responsible for market settlements, market design and market development. I have worked at PJM in market operations, market design and market development since October, 1996. I have substantial experience in electricity market design and development. Prior to joining PJM, I worked as a power systems engineer in transmission planning and operations for 13 years. I have a BS in electrical engineering and an MS in mathematics and applied statistics.

I am submitting this affidavit to explain and support several aspects of the Reliability Pricing Model ("RPM") filed by PJM in this proceeding. In particular, in this affidavit, I will:

- provide an overview of RPM;
- explain the RPM auction-clearing process;
- describe how LSEs can avoid the uncertainties of the auction process by self-scheduling their owned or contracted resources, including RPM's option for flexible self-scheduling;
- explain and support RPM's four-year-forward approach to assuring resource adequacy;
- explain and support RPM's use of a downward-sloping variable resource requirement ("VRR") curve;
- describe and justify the particular VRR curve PJM has selected for initial use in RPM;
- demonstrate how RPM is likely to produce energy-cost savings;

- explain how RPM integrates load management solutions to assuring reliability;
- explain how RPM will set separate capacity prices by season, thereby encouraging greater competition and efficiency;
- explain how RPM addresses the PJM region's need for resources with quick-start and load-following capabilities;
- explain and support RPM's reliability backstop provisions; and
- provide an estimate of PJM's administrative costs to implement RPM.

I. Overview of RPM

Under RPM, PJM will administer a series of auctions for each Delivery Year,[1] to match the region's reliability requirements with offers to sell capacity resources, taking into account all capacity resources that LSEs have self-supplied or bilaterally contracted (I discuss these "self-scheduling" options in more detail in section III below), and to establish corresponding reliability charges for each season of such year. Figure 1 on the following page provides a graphical overview of the RPM auction process in relation to the Delivery Year.

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1 As with the Planning Period used in PJM today, a Delivery Year is the 12-month period from June 1 of a calendar year to May 31 of the following calendar year.

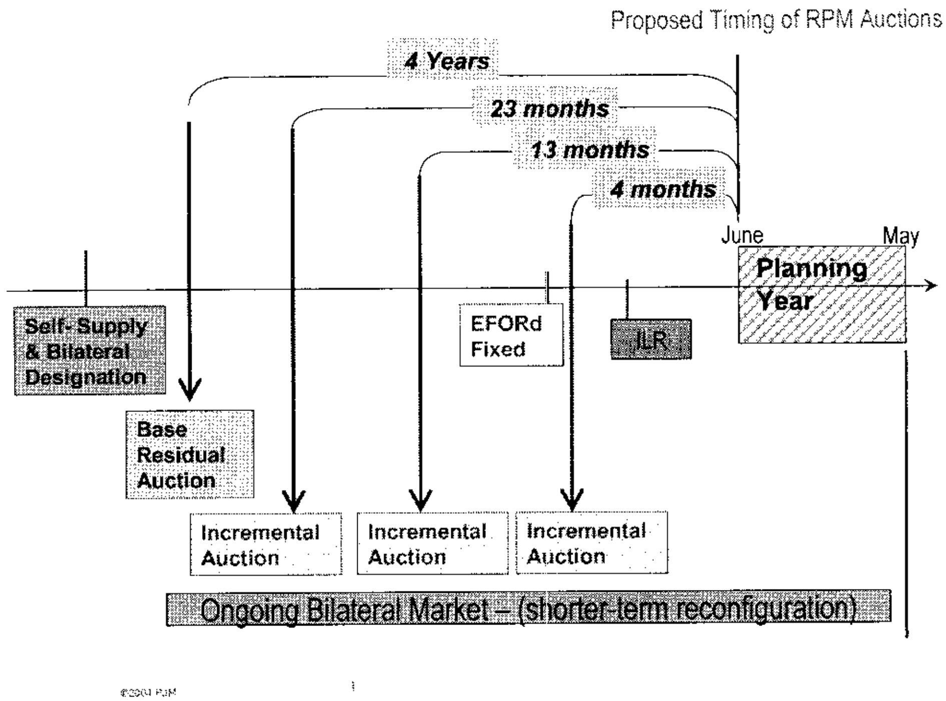

Figure 1 – RPM Auction Timing

Four years before each Delivery Year, PJM will conduct a Base Residual Auction to enable commitment of capacity resources needed to satisfy remaining capacity needs of loads after taking account of LSEs' owned and contracted resources. The market clearing method used in the auction will consider locational transmission constraints, as well as the PJM Region's need for a minimum amount of capacity capable of adjusting output to follow changes in load, and a minimum amount capable of starting in 30 minutes or less. I discuss in more detail in section X of my affidavit the PJM system's need for thirty-minute-start and load-following resources, and how RPM will help the PJM region meet that need.

The auction-clearing model will use marginal pricing to set prices based on these locational and operational reliability constraints, the submitted supply offers, and a Variable Resource Requirement ("VRR") Curve. As explained in sections V and VI of my affidavit, the VRR Curve will replace the current single-value rate paid by loads that are deficient in satisfying their capacity obligations, and charts a downward-sloping relationship between price and unforced capacity to identify the level of capacity that will provide an acceptable level of reliability. After extensive analysis, as described in the affidavit of Professor Benjamin F. Hobbs of Johns Hopkins University, PJM selected the following VRR curve (shown in Figure 2 on an unforced capacity basis)[2] for initial use in RPM:

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2 The VRR Curve shown reflects the cost of new entry ("CONE") estimate for certain zones in the eastern PJM region. There are two other CONE estimates

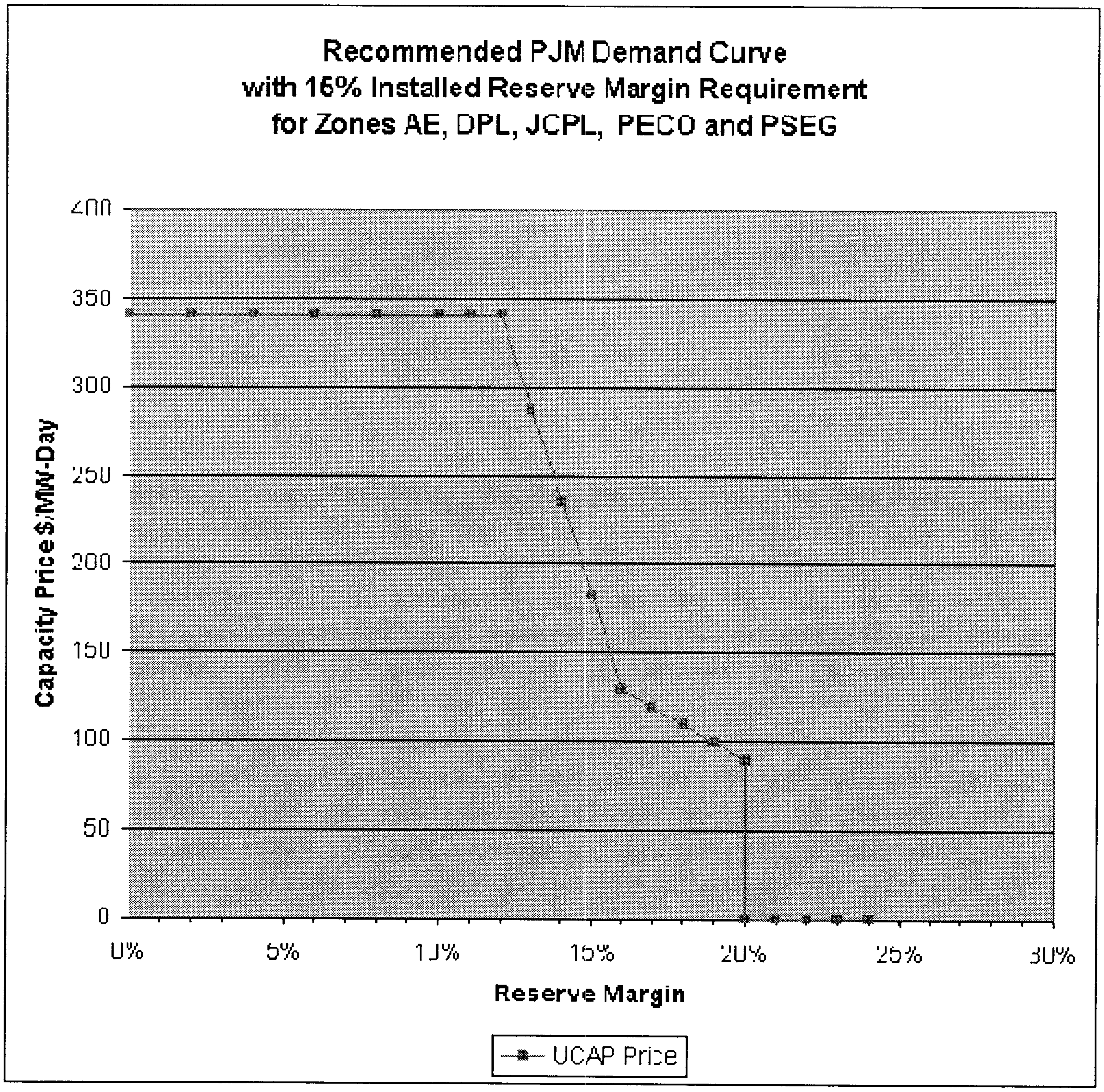

Figure 2 – Recommended VRR Curve

Based on the VRR Curve and the other inputs described above, the auction will set: (1) the price paid to capacity resources that are committed to the region in the auction; and (2) the corresponding amounts to be paid by LSEs as a Locational Reliability Charge. A resource will be accepted in the auction, and committed to provide capacity to the PJM system during the Delivery Year, if its offer is at or below the clearing price (including any adders applicable to such resource, as discussed below) determined through the auction. All payments and charges determined as a result of the

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(reflecting slight geographic differences in equipment, labor, or other costs) that together cover the remaining zones in PJM. Because the CONE estimates vary by only a few thousand dollars, all three resulting curves have essentially the same shape, i.e., that shown here.

RPM actions will be billed on a monthly basis during the Delivery Year and settled at that time.

As a result of the locational constraints, the clearing price could vary among identified areas, known as Locational Deliverability Areas ("LDAs"), depending on whether transmission limits into such LDAs bind in the auction. As PJM's Vice President of Planning, Mr. Steven R. Herling, explains in his affidavit, PJM's regional transmission expansion planning ("RTEP") process currently identifies areas that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations, or stability limitations, but that information is not reflected in current capacity prices. Those areas identified in the planning process now will be used as LDAs in RPM.

Similarly, if either or both of the operational reliability constraints bind in the auction (i.e., the clearing prices otherwise established are not sufficient to attract the needed capacity from qualifying resources), then resources supplying load-following or 30-minute-start capabilities (depending on which type of resource is needed) will receive additional compensation, based on the bids of such resources and the minimum required level of such resources needed for system reliability.

Within each Base Residual Auction and incremental auction (described below), PJM will clear prices separately for each of four seasons.[3] The capacity obligation (which is based on peak summer loads) will be the same throughout the year, but price offers and clearing prices may (and likely will) vary by season. As I explain in section IX of this affidavit, seasonally differentiated prices should promote efficiency, by encouraging competition from resources (such as external generation resources) that are not available for the full year, or that can apply greater price pressure during the seasons they are available.

RPM will allow many more types of resources than today to qualify as capacity resources. Under RPM, Capacity Resource offers will include both existing and planned generation resources, as well as both existing and planned load management programs (referred to when offered in an RPM auction as "Demand Resources"). Moreover, planned merchant transmission upgrades that provide incremental increases in import capability into constrained LDAs can be offered into the auction. As Mr. Herling explains, this added feature will allow transmission upgrades to compete directly with local generation in constrained LDAs, ensuring that the auction does not consider local generation as the only solution to deliverability limitations that could be solved economically by transmission.

In addition to the Base Residual Auction, PJM will hold incremental auctions for the Delivery Year to provide market participants the opportunity to adjust their capacity market positions. The First Incremental Auction, held twenty-three months before the

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3 The four seasons are summer (June 1 to August 31), fall (September 1 to November 30), winter (December 1 to February 28), and spring (March 1 to May 31).

Delivery Year, will allow market participants an opportunity to replace resources previously committed in the Base Residual Auction that become unavailable for such reasons as cancellation, delay, derating, an increase in the forced outage factor ("EFORd"), or a decrease in the value of a Planned Demand Resource.[4] The costs of the resources committed in the First Incremental Auction will be recovered from the parties that needed to secure replacement resources.

PJM will conduct a Second Incremental Auction thirteen months before the Delivery Year, but only if PJM projects that the PJM region will be short of capacity for that Delivery Year by more than 100 megawatts, as a result of a higher load forecast.[5] When these conditions are met, the auction will be held to commit the needed additional capacity. The costs of the additional resources committed in the Second Incremental Auction, which are needed for the entire region, will be recovered from all LSEs in the PJM Region, by adjusting the preliminary "base" (region-wide) capacity price established in the Base Residual Auction.

PJM will conduct a Third Incremental Auction four months before the Delivery Year. As with the First Incremental Auction, this auction will allow market participants an opportunity to replace resources committed in the prior auctions, that since have become unavailable, or reduced in value due to a revised calculation of $EFOR_D$. As with the First Incremental Auction, the cost of resources committed in this auction will be recovered from the parties that need to secure replacement resources.

In addition to having the opportunity to compete with generation in the RPM auctions, load management programs can be nominated three months before a Delivery Year as Interruptible Load for Reliability ("ILR"). PJM will certify the nominated resources as ILR if they meet the criteria established for load management, such as being available for interruption at PJM's direction for a minimum number of hours, for a minimum number of times per year. Certified ILR will receive the same type of payments as Demand Resources that are offered and cleared in the auctions. I discuss the role of load management in RPM in greater detail in section XIII of my affidavit.

To ensure that committed resources fulfill their commitments during the Delivery Year, RPM includes various compliance and deficiency charges. These are closely

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4 Previously committed capacity resources will not be permitted to offer into an incremental auction. Rather, resources that would participate in an incremental auction include those that offered above the clearing price in the earlier auctions, planned resources developed after the earlier auctions, and external resources that chose not to participate in earlier PJM auctions for that Delivery Year.

5 PJM will prepare a preliminary load forecast for the Delivery Year before the Base Residual Auction, and then update that forecast 15 months before the Delivery Year, so that there is enough time to conduct a Second Incremental Auction if necessary.

patterned on the similar charges assessed under the RAAs today, but adapted to address the additional types of resources that can be committed in RPM.

As described by PJM's market monitor, Joseph E. Bowring, in his affidavit, RPM also includes provisions designed to protect against potential market power, including market structure tests, and offer caps based on avoidable-cost determinations similar to those addressed in other PJM proceedings.

Because RPM, when fully implemented, will address Delivery Years four years in the future, it includes transition provisions to address the first three Delivery Years after implementation, and to phase in certain of its new features.

Finally, RPM will include a reliability backstop auction to ensure that sufficient capacity is procured if there are repeated failures to commit adequate resources through the auctions described above. As I explain in section XI of this affidavit, the backstop will be triggered only if significant shortages are observed in the auctions applicable to four consecutive Delivery Years.

II. RPM Auction Clearing Process

The RPM optimization clearing approach will use marginal pricing to set prices based on generation capacity offers, Demand Resource offers, and the variable resource requirement curve while satisfying the operational reliability constraints and locational transmission constraints.[6]

If the auction clearing results in no binding constraints, all types of capacity will receive the same price. On the other hand, if the overall capacity requirement is met, but the operational reliability or locational constraints bind, then resources that are required to satisfy these constraints will receive additional compensation, as necessary to attract sufficient resources that provide these capabilities. A complete description of the market clearing algorithm is provided in Attachment 1 to my affidavit.

The incremental auctions similarly will employ an optimization-based market clearing algorithm, similar to the clearing algorithm used in the Base Residual Auction. The incremental auction clearing algorithm will have the objective of minimizing capacity procurement costs given the generation resource offers, demand resource offers, buy bids from parties that need replacement resources, locational constraints and

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[6] Since each resource may submit multiple offers for different products (i.e., base capacity and operational reliability attributes) the optimization algorithm uses a mixed integer programming formulation to ensure that only one offer for each resource is cleared. The optimization formulation objective is to minimize the overall objective function cost of meeting the variable resource requirement using the available resources while considering the locational and operational reliability constraints.

operational reliability constraints. Unlike the clearing method for the Base Residual Auction (as described below) the incremental auctions will not use a VRR. Curve. The First and Third Incremental Auctions will clear at the intersection of the curve formed by the buy bids for replacement capacity, and the curve formed by the offers to sell replacement capacity.[7] The Second Incremental Auction will clear at the point on the supply curve that provides the additional supply needed to meet the increased load forecast.

The optimization algorithm will clear the Base Residual Auction at the intersection of the supply curve and the variable resource requirement curve at the marginal segment[8] on either the supply curve or the VRR curve. The clearing price will be the offer of the marginal resource if the marginal segment is the supply curve and the price of the Variable Resource Requirement if the marginal segment is the VRR curve. Generally, all sellers offering capacity resources at or below the clearing price will be committed as capacity resources in the auction[9] and their resources become committed to meet the region's capacity needs for the Delivery Year; and they will receive that clearing price (plus any adders appropriate to the type or location of their resource) during the Delivery Year. However, if a seller's offer is on the supply curve past (to the right of) the intersection with the VRR curve, then its offer is not accepted and its resource therefore does not clear in the auction.

If the two curves do not intersect (meaning that the supply curve "stopped" before it could reach the VRR Curve), then the end of the supply curve will be extended vertically until it intersects the VRR curve. The supply curve is extended vertically because the "stopping" or termination of the supply curve at a given capacity level indicates that supply is fully utilized at that capacity level. When the supply is fully

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7 Although provided as vehicles to replace specific resources that became unavailable, the First and Third Incremental Auctions generally will not procure specific resources for specific buyers. Rather, all buyers that need replacement resources will pay a clearing price for the megawatts of replacement capacity they require based on the clearing price of all replacement capacity. The exception to this rule is that if a resource that has become unavailable was needed to relieve a locational or operational reliability constraint, the buyer must pay for replacement capacity that also relieves that constraint.

8 The marginal segment is the last fraction of a supply offer, or the last point of the VRR curve, that must be partially cleared to match supply and demand and clear the auction.

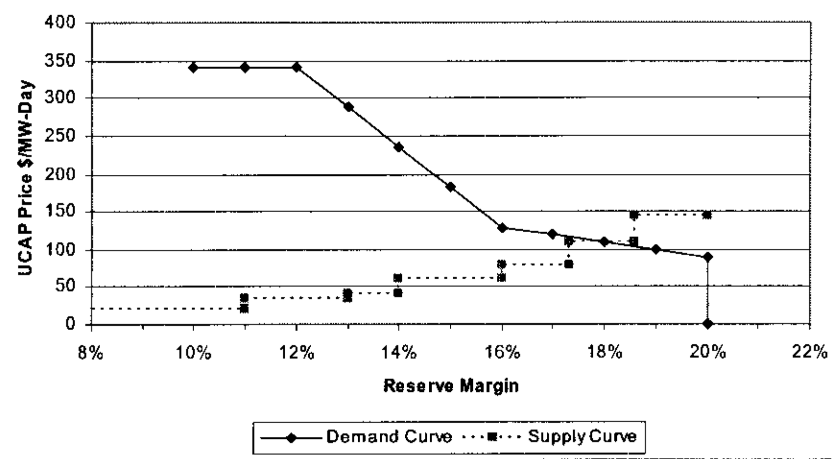
9 While it is generally true that all resources with offers below the clearing price are accepted and all resources with offers above the clearing price are not accepted, it is not always true. In some cases generators with lower offers but with restrictive offer parameters, such as minimum MW amount and seasonal offers, may be more costly to the overall solution than more flexible generator offers with a slightly higher offer price. In these cases the higher priced but more flexible unit may be committed instead of the lower priced less flexible generator.

utilized in this manner, the VRR curve becomes marginal. This condition indicates that the resource requirement is adjusted in the auction solution to recognize the restricted availability of supply and the VRR curve will set the clearing price to properly reflect the marginal value of capacity at that point on the curve.

As explained by Mr. Herling, capacity adequacy in PJM is defined by an Installed Reserve Margin ("IRM") for the PJM region, set by the PJM Board with the advice of the PJM Reliability Committee. Currently, that IRM is 15%. Under RPM, an auction may clear at a capacity level above the target IRM, but this will happen only when the higher capacity commitment can be obtained at lower cost. To be clear, this will not occur merely if the unit cost of securing more capacity is less. As shown below, the auction algorithm produces this result only if <u>more</u> capacity is secured at a <u>lower</u> total cost, which obviously benefits the region.

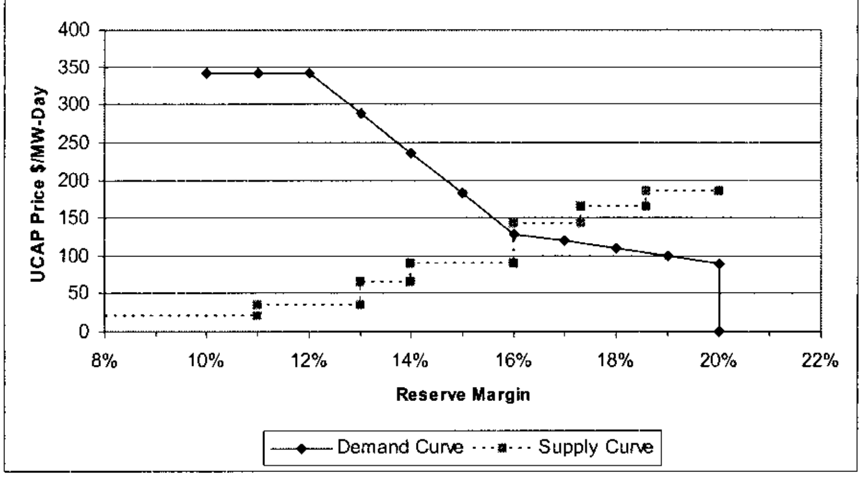
Several examples will help to illustrate these points. First, given the offers and VRR Curve in figure 3, the optimization would clear at the marginal supply offer of $109/MW-Day, where the supply curve intersects the VRR Curve

Figure 3 - RPM Optimization Clearing
Intersection of Supply Curve & VRR



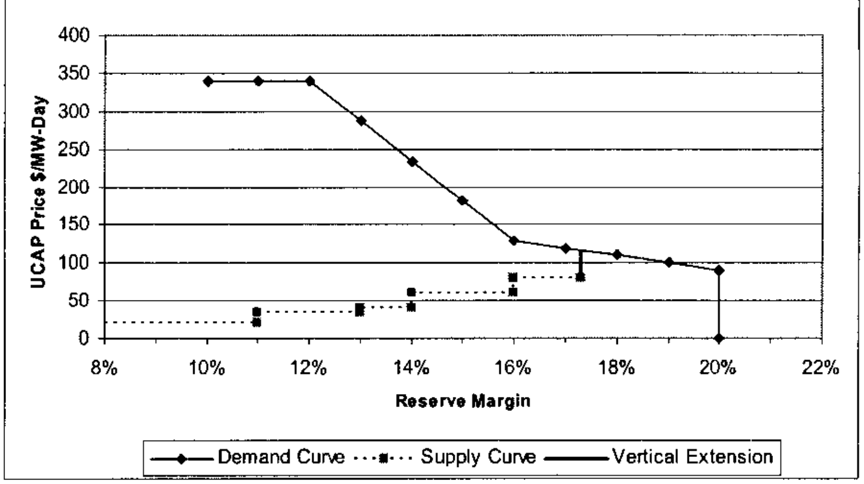
In the next example, given the same VRR curve but a higher supply curve as shown in Figure 4, the supply curve intersects the VRR at a point between two different supply offers. This type of scenario could result from "block bid" offers, i.e., offers to serve a block of additional capacity at a given price. In this situation, the optimization would clear at the marginal price on the VRR curve of approximately $129/MW-Day, as defined by the vertical line between the two sell offers.

Figure 4 - RPM Optimization Clearing
VRR Marginal



Now consider the case in which the sell offers forming the supply curve do not intersect the Variable Resource Requirement Curve, which could happen if all supply offers are priced below the VRR curve. Figure 5 shows the supply curve in this example ending with the last supply segment offered at approximately $80/MW-Day. In this instance, the marginal value of system capacity will be set by extending the supply curve vertically from its end point until it intersects the Variable Resource Requirement Curve, thereby clearing at a price of approximately $115/MW-Day.

Figure 5 - RPM Optimization Clearing
No Intersection - Supply Curve Vertically Extended



Note also what would happen if the clearing price was set at the IRM of 15%. Figure 6 uses the same VRR curve and supply curve as the first example (Figure 3) and extends the supply curve from the point where it provides 15% reserve margin vertically until that vertical line intersects the VRR Curve, resulting in a clearing price of $182/MW-Day.

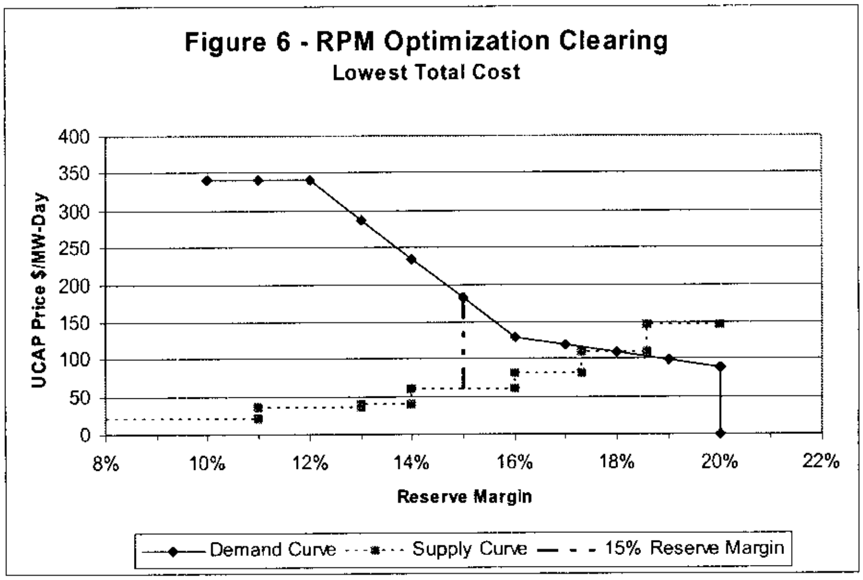


Figure 6 - RPM Optimization Clearing

If the system peak was 1000 MWs, then clearing at $182/MW-Day with a 15% reserve margin would result in a system cost of:

System Cost = System Peak *x* (1 + Reserve Margin) *x* Clearing Price
= 1000 MWs x (1 + .15) x $182/MW-Day
= $209,300/Day

Under RPM, an auction may clear at a capacity level above the target IRM, but this will happen only when the higher capacity commitment can be obtained at lower cost. This will not occur merely if the unit cost of securing more capacity is less. The auction algorithm produces this result only if <u>more</u> capacity is secured at a <u>lower</u> total cost, which obviously benefits the region. In the case of Figure 6, the optimization algorithm yields an overall lower clearing cost by continuing beyond the point at which it provides 15% reserve margin to the intersection of the supply curve and the VRR curve. This produces a clearing price of $109/MW-Day with an 18% reserve margin. By clearing at this level, the system cost is as follows:

System Cost = System Peak *x* (1 + Reserve Margin) *x* Clearing Price
= 1000 MWs x (1 + .18) x $109/MW-Day
= $128,620/Day

The relationship illustrated here—i.e., more capacity at lower cost—holds for every point on the proposed VRR Curve, as shown on Table 1. It also holds regardless of the load level, i.e., whether the curve is applied to clear the region as a whole or to clear only an individual LDA. As can be seen, the overall cost to procure capacity is highest in scarcity conditions, i.e., when the reserve margin achieved by the resources cleared in the auction falls short of the IRM target set by the PJM Board. The total capacity cost then goes down (not just on a unit basis, but on a total-cost basis) as more capacity is cleared.

Table 1
When the VRR Curve Clears Above the IRM,
It Clears More Capacity at Less Cost

Region-wide Unforced Capacity Obligation 147321

Reserve Cleared by Auction	Capacity Cleared MW	Capacity Price from VRR $/MW-Day	Capacity Cost $ Million per Day	Reduction in Cost $ Mil/Day	Reduction in Cost $ Bil/yr
12%	143478	340	49	Reference	Reference
13%	144759	288	42	7	3
14%	146040	235	34	15	5
15%	147321	182	27	22	8
16%	148602	129	19	30	11
17%	149883	119	18	31	11
18%	151164	109	16	32	12
19%	152445	99	15	34	12
20%	153726	89	14	35	13

III. Self-Scheduling Options

LSEs have the option to specify their self-owned generation or unit-specific bilateral contracts to hedge their reliability charges under RPM. LSEs that elect to "self-schedule" will enter their owned or contracted resources into the auction (technically as "sellers" of such resources, like any other seller of a capacity resource in the auction), and then the auction will procure any remaining capacity required for the region. LSEs relying on self-supply or bilateral contracts will be price-takers in the auction, submitting a zero-price offer and then receiving revenue during the Delivery Year based on the capacity of their resources and the clearing prices established by the auctions. Such LSEs then will pay only the difference, if any, between the revenues they receive for their self-scheduled resources and the RPM reliability charges. A difference between the LSE's resource revenues and its reliability charges can arise because: (i) the final clearing price may change from the first auction to the delivery year due to changes in the forecasts of peak load; (ii)the final amount of ILR certified for the Delivery Year may differ from the forecast of ILR relied on for purposes of that first auction; or (iii) the LSE's resources are not thirty-minute-start or load-following resources, and so the LSE still must contribute to the system's cost for such resources committed by other sellers.

RPM also offers LSEs an opportunity to hedge these potential differences, using a "flexible self-scheduling" option. This option allows an LSE to designate a resource as self-scheduled to the extent needed to meet the capacity charges attributable to its loads, while also specifying a selling price to offer the resource into the auctions to the extent it is not needed to meet the LSE's reliability charge obligations.

Accordingly, a flexible self-scheduled sell offer must specify an offer price for use in the auction clearing in the event the resource is not needed to cover the calculated capacity obligation. The LSE must also specify the portion of its peak load in each transmission zone it wishes to cover with self-scheduled resources. A flexible self-scheduled resource will automatically be cleared in the auction if needed to supply the LSE's obligation associated with that specified load; otherwise the resource will be treated as offered into the market.

In the event the LSE does not need all of the generators that were specified as self-scheduled generators to meet its obligation, the RPM auction-clearing algorithm will consider the excess (defined as the units in the LSE's offer portfolio with the highest offer prices) as offered into the market. In the event the LSE did not specify sufficient self-scheduled generation to meet its calculated obligation, then the LSE will be notified that it must purchase the additional required generation to cover its obligation.

IV. Four-Year Forward Auctions and Resource Commitments

PJM's experience with the current short-term capacity market indicates that market has design flaws. It does not adequately quantify reliability requirements, nor has it demonstrated the capability to sustain generation investment. Moreover, the current short-term market simply does not provide a reasonable opportunity for planned generation resources or planned demand resources to compete with existing resources, which raises market-structure concerns.

The short-term nature of the current PJM capacity market and current capacity obligation rules are fundamentally inconsistent with the need to preserve system reliability over the long term. The need for a capacity market is fundamentally driven by reliability requirements. The current capacity construct allows LSEs to commit generation resources to provide installed capacity to serve their network load capacity obligation on a day-by-day basis. Under the current rule, generation resources committed to the system as capacity resources can "de-list" from capacity resource status with as little as 36 hours notice. As discussed by Mr. Bowring in his affidavit, the current construct has not provided sufficient revenue to generators, thus sending a signal to those generators that they are not valued for reliability. Recently PJM has had to develop and file with FERC generation deactivation rules as a stop-gap measure to deal with announced retirements of generation units that are needed for reliability. The fundamental inconsistency between quantified reliability needs and the observed generation revenue adequacy results indicates that the current capacity construct does not properly quantify the reliability needs of the system.

By contrast, RPM is based on a four-year forward pricing regime that provides a direct opportunity for planned generation, planned transmission upgrades, and planned demand resources to compete with existing resources. A market incorporating both pricing and lead-times that support new entry will help establish transparent investment signals and should significantly reduce market power concerns. The four-year-forward price signal, based on competitive generation, transmission, and demand resource sell offers, should reflect the market's expectations about future conditions, including such factors as relative fuel costs and regulatory changes, such as environmental regulations. That information should be very valuable to investors considering alternative resource options. Moreover, because it is a long-term price signal, it should be relatively stable, especially compared to the volatile short-term pricing that characterizes the current PJM capacity market.

Longer-term price signals also should incent longer-term bilateral contracts, as an effective means of hedging the reliability charges assessed under RPM. This will help orient market participant objectives with the system's reliability needs, and help ensure the long-term viability of the competitive market model in the electric industry. Capacity market reform alone cannot achieve these objectives, but it cannot be ignored either. Embedding a longer-term view in the capacity markets is consistent with, and will support, parallel efforts in PJM to ensure a longer-term view in transmission planning (as discussed by Mr. Herling) and a longer-term view in load management, through such measures as a forward energy reserve market and additional revenue sources to help establish and sustain load management.

Some have argued that a voluntary forward capacity market could achieve the same objectives as the four-year forward RPM auction design. This is not true because of the reliability constraints that must be satisfied for the entire system on a forward basis. The capacity construct is directly related to long-term reliability requirements of the system to ensure both adequate generation supply and adequate transmission delivery capability to each region of the market. A voluntary forward market would provide load serving entities with the alternative to contract with capacity resources on a longer term basis but would not require entities to arrange to cover all of their load obligation until a short term residual auction is held a few months before the delivery year. This type of voluntary forward market would create fundamental inconsistencies between the forward market results and the reliability requirements. For example, under such a voluntary forward market, it is probable that only a portion of the total load would elect to participate and that as a result certain critical generation in a constrained LDA would not be contracted by load on a forward basis. This would result in the same short term crisis scenarios that have been experienced under the current capacity construct. As we have seen, such situations would require out of market, Reliability Must Run contracts which distort the forward market investment signals and which in turn would adversely impact investment. Since the reliability requirements are based on ensuring that all firm load is served, it is imperative that the forward market contains all of the firm load so that the market results accurately reflect all of the reliability constraints. Under the RPM model, the load also has the choice to offset or to avoid the capacity payment by offering in Demand Resources or specifying the load as ILR.

As discussed by Mr. Herling, recent generation retirements have highlighted a fundamental problem with the long-term planning of the transmission system. The load deliverability analysis performed in the RTEP process requires as input the generation resources that will be available to support delivery of imported energy to load. Uncertainty in the generation resource availability for future years creates a significant amount of uncertainty in the future regional transmission plan. Since reliability is a fundamental requirement, this planning uncertainty cannot be sustained. To correct this problem, the PJM region needs to return to a longer-term forward capacity obligation to commit generation for future years. A four-year forward commitment period is needed for generation capacity obligations to ensure that the five-year PJM RTEP has adequate forward information on generation conditions, so that proper planning and coordination of transmission upgrades can be assured.

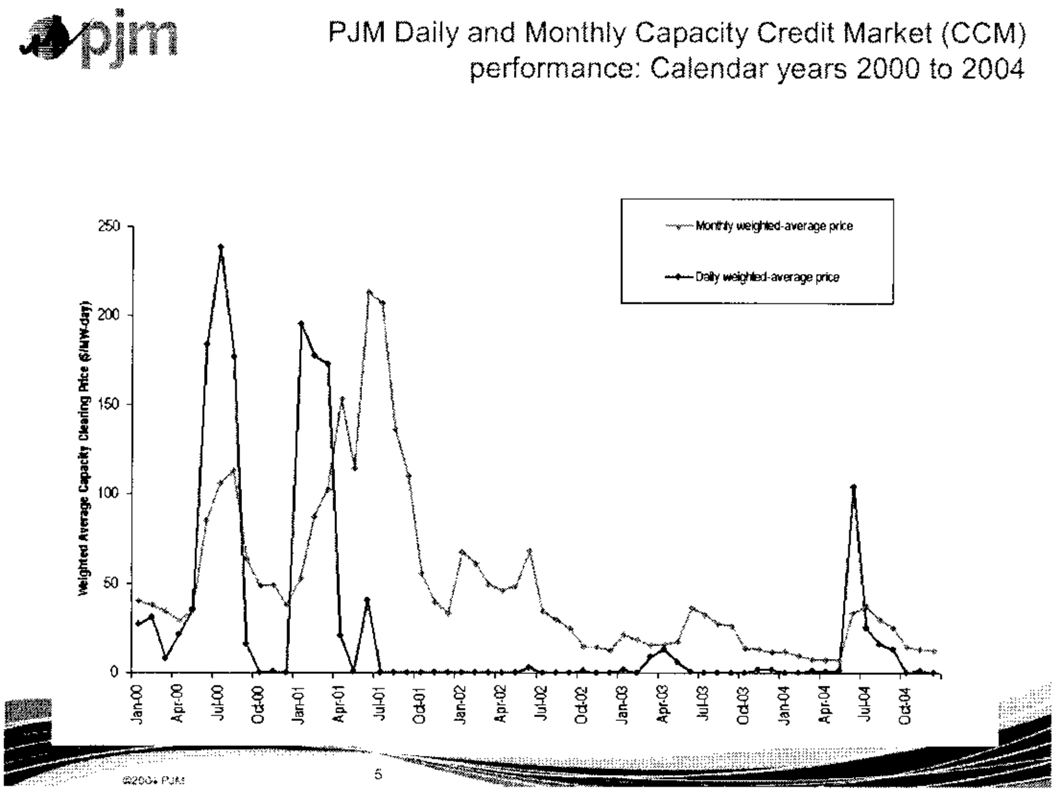
The incremental auctions that were mentioned previously provide market participants with the flexibility to adjust their positions from the Base Residual Auction. This incremental auction is an important feature of the RPM that reduces the risk of participation in the four-year forward auction for various entities, such as new generation projects or new demand resources, by providing a mechanism for them to purchase an alternative, replacement resource should they experience construction delays or other unforeseen events. This feature also eliminates potential seams issues with adjacent capacity markets by providing near term adjustment capability for resources that choose to participate in adjacent capacity markets that have shorter time horizons such as NYISO's market.

V. Benefits of a Variable Resource Requirement Approach to Setting Capacity Prices

As explained by Professor Hobbs, a variable resource requirement curve has significant advantages over the single-value installed capacity approach used in PJM's current capacity market. In a single-valued IRM system, prices are very high if there is a shortage of only a few megawatts below the installed reserve margin, but drop to zero if there is a surplus of only a few megawatts of excess capacity above the IRM level. As Professor Hobbs explains, this too is a form of price-capacity curve, but it has a dramatic vertical drop—to a price of zero—at the IRM capacity level. In contrast, a more gradually downward-sloping variable resource requirement curve recognizes that additional capacity over and above a target reserve margin has some value. In part because it recognizes this value, a Variable Resource Requirement curve should help reduce the capacity price volatility that has been observed in the current PJM daily capacity market, as illustrated in Figure 7 on the following page.

Figure 7
PJM Daily and Monthly Capacity Credit Market Clearing Prices
Calendar Years 2000-2004

Source: 2004 PJM State of the Market Report, page 159



This type of price volatility actually experienced in the PJM capacity market corresponds to the price volatility predicted by Professor Hobbs in his long-term dynamic economic simulation of capacity markets with vertical demand curves, such as PJM's. current market. As he explains, such volatility creates a significant degree of uncertainty for investors, which increases their perceived risk of attaining an adequate return on investment. Since the current capacity market has exhibited pricing behavior that bounces between two pricing extremes, depending on whether there is too little capacity or too much relative to the target Installed Reserve Margin, the result has been increased forward uncertainty for generation. Therefore, the PJM market has experienced a period of very low capacity prices, which has resulted in generation retirements and in very little new generation additions in the future, which in turn has created reliability criteria violations.

Some stakeholders have argued that the PJM market results are simply illustrating a normal investment cycles and that no capacity market reform is necessary. However, such investment swings are in direct conflict with the fundamental reliability requirements, which should not be compromised. The PJM market structure has included a generation capacity market construct as a means to ensure long-term adequacy of supply so that the short-term availability of generation to meet demand can be ensured.

The existence of a generation capacity product is driven by the fact that electric energy is an essential commodity, and it is simply unacceptable to have shortages. The August 2003 blackout dramatically illustrated the tremendous negative effect that failure of electric supply has on social welfare and on the economy. The justifiable social requirement for high reliability standards coupled with the inability to easily store electric energy during times of excess supply for later use clearly indicates that a capacity market reform to ensure stable and sustainable supply adequacy is required.

As described by Professor. Hobbs, the variable resource requirement approach provides a much more stable pricing than is likely to result from a vertical demand curve approach. Therefore, a major advantage of a variable resource requirement curve compared to the single-value IRM is that the stream of capacity payments received by generators will be more stable. Because investors do not like risk, more volatile profits mean that higher rates of return will be required for new generation investments under the current capacity construct. In order to obtain the higher returns required by risk-averse investors, shortages of capacity would have to happen more frequently, resulting in higher costs and risks to consumers of inadequate supply. In comparison, as shown in the dynamic economic analysis performed by Professor Hobbs, a variable resource requirement curve-based system should help reduce variability in generator revenues, especially for peaking capacity. Further reductions in risk to investors result if capacity commitments are made years in advance, as opposed to the present PJM system. Market simulations of RPM show that risk-averse investors will accept lower rates of return, ultimately decreasing costs and risks to consumers.

In addition to lowering consumer cost, Professor Hobbs' dynamic economic analysis results indicate that a higher level of reliability will be achieved with a variable resource requirement approach. The higher level of reliability is achieved through investment response to the more stable price signals, which means that the target Installed Reserve Margin will be achieved in many more years than under the current capacity construct. Therefore, since the variable resource requirement will incent earlier investor response to upcoming reliability shortages, there will be less dependence on out-of-market regulatory intervention, such as reliability backstop mechanisms or special credits to keep generators needed for reliability from retiring.

VI. Variable Resource Requirement Parameters

To help select a particular VRR Curve for use in RPM, PJM commissioned Professor Hobbs to perform dynamic simulations of the long-term investment behavior resulting from differing demand curves. The analysis was performed in order to determine the variable resource requirement characteristic parameters that result in an adequate level of generation net revenue. As explained by Professor Hobbs, the relative performance of each variable resource requirement curve was assessed based on a reliability performance measure and a capacity cost measure. The reliability performance measure quantified the investment response in terms of its ability to sustain investment to meet or exceed the net load growth such that installed reserve standards are satisfied in each future year. The measure of capacity cost was based on annual capacity price results in the simulation.

Professor Hobbs considered five demand curves in his base case analyses. Each of these curves is displayed in Figure 8. In these curves, the "X" axis is expressed as a ratio of the unforced reserve margin to the target unforced reserve margin, so that a value of 1 signifies that the target is just met. Multiplying this ratio by (100% + the target reserve in percent)and then subtracting 100% converts the ratio into a reserve margin. For example, the three sloped curves in the figure below drop to zero price at a ratio of 1.043. This equates to a reserve margin of 20%, i.e., 1.043 * (100% + 15%) – 100% equals 20%.

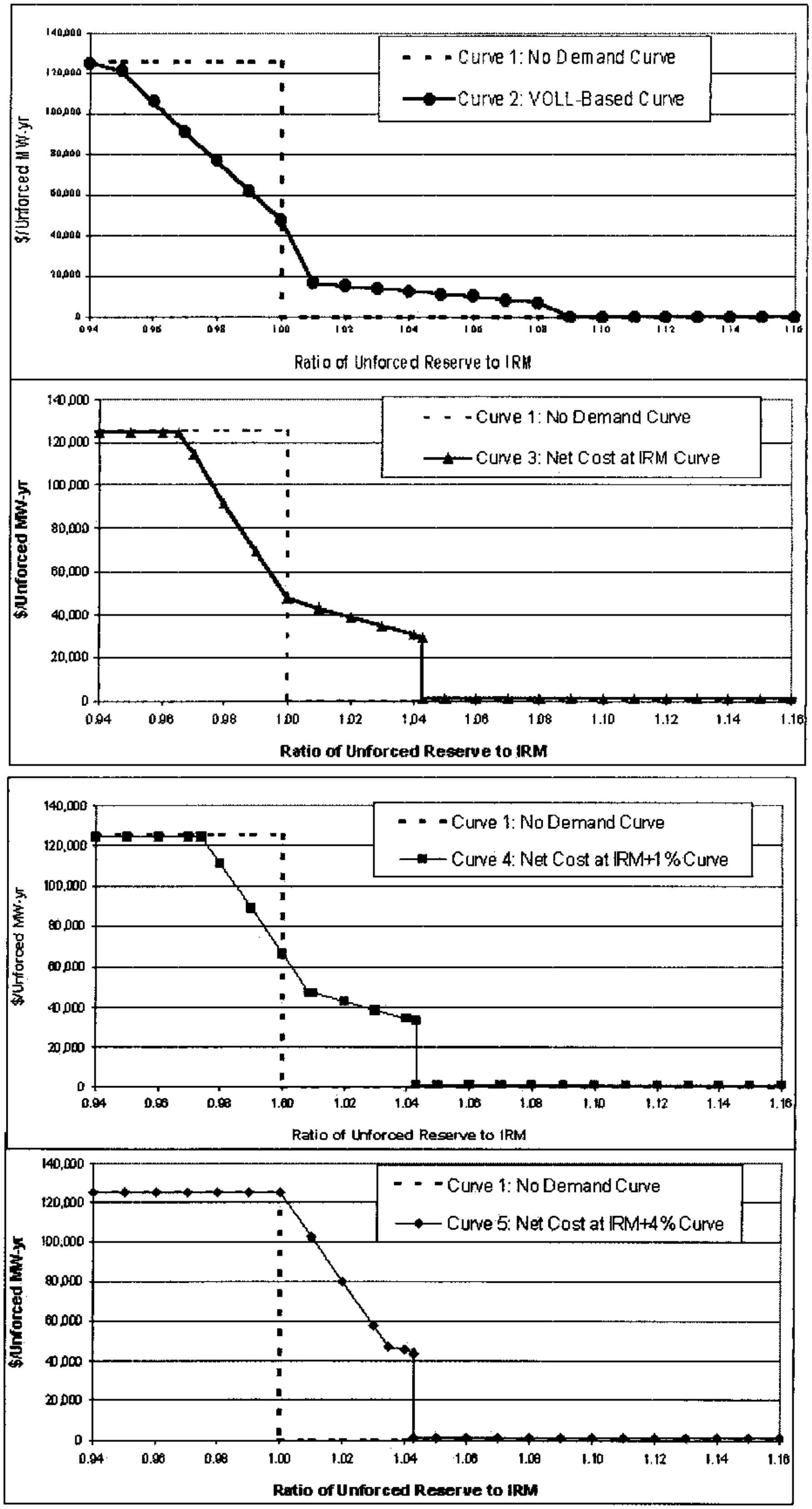


Figure 8. Five Alternative Demand Curves: ICAP Price Paid to Unforced Capacity as Function of Reserve Margin (Expressed as Ratio to Target Unforced Capacity)

As shown, the five curves consist of one similar to PJM's current vertical demand curve approach, one based on the value to customers of an increment of lost load, and three based on the cost to generators of installing a new peaking plant to serve an increment of additional load. In the last three curves, the estimated net cost of new entry is used as a reference price to ensure that as reserve margin levels decrease, capacity prices rise to incent new investment. As Professor Hobbs explains, the dynamic economic analysis revealed that the most significant parameter affecting the reliability performance of the curves was the distance the Net Cost of New Entry reference price was shifted to the right or the left of the Installed Reserve Margin threshold. Accordingly, of the three curves based on the net cost of new entry, one pairs that value with the IRM, one pairs that value with the IRM plus one percentage point, and one pairs that value with the IRM plus four percentage points.

Table 2 on the following page summarizes the results of Professor Hobbs' dynamic economic analyses of these five demand curves, showing how each fared in terms of reliability (how often the IRM was met or exceeded, and how large that exceedance (or shortfall) was on average), and costs (total consumer payments, scarcity payments, and capacity payments).

Table 2.

Summary of Results of Dynamic Analyses of Five Alternative Demand Curves

Curve	Forecast Reserve Indices: % Years Forecast Reserve Meets or Exceeds IRM	Forecast Reserve Indices: Average % Forecast Reserve over IRM (Standard Deviation)	Generation Profit, $/kW/yr (standard deviation [s.d.]) /IRR	Components of Generation Revenue: Scarcity Revenue $/kW/yr (s.d.)	Components of Generation Revenue: E/AS Fixed Revenue $/kW/yr	Components of Generation Revenue: ICAP Payment $/kW/yr (s.d.)	Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
1. No Demand Curve	39	-0.44 (1.92)	66/35.3% (113)	47 (85)	10	70 (57)	129 (121)
2. Original PJM Curve, Based on VOLL	54	-0.06 (0.74)	25/21.2% (73)	37 (70)	10	39 (14)	84 (78)
3. Alternative Curve with New Entry Net Cost at IRM	92	1.23 (0.87)	15/17.5% (53)	26 (52)	10	40 (4)	74 (55)
4. Alternate Curve with New Entry Net Cost at IRM+1%	98	1.79 (0.90)	12/16.6% (46)	21 (44)	10	42 (7)	71 (48)
5. Alternate Curve with New Entry Net Cost at IRM+4%	98	3.40 (1.05)	13/17.0% (41)	14 (31)	10	50 (20)	74 (43)

Curve 1: All of the downward sloping VRR curves perform better than the vertical curve (analogous to PJM's current capacity pricing). For the vertical curve, the average percentage reserve margin is less than the target IRM, and has a large standard deviation, reflecting substantial fluctuations above and below the reserve margin. Similarly, the average profits demanded by generators are higher than for any other case, and again have a large standard deviation, indicating substantial swings and volatility. Continuing the trend, the average payments by consumers (for both scarcity payments in the energy market and capacity payments) are highest for the vertical demand curve case, again with a very large standard deviation.

Curve 2: PJM considered a requirement curve based on the value of lost load as an alternative to relying on the cost of new entry. Rather than valuing incremental capacity at replacement cost (i.e., the cost of new entry), this curve values capacity based on the cost to the customer of having its service interrupted. As can be seen from the results for "Curve 2," this approach performed poorly, providing inadequate assurance of reliability, and relatively high cost.

Curve 3: Comparing the three downward sloping curves, the curve that pairs the net CONE with IRM (Curve 3) performs reasonably well, but not as well as the other two. That curve achieves the target IRM in fewer of the years, and results in slightly higher costs to consumers.

Curve 4: The curve that pairs net CONE with IRM + 1% (Curve 4) exhibits better reliability, with reserves at or exceeding IRM in 98% of the years. Capacity payments by consumers are only very slightly above the capacity payments for the IRM + 0% curve, and total consumer payments (including both capacity and scarcity payments in the energy market) are less. Profits demanded by generators are comparatively low, as are the standard deviations for all three metrics, indicating less volatility.

Curve 5: The last downward-sloping curve, which pairs net CONE with IRM + 4% (Curve 5), exhibits the same level of reliability as Curve 4. However, consumer payments for capacity are higher than for Curve 4, with a greater standard deviation. Although scarcity costs for curve 5 are the lowest of any curve, these do not offset the higher capacity costs, so total costs to consumers are higher than for Curve 4.

Based on these results, PJM chose Curve 4 as the initial VRR Curve for this RPM filing. This is the curve that sets the price of capacity at the cost of new entry, when the capacity level is one percentage point above the IRM. This curve appears to offer the best combination of adequate generation reserves and reliability for reasonable cost.

Professor Hobbs tested his results by running numerous sensitivity cases, varying certain inputs or assumptions and recalculating the results. Among other things, he looked at the impact of varying the intersection of the curve with the horizontal axis, i.e., the capacity level at which the price of capacity is zero. Recall that the vertical demand curve assigns zero value to capacity above the installed reserve margin. Accordingly, the closer the zero-price point is to the installed reserve margin, the steeper (more vertical) the resulting curve will be. To assess the differing performance of curves with various zero-crossing points, Professor Hobbs compared curve with a zero-crossing point at the IRM plus five percentage points, and with a zero-crossing point at the IRM plus ten percentage points. For Curve 4 above (which pairs the cost of new entry with the IRM plus 1%), he found negligible difference in reliability and cost with these alternative zero-crossing points. Given these results, PJM is recommending the curve with a zero-crossing point at IRM + 5% because it does not diminish reliability compared to the other alternative. This curve, which is closer to the current vertical demand curve, moderates the cost of capacity since it values at zero all capacity cleared at more than five percentage points above the target IRM. Had Professor Hobbs found that this curve resulted in lower overall reliability, or higher overall long-term cost, PJM would not adopt it. But as it appears to result in no significant reduction in reliability or increase in cost, this curve is preferable as it may help ease the transition to a downward-sloping capacity pricing curve.

While PJM has devoted considerable resources to selecting the VRR Curve for use in RPM, PJM recognizes that the curve may need to be adapted over time. Accordingly as part of the RPM design, PJM has committed to a stakeholder process to evaluate the performance of the VRR curve parameters at least every three years. The ongoing performance analysis will ensure that the VRR curve is adjusted as necessary to satisfy changing system conditions.

VII. Expected Energy Cost Savings from RPM

The benefits of the VRR curve extend beyond increasing reliability and reducing total capacity costs. There also can be additional consumer benefits in reduced energy prices, since the commitment of capacity at a higher reserve level will tend to decrease energy market prices. To assess these possible savings, PJM staff, under my direction, estimated the impact of varying reserve margins on load payments, locational energy prices, and generator production cost. As discussed in this section of my affidavit, PJM found that these savings could be quite significant, i.e., in the hundreds of millions of dollars.

A. Methodology

The objective of this analysis was to estimate the impact of varying PJM's reserve margin on the PJM regional energy market. The market impacts were measured in terms of load payment, locational marginal prices, and generator production cost for each reserve margin scenario.

PJM used the General Electric Multi-area Production Simulation ("GE_MAPS") megawatt flow program, a commonly-used production costing model, for this analysis. The GE-MAPS model was used because it can simulate security constrained unit commitment and economic dispatch scenarios using realistic generation operating constraints, and produce prices consistent with an LMP-based energy market such as PJM's market. PJM also used the detailed generation database maintained by GE Power System Energy Consulting, as well as a detailed electrical model of the entire transmission system.

The GE MAPS program calculates hour-by-hour production costs while recognizing constraints on generation dispatch that are imposed by the transmission system. The program uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved AC power flow model, to calculate the power flows for each hourly generation dispatch in the simulation. The program provides production costing results and hourly spot prices at individual buses and flows on selected transmission lines. The GE MAPS program formulates the generating system dispatch as a linear programming problem where the objective function is to minimize production costs subject to electrical constraints. The objective of the commitment and dispatch algorithms is to determine the most economic operation of the generating units on the system. The simulation is subject to the operating characteristics of the individual generating units, the constraints imposed by the transmission system, and operating and spinning reserve requirements. Accordingly, the analysis provides a reasonable estimate of the impact of varying levels of installed generation reserve where security-constrained economic dispatch is used to meet entire market demand.

A study base case for the PJM region with updated fuel costs for 2007 was developed from a GE MAPS 2003 Eastern Interconnection base case. Additional base case detail is presented in Attachment 2 to my affidavit. Each scenario was developed by retiring PJM capacity resources, starting with the earliest unit installation date and moving progressively to later installation dates, until the desired reserve margin was achieved (22%, 20%, 18%, 16%, 15%, 14%, 12%, and 10%). A calendar year 2007 annual run was completed for each scenario. The PJM forecast annual peak load for 2007 is 137,043 MW, and the forecast annual energy demand is 714,458 GWh.

B. Results

The results of each scenario are shown in Table 3 below, which demonstrates that as reserve margins tighten, customer payments for capacity and total energy production rise, while higher capacity reserve margins enable greater competition and lower total energy costs.

Table 3
Load Payments and Generation Production Cost in 2007 for Varying Levels of Reserve Margin

Reserve Margin	Annual Load Payment ($Million)	Wtd Avg LMP ($/MWh)	Summer Installed Capacity (MW)	Generation Production Cost ($Million)
22%	26,445	37.01	168,305	16,194
20%	26,743	37.43	164,805	16,294
18%	27,218	38.10	162,195	16,401
16%	27,840	38.97	159,359	16,532
15%	28,154	39.41	158,182	16,615
14%	28,457	39.83	156,762	16,691
12%	29,262	40.96	154,089	16,921
10%	30,238	42.32	151,413	17,175

Each column of Table 3 is defined below:

Reserve Margin - Amount of installed generation capacity (in %) above the PJM forecast annual peak load, i.e.,:

$$\frac{\text{Total PJM Summer Installed Capacity} - \text{PJM Forecast Annual Peak Load}}{\text{PJM Forecast Annual Peak Load}}$$

Annual Load Payment – Total annual load payment (in $Millions) for PJM load, calculated as the sum of hourly PJM loads multiplied by the corresponding hourly LMPs.

Wtd Avg LMP - The load weighted average rate for load payment, i.e.,:

$$\frac{\text{Total annual load payment}}{\text{Forecast annual energy demand}}$$

Summer Installed Capacity – Total of the summer capacity ratings for all PJM capacity resources.

Generation Production Cost - costs to operate generation at the desired level of output for each simulation hour, calculated as the summation of the hourly fuel cost, operation and maintenance cost, start-up cost, and emission cost for each thermal generating unit when dispatched at the simulated MWh output level.

C. Discussion of results

The annual energy market simulation results indicate that the average annual energy prices and total costs decrease with increasing installed generation reserve margin. For example, as shown in Table 3, the total annual load payments at a 15 percent installed reserve are estimated at $28,154 million. However, at an 18 percent installed reserve margin, total annual load payments were reduced to $27,218 million, or a decrease in total load payments of $936 million for the year. Similarly, the generation production costs decreased by $214 million from the 15 percent installed reserve margin case to the 18 percent installed reserve margin case. These energy cost savings would be in addition to the savings in capacity costs by clearing excess reserve on the VRR curve as shown in Table 2 above.

These savings greatly exceed the cost of procuring capacity at higher levels of reserves. For example, if we assume that the capacity market clearing price is $100 per MW day, and that the market clears along the VRR curve at approximately the 18 percent installed reserve level, then the annual capacity cost of the excess reserve above 15 percent would be $100/MW day * 365 days * (4013 MW[10]) = $146.5 million. This cost increase is less than the annual energy market savings of $936 million in reduced annual

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[10] 4,013 MW is the difference in capacity MW cleared at the 18% reserve level (162,195 MW) compared to capacity cleared at the 15% reserve level (158,182 MW).

load payments between the 18% and 15% installed reserve cases that are illustrated in the simulation results from Table 3. It is also less than the $214 million reduction in annual generation production cost that results from the 3 percent increase in installed reserve. These results indicate a substantial benefit to consumers in energy market savings through the application of the variable resource requirement curve in the RPM model.

VIII. Role of Load Management in the Reliability Pricing Model

A. Overview

Consistent with a long-term goal of encouraging development of load-management solutions as a cost-effective alternative to building more generation and transmission plant, PJM and its stakeholders are working on several initiatives that will open to load management resources opportunities that today are limited to generation resources, including developing a forward energy reserve market; rewarding demand reductions not only for reducing the need for energy, but also for reducing the need for certain ancillary services; and refining the treatment of, and compensation for, load management during emergencies to make it more comparable to the various ways in which PJM can call on and compensate generation in emergencies.

RPM supplements these efforts by eliminating a significant economic difference between generators and load management projects—the opportunity to receive compensation as a capacity resource. Until some future date when the PJM market is able to transition to an energy-only market, most generators' primary sources of revenue will be split between energy and capacity. To ensure the proper investment signals are communicated, resources should have access to both revenue streams. However, load management solutions do not currently have an opportunity to compete directly for the capacity share of available compensation. RPM will remedy this shortcoming. Under RPM, a load serving entity's obligations can be satisfied not only with existing and planned generation resources, but also with existing and planned demand resources, all of which will be allowed to offer into the RPM auctions as capacity resources.

RPM therefore will create a significant new forward revenue stream for load management resources that should encourage load response providers and plant operators towards long-term development of solutions that capture those revenues, reduce energy costs, and improve their bottom line. In short, RPM should facilitate capital investment in load management resources. Moreover, by allowing load-management resources the opportunity to bid competitively to satisfy system reliability requirements, the region as a whole will realize reliability-cost savings whenever those solutions are more cost-effective than generation or transmission alternatives.

RPM will establish two principal mechanisms for load-management alternatives to help meet the region's reliability needs: Interruptible Load for Reliability ("ILR") and Demand as a Resource ("DR"). For any given planning year, a demand responsive load may choose to be either, but not both types of resource, which will significantly expand the opportunities for load response over the current capacity model.

B. Interruptible Load for Reliability

ILR is a direct successor to current rules in PJM that allow load-serving entities to obtain credit against capacity obligations through qualifying load-management programs, known as Active Load Management, or "ALM." As an ILR provider, a load will offer to PJM up to ten 6-hour interruptions per year that can be invoked at PJM's sole discretion. This is the same number and duration as today in the ALM program. In return, the ILR provider will receive a credit against its RPM reliability charge. The credit will offset both the base (region-wide) reliability charge and the locational price adder (recognizing the locational value of the reduction in demand), but will not offset the portion of the charge that compensates for the operational reliability benefits that are unique to certain types of generators.

ILR may be certified as late as three months prior to the delivery year. Because RPM establishes capacity values for each year up to four years ahead, a customer that elects to participate as ILR in a given delivery year will know the value of capacity in PJM not only for that upcoming year but also for each of the next three years. This revenue certainty will help load response providers or end-use customers plan and implement the most cost-effective load-management processes or strategies. Therefore, even a customer that is reluctant to commit its load-response capability as a resource in an RPM auction still will have options under RPM to receive several years of capacity revenues (in the form of an ILR credit against the LSE capacity payment otherwise due in each of those years). And it can wait until after the results of the RPM auctions are known before making those resource plans. As a further option, the LSE could choose to offer its load management capability into one of the incremental auctions for the delivery year as a Demand Resource, to see if it can improve on the value it could obtain from that resource during the Delivery Year as ILR (which value was set by the base residual auction).

To ensure the market realizes the benefit of capacity offsets expected from ILR resources, PJM will net a forecast quantity of expected ILR from the total quantity of capacity to be obtained through the four-year-ahead base residual auction. By reducing the amount of capacity that must be procured in the auction, this netting of expected ILR likely will lower the clearing price. The ILR forecast will be adjusted for each succeeding delivery year based on the most recent experience with actual ILR resource certification in the most recent five-year period. Based on discussions of this issue in stakeholder forums, PJM anticipates a possible transition from this lagging forecast methodology to a dynamic price-based forecast once experience with RPM enables development of an ILR supply price curve.

C. Demand as Resource

In addition to granting customers credit against reliability charges through ILR, RPM offers load-management providers an opportunity to bid their resources (upon certification by PJM) into the auction, just like any generation resource. Both existing and planned Demand Resources can participate in the RPM auctions (both the Base Residual Auctions and Incremental Auctions), which commit resources years or months in advance to satisfy capacity obligation in a Delivery Year. The RPM auctions (base residual auction and incremental auctions) provide opportunities for DR providers to commit their demand resources 48 months, 23 months, 13 months, and four months before a Delivery Year. Demand resources will be paid the base capacity price in the PJM Region, plus any Locational Price Adders for the LDA in which the resource is located (but will not get the portion of the charge that compensates for the operational reliability benefits that are unique to certain types of generators.). This provides a potentially significant additional tool to help resolve deliverability concerns in constrained LDAs in a timely and cost-effective manner.

Thus, participation in the RPM auctions will provide demand response participants with a future revenue stream on which they can rely to aid their installation or expansion of demand resources. Demand Resources can incorporate these future guaranteed revenues into their planning processes to create new load-reducing capabilities, or enhance existing capabilities. Stated differently, these guaranteed revenues will spur greater capital investment in demand resources and encourage more demand response.

IX. RPM Seasonal Prices

In addition to varying prices by location and type of resource, clearing prices in RPM will also be allowed to vary by season. While each LSE's overall capacity obligation (which is based on summer peak loads) will remain the same, seasonal price-clearing will open opportunities for competition from resources (such as external generation resources) that may not be available to PJM loads year-round or that may offer greater price pressures during the seasons they are available.

Therefore, prices will be cleared separately in the Base Residual Auction and the three Incremental Auctions for four seasons: summer (June 1 to August 31), fall (September 1 to November 30), winter (December 1 to February 28), and spring (March 1 to May 31). Only prices will vary; the total capacity obligation in the Base Residual Auction will remain the same for the entire Delivery Year. Similarly, the incremental obligation procured in the Second Incremental Auction will be constant for the entire Delivery Year.

Under the seasonal approach, sellers of capacity from generation resources will have the option to offer that capacity for each season, with separate price bids by season, or for the entire year with a single bid. Transmission enhancements, which by definition are in the PJM region footprint and necessarily are committed to the PJM region for the entire year, may bid only on an annual basis. Sellers of Demand Resources will have an option of bidding their resources for the entire year, or only for the summer season (consistent with the summer performance criteria currently used to qualify ALM, which also will be used under RPM to qualify ILR and demand resources). If a demand resource is offered for the summer season only, then it will clear only if its price is at or below the clearing price determined for the summer season. If the summer-only demand resource clears, then the seller will receive revenues only for the summer period. Similarly, a generation resource offered at differing prices for differing seasons will clear only to the extent its offered price in a season is at or below the clearing price for that season. By contrast, a resource offered for the entire year (whether generation, transmission, or demand) will clear if its offer price is at or below the average of the clearing prices of the four seasons.

X. RPM's Role in Helping Meet the System's Operational Reliability Requirements.

RPM also will help address a recent decline in load-following and thirty-minute-start capabilities on the PJM system. While PJM presently is capable of meeting load-following criteria[11] on a reliable basis, PJM has experienced a significant decline in recent years in dispatchable and quick-start capabilities. RPM will value these capabilities, and encourage the investment needed to maintain and expand these capabilities.

PJM's current capacity construct treats all installed generation capacity the same, even though some units have added capabilities that bring added value to preserving system reliability. For example, loads can increase at a rapid rate on a typical summer day, and the system dispatcher must have at his disposal units that can dynamically track that increase in load. Similarly, loads can increase rapidly, drop off, and then rise to a second peak on a typical winter day; so the system dispatcher must have at his disposal units that can start, stop, and re-start potentially multiple times during a day. In any season, the rate of change in load at the start of a typical work-day is usually thousands of megawatts per hour. To ensure reliable service, therefore, the PJM region must have available an adequate amount of resources that can respond to rapid increases in load, known as "load-following" resources; and resources that can start and stop several times a day on relatively short notice, known as "thirty-minute-start" resources.[12]

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[11] NERC defines acceptable load/generation balance limits with its Control Performance Statistic ("CPS") criteria. In simplified terms, over any 10-minute period the average value of area control error ("ACE"), which is the instantaneous mismatch between load and generation plus net interchange, must not exceed a predefined limit (for example, 194 MW for the PJM Mid-Atlantic Region). If this limit is exceeded, a CPS violation is recorded. On average over every month, at least 90 percent of the 10-minute periods must be without violations in order to comply with the NERC criteria.

[12] More technically, the PJM RAA defines load-following resources as resources "that are capable of either dispatching within a given range at or above a minimum ramp rate, or cycling on- and off-line to respond to changes in system load as they occur" and thirty-minute-start resources as resources "that have generating capability over and above that needed to meet day-to-day peak demand that can be converted fully into energy within thirty minutes of a request from PJM." PJM RAA, Schedule 9.1.

The mix of pool-dispatched generating units must have a number of other characteristics to maintain reliability, including, for example, regulation capability, spinning reserve capability, and quick-start (i.e., ten-minute) capability. PJM's market rules already recognize the added value of regulation and spinning reserve capabilities, through real-time ancillary service markets for these products. In contrast, load-following and thirty-minute-start services are not well-suited to valuation in conjunction with the real-time energy market under current conditions. Unlike spinning and regulation service, load-following service is not a product that a generator provides in lieu of energy; rather it refers to the manner in which a unit provides energy, e.g., the unit's ramping or rate-of-change capability. In addition, energy and ancillary service markets currently are settled on an integrated or averaged hourly basis, but the essence of load-following service is the ability to change output within the hour, so payment for average hourly production does not recognize the value provided by load-following resources. This problem is hard to remedy—sub-hourly settlement to recognize real-time production would require substantial investment in new metering infrastructure. Similarly, a real-time market for thirty-minute-start service would be expensive to implement, out-weighing any benefit that a real-time market might offer compared to longer-term procurement of that service using a mechanism such as RPM.

The decline in load-following capability can be seen from the offer data provided to PJM by on-line units offered into the PJM energy market. Over the past four years, the amount of load-following generation offered in PJM has declined by nearly one-quarter. In June 2000, approximately 44 percent of all generation megawatts offered in PJM was dispatchable (i.e., capable of load-following), meaning that generators could ramp greater than 1 MW per minute over 44 percent of the region's total generation capacity. Currently, only 34 percent of total generation is dispatchable.

PJM also has seen a decline of about one-third in the number of available starts-per-day (i.e., the number of times the unit can be turned on, turned off, and turned back on during the day to help the system track rapid increases in load) offered by combustion-turbine units. Market sellers submit the available number of daily starts for their fast-start combustion turbines on a daily basis as part of their bid for the unit. Daily starts offered by market sellers have decreased from an average of 4.6 starts per day in June 2000 to 3.1 starts per day in August 2004, i.e., by about one-third.

A significant reason for the decline in economically dispatchable generation stems from the high costs of maintaining older fossil-fueled steam units in a condition that allows them to ramp more quickly and cycle more frequently. Frequent cycling of such units accelerates wear and tear and increases maintenance costs. Owners of such units need an increased economic incentive to cover these increased maintenance costs and preserve the economically dispatchable range and cycling capabilities of these units. PJM's current capacity payment mechanism does not separately value these costs, nor are they separately compensated in the energy or ancillary service markets.

While most of the units recently retired in PJM had load-following capability, that capacity is not being replaced by new load-following units. Of the approximately 1,500 MW of generation resources that have retired from service in PJM in the past two years, more than 1,200 MW were fossil-fueled steam resources, which traditionally have supplied PJM's load-following capability. And although more than 8,000 MW of new generation came on line in PJM in the past two years, none of it was from load-following resources. The units added were combustion turbines, gas-fired combined-cycle units or wind resources. None of these resource types are considered load-following resources because they can run only within a specific output range, and typically can start up only once per day. Although PJM estimates that approximately 1,800 MW of planned generation projects in the PJM interconnection queue has a high commercial probability of completion none of those projects (combined-cycle units, combustion turbines, and one wind project) have load-following capability.

To help address these concerns, the RPM auction-clearing algorithm will produce higher compensation for Load-Following Resources and Thirty-Minute-Start Resources to the extent needed to meet the system's requirements for such resources. Prior to the RPM auctions, PJM will determine the region's minimum requirement for each of these types of resources, and certify units capable of meeting those requirements. Market sellers with such resources can specify in their offers the added price, if any, they desire to offer these capabilities. If either of the operational reliability constraints bind in the auction, then the price will clear higher as necessary to ensure the minimum required amount of resources with such capability are committed in the auction. All generation resources in the region that provide that needed capability then will receive the same price adder.[13]

To ensure the capability is provided, resources committed in the auctions to resolve the operational reliability constraints must pass capability tests in the Delivery Year, and must specify and offer such capabilities in their offer data for the PJM energy market. If a seller does not provide the promised capability during the Delivery Year, it will be assessed penalties.

XI. RPM's Reliability Backstop Provisions

It is theoretically possible that a capacity auction might not elicit sufficient sell offers to ensure that enough capacity is committed to satisfy the region's reliability requirements. To address this contingency, RPM includes a backstop mechanism, under which PJM would hold a special auction (without relying on a VRR curve) to solicit offers to enter into long-term capacity sales agreements directly with PJM.

This backstop will not be lightly invoked; RPM sets a high hurdle for PJM to intervene in this manner. Specifically, the backstop will be triggered only if a shortage is observed in the auctions for four consecutive Delivery Years, and only subject to FERC approval. If PJM administers four consecutive base residual auctions in which

[13] The adder may differ for the two capabilities, i.e., Load-Following versus Thirty-Minute-Start. If the Load-Following constraint binds in the auctions, all Load-Following resources will receive the adder for that constraint; and if the Thirty-Minute-Start constraint binds, all Thirty-Minute-Start resources will receive that adder.

insufficient capacity is committed, then PJM will file with FERC for approval to conduct a reliability backstop auction within four months after the last such base residual auction.

If held, a Reliability Backstop Auction will seek commitments of additional generation resources for a term of up to fifteen years, based on the sell offer(s) that satisfy the posted reliability requirements at the lowest price. If a Market Seller's Sell Offer is accepted in the Reliability Backstop Auction, then PJM will enter into a long-term purchase agreement (on behalf of all LSEs in the PJM Region) with that Market Seller. Under this agreement, the Capacity Market Seller will be paid its offer price, less any payments the Market Seller is entitled to receive for commitment of such resource through the regular RPM auctions, and less any contributions to the fixed cost of its resource from the energy or ancillary service markets. The resulting agreement will be filed with FERC. PJM will recover the costs of such payments through a charge, in addition to the Locational Reliability Charge, assessed on all LSEs pro rata based on their Daily Unforced Capacity Obligations.

If its offer is selected in a backstop auction, the seller must offer all Unforced Capacity of its base load resource into the Base Residual Auctions held after the backstop auction for all Delivery Years in the term of its offer. The seller must offer such resources at zero price, and will receive the clearing price determined in each such auction.

XII. PJM's Administrative Costs to Implement RPM

Implementing RPM as proposed in this filing will not create substantial new administrative costs for PJM. PJM currently estimates that the up-front project implementation cost will be $1.6 million, which includes system design, software development, testing, participant training, and documentation costs. Moreover, PJM expects that the ongoing operational costs to administer the RPM auctions will not be greater than the current operating costs to administer the existing capacity market construct. PJM expects that the increased analytical requirements for the RPM locational and operational constraints will be offset by the reduction in the number of capacity auctions that PJM staff must execute on an annual basis.

This concludes my affidavit.

) Commonwealth of Pennsylvania
SS:)
) County of Montgomery

AFFIDAVIT OF ANDREW L. OTT

Andrew L. Ott, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Andrew L. Ott on behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ Andrew L. Ott
Andrew L. Ott

Subscribed and sworn to before me this 30th day of August, 2005.

/s/ April Mays-Parks
Notary Public

My Commission expires: 9/8/08

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
April Mays-Parks, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Sept. 8, 2008
Member, Pennsylvania Association Of Notaries

ATTACHMENT I

RPM AUCTION CLEARING OPTIMIZATION DETAILS

Objective function:

$$Z = \sum_{i,seg,oa}\left(BidMWBaseCleared_{i,seg,oa} \times Bid\text{Price}_{i,seg,oa}\right) + \sum_{j,rg}\left(TransMWCleared_{j,rg} \times Trans\text{Price}_{j,rg}\right) - \sum_{rg,seg}\left(SegMWCleared_{rg,seg} \times Seg\text{Price}_{rg,seg}\right)$$

This optimization problem is subject to the following constraints.

(1) $0 \le BidMWBaseCleared_{i,seg,oa} \le MaxBidMWBase_{i,seg,oa}$

(2) $ResourceMWBase_{i,oa} = \sum_{seg} BidMWBaseCleared_{i,seg,oa}$

(3) $0 \le BidMWOaCleared_{i,seg,oa} \le MaxBidOaMW_{i,seg,oa}$

(4) $ResourceMWOa_{i,oa} = \sum_{seg} BidMWOaCleared_{i,seg,oa}$

(5) $ResourceMWOa_{i,oa} \le OaCapacityCleared_{i,oa} \times MaxBidOa_{i,oa}$

(6) $ResourceMWBase_{i,oa} \le OaCapacityCleared_{i,oa} \times MaxBidBase_{i,oa}$

(7) $\sum_{oa} OaCapacityCleared_{i,oa} \le 1$

(8) $ResourceMWOa_{i,oa} \le ResourceMWBase_{i,oa}$

(9) $0 \le TransMWCleared_{j,rg} \le MaxTransMW_{j,rg}$

(10) $0 \le SegMWCleared_{rg,seg} \le MaxSegMW_{rg,seg}$

(11) $\sum_{oa,i \in rg} \text{Re}sourceMWBase_{i,oa} = \sum_{seg} SegMWCleared_{rg,seg}$, for all regions

(12) $\sum_{i} ResourceMWOa_{i,oa} \ge ReliabilityReq_{oa}$, oa is not equal to Base

(13)

$$\sum_{seg} SegMWCleared_{rg,seg} - \sum_{oa,i \in rg} \text{Re}sourceMWBase_{i,oa} \le \left(Limit_{rg} + \sum_{rg} TransMWCleared_{j,rg}\right)$$

(14) $\sum_{oa,i} ResourceMWBase_{i,oa} = \sum_{rg,seg} SegMWCleared_{rg,seg}$

Where

- $BidPrice_{i,seg,oa}$: Bid price of resource i and segment seg corresponding to operating attribute oa;

- $BidMWBaseCleared_{i,seg,oa}$: MW value cleared for resource i and segment seg and operating attribute oa;
- $SegMWCleared_{rg,seg}$: MW value cleared for variable resource requirement of region rg and segment seg;
- $SegPrice_{rg,seg}$: Price for variable resource requirement of region rg and segment seg.
- $Trans\text{Price}_{j,rg}$: Bid price of Participant-Funded Transmission upgrade j corresponding to Locational Deliverability Area rg;
- $Trans\text{M}WCleared_{j,rg}$: Import MW value cleared for Participant-Funded Transmission upgrade j and Locational Deliverability Area rg,
- $MaxBidMWBase_{i,seg,oa}$: Max bid for Fixed capacity for resource i and segment seg and operating attribute oa.
- $Limit_{rg}$: Available import capability for region rg.
- $ReliabilityReq_{oa}$: Market footprint-wide reliability requirement limit for operating attribute oa.
- $OaCapacityCleared_{i,oa}$: a $\{0,1\}$ decision variable indicating whether capacity for operating attribute oa is cleared.
- $MaxBidOa_{i,oa}$: Max bid-in capacity for operating attribute oa and resource i.
- $MaxBidBase_{i,oa}$: Max bid-in Fixed capacity with operating attribute oa for resource i.
- $BidMWOaCleared_{i,seg,oa}$: MW value cleared for resource i and segment seg and operating attribute oa;
- $MaxBidOaMW_{i,seg,oa}$: Max bid for resource i and segment seg and operating attribute oa.

Attachment 2

Base Case Model Details

The GE MAPS 2003 base case was utilized to develop the base case model for this analysis. The powerflow model included a full network transmission model representation of the entire Eastern Interconnection for the 2007 simulation year. The GE MAPS 2003 base case that represented the starting case for this study had the following characteristics. The annual peak-hour demand and annual energy demand for the regions were developed from the NERC Electricity Supply and Demand Database (2002 release). Hourly load data from 1997 was used to build hourly load shapes. The peak load and annual energy requirement are applied to the hourly load shapes for the Eastern Interconnection regions. The installed generating capacity for 2007 was based primarily on unit information contained in the RDI Basecase database (August 2001 release).

Operation and Maintenance (O&M) costs were developed by GE - PSEC in 1997 and 1999. Table 2 shows a summary of the range of the values applicable to generation plants PJM.

Table 2 - Operation and Maintenance Costs

	Variable Costs ($/MWh)
Nuclear	**0.6**
Gas Turbines	**1.5 – 4.0**
Steam Turbines	**0.6 - 1.4**
Combined Cycles	**1.2 - 1.5**

The generation outage rates included both maintenance outages and forced outages based on historic analysis using NERC GADS data for the period 1995-1999. Table 3 shows the outage rates used in the simulations.

Table 3 – Generation Outage Rates

Unit Type	Size(MW)	Planned Outage Rate	Forced Outage Rate
Nuclear	All	10	6
Fossil-Coal	0-99	9.6	4.8
	100-199	10	5.7
	200-299	10.6	6.1
	300-399	11.6	8.2
	400-599	11.9	8
	600-799	9.8	6.4
	800-999	9.7	5.9
	>=1000	12	7.7
Fossil-Oil	0-99	7.6	4.6
	100-199	10	5.6
	200-299	11	9.6
	300-399	13.4	6.9
	400-599	13.4	5.4
	600-799	14.4	7
	800-999	8.1	5.1
Fossil-Gas	0-99	6.4	4.2
	100-199	10.2	5.3
	200-299	12.4	3.8
	300-399	15.2	6.7
	400-599	13.2	5.4
	600-799	14.2	6
	800-999	10.5	6.1
GT	All	6.3	4.3
CC	All	10.5	3.3

The plant emission rates for large coal plants in PJM were derived using 1998 Continuous Emissions Monitoring System (CEMS) data. Default emission rates were used where specific information was not available. The default values used for the analysis are shown in Table 4.

Table 4 – Default Emissions and Heat Rates

	Default Emissions & Heat Rates						
	Full Load Heat Rate (MBTU/KWh)				Release Rates (lbs/MBTU)		
	<100 MW	100-250 MW	250-500 MW	>500 MW	SO_2	CO_2	NO_x
Coal-Fired Steam Boilers	11970	10950	10800	10400	1.38	205	0.48
Heavy Oil-Fired Steam Boilers	13370	11060	11990	10970	0.91	160	0.27
Natural Gas-Fired Steam Boilers	11860	10350	9970	9340	0	119	0.2

A set of annual average fuel prices was derived for MAAC fuels from PJM internal sources for 2004. The relationship between regions and the monthly profile was obtained from the RDI Basecase database (February 2002 release). The fuel prices used for the simulations are shown in Table 5.

Table 5 - Fuel Prices for 2007

$/mmbtu

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
MAAC Coal	2.77	2.74	2.77	2.80	2.74	2.71	2.75	2.75	2.73	2.72	2.74	2.77
MAAC Natural Gas	6.12	6.01	5.11	5.64	5.53	6.25	5.69	8.07	6.11	7.31	8.08	9.90
MAAC Oil #6	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
MAAC Oil #2	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95
ECAR Coal	2.47	2.41	2.42	2.49	2.44	2.50	2.53	2.50	2.47	2.44	2.52	2.50
ECAR Natural Gas	4.37	5.31	4.25	6.79	7.17	9.01	6.70	6.17	6.98	7.55	4.15	7.70
ECAR Oil #6	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
ECAR Oil #2	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95
MAIN Coal	2.38	2.38	2.33	2.36	2.40	2.40	2.38	2.40	2.36	2.30	2.26	2.23
MAIN Natural Gas	4.68	4.50	5.35	4.54	6.43	5.37	5.27	6.02	8.43	7.34	5.75	8.80
MAIN Oil #6	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
MAIN Oil #2	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95
VACAR Coal	3.08	3.09	3.06	3.08	3.08	3.07	3.07	3.03	3.03	3.02	3.00	3.02
VACAR Natural Gas	5.17	5.80	5.01	4.66	5.36	6.91	5.63	6.40	6.73	10.23	9.04	5.59
VACAR Oil #6	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
VACAR Oil #2	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95	8.95

TAB F

Affidavit of Steven L. Herling

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER05-______

AFFIDAVIT OF STEVEN R. HERLING
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

I, Steven R. Herling, being duly sworn, depose and state as follows:

My name is Steven R. Herling, and I am the Vice President of Planning for PJM Interconnection, L.L.C. ("PJM"). I am submitting this affidavit in support of PJM's proposed Reliability Pricing Model ("RPM"), in particular RPM's integration of planning and reliability requirements. Specifically, in this affidavit, I will:

- briefly present the history of PJM's capacity adequacy rules;
- describe PJM's regional transmission expansion planning ("RTEP")[1] process;
- describe reliability criteria violations recently identified by PJM, and PJM's response—payments to select retiring generators and transmission enhancements that can be accomplished in the near-term—to those potential reliability issues;
- show how RPM will provide a comprehensive framework for a long-term, integrated response to similar issues as they arise in the future, thus enhancing reliability;
- explain how RPM's locational element will help to satisfy the system's reliability needs as determined through the RTEP process;
- describe the benefits from RPM's assurance that system planning several years in advance will be informed by commitments of system resources (including generation, transmission, and load management) several years in advance; and
- explain in more detail how RPM will allow transmission enhancements and generation additions to compete to satisfy reliability needs.

I. Professional Qualifications and Background

As PJM's Vice President of Planning I am responsible for the Transmission Planning Department, which develops the RTEP and evaluates interconnections to the transmission system by new generation and merchant transmission projects, the

[1] I also use the acronym "RTEP" in this affidavit to refer to the regional transmission expansion plan produced each year through the planning process.

Interconnection Planning Department, which coordinates the activities required to implement generation and transmission projects on the PJM system, and the Capacity Adequacy Planning Department, which, in consultation with load-serving entities, sets and enforces requirements for the sufficiency, adequacy, and availability of the generation resources needed to ensure reliable service to loads.

I have been employed by PJM since May 1990, when I began work as an Engineer in the Operations Planning Department. I was promoted to Senior Engineer in 1993 and to Manager of the System Planning Department in 1994. I then held a number of management positions until I was promoted to Executive Director, System Planning Division in 2003. I was promoted to my current position in May, 2004.

While at PJM, I have contributed to or led a wide range of milestone achievements in its evolution and growth as a regional transmission organization ("RTO"), including the creation of the RTEP process, the development of procedures and standard terms and conditions for generator and merchant transmission interconnections, and the reliability and adequacy aspects of successive integrations of additional control areas that have more than doubled the size of the PJM market area in the last four years.

In addition to my work for PJM, I have contributed to the development of the planning standards and related compliance processes of the North American Electric Reliability Council ("NERC") as chair of NERC's Interconnection Dynamics Working Group and as a participant in its Standards & Compliance Task Force, and have served on various regional and industry working groups and committees addressing reliability and planning matters. I also have testified on a number of occasions on system planning and reliability issues in proceedings before FERC, state commissions, and legislative task forces.

Prior to joining PJM, I worked for the General Public Utilities Service Corporation for three years in systems operations, where I was responsible for dispatcher training and certification, operations planning activities, and energy management system ("EMS") and operational support tools. Prior to that, I worked for the American Electric Power ("AEP") Service Corporation for eight years in bulk transmission planning. In that position, I performed a range of power system analyses related to mechanical behavior of turbine-generator shaft systems, the AEP 765 kV transmission system, and generator and circuit breaker dynamic modeling.

I hold a Bachelor of Science in Electrical Power Engineering and a Master of Engineering in Electric Power Engineering, both from Rensselaer Polytechnic Institute. I am a licensed Professional Engineer in the state of Ohio.

II. PJM's Current Capacity Construct

For decades, PJM and its predecessor, the PJM Interconnection Association power pool, have set requirements for installed generating capacity to assure reliable service to loads. PJM and other system planners long have abided by well-established criteria to quantify adequate installed generation capacity, including the "loss of load expectation" ("LOLE") criterion underlying PJM's current installed capacity requirement. The LOLE is a measure of the likelihood that system demand will exceed the available generation capacity; in PJM and elsewhere, the LOLE goal is for demand to exceed capacity no more than one day in ten years on average.

The installed capacity ("ICAP") required to meet this criterion is expressed in terms of a percent reserve above the forecast peak load. Since the 1960's, PJM has been using probabilistic methods to determine the percent reserve margin that satisfies the established one-day-in-ten-years LOLE. The probabilistic analysis takes into account factors related to generation performance and load characteristics that affect reliability, such as generator forced and maintenance outage rates, load variability, load diversity, forecast uncertainty, and the availability of emergency assistance from neighboring systems. For many years, a committee composed of the utility members of PJM set the installed reserve margin ("IRM"), based on PJM planning staff analyses, to meet the LOLE. When it approved PJM as an RTO, the Commission assigned the IRM decision to the independent PJM Board of Managers, based on the advice of the load-serving entities in the region. The current IRM is 15% (i.e. 15% margin above forecasted peak load).

In addition to the region-wide generation adequacy standard, PJM has long used a deliverability standard to test the transmission system's ability to deliver energy from, and to, various parts of the region. PJM evaluates both generation deliverability and load deliverability. Generation deliverability refers to the capability of the system to deliver excess energy from a cluster of generators experiencing higher than normal availability to the remainder of the system experiencing a distributed shortage of capacity. Load deliverability refers to the system's capability to deliver energy from the aggregate of all capacity resources to an electrical area experiencing a capacity deficiency. As with generation adequacy, the load deliverability test employs probabilistic techniques and an LOLE standard.[2]

From 1974 to 1999, the PJM power pool imposed a two-year-forward annual capacity obligation. The total capacity requirement for the pool was allocated among all member utilities, and each utility was required to demonstrate that it had, or would have, sufficient ICAP to meet its load and reserve margin obligations two years ahead of the planning year. Any utility that then failed to meet its capacity obligation was assessed a capacity deficiency rate, based on the estimated annualized cost of adding a new combustion turbine to the pool.

In 1999, PJM replaced the two-year-forward annual obligation with the current approach, relying on a daily capacity obligation, supplemented with daily and monthly (covering up to twelve months) capacity credit markets, to accommodate the introduction of retail access. The daily obligation approach facilitated retail competition, by ensuring that the capacity obligation associated with a particular load (e.g., a retail customer)

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2 For testing internal transmission adequacy, the currently acceptable LOLE is one day in 25 years.

would promptly shift from one load serving entity ("LSE") to another when the customer changed suppliers. However, the LOLE criterion of one day in ten years, and the probabilistic determination of a region-wide mandatory reserve requirement, remained the same.

In 1999, PJM also revised the construct to discount the megawatt value of capacity based on the likelihood the resource will suffer a forced outage and become unavailable when needed by the PJM system. The unforced capacity, or "UCAP," approach, discounts a generator's installed capacity based on its "$EFOR_D$," which is the historical probability of that unit failing to perform when called upon by PJM. The resulting UCAP values are used to define the pool-wide reserve margin for the region, the individual capacity obligations met by LSEs, and the maximum amount of capacity provided by a resource.

Following the initial implementation of revised capacity rules for retail open access, PJM and its stakeholders have made various incremental changes to those rules. For example, in an attempt to address market power and potential withholding concerns, the capacity rules were revised to encourage generation owners to commit their resources to PJM for three- to five-month periods (as opposed to only daily). The other significant change since PJM was established as an ISO (and then as an RTO) has been the integration of neighboring systems into the PJM region. As these areas have been integrated into the PJM energy market and tariff, they also have become subject to the PJM capacity adequacy construct, which now sets a single unforced capacity reserve margin applicable throughout the entire region. Moreover, based on the planning assumption that the aggregate of all generation is deliverable to the aggregate of all load, capacity resources—and their prices—are not differentiated by location under the current construct.

III. Regional Transmission Expansion Plan

The rules and procedures for the RTEP process are set forth in Schedule 6 of the PJM Operating Agreement. In accordance with those rules, PJM annually prepares a plan for the enhancement and expansion of transmission facilities to meet demands for firm transmission service, and to support competition in the PJM region. The current PJM planning process tests for reliability criteria violations in each of the succeeding five years, but also assesses potential violations beyond that period, up to ten years out. The adopted RTEP will include transmission upgrades needed to resolve reliability criteria violations identified in the five-year horizon. The five-year plan, with the identified upgrades, establishes the baseline reliable system used in system impact studies for proposed generation or merchant transmission interconnections. As I discuss below, while the five-year RTEP horizon struck a reasonable balance when the current approach was adopted, PJM and its stakeholders now are considering options to extend that horizon, i.e., to order transmission upgrades based on reliability violations identified more than five years out.

In developing the RTEP, PJM annually tests the adequacy of the transmission system to deliver energy and capacity resources to loads in all areas of the PJM region.

For this purpose, PJM tests load deliverability (as defined above) for each relevant electric area within PJM. Specifically, PJM determines the amount of capacity that must be imported into an area during an emergency to ensure that such area can satisfy a transmission-related loss of load expectation of only one day in 25 years. This required emergency level of capacity imports is referred to as the capacity emergency transfer objective or "CETO." After PJM determines the required level of emergency capacity transfers into a zone (i.e., the CETO), it then determines the capability of the transmission system to transfer capacity into such zone under those emergency conditions, referred to as the capacity emergency transfer limit or "CETL." For the RTEP, PJM compares each area's forecasted CETO with the forecasted CETL for that area. If the CETO exceeds the CETL for a given area, PJM will identify transmission upgrades necessary to increase the CETL and resolve the problem.

The relevant electric areas tested in this fashion are determined functionally, based on the topology of the electric system and the location of transmission constraints. The areas addressed may include transmission-owner zones, aggregates of such zones, or sub-zones within such zones, i.e., wherever there are constraints that are likely to limit emergency transfers into an area of load.

Several factors affect the system's ability to pass the CETO/CETL load deliverability test: (1) new generation installed in a zone, which reduces the need to import energy using the transmission system; (2) retirements of existing generation in a zone, which increases the need to import energy using the transmission system; and (3) load growth, which, in the absence of new generation, increases the need to import energy using the transmission system.

As mentioned above, in the event that the analyses conducted in the RTEP process indicate that there are reliability criteria violations (e.g., a failure to satisfy the load deliverability test), PJM identifies transmission upgrades necessary to remove the violations. However, such load deliverability problems often could be resolved by generation additions or load response mechanisms. Under the current process, the adopted RTEP will take into account any previously proposed generation projects, capacity imports, or load response solutions, but the RTEP process does not order or solicit any generation projects or load response solutions, or set price signals to guide developers of such projects.

In 2004, the Commission approved changes to the RTEP process that allow PJM, in certain narrowly defined circumstances, to order transmission upgrades needed to enhance competition, in addition to those needed to resolve reliability criteria violations. Under these recently implemented rules, PJM relies on its ongoing assessments of transmission congestion to identify transmission upgrades needed to address congestion that is deemed to be "unhedgeable." Rather than immediately ordering such upgrades, however, the economic planning process incorporates a "market window," i.e., a period of time for competition among alternative solutions to come forward voluntarily and resolve the congestion issue. Only if market forces do not resolve such congestion within the window will PJM order construction of transmission upgrades.

PJM presently is working with stakeholders to consider possible reforms in the RTEP process. Until recently, the 5-year horizon in the RTEP process has been sufficient to identify baseline transmission requirements related to load growth. Transmission owners have been able to install within the 5-year horizon the upgrades identified in the RTEPs adopted so far. Consequently, market participants (particularly interconnection customers) have been able to rely on the baseline system identified in the RTEP, since the upgrades identified for installation actually have been installed. Certainty about transmission upgrades was matched to some degree by certainty about generation additions. The five-year RTEP horizon itself reflected the limits of certainty about generation additions, as the successful projects in the interconnection queue typically were built within about 3-4 years. Moreover, while there was no requirement for a long-term commitment of generation resources, there were a substantial number of projects under development when the RTEP process was first established, allowing system planners to anticipate with reasonable confidence that some level of generation additions would occur. Accordingly, the 5-year horizon seemed to provide the right balance of certainty with respect to expected system conditions and the ability to construct transmission in a timely fashion in order to assure continued reliability.

Now, however, there is concern that at least some of the potentially more substantial or extensive transmission additions that may be required in the future cannot be built within the current 5-year RTEP horizon. Further, the number of generation projects pending in the interconnection process generally has been lower than it was when the RTEP was first established. Lastly, recent experience with generation retirements (discussed below) has increased uncertainty for planners concerning the future system configuration.

As can be seen on Attachment 1 to my affidavit, the PJM Board of Managers ("PJM Board") has recognized that "the level and nature of transmission investment required for the region requires a longer time period" than the five-year planning horizon in the current RTEP process, and therefore has directed PJM to work with stakeholders to develop protocols that embed a longer-term view in the planning process. Moreover, the PJM Board has observed that it is not clear that the recently implemented economic planning rules "are achieving the desired outcome of ensuring adequate transmission investment to support robust competitive markets." The PJM Board therefore has directed PJM to review its current economic planning process and work with stakeholders to identify appropriate changes.

Accordingly, PJM is working with the states and stakeholders to shape enhancements to the RTEP rules, with a goal of filing such changes with the Commission in the near future. PJM will be working with its members and state commissions to refine its planning process, and in particular to resolve: 1) how far into the future the process should look; 2) how to account for the possibility that older or less economic "at-risk" generation units may retire during the planning horizon; and 3) the specific kinds of econometric modeling that should be incorporated into the process.

This initiative does not eliminate the need to reform generation capacity markets in PJM. To the contrary, extending the transmission planning horizon makes it all the more important to provide for forward commitment of generation capacity. For example, while it is not clear how generation that is at-risk of retirement will be identified and factored into the projections, it seems very unlikely that PJM could accurately identify such generation further into the future than five years. Forward commitments of capacity would substantially resolve this retirement risk. More broadly, extending the planning horizon places a higher value on reducing uncertainty concerning elements of the system plan, including the level of generation additions and the level, nature, and scope of load response programs. A system that commits capacity resources several years in advance will help manage some of the greater uncertainties inherent in longer-term planning. Moreover, capacity market reform will allow PJM to coordinate the identification in the RTEP process of areas experiencing load deliverability criteria violations with locational capacity pricing areas (known in RPM as Locational Deliverability Areas or "LDAs"). Identifying such areas for capacity market purposes as they are identified for system planning purposes will allow generation projects sufficient opportunity to resolve deliverability criteria violations before such violations occur and require transmission solutions.

IV. Recent Reliability Criteria Violations, and the Trends Contributing to Such Violations.

As mentioned above, several factors affect a system's ability to meet reliability criteria (such as the load deliverability test), including load growth, generation additions, and generation retirements. A large number of generation retirements announced in the last two years have caused multiple reliability criteria violations in eastern PJM, particularly in New Jersey. Steady load growth and declining or flat generation additions contributed to those violations. If present trends continue, reliability criteria violations will likely re-appear in New Jersey, and spread to other areas of PJM where similar conditions exist.

PJM estimates that in New Jersey load will increase by 1,950 MW (9.8%) between 2005 and 2010, but generation additions are not expected to keep pace. In 2003 and 2004, only 51 MW of new generation were constructed in New Jersey; and only 1340 MW are under construction.[3]

Similarly, load growth in the Delmarva peninsula is projected to be 2.7 percent per year, or an increase of 573 MW over the next five years, but planned generation additions are minimal. Only 60 MW were added on the Delmarva peninsula in 2004; and 150 MW are being studied in the interconnection process. In the Baltimore-Washington

[3] A substantial number of projects have been proposed for New Jersey in the most recent PJM interconnection queues, but projects at this earliest state of development in PJM typically suffer the highest rates of attrition, and therefore are highly uncertain. It may also be possible, given the modest initial cost to secure a place in the queue, that some of the very recent New Jersey projects in the queue represent a "bet" that RPM will be implemented soon, resulting in an increase in available capacity resource revenues in New Jersey in the near future.

area, only 77 MW of generation were added in 2004 and none is being studied in the interconnection process.

Against this backdrop, the PJM region has experienced a dramatic spike in generation retirements. For the four years from 1999 through 2002, inclusive, 274 megawatts of generation in the Mid-Atlantic region retired. By contrast, from January 1, 2003 through June 22, 2005, 1,709 megawatts of generation capacity retired, and an additional 1,694 megawatts are proposed for retirement in the Mid-Atlantic region from 2006 through 2008. Attachment 2 provides a listing of the generating units retired since January 2003 and those currently proposing retirement in the Mid-Atlantic region. Of the units identified in Attachment 2, 40% are located in New Jersey. The generation owners responsible for these retirements generally have claimed that the retirements are due to the current excess of generation in PJM (which is located mostly in the western region of PJM), and the inability of these particular units to compete economically.

The Commission recently determined that PJM cannot compel the owners of units proposed for retirement to remain in service; and that such retirements may take effect upon 90 days prior notice. This time period is designed to allow PJM to assess the reliability effects of proposed retirements, and to make compensation arrangements with the owner to retain in service units needed for reliability, as more fully described below. Although the system had been found reliable in prior RTEP reports, the announcement of these retirements with little notice resulted in the identification of reliability criteria violations for 2005 and each subsequent year in the most recent planning horizon, i.e., 2006, 2007, 2008, and 2009. Accordingly, although these units are critical to assuring deliverability to load in New Jersey, PJM's current capacity market rules attach no additional locational value to these units commensurate with their significance to local deliverability. Moreover, because the current capacity market rules do not require long-term capacity commitments, a system that had been found reliable in earlier RTEP analyses can experience violations of reliability criteria on relatively short notice, as the New Jersey experience demonstrates.

The trends noted above make other areas, such as Baltimore-Washington and the Delmarva peninsula, similarly vulnerable to possible reliability violations. In fact, 101 MW of generation retired in the Baltimore area in 2003, and recent planning studies found deliverability violations for both Baltimore-Washington and the Delmarva peninsula for 2008. These violations are to be resolved by planned transmission upgrades, but those are only a temporary solution. Unless additional generation is sited in these areas, further load growth would require more extensive and costly transmission upgrades. Moreover, any additional unanticipated retirements in either Baltimore-Washington or the Delmarva peninsula could cause these areas to experience load deliverability violations similar to those in New Jersey.

V. PJM's Response to the Reliability Violations.

Given the number of generation retirements implemented or announced in the last two years, and their short notice, the network upgrades needed to resolve the resulting reliability criteria violations will be significant and cannot be completed before the time periods for which the violations were identified. Consequently, in order to assure compliance with reliability criteria, PJM identified a number of the retiring generators that, if they remained in service, would resolve the reliability violations. The operators agreed to retain these units in service beyond their proposed retirement dates, subject to compensation in accordance with the generation deactivation provisions recently added to the PJM Tariff.

The retention of these units in service, along with the completion of a number of transmission upgrades, has enabled the PJM system to remain in compliance with all relevant reliability criteria for the current planning period (June 1, 2005 through May 31, 2006). However, as explained above, PJM also faces reliability criteria violations for each of the next four years. Additional transmission upgrades will be needed before each of the next four summer seasons to ensure continued compliance with reliability criteria. PJM also will need to retain in service for a number of years beyond 2005 the retiring generators that have been identified as needed for reliability. How long these units must be kept in service will depend on the pace of transmission construction.

In part as a result of these generation retirements, PJM's RTEP process recently has had to order unprecedented levels of baseline transmission upgrades to the system. Of the more than $1 billion worth of upgrades in the most recent plan, almost 60% are baseline reliability upgrades. Of these, approximately $200 million in upgrades are needed to address reliability violations from the New Jersey retirements for the years 2005 through 2007. Approximately another $300 million is estimated for the transmission upgrades needed to address retirement-related reliability violations for 2008 to 2009. It is possible that PJM may also need to install a new 500 kV circuit to help deliver energy from Pennsylvania to New Jersey. If required, this upgrade is expected to cost in excess of another $100 million. Should one more large generating unit in New Jersey retire, then the 500 kV circuit certainly would be required in addition to $100-200 million in further upgrades depending on the location of the retiring generator and the magnitude of the resulting local delivery problem.

The plan also currently includes baseline transmission upgrades needed to address load criteria violations previously identified for the Delmarva peninsula and Baltimore-Washington area for 2008. In the Baltimore-Washington area the addition of over 900 MVAR of capacitors are required over the next three years to maintain adequate voltages. In addition, a 500/230 kV transformer at Doubs substation will be replaced later this year with a higher rated transformer to provide additional transmission capability to support the Baltimore-Washington load. The cost of these system upgrades is estimated at $20 million. In the Delmarva peninsula, a new 230 kV line between Red Lion and Indian River will be installed in 2006 at a cost estimate of $47 million. Should any additional generators in these areas announce their retirement, additional substantial and costly transmission upgrades will be needed.

There are no quick, easy and inexpensive transmission solutions to the reliability issues that have arisen in the eastern portion of the PJM region, and if present trends continue, with few generation additions and additional retirements, the next round of available transmission solutions will become even more challenging and expensive. This is not to prejudge whether generation or transmission solutions will be the most cost effective in resolving future reliability criteria violations. However, it does underscore that the PJM region should not rely solely on transmission solutions under the current RTEP process to address any issues that may arise. Aside from their expense, there is the risk that transmission upgrades would not be built in sufficient time to avoid reliability problems. For example, construction of a new 500 kV circuit typically would be expected to take ten years or longer.

Forestalling generation retirements also is not an adequate solution to deliverability issues. While the Commission has allowed generators to receive compensation under the PJM Tariff for not deactivating if such units are needed for reliability, such special arrangements are temporary at best and fail to provide a long-term solution to the problem. As PJM's witness Joseph E. Bowring explains, such special arrangements fail to provide the market signal or incentive needed for other generators to propose solutions to the system's reliability issues. Moreover, units proposed for retirement often are near the end of their useful life and therefore their deactivation cannot be forestalled indefinitely.

VI. RPM's Locational Elements Are Coordinated with PJM's Transmission Planning Process.

A basic principle of RPM is that if generation capacity in a particular location is critical to reliability, it should be valued accordingly. With the appropriate locational valuation of generating capacity and a longer-term resource commitment, owners of existing resources will have the appropriate incentive to make the investments needed for their units to stay in the market, and project developers will have the appropriate incentive to locate new resources where they are most needed.

The best method of achieving these locational goals implicates another basic principle of RPM, i.e., that generation and transmission solutions should have an equal opportunity to compete to resolve deliverability constraints. Through its planning process, PJM identifies deliverability constraints for a wide range of load areas, including individual transmission owner service territories, sub-zones in such territories, and large regions comprised of multiple service territories. When PJM finds that one of these areas fails the deliverability test, the available transmission solution that resolves that reliability violation will be the upgrade that addresses the particular constraint limiting deliverability to that particular area. Similarly, the effective generation solution will be a plant located within that particular area, thereby effectively mooting the transmission constraint that is limiting deliveries into that area.

Accordingly, the capacity areas used in RPM must be consistent with the areas found by the transmission planning process to have deliverability issues. If the areas are not consistent, then generation sited in response to elevated locational capacity prices might not resolve the deliverability problem that resulted in the elevated capacity price. Generators would receive the higher capacity prices, but a transmission solution still would be needed. For example, if a locational capacity market paid higher prices in all of the eastern PJM region, but the deliverability problem was in northern New Jersey, then generation added on the Delmarva peninsula would receive the higher price, but would not solve the problem in New Jersey.

Moreover, because the areas affected by deliverability issues will change over time, the capacity pricing areas also should be dynamic. For example, large regions may be appropriate for parts of PJM today that are not experiencing localized deliverability issues, but those larger capacity pricing areas would not be effective at resolving zonal or sub-zonal issues should they arise in the future.

Finally, transition provisions may be appropriate to mitigate the initial price increases expected to result in constrained areas from the introduction of locational capacity pricing. However, such transitions should be limited since they also could have the effect, described above, of requiring loads to pay higher prices without targeting the incentive to the area most in need of relief from a deliverability problem.

The capacity areas used in RPM, known as LDAs, satisfy these principles. Under PJM's RPM proposal, LDAs will be determined using the same load deliverability analyses performed by PJM in the RTEP process, i.e., the comparison of CETO and CETL using a transmission-related LOLE of 1 day in 25 years. Based on these analyses, the LDAs will be those areas that have a limited ability to import capacity due to physical limitations of the transmission system, voltage limitations, or stability limitations. When RPM is fully implemented, PJM will determine and post the LDAs applicable to a particular delivery year (based on these deliverability considerations) at least four months before the start of the first RPM auction for such year. Accordingly, RPM will value capacity in a way that accounts for the transfer limits of the transmission system.

However, as a transitional matter, and to provide greater certainty for market participants as the new capacity market is implemented, the RPM tariff fixes the LDAs in effect for the first two delivery years, starting with two large LDAs in the first year and expanding to four LDAs in the second year. This approach was designed through the stakeholder process to acknowledge the impact that RPM may have on state retail auctions in New Jersey and Maryland, and to minimize the impact on bilateral contracts effective during the 2006 and 2007 delivery years.

For the first year under RPM, i.e., June 1, 2006 through May 31, 2007, the LDAs will be (1) the Mid-Atlantic Area Council ("MAAC") region plus the Allegheny Power System ("APS") zone; and (2) an area comprised of the zones of Commonwealth Edison Company ("ComEd"), American Electric Power System-East Operating Companies ("AEP"), Dayton Power and Light Company ("Dayton"), Virginia Electric and Power Company ("Virginia Power"), and Duquesne Light Company ("Duquesne").

In the second year, 2007-2008, the LDAs will be (1) the MAAC region plus the APS zone; (2) an area consisting of the zones of ComEd, AEP, Dayton, Virginia Power, and Duquesne;; (3) the eastern MAAC region, consisting of the zones of Public Service Electric & Gas Company ("PSEG"), Jersey Central Power & Light ("JCPL"), Philadelphia Electric Company ("PECO"), Atlantic City Electric Company ("AE"), Delmarva Power & Light Company ("Delmarva"), and Rockland Electric Company; and

(4) the southwestern MAAC region, consisting of the zones of Potomac Electric & Power Company ("PEPCO") and Baltimore Gas & Electric Company ("BGE").

In the third (2008-2009) and fourth (2009-2010) years, PJM will implement a full complement of LDAs, corresponding to the areas currently tested in the RTEP process. For those years, the LDAs will be (1) the MAAC region; (2) the PJM West region consisting of the zones of ComEd, AEP, Dayton, APS, and Duquesne; (3) the PJM South region consisting of the Virginia Power zone; (4) the eastern MAAC region; (5) the southwestern MAAC region;; (6) the western MAAC region consisting of the zones of Pennsylvania Electric Company ("Penelec"), Metropolitan Edison Company ("MetEd") and PPL; (7) the ComEd zone; (8) the AEP zone; (9) the Dayton zone; (10) the Duquesne zone; (11) the APS zone; (12) the AE zone; (13) the BGE zone; (14) the Delmarva zone; (15) the PECO zone; (16) the PEPCO zone; (17) the PSEG zone; (18) the JCPL zone; (19) the MetEd zone; (20) the PPL zone; (21) the Penelec zone; (22) the PSEG North region; and (23) the Delmarva South region.[4]

Under RPM, there will be separate variable resource requirement ("VRR") curves (the VRR curve is more fully described by PJM witnesses Ott and Hobb) determined for each LDA, reflecting differences in the cost of new entry[5] for those LDAs. Capacity Resources eligible to be offered into the RPM auctions will be identified by LDA. In the RPM auctions, the optimization algorithm (as described by Mr. Ott) will take into account, among other factors, the resources available in each LDA, the price offers from such internal resources, the constraints on delivering capacity into such LDAs (i.e., the CETLs), and the price offers from resources external to each LDA.

If an LDA is constrained, i.e., it has reached the limits of its ability to import less expensive capacity from outside the LDA, then the capacity price in that LDA will separate from capacity prices in the rest of the PJM region, similar to the LMP price separation that occurs today in the day-ahead and real-time energy markets when congestion arises. In RPM, this higher price is referred to as a Locational Price Adder. The Locational Price Adder reflects the added value of capacity resources located inside the constrained LDA, and will be available to existing or planned generation capacity resources, and existing or planned Demand Resources, so long as they are located in the LDA. As explained in more detail below, the Locational Price Adder also will be available to planned transmission upgrades that clear in an RPM auction, if the upgrade increases the CETL of the LDA.

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4 The LDAs are reflected in Attachment 3 to this affidavit.

5 As shown by PJM witness Ray Pasteris, the cost of new entry varies slightly in different parts of the PJM region, reflecting geographic differences in labor and other expenses. If an LDA covers more than one area for which PJM determined the cost of new entry, PJM will use the lower CONE value in that LDA.

VII. RPM Will Reasonably Apportion the Benefits of Import Capability into a Constrained LDA Among All LSEs Serving Load in that LDA.

When an LDA is constrained, resulting in a Locational Price Adder, RPM will mitigate the impact of that higher price on loads, by apportioning the benefits of import capability to all LSEs. Specifically, RPM will grant each LSE in a constrained LDA a Capacity Transfer Right ("CTR"), which entitles the LSE to a credit equal to the Locational Price Adder, times the LSE's pro rata share (based on the LSE's RPM capacity obligation) of the capacity imported into the LDA. Similar to the Financial Transmission Rights used by loads to hedge transmission congestion under the PJM Tariff, CTRs will entitle the LSE to credits that offset, in part, the higher capacity price it will pay to ensure reliable service to its loads in an import-limited LDA. This allocation method is reasonable, as it ensures that LSEs receive credit for the capacity imported into the LDA on the same basis that they will bear the added cost of capacity located inside the LDA, i.e., based on their daily RPM capacity obligation,[6] and based on the higher cost of capacity located inside the constrained LDA.

There is one exception to the rule that the benefit of import capability into a zone (i.e., the CETL) is apportioned among all LSEs serving load in that LDA. To the extent part of that import capability is attributable to an interconnection customer that bore the cost of a transmission upgrade that increased the import capability into the LDA, such customer will receive Incremental CTRs based on that increase in capability. These Incremental CTRs are available to any interconnection customer that became obligated to bear the costs—through a facility-specific charge—of transmission upgrades needed to satisfy its interconnection request at any time under Part IV of the PJM Tariff (which took effect on April 1, 1999), so long as that upgrade increased the CETL into the LDA at issue.

The Incremental CTR entitles the holder to a payment equal to the increase in CETL provided by the upgrade, times the Locational Price Adder for the LDA at issue. Moreover, because that portion of the CETL into the LDA is attributable to a participant-funded upgrade, and the funding participant gets credit for that share of the CETL, that share will be deducted from the import capability apportioned (through CTRs) to the LSEs in the LDA.

CTRs and Incremental CTRs will be fully transferable. The seller and purchaser of the rights simply must notify PJM of the transfer, in accordance with procedures that will be specified in the PJM manuals. The purchaser then will receive the payment stream associated with those CTRs.

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[6] An LSE's RPM capacity obligation can change each day, since the loads for which it is responsible can change (as a result of retail competition, for example) on any day. If an LSE, for example, gains a retail customer in a constrained LDA, it will become responsible for the Locational Price Adder for service to that load, but it also will be entitled to the CTR attributable to that load.

VIII. RPM's Four-Year Forward Auction, aud PJM's Long-term RTEP Process, Will Support One Another.

RPM will substantially improve on the current construct by providing closer integration of capacity commitments and transmission planning. As noted, locational constraints identified in the planning process will determine the capacity pricing areas used in the RPM auctions. The forward-looking transmission planning process will now be partnered with a comparably forward-looking capacity commitment process, allowing market participants in each process to take account of developments in the other. PJM will aid this process by supplying market participants with extensive information before each auction, including PJM's planning analyses of future loads, system resources, and capabilities. For this purpose, PJM anticipates providing more information than currently available in the RTEP five-year plan (which tests for actual load deliverability criteria violations), identifying areas that may be trending toward such violations beyond five years. While PJM does not currently rely on such longer-term projections for purposes of mandating transmission enhancements in the RTEP, there is no reason not to supply capacity market participants with this information. The market can decide how to discount any uncertainty in such longer-term projections.

The information from the planning process about expected future system conditions then can be distilled by auction participants into the most important single piece of information: the auction clearing price for commitments of capacity in future delivery years, varying by location, and changing from delivery year to delivery year. These price signals and trends should be of great assistance to market participants, especially in helping them to shape long-term bilateral capacity contracts.

IX. RPM Allows Proposed Transmission Solutions to Compete Directly with Generation Solutions to Resolve Deliverability Problems.

RPM will create direct opportunities for transmission upgrades to resolve local import concerns more efficiently than local generation, further reducing the likelihood of future reliance on out-of-market compensation. In addition to existing or planned generation projects, and existing or planned load response projects, RPM will allow planned transmission upgrades that provide incremental increases in import capability into constrained areas to be offered into the auctions. This will provide direct competition between generation and transmission solutions to meet the region's future reliability needs.

To participate in an RPM auction, a planned transmission upgrade must (i) increase the CETL into an LDA; (ii) be subject to a demonstration that it will be in service on or before the first delivery year for which it is offered; and (iii) be funded by a customer or owner through a rate specific to the facility. The last requirement ensures that a party receiving RPM revenues for a transmission upgrade is the party that bore the cost of the upgrade. A transmission upgrade may not be offered into an RPM auction unless it has been approved by PJM at least 45 days before the auction, which will include certification of the increase in CETL provided by the upgrade; confirmation that a

Facilities Study Agreement under the PJM Tariff has been executed for the upgrade; and certification that the upgrade conforms to all applicable RTEP standards.

When a seller offers a transmission upgrade into an RPM auction, it will state its offer price in terms of a price difference between a Capacity Resource located outside the LDA and a Capacity Resource located inside the LDA. This allows for direct comparison between the benefits offered by the transmission upgrade versus the benefits offered by competing generators. A transmission upgrade will compete directly with a proposed new generator to be built inside a constrained LDA to capture the Locational Price Adder that will be paid by loads inside the LDA. The market participant—transmission, generation, or demand resource—that offers the lowest Locational Price Adder needed to satisfy loads in the LDA will set the clearing price for the auction, and all sellers—transmission, generation, or demand resource—offering up to that price will clear. When a transmission upgrade clears in the RPM auction, the seller will receive payments during the delivery year equal to the cleared Locational Price Adder times the MW amount by which the upgrade increased the CETL into the LDA.

As designed, these rules give a single market participant the option of combining a generator located outside a constrained LDA with a transmission upgrade that increases the CETL into the LDA, so that the external generator can compete to satisfy loads in the LDA. While the sponsor of a transmission upgrade does not need to tie it to a specific external generator, it might choose to structure a generation plus transmission project that permits it to capture some of the higher value of capacity in a constrained LDA, in the process reducing overall capacity costs for customers in the LDA.

Finally, a market participant cannot receive both RPM auction revenues and Incremental CTRs for the same transmission upgrade. Rather, these represent alternative methods for obtaining an identical revenue stream (i.e., the upgrade's CETL increase times the LDA's Locational Price Adder) for qualifying upgrades.

This concludes my affidavit.

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AFFIDAVIT

Commonwealth of Pennsylvania)
) ss:
County of Montgomery)

AFFIDAVIT OF STEVEN R. HERLING

Steven R. Herling, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Steven R. Herling On behalf Of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/
Steven R. Herling

Subscribed and sworn to before me this 30th day of August, 2005.

/s/
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
April Mays-Parks, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Sept. 8, 2008
Member, Pennsylvania Association Of Notaries

My Commission expires: 9/8/08

Attachment 1

May 31, 2005

Dear PJM Members and Interested Stakeholders,

The PJM Board of Managers extends its sincere appreciation to all Members and Interested Stakeholders for their valuable input and dialogue on the Reliability Pricing Model (RPM) and on proposed enhancements to the Stakeholder processes, as well as the other matters addressed at the Annual Meeting. The Board is now in the process of evaluating how best to proceed with the current RPM proposal. In this letter, we update the Members on the Board's current thinking with respect to RPM and the Stakeholder processes.

As you may be aware, FERC has convened a technical conference on RPM on June 16, 2005. In light of significant difference of opinion on many aspects of RPM, the Board understands and welcomes FERC's interest in supporting PJM and its Members' efforts to reach a satisfactory resolution of this challenging topic. Thus, as a preliminary matter, the Board has elected to defer a decision on the RPM proposal until it has had a chance to consider the record which will develop during the FERC Technical Conference.

The Board also notes that the RPM proposal focused principally on establishing a longer-term generation commitment to facilitate the attraction and retention of generating capacity required for system reliability. The comments that we have received over the last year and particularly during the Annual Meeting crystallized the important perspective that an adequate capacity market cannot be developed in a vacuum. Rather, capacity solutions must be integrated with transmission planning and the development of robust demand side alternatives. For these reasons, and independent of the direction PJM ultimately may take with regard to RPM, the Board is directing PJM to undertake the following initiatives:

1. **Long term transmission planning –** The Regional Transmission Expansion Process (RTEP) currently uses a five-year planning horizon. It has become apparent that the level and nature of transmission investment required for the region requires a longer time period. The Board is directing PJM to work with the Membership to develop protocols for establishing a ten-year planning process by year end.

2. **Economic Planning –** The Board is concerned that PJM's current methodology for economic planning may not be achieving the desired outcome of ensuring adequate transmission investment to support robust competitive markets. The Board is directing PJM to review its current economic planning process and work with the Members to identify appropriate changes. To the extent feasible, PJM will undertake this analysis in conjunction with the development of the longer term planning process.

3. **Long-term FTRs –** The Board understood the concern of a number of Stakeholders that the absence of long-term FTRs is impeding transmission investment and the development of long-term bilateral capacity contracts. The Board understands that FERC has commenced a proceeding on this topic. The Board is appreciative of this initiative and will encourage timely completion of PJM's efforts in this regard.

4. **Demand Response –** PJM currently has several initiatives, including RPM, to integrate demand response programs into its markets and to expand the usage of demand response in the wholesale market. The expectation is that these initiatives will be filed with FERC by year-end. PJM is also working with its States to identify and resolve regulatory and other impediments to maximum participation of load in the markets. In this regard, the Board applauds the efforts of the States and the Membership and encourages their timely completion.

5. **Near-term generation and transmission adequacy and reliability requirements –** The RPM analysis revealed significant reliability concerns in Northern New Jersey beginning in 2008. Regardless of how RPM proceeds, the Board is convinced that these issues must be resolved expeditiously. The RTEP processes have already identified the near-term transmission requirements for these regions. The Board also understands that PJM and the transmission owners are taking the necessary steps to invest in and secure the reliability of the local grid. The Board will continue to monitor these efforts. In addition, the Board is directing PJM to work with the State of New Jersey and affected generation owners and load representatives to ensure that the appropriate contracts are in place to retain adequate generation in the region as well as to explore avenues to optimize the availability of demand response.

Finally, the Board is encouraged by the Members' response to the PJM Whitepaper which suggested modifications to the current Stakeholder process. The Board is pleased with the formation of a working group to address this topic and looks forward to the results produced by the group.

In closing, the Board appreciates the members' dedication to improving the PJM markets. As the PJM markets mature and the Membership increases, there will remain many opportunities to find and implement market design changes that will enhance the ability of the markets to meet electric customer needs. In almost every instance, there will be differences of opinion and new approaches to resolve the identified problems. As in the case of RPM, the Board believes that debate among the Members will improve the quality of the final product and identify other opportunities to improve reliability and market participation. The Board will continue to consider the RPM proposal and will inform the Members of its decision at the earliest possible opportunity, taking into account in its deliberations the record of the Commission's technical conference.

Sincerely yours,

Phillip G. Harris on behalf of the PJM Board
PGH/AAZ/cf/gks

Attachment 2

ATTACHMENT 2: GENERATOR RETIREMENTS and DEFERRALS[1] IN THE MID-ATLANTIC REGION (as of June 17, 2005)

Unit	Capacity	Trans Zone	Official Owner Request	Requested Retirement Date	Actual Retirement Date	PJM Reliability Status
Hudson 3 CT	129	PS	10/16/2003	10/16/2003	10/17/2003	No Reliability Issues
Seward 4	60	PN	11/19/2003	11/19/2003	11/20/2003	No Reliability Issues
Seward 5	136	PN	11/19/2003	11/19/2003	11/20/2003	No Reliability Issues
Gould Street	101	BGE	11/4/2003	11/1/2003	12/1/2003	No Reliability Issues
Sayreville 4	114	JC	11/1/2003	2/14/2004	2/19/2004	Reliability Issues Identified and Resolved
Sayreville 5	115	JC	11/1/2003	2/14/2004	2/19/2004	Reliability Issues Identified and Resolved
Delaware 7	126	PE	12/12/2003	3/1/2004	3/5/2004	No Reliability Issues
Delaware 8	124	PE	12/12/2003	3/1/2004	3/5/2004	No Reliability Issues
Burlington 101-104	208	PS	1/8/2004	4/4/2004	4/4/2004	No Reliability Issues
Burlington 105	52	PS	1/8/2004	4/4/2004	4/4/2004	No Reliability Issues
Wayne CT	56	PN	2/12/2004	As soon as possible	5/5/2004	No Reliability Issues
Sherman VCLP	46.6	AE	2/2/2004	3/15/2004	6/25/2004	No Reliability Issues
Warren 3 CT	57	PN	2/12/2004	Mothballed on 5/1/2004, relisted from 7/1/04 until 10/1/04	10/1/2004	No Reliability Issues
Riegel Paper NUG (Milford Power LP)	27	JC	6/11/2004	Planned to retire 6/30/04, request delayed until 12/31/04	1/1/2005	No Reliability Issues
STI 3 & 4 (Cat Tractor)	20	ME	9/29/2004	1/1/2005	1/1/2005	No Reliability Issues
Madison St. CT	10	DPL	10/13/2004	12/31/2004	1/7/2005	No Reliability Issues
Deepwater CT A	19	AE	10/13/2004	4/1/2005	5/1/2005	Reliability Issue resolved (Blackstart)

Kearny 7	150	PS	9/8/2004	12/7/2004	6/1/2005	Reliability issue identified and resolved
Kearny 8	150	PS	9/8/2004	12/7/2004	6/1/2005	Reliability issue identified and resolved
Howard M. Down (Vineland) Unit 7	8	AE	2/24/2005	5/31/2005	6/17/2005	No Reliability Issues
Total Retired:	**1708.6**					
Shawnee CT	20	PN	2/12/2004	Black Start Unit operational until at least 12/05	Deferred	Reliability Issue - Blackstart
Blossburg CT	19	PN	2/12/2004	Black Start Unit operational until at least 12/05	Deferred	Reliability Issue - Blackstart
Glen Gardner 1&5	40	JC	2/12/2004	Black Start Unit operational until at least 12/05	Deferred	Reliability Issue - Blackstart
Gilbert 1&4 CTs	50	JC	2/12/2004	Black Start Unit operational until at least 12/05	Deferred	Reliability Issue - Blackstart
Gilbert 2 & 3 CTs	48	JC	2/12/2004	Request Withdrawn	Withdrawn	No Reliability Issues
Glen Gardner 2-4, 6-8 CTs	120	JC	2/12/2004	Request Withdrawn	Withdrawn	No Reliability Issues
Werner 1-4 CTs	212	JC	2/12/2004	Request Withdrawn	Withdrawn	No Reliability Issues
Total Deferred:	**509**					

NOTE (1): This list includes retirements addressed as part of the PJM retirement process started in 2003. The list does not include generators retired prior to 2003.

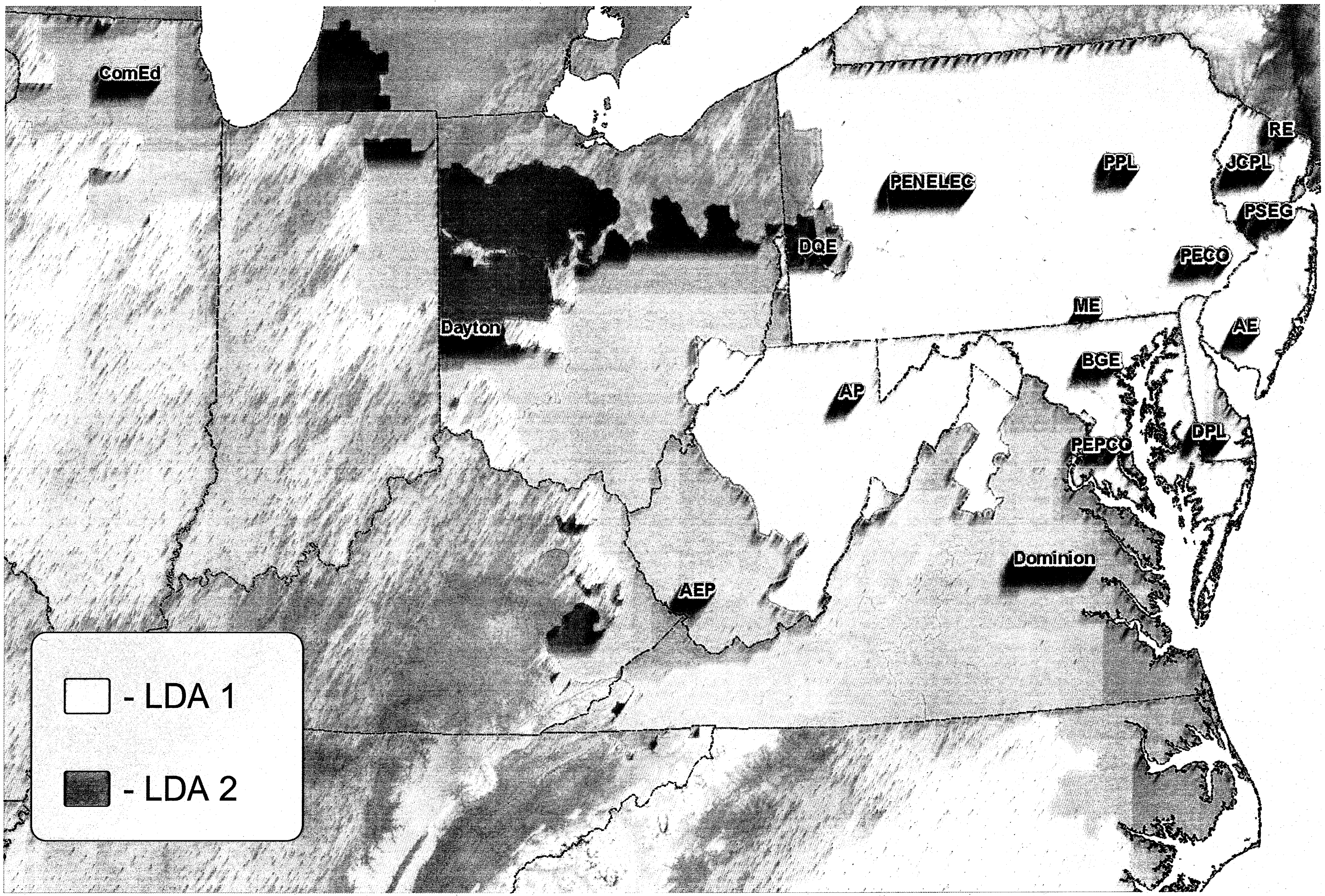
ATTACHMENT 2: FUTURE GENERATOR RETIREMENTS IN THE MID-ATLANTIC REGION (as of June 6, 2005)

Unit	Capacity	Trans Zone	Official Owner Request	Requested Retirement Date	Actual Retirement Date	PJM Reliability Status[1]
Martins Creek 1	140	PPL	3/19/2004	9/15/2007	None	No Reliability Issues
Martins Creek 2	140	PPL	3/19/2004	9/15/2007	None	No Reliability Issues
Gude Landfill 1	1.1	PEP	8/12/2004	10/1/2004	None	No Reliability Issues
Gude Landfill 2	1.1	PEP	8/12/2004	10/1/2004	None	No Reliability Issues
Sewaren 1	104	PS	9/8/2004	12/7/2004	None	Reliability Issues Identified - Unit retained through summer 2008
Sewaren 2	118	PS	9/8/2004	12/7/2004	None	Reliability Issues Identified - Unit retained through summer 2008
Sewaren 3	107	PS	9/8/2004	12/7/2004	None	Reliability Issues Identified - Unit retained through summer 2008
Sewaren 4	124	PS	9/8/2004	12/7/2004	None	Reliability Issues Identified - Unit retained through summer 2008
Hudson 1	383	PS	9/8/2004	12/7/2004	None	Reliability Issues Identified - Unit retained through summer 2008
B L England 1	129	AE	9/21/2004	12/15/2007	None	Reliability Issues Identified and expected to be resolved by 12/2007
B L England 2	155	AE	9/21/2004	12/15/2007	None	Reliability Issues Identified and expected to be resolved by 12/2007
B L England 3	155	AE	9/21/2004	12/15/2007	None	Reliability Issues Identified and expected to be resolved by 12/2007
B L England IC1-IC4	8	AE	9/21/2004	12/15/2007	None	Reliability Issues Identified and expected to be resolved by 12/2007

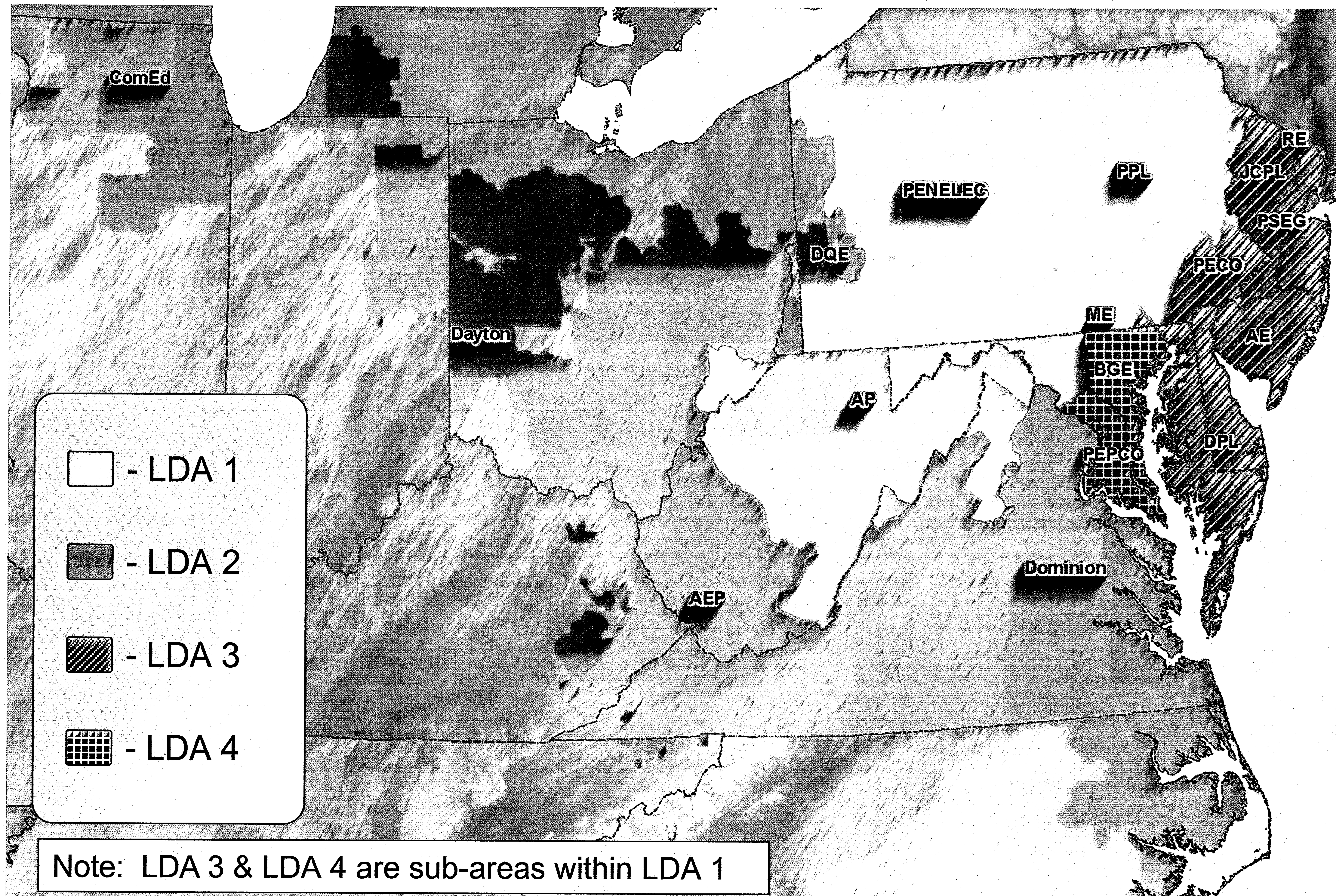
TOTAL: 1565.2

Attachment 3

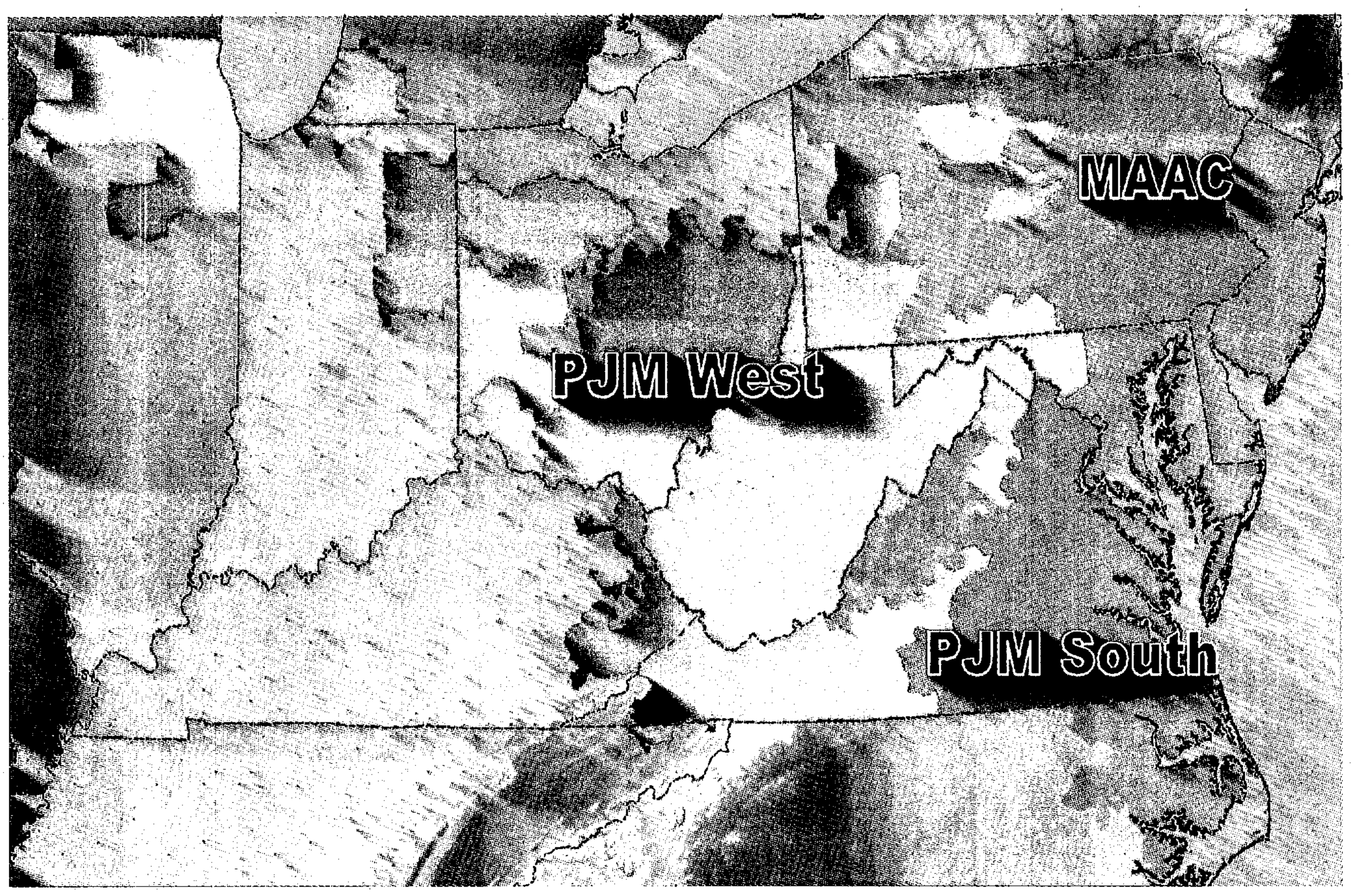
Attachment 3: Locational Deliverability Areas – 2006/2007

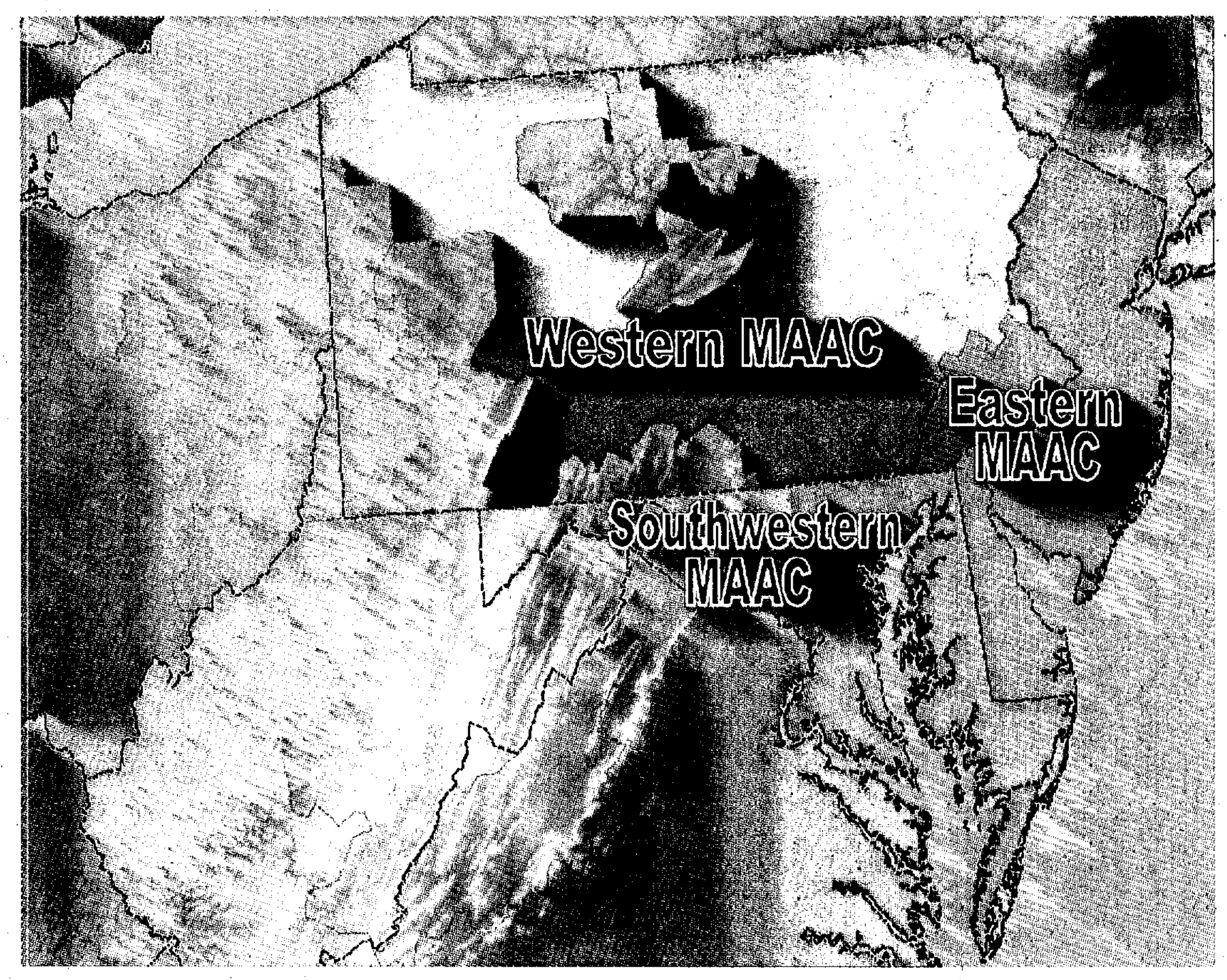


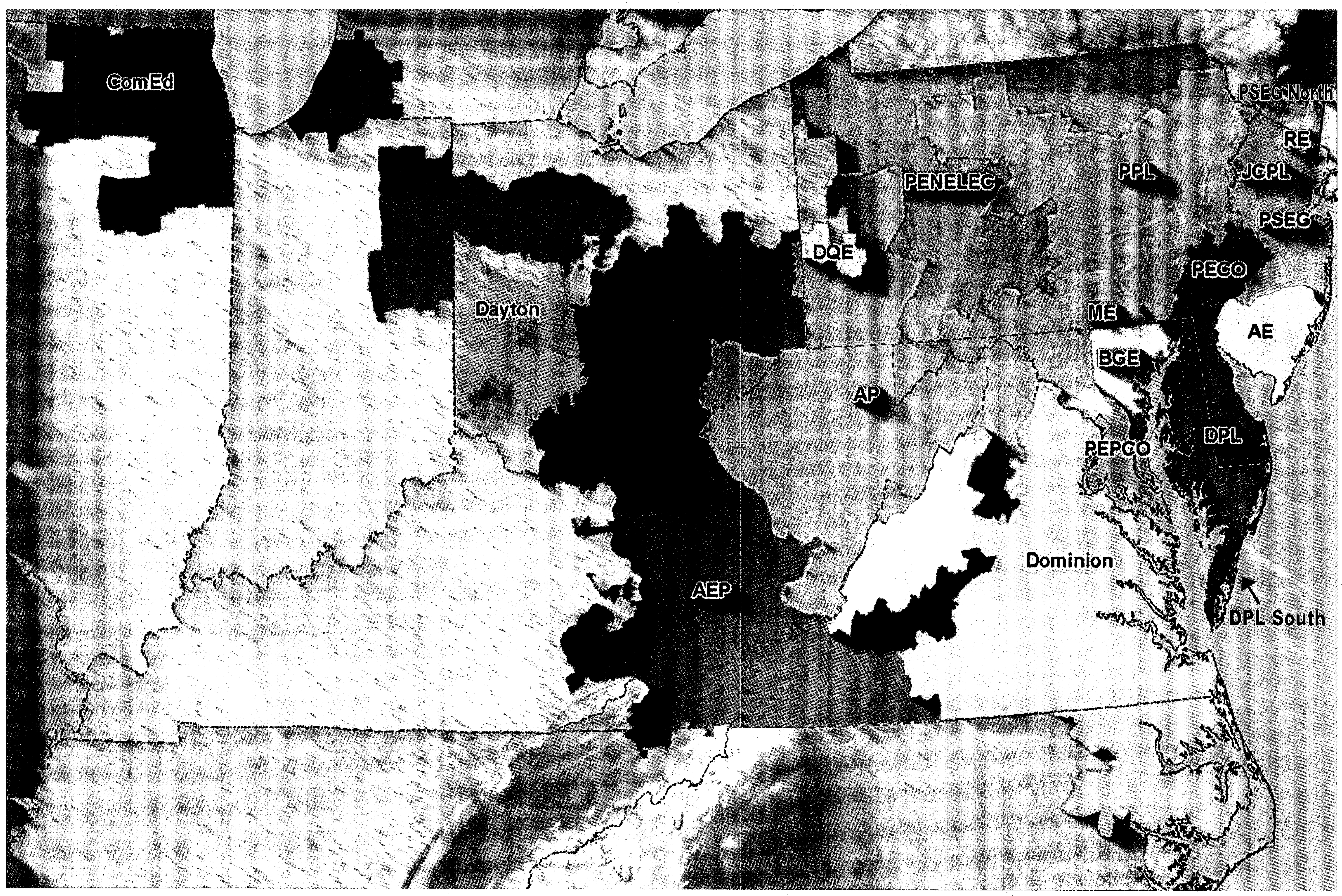
Attachment 3: Locational Deliverability Areas – 2007/2008



Attachment 3: Locational Deliverability Areas – 2008/2009 and 2009/2010







TAB G

Affidavit of Joseph E. Bowring

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM INTERCONNECTION, L.L.C.	)	**Docket No. ER05-____-000**
	)	**and EL05-____-000**

AFFIDAVIT OF JOSEPH E. BOWRING ON BEHALF OF PJM INTERCONNECTION, L.L.C.

My name is Joseph E. Bowring and I am the PJM Market Monitor. My business address is 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403. I am responsible for the market monitoring activities of PJM. These activities are defined by the PJM Market Monitoring Plan, Attachment M to the PJM Open Access Transmission Tariff. I am a Ph.D. economist and have substantial experience in applied energy and regulatory economics. I have taught economics as a member of the faculty at Bucknell University and at Villanova University. I have served as a senior staff economist for the New Jersey Board of Public Utilities and as Chief Economist for the New Jersey Department of the Public Advocate's Division of Rate Counsel. I have worked as an independent consulting economist. I have been the PJM Market Monitor since March 1999.

I am submitting this affidavit to explain and support several aspects of the Reliability Pricing Model ("RPM") filed by PJM in this proceeding. In particular, in this affidavit, I will:

- explain and support the methodology used in RPM to calculate the net energy and ancillary services revenue offset to the cost of new entry;
- explain and support the use of a nominal levelized financial model to calculate the cost of new entry;
- review the level of net revenues received by generation owners since the PJM energy market started operations in 1999; and
- explain and support the market power mitigation rules filed as part of RPM.

I. Net Energy and Ancillary Service Revenue Offset Against the Cost of New Entry

As explained by Mr. Andrew Ott in his affidavit for PJM, RPM uses a variable resource requirement curve ("VRR Curve") to represent the demand side in each RPM auction market. The cost of new entry ("CONE") for a new generation unit, net of the revenues such a unit would receive in the energy and ancillary services markets ("net CONE"), is a key parameter of the VRR Curve and therefore of the maximum price that will be paid for capacity under various supply conditions. In his affidavit for PJM, Mr.

Ray Pasteris calculates the cost of new entry for a combustion turbine ("CT") generator. He bases his estimate of the capital and fixed operating costs of a new entrant on a power plant configuration utilizing two 170 megawatt GE Frame 7FA turbines (the "Reference Resource"). Recent CT plants installed in PJM and other regions have incorporated these turbines. The 170 megawatt GE Frame 7FA turbine was chosen by Mr. Pasteris because it has lower capacity costs than the alternative CT technology evaluated.

Mr. Pasteris' calculations incorporate all fixed costs of a new generator including equipment and construction costs, interest payments, depreciation, taxes, fixed operation and maintenance expenses and return on investment. These are the costs that must be recovered from all PJM markets including energy, capacity and ancillary services markets. In PJM, capacity, energy and ancillary service markets are all significant sources of revenue to cover the fixed costs of generators.

If a new unit is to recover all of its costs from the PJM markets in equilibrium, the unit needs to recover from the capacity market only those costs not recovered in the other PJM markets. A competitive offer price in the RPM market for a new CT for its first year of operation equals the total annual fixed costs of the CT, less expected net revenues from all other sources. This is the incremental cost of new capacity. Accordingly, the CONE value provided by Mr. Pasteris must be reduced by an amount equal to the revenue a new CT can expect to receive from the PJM energy and ancillary services markets, less the variable expenses incurred to obtain those revenues ("revenue offset").

Net revenue is the contribution to fixed costs received by generators from PJM energy and ancillary services markets.[1] Although generators receive operating reserve payments as a revenue stream, these payments are not included here as a component of net revenues because the analysis is based on economic dispatch in the PJM model. Gross energy market revenue is the product of the energy market price and generation output. Gross revenues are also received from ancillary services markets. Net revenue equals total gross revenue less variable operating costs.

The RPM proposal relies on a formula to determine this revenue offset amount for the Reference Resource. As set forth in section 5.10 of new Attachment Y to the PJM Tariff, PJM will determine the energy market portion of the revenue offset as the annual average of the revenues that would have been received by the "Reference Resource" in the preceding six years based on "(1) the heat rate, variable cost, and other characteristics of the Reference Resource; and (2) the actual fuel prices and Locational Marginal Prices experienced in the PJM Region during such six-year period." Under this approach, the revenue offset is equal to the net revenues calculated based on how a unit with the characteristics of the CT for which the CONE is calculated would have operated under actual PJM prices.

1 The net revenues calculated in the Market Monitoring Unit's PJM State of the Market Report include capacity market revenues. Such revenues are not included here as the goal is to determine a competitive offer price in the capacity market for new entry after accounting for net revenues from all the markets except the capacity market.

While the CONE will be a stated amount in the PJM Tariff, a formula will be used to determine the revenue offset from the energy and ancillary services markets net revenues to subtract from the CONE. The CONE is generally not expected to change significantly from year to year. As explained by Mr. Pasteris, the primary determinants of the cost of a new CT include the cost of the generating equipment, the cost of construction, the cost of capital, the cost of land, the cost of labor, and taxes. Although these costs are subject to market pressures and may move up or down in response to those pressures, they generally are not expected to change significantly from year to year.[2]

In contrast, net revenues from the PJM energy market can be expected to change significantly from year to year, based on changes in the level of energy prices. As shown below, actual net revenues in PJM have shown such significant year to year changes since the PJM energy market was established (e.g. Table 1 and Figure 1). Net revenues are high in years with a high spread between energy prices and fuel prices and net revenues are low in years with a low spread between energy prices and fuel prices. A formula therefore will be more accurate than a stated rate in capturing net energy market revenues that vary significantly over time.

The revenue offset is based on the operating parameters of the same resource on which the CONE is based. The CONE is based on the GE Frame 7FA combustion turbine and the net capacity and net heat rate of this Reference Resource are used to calculate revenue offset values based on historical data from defined time periods.

The revenue offset calculation is used in RPM auctions that will determine capacity prices for Delivery Years four years in the future. The objective in the revenue offset calculation is to get the incentives right both for investors in generation and for load that will purchase capacity. In determining how best to calculate an appropriate revenue offset in the present period for a future period, the choice is between historical data and forward prices. (This assumes that there will not be an offset based on actual market conditions during the delivery year.) Historical data appear to be the only choice as there is no reliable source of market-based data on LMP and fuel costs for four years in the future. Given reliance on historical data, the choice is among possible numbers of years and annual weights. Investors are making decisions about constructing capacity based on expectations of energy revenues for the economic life of the facility. Thus investors are unlikely to build a unit based on the expectation that the last one or two years of net revenues represents future net revenues, especially in light of actual historical net revenue fluctuations. Historical net revenues over a representative measure of a full market cycle are a proxy for the expectations of investors about net revenues in the PJM energy market. Ultimately, investors focus on the actual net revenues received. The actual net revenues in the PJM energy market are a function of the actual market conditions during the delivery year.

I recommend the use of a rolling six-year simple average of net revenues for the Reference Resource for the revenue offset calculation. A six-year simple average provides equal weight to each year and covers a sufficiently long period that it is likely to

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[2] The RPM Tariff requires PJM to review the parameters of the VRR Curve, including the CONE, within three years.

capture the effects of both relatively high net revenue years and relatively low net revenue years.

In order to get the incentives right, reliance on six years of history is clearly preferable to relying on one or two recent years. If the most recent year were a low net revenue year, use of a single year would understate likely future net revenues and therefore overstate the cost of capacity and overstate the required investment incentives. If the most recent year were a high net revenue year, use of a single year would overstate likely future net revenues and therefore understate the cost of capacity and understate the required investment incentives.

Nonetheless, neither PJM nor investors can perfectly predict net revenues for the operating year. One goal in calculating both the CONE and the revenue offset is to define a reasonable measure of the competitive cost of new entry while leaving room for competitive forces to actually determine the clearing price in the capacity auctions, subject to the constraint of the VRR Curve. If actual competitive participant offers are less than the estimated net CONE, the clearing price will be lower than the net CONE and if actual competitive participant offers are greater than the estimated net CONE, the clearing price will be higher than the net CONE. (The net CONE is Mr. Pasteris' CONE calculation less the revenue offset for the Reference Resource.)

Another goal of calculating the revenue offset is to provide a mechanism for equilibrating the results of the energy markets and the capacity market. If the revenue offset is high, the competitive offer price for new entry will decline correspondingly as will the net CONE. The reverse is also true. In the absence of such an equilibrating mechanism, there is a risk that total payments from all markets could exceed or fall short of the incentives consistent with resource adequacy. In addition, such an equilibrating mechanism provides a disincentive to the exercise of market power in the energy market. If market power is exercised in the energy market so as to increase prices and net revenues, this mechanism would reduce the capacity market price correspondingly but the impact would be attenuated by the inevitable differences between the historical average revenue offset and actual delivery year results.

The revenue offset formula includes an estimate of variable operations and maintenance costs. These are the variable costs that, along with fuel costs, are incurred when the unit operates and are therefore required to realize the energy market revenues. For this purpose, the formula uses an amount of $5.00 per MW-hour, which Mr. Pasteris explains in his affidavit is an appropriate variable cost for the GE Frame 7FA plant configuration.

The revenue offset formula calculates energy market revenues using a "perfect dispatch" approach. The perfect dispatch approach assumes that a unit will operate whenever the LMP is greater than the marginal costs of the unit (fuel plus variable operation and maintenance expense). This is the simplest approach and thus works well in a tariff formula but it does not take account of operating constraints like minimum run times and other similar constraints.

A revenue offset can also be calculated for the Reference Resource from historical data using a "peak-hour" approach which explicitly accounts for such operating constraints for the Reference Resource. This approach produces a more refined estimate but also requires a number of detailed assumptions about how the unit would run. I present the results in the following section for the revenue offset calculated using both methods. The peak-hour revenue offset results assume that the CT plant will be dispatched by PJM in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average PJM real-time LMP is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block.[3] The blocks are dispatched independently. If there are not at least two economic hours in any given block, then the CT is not dispatched for the block.

While the submitted tariff sheets reflect the perfect economic dispatch approach, I believe either of these approaches could be acceptable. If the peak-hour approach is adopted, the detailed assumptions could be specified in the PJM Manuals.

The revenue offset formula adds $2,254 per MW-year for the ancillary service revenues likely to be realized by the Reference Resource. For CT units based on the GE Frame 7FA turbine, the type of generator on which the CONE value is based, the source of ancillary service revenues is Schedule 2 of the PJM Tariff, "Reactive Supply and Voltage Control from Generation Sources Service." To maintain acceptable transmission voltage levels, PJM has the authority to direct generator operations in a way that produces, or absorbs, reactive power. Generators capable of providing this service receive payments based on their reactive service revenue requirements approved by FERC, as stated in Schedule 2. Such revenue requirements vary from one generator class to another. For example, the cost of supplying reactive service from a combined cycle unit will not be fairly representative of the cost of supplying reactive service from a CT. The reactive service revenue amount of $2,254 per MW-year in the revenue offset formula is a weighted-average figure calculated from the reactive service revenue requirements filed for the 20 CT units that have been approved for recovery by FERC under PJM's Schedule 2. The details of this calculation are shown on Attachment I to my affidavit. The formula uses a fixed number for ancillary services revenues because the reactive services revenue requirement is not likely to change significantly from year to year. However this element of the offset also could be reviewed at the same time that the CONE is reviewed.

The revenue offset formula does not include revenues from other types of ancillary services because CT units based on the GE Frame 7FA are less likely to provide these services. Such units typically are not configured to provide either spinning reserve or regulation service, so no net revenues are included for either of those services. Similarly, these units are not routinely configured to provide black-start service, which requires a significant added investment in equipment needed to start the unit without an outside electrical supply. The filed CONE values do not reflect the cost of such equipment and as a result, no offset is included here for revenues from black-start service.

[3] The first block represents the four-hour period starting at hour ending 0800 EPT until hour ending 1100 EPT. The second block represents the four-hour period starting at hour ending 1200 EPT until hour ending 1500 EPT. The third block represents the four-hour period starting at hour ending 1600 until hour ending 1900 EPT, and the fourth block represents the four-hour period starting at 2000 EPT until hour ending 2300 EPT.

The revenue offset formula does not include operating reserve payments. Under the PJM tariff, operating reserve payments are a form of make-whole payment for generation units that operate at PJM's request when the LMP applicable to the unit is less than the unit's offer over the day of operation. Such payments are made when daily net revenue would otherwise be negative. The formula does not include negative net revenue days.

II. Calculation of Net Revenue Offset per Formula for Recent Years

To demonstrate the application of the formula, I present a calculation of the energy and ancillary services revenue offset, using data from the six years 1999 through 2004. As explained above, the revenue offset formula includes a calculation of the net energy market revenues that would have been received by the Reference Resource had it operated in the PJM market for the prior six years, based on actual fuel prices and LMPs in the PJM region during that time period.

As stated above, the Reference Resource is the same plant configuration on which Mr. Pasteris based the CONE value, i.e., a natural gas-fired combustion turbine consisting of two GE Frame 7FA units, equipped with full inlet air mechanical refrigeration and selective catalytic reduction ("SCR") for NO_x reduction.

For this calculation, the period from 1999 through 2004 constitutes the most recent six years of energy market experience. Burner-tip gas prices in the PJM Region are based on the published daily prices at the "Transco Zone 6 Non-New York" delivery point, adjusted for local transportation costs. The net revenue calculation uses daily fuel costs.

The calculation uses the actual LMPs in effect for each hour of the period 1999-2004, inclusive. This data, which is voluminous, is available for download from the PJM web site.

Per the filed formula, the variable O&M expenses for the Reference Resource are $5 per MWh. This cost is incurred as a result of unit starts and each hour the unit operates. Similarly, in accordance with the formula, ancillary service revenues are $2,254 per installed MW-year.

I present the results of two approaches to calculating the revenue offset. The first is the perfect dispatch approach and the second is the peak dispatch approach.

Had the Reference Resource been in service in the PJM region from the period 1999 through 2004, and had it been dispatched by PJM under the perfect dispatch assumptions (i.e. whenever the PJM LMP exceeded the plant's costs to generate including start-up and no-load costs) then, based on unit characteristics, the fuel prices, LMPs, reactive revenues, and variable O&M expenses described above, the plant's estimated net energy and ancillary service revenues would have been as shown in Table 1

Table 1 Energy market and ancillary service net revenues for a combustion turbine plant (dollars per installed MW-year) – perfect dispatch case.

	Energy	Reactive	Total
1999	$62,065	$2,254	$64,319
2000	$16,476	$2,254	$18,730
2001	$39,269	$2,254	$41,523
2002	$23,232	$2,254	$25,486
2003	$12,154	$2,254	$14,408
2004	$8,063	$2,254	$10,317
AVG	$26,876	$2,254	$29,130

Had the Reference Resource been in service in the PJM region from the period 1999 through 2004, and had it been dispatched by PJM during peak daily hours (see above for detailed description of parameters) when LMPs exceeded the plant's costs to generate (including start-up and no-load costs) then, based on unit characteristics, the fuel prices, LMPs, reactive revenues, and variable O&M expenses described above, the plant's estimated net energy and ancillary service revenues would have been as shown in Table 2.

Table 2 Energy market and ancillary service net revenues for a combustion turbine plant (dollars per installed MW-year) – peak dispatch case

	Energy	Reactive	Total
1999	$55,612	$2,254	$57,866
2000	$8,498	$2,254	$10,752
2001	$30,254	$2,254	$32,508
2002	$14,496	$2,254	$16,750
2003	$2,763	$2,254	$5,017
2004	$919	$2,254	$3,173
AVG	$18,757	$2,254	$21,011

The results in Table 1 and Table 2 are for the PJM region as a whole. However RPM relies on CONE values for three subregions of PJM, eastern, central, and western. (See Attachment II - CONE Map.) Thus, net revenue calculations are needed for each subregion. The formula specifies that subregional offsets will be calculated only when there are at least two full calendar years of LMP data available. The PJM region average net revenue will be used where there is not such data.

In Table 3 and Table 4, I present data on the net energy and ancillary services revenues for the eastern and central subregions. As there are not two full calendar years of data available for the Commonwealth Edison Company ("ComEd") zone in Illinois, a subregional revenue offset is not calculated for that zone. When such data becomes available, the revenue offset for that subregion will be calculated in the same manner as described below, except that the relationship between the subregion and PJM region-wide numbers in the years for which data is available will be used to estimate the subregion revenue offset in the years for which PJM market data is not available in that subregion.

When he prepared the CONE estimates, Mr. Pasteris assumed the new entry plant for the eastern region would be located in the Atlantic City Electric Company ("AECO") service area and that the central region plant would be located in the Baltimore Gas & Electric Company ("BG&E") service area. Accordingly, the eastern and central subregion revenue estimates use 1999-2004 LMP data for the AECO and BG&E transmission zones, respectively.[4]

Table 3 presents the results of the applying the revenue offset formula to a CT with AECO zonal prices using the perfect dispatch method. The AECO zone average net revenue results are $6,892 per MW-year higher than the corresponding PJM-wide perfect dispatch results because the AECO zonal LMPs have been higher than the PJM region average LMPs.

Table 3 Energy Market and Ancillary Service Net revenues for a combustion turbine plant at AECO zonal average prices (Dollars per installed MW-year) – perfect dispatch case

	Energy	Reactive	Total
1999	$62,798	$2,254	$65,052
2000	$21,187	$2,254	$23,441
2001	$51,880	$2,254	$54,134
2002	$29,715	$2,254	$31,969
2003	$16,643	$2,254	$18,897
2004	$20,385	$2,254	$22,639
Avg	$33,768	$2,254	$36,022

Table 4 presents the results of applying the revenue offset formula to a CT with BG&E zonal prices using the perfect dispatch method. The BG&E zonal net revenue results are only $593 per MW-year higher than the corresponding PJM-wide perfect dispatch results because the BG&E zonal prices are almost identical to the PJM region average LMPs.

Table 4 Energy market and ancillary service net revenues for a combustion turbine plant at BG&E zonal average prices (Dollars per installed MW-year) – perfect dispatch case

	Energy	Reactive	Total
1999	$61,148	$2,254	$63,402
2000	$14,395	$2,254	$16,649
2001	$31,026	$2,254	$33,280
2002	$30,455	$2,254	$32,709
2003	$15,207	$2,254	$17,461
2004	$12,581	$2,254	$14,835
Avg	$27,469	$2,254	$29,723

[4] The analysis for each of the two transmission zones uses the zonal-average LMPs for all nodes for such zone.

III. Use of Nominal Levelized Financial Model to Determine CONE

Mr. Pasteris uses an iterative process to calculate the revenue requirements needed over the twenty-year financing life of a new CT plant to recover the plant's costs. As he explains in his affidavit, he starts with an initial estimate of an annual revenue requirement. The financial model deducts from that revenue the amounts needed to recover the operating costs and capital costs, other than the return to equity, escalated at a predetermined 2.5% per year, including interest, taxes, debt principal and other cash flow items, and calculates the resulting internal rate of return ("IRR"). Mr. Pasteris' calculations result in the annual revenue requirement necessary to achieve the target IRR.

Mr. Pasteris presents the revenue requirements in two ways. The first method, "real levelized," is a stream of increasing payments over 20 years which vary only by the assumed inflation rate of 2.5%. This method is termed real levelized because it is constant in real, or inflation adjusted, terms. The second method, "nominal levelized," is a stream of 20 constant annual payments. This method is termed nominal levelized because it is constant in nominal, non-inflation adjusted, terms. Both payment streams provide the same net present value ("NPV") to the project developer. The nominal levelized revenue stream provides higher payments earlier in the project life and lower payments later in the project life than does the real levelized revenue stream. Thus, if the project developer owned the unit for 20 years and received the specified annual revenues in each year, the developer would be indifferent between the revenue streams resulting from the two methods.

Both methods result in levelized annual revenue requirements and both provide for full recovery of project costs including inflation and realization of the target rate of return over the project's twenty-year life, rather than focusing only on the accounting costs accrued in a single test year. As Mr. Pasteris states, levelized approaches to evaluating power generation investments are commonly used by owners and developers. The only difference between the two levelization methodologies is that the real revenue requirement increases each year by the assumed inflation rate whereas the nominal revenue requirement remains constant each year.

In the RPM model this matters because new entry can set the price of capacity in the market based on its full cost of entry only when it is offered as a new unit and cannot set the price of capacity based on its full cost of entry after operation has begun.[5] An actual competitive offer by a potential entrant could reasonably be based on either method of levelizing the revenue requirements. The net CONE calculation functions as an upper bound on the price that will be paid to new entrants in the capacity market, recognizing that when the reserve margin is less than IRM plus 1 percent, the price will exceed the net CONE but will be a function of the CONE.

I recommend the use of a nominal levelized revenue requirement for the CONE. As a general matter, the RPM construct relies upon market forces to ensure that the offer prices of new capacity are competitive. It is appropriate to base the CONE calculation

[5] A unit is defined to be new for purposes of offering into the RPM until its commercial date.

and therefore the demand curve on the nominal levelized payment stream in order to ensure that the market rules do not exclude reasonable competitive offers. If potential entrants make offers at the real levelized net cost of new entry, they will appropriately win the auction, the clearing price would equal the real levelized net cost of new entry and there will not be an issue. However if potential entrants determine that a competitive offer is equal to the nominal levelized payment stream then a demand curve based on the nominal levelized payment stream would result in the same price as the demand curve based on the real levelized payment stream, assuming all new entry offers at the same price. However, more capacity would be purchased at the clearing price if the VRR is based on the nominal levelized CONE rather than the real levelized CONE under certain conditions. In addition, if total supply offers are less than the demand curve, the clearing price would be higher under the nominal levelized payment CONE than under the real levelized payment CONE.

The nominal levelized method results in an annual revenue requirement that incorporates expected cost increases over the life of the project in the first year revenue requirement. The real levelized method results in a first year annual revenue requirement that does not reflect expected inflation-based cost increases over the life of the project. The nominal levelized approach is appropriate for a fixed CONE value that will be used to clear auctions for multiple delivery years several years in the future. The CONE estimate prepared by Mr. Pasteris is based on a project with its first year of operations in 2006. Under the filed RPM market rules, that CONE value will be used to clear markets in auctions for delivery years at least through 2010,[6] and probably several years thereafter.[7] The CONE value stated in the tariff can only be changed following a stakeholder process and with FERC approval. It would be inappropriate to ignore cost escalation beyond 2006 as this would result in an underestimate of the cost of new entry and thus reduce incentives for new entry in auctions for subsequent years.

As an example, the 2006 revenue requirement under the real levelized approach is \$61,726 per MW-year while the 2006 revenue requirement under the nominal levelized approach is \$72,207. The 2010 revenue requirement under the real levelized approach is \$68,134 per MW-year while the 2010 revenue requirement under the nominal levelized approach is \$72,207. The real levelized method would result in an understatement of the cost of new entry for each year after 2006. The cross over point where the two revenue requirements are equal occurs between 2012 and 2013. Beginning in 2013, the annual revenue requirement under the real levelized approach exceeds the annual revenue requirement under the nominal levelized approach.

IV. Generator Net Revenues in PJM

In this section of my affidavit, I present data on generator net revenues in the PJM markets. Generator net revenue is an indicator of generation investment profitability, and thus is a measure of overall market performance as well as a measure of the incentive to

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6 Under the RPM transition provisions, auctions for the first four delivery years, through 2010, will be conducted in 2006.

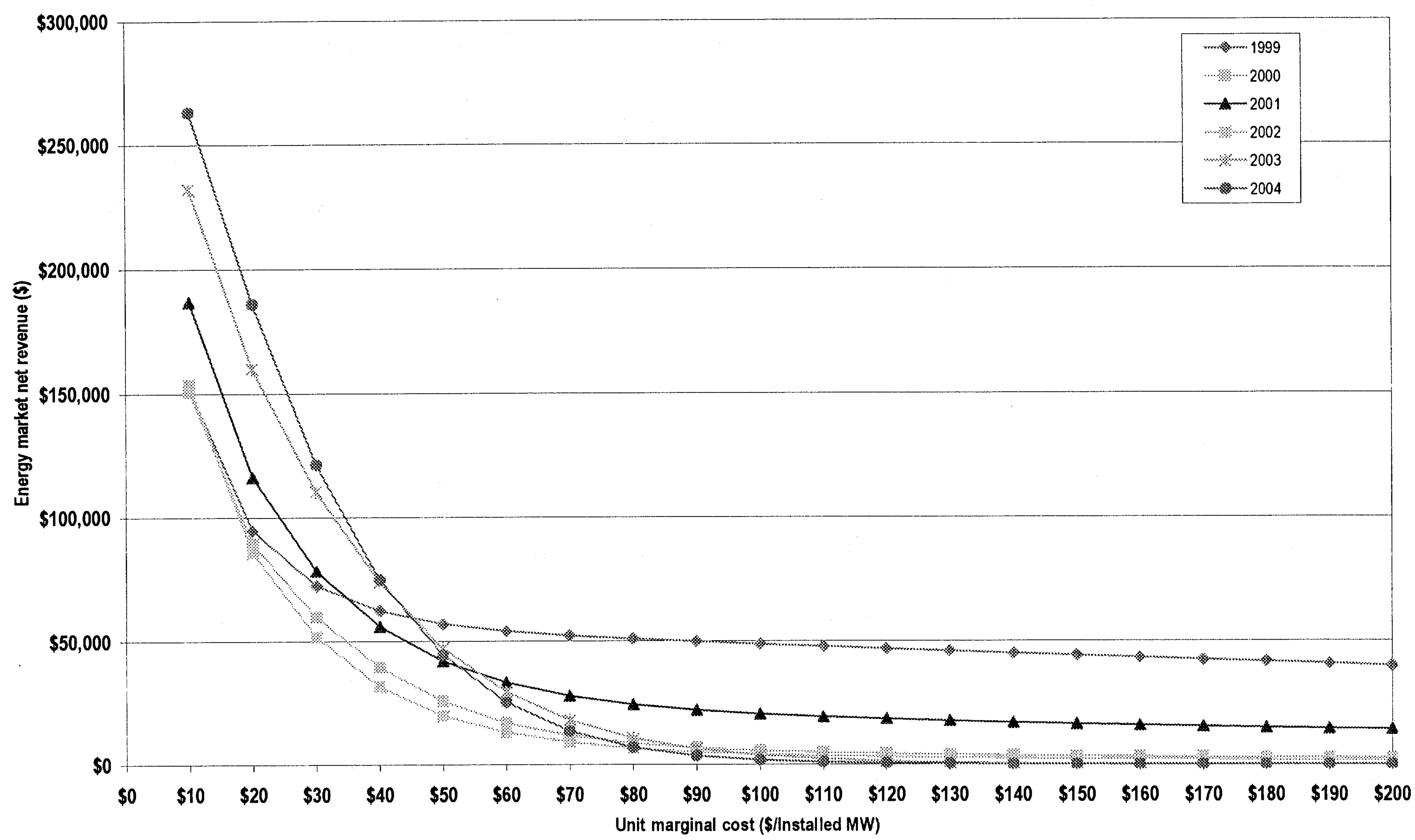
7 The CONE value is to be reviewed no later than three years after RPM is implemented, i.e., by 2009, by which time PJM will be clearing auctions for the 2013 delivery year.

invest in new generation to serve PJM markets. Net revenue quantifies the contribution received by generators from all PJM markets to cover fixed costs including a return on investment, depreciation, taxes, and fixed operations and maintenance expenses. As discussed below, the levels of generator net revenue may result from cyclical supply and demand fluctuations, but also can highlight market design shortcomings.

In a perfectly competitive, energy-only market in long-run equilibrium, net revenue from the energy market would be expected to equal the total of all fixed costs for the marginal unit, including a competitive return on investment. In PJM, the capacity, energy and ancillary service markets are all significant sources of revenue to cover fixed costs of generators, as are payments for the provision of black start and reactive services. Thus, in a perfectly competitive market in long-run equilibrium, with energy, capacity and ancillary service payments, net revenue from all sources would be expected to equal the fixed costs of generation for the marginal unit. Net revenue is a measure of whether generators are receiving competitive returns on invested capital and of whether market prices are high enough to provide an incentive to the entry of new capacity. Net revenue fluctuates annually based on actual conditions in all relevant markets.

Figure 1 displays net revenue curves for the PJM energy market, showing net revenues that would be earned by units with a range of marginal costs, for each year from 1999 through 2004. Differences in the shape and position of net revenue curves for the six years result from different distributions of energy market prices. These differences illustrate, among other things, the significance of a relatively small number of high-priced hours to the profitability of high marginal cost units. Periods of high prices were responsible for the shape of the 1999 net revenue curve. The limited number of high-priced hours in 2000, 2002 and subsequent years resulted in lower energy market net revenue for units operating at higher marginal costs.

Figure 1. PJM energy market net revenue by unit marginal cost: Calendar years 1999 to 2004



The PJM Market Monitoring Unit analyzes generator net revenues as part of its ongoing assessments of the state of the PJM markets. These analyses consider the net revenues available for new entrants assuming three different power plant configurations: a natural gas-fired combustion turbine ("CT"), a two-on-one natural gas-fired combined-cycle plant ("CC") and a conventional pulverized coal-fired, single reheat steam generation plant ("CP").

In 2004, total PJM net revenues for a CT, a CC and a CP were significantly below the level required to cover the fixed costs of each unit type. Using essentially the same methodology Mr. Pasteris describes in his affidavit to estimate the CONE, the PJM MMU has estimated the 20-year nominal levelized annual cost of a new CT plant as $72,207 per MW, a new CC plant as $93,549 per MW, and a new CP plant as $208,247 per MW.

The PJM MMU estimates that, under perfect dispatch assumptions (as described above), a new entrant CT plant's net revenue from 1999 through 2004 would have averaged $44,177 per installed MW-year, a new entrant CC plant would have averaged $77,107 per installed MW-year, and a new entrant CP plant would have averaged $141,747 per installed MW-year. Thus, over the six-year period, average net revenue was not adequate to cover the fixed costs of a CT, CC, or CP plant under the perfect dispatch calculations. These reported net revenues include payments from the current capacity markets.

Figure 2, Figure 3 and Figure 4 compare total net revenues calculated using the perfect dispatch assumptions to the nominal levelized fixed costs for combustion turbine, combined cycle and pulverized coal plants. The flat line in each graph represents the 20 year nominal levelized fixed costs for each unit type. The bars show the annual capacity market revenues separately for reference purposes although these capacity market revenues are included in the net revenue line. The net revenue line in each graph includes net revenues from the energy and ancillary services markets plus the revenues from the capacity markets. This net revenue line represents the total contribution to unit fixed costs from these PJM markets.

Figure 2. PJM total net revenue for a combustion turbine plant and nominal levelized fixed costs: Calendar years 1999 to 2004. Perfect dispatch case.

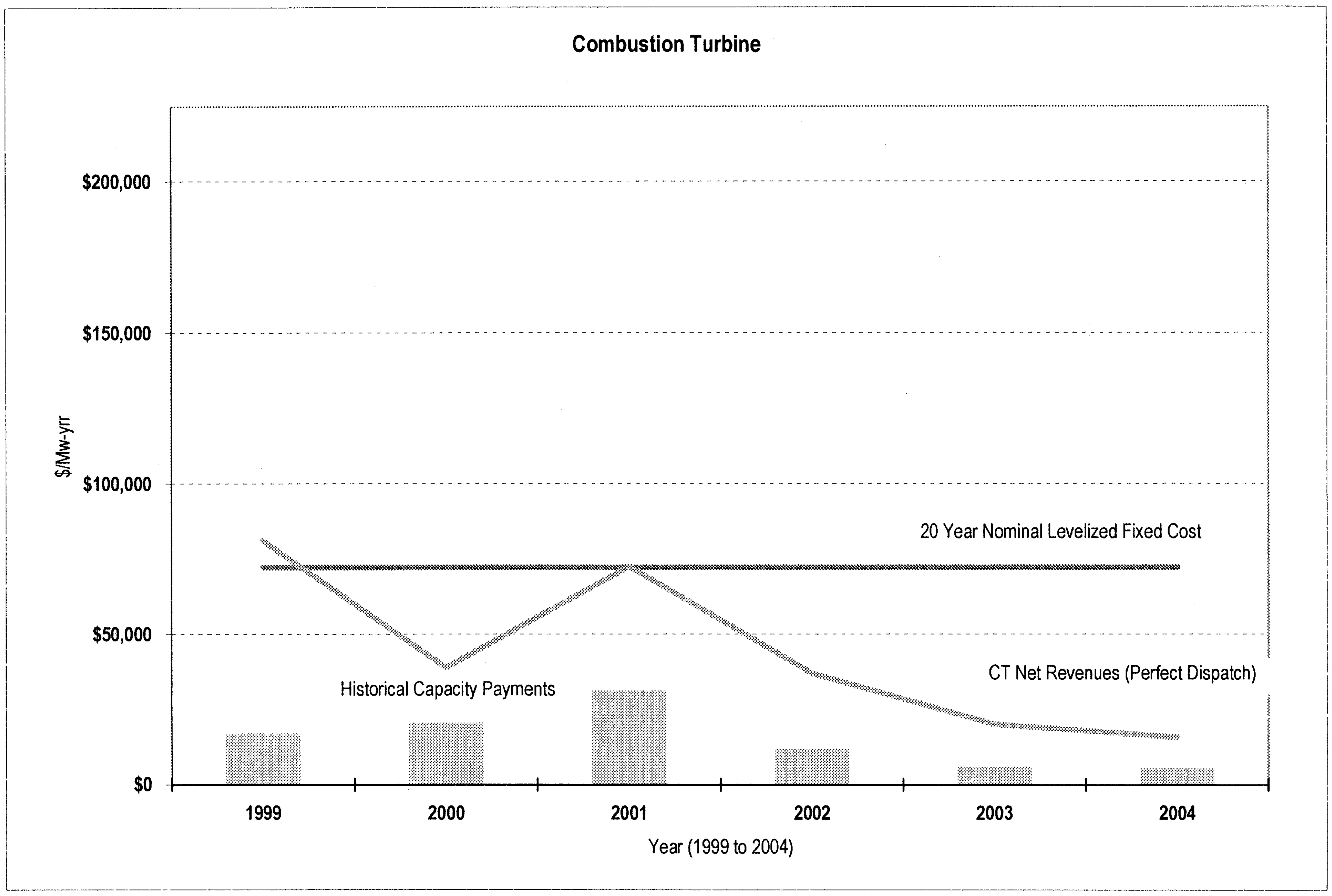


Figure 3. PJM total net revenue for a combined cycle plant and nominal levelized fixed costs: Calendar years 1999 to 2004. Perfect dispatch case.

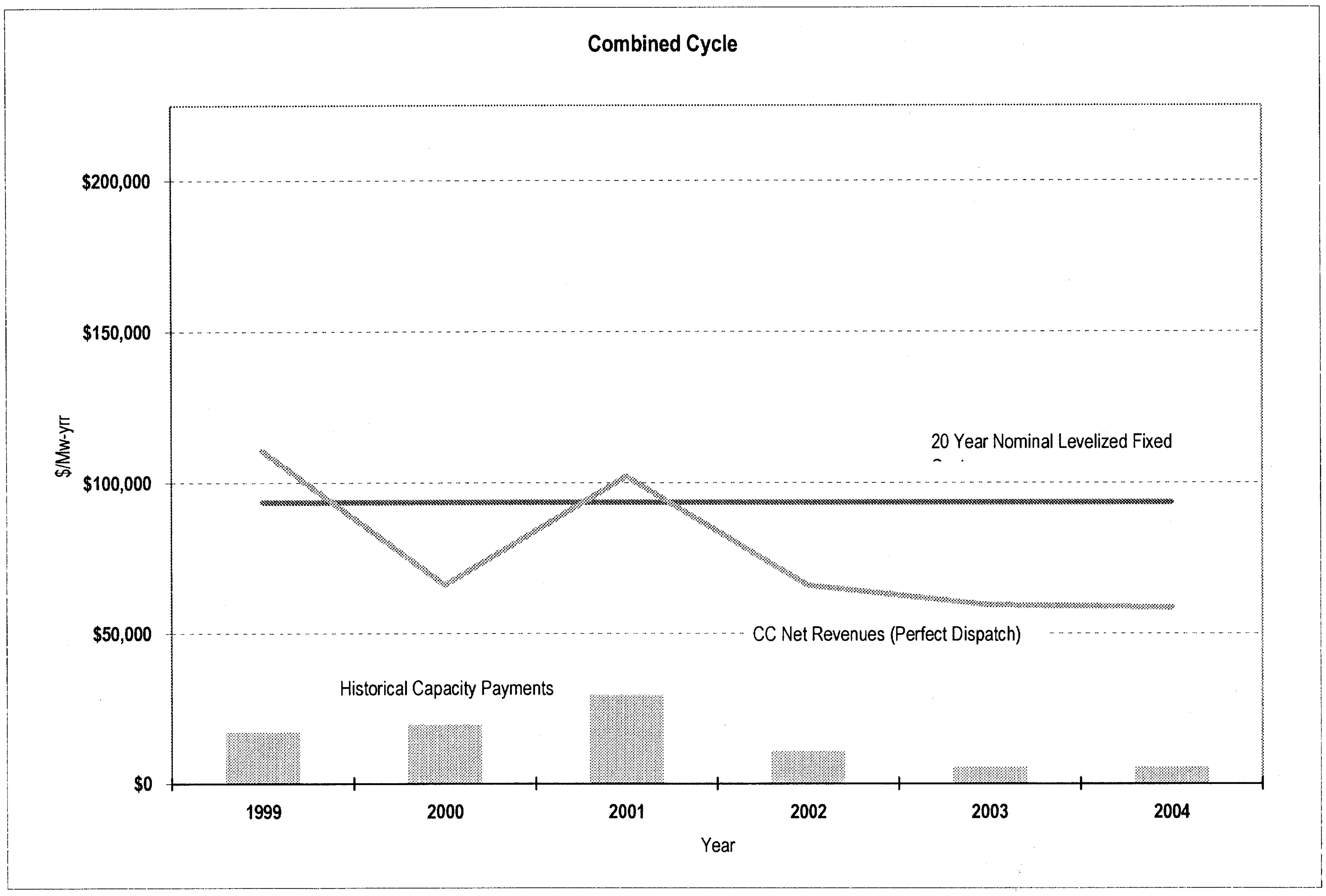
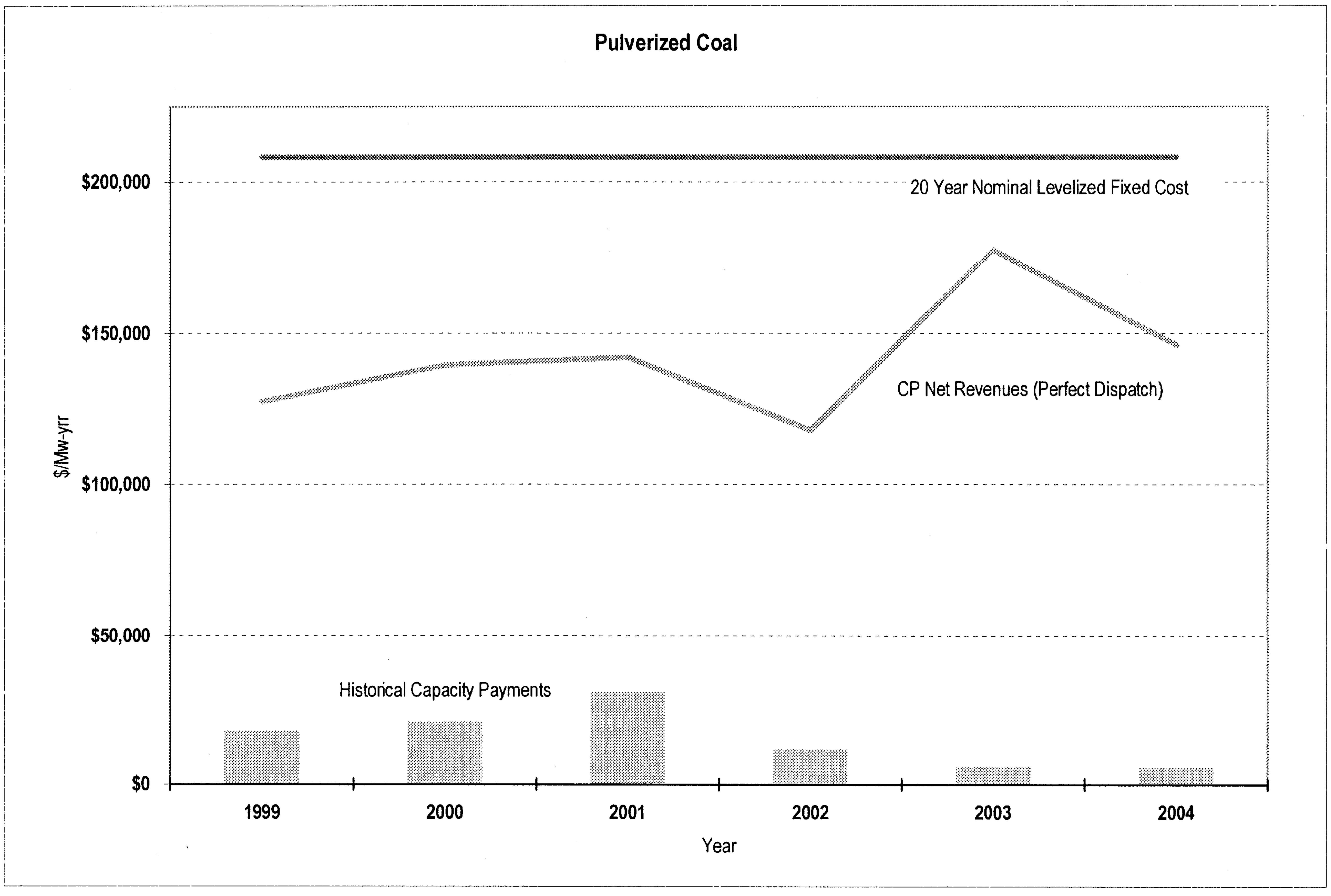


Figure 4. PJM total net revenue for a pulverized coal plant and nominal levelized fixed costs: Calendar years 1999 to 2004. Perfect dispatch case.



Although it can be expected that in the long run, in a competitive market, net revenue from all sources will cover the fixed costs of investing in new generating resources, including a competitive return on investment, actual results are expected to vary from year to year. Wholesale energy markets, like other markets, are cyclical. When the markets are long, prices will be lower and when the markets are short, prices will be higher. When the weather is extreme, prices will be higher, as they were in 1999 and 2001, and when the weather is mild, prices will be lower as they were in 2004. Combinations of market conditions and weather will produce a wide range of results. Analysis of 2004 net revenue shows that generators' net revenues were less than the fixed costs of generation and that this shortfall emerged from lower energy and capacity market prices which were, in turn, a result of market fundamentals.

While net revenue in PJM has been sufficient to cover the costs of new peaking units in some years, net revenue has been below the level required to cover the full costs of new generation investment for several years, and below that level on average for new peaking units for the entire period PJM has operated an energy market. (See Figure 2.) While to some degree this reflects cyclical fluctuations in supply and demand, this generally low level of revenues, coupled with the fact that some units needed for reliability in PJM are retiring because they are not receiving enough revenue to cover annual going forward costs, suggests that market price signals and reliability, or resource adequacy, needs are not fully synchronized. While retirements are a normal part of the operation of markets, the desire of generators to retire due to inadequate revenues raises a concern when such generators are critical to maintaining regional grid reliability. This suggests that market price signals and reliability needs are not fully synchronized and that the revenue inadequacy observed in PJM is not merely the result of expected cyclical fluctuations. The fact that the retirement of units with low net revenues would lead to unreliable operations in the absence of out of market actions suggests that market conditions in the region where these units are located are not reflected in the capacity market prices.

Moreover, when PJM determines that a retirement will result in reliability issues, the PJM market rules permit out of market payments to the units to keep them in service. While making such payments is an appropriate short run response to maintain reliability, this response is a symptom of the underlying investment incentive issue and cannot resolve the issue in the long term, consistent with markets. The logical end result of this approach would be out of market contracts with a significant number of peaking units in affected regions. This creates an incentive to declare unit retirements which in turn has a detrimental effect on the dynamics of the capacity market.[8] Units which are compensated via an RMR contract are indifferent as to the clearing price in the capacity market and have no incentive to make competitive offers or optimal offers in the capacity markets. If a regional shortage of capacity is reflected only in RMR payments and not in capacity market prices, there is no market signal for entry. The fact that RMR contracts continue to be needed to protect local reliability indicates that the market is not solving the regional reliability problem. The continued use of RMR contracts will simultaneously undermine the ability of the market to solve the reliability problem.

8 It is not generally economically rational to retire a unit if is earning more than its annual avoidable costs but less than its full annual revenue requirements.

A rational approach to the resource adequacy issue in wholesale electricity markets with administratively enforced reliability requirements is a capacity market. The capacity market can be designed to achieve a competitive outcome that can be evaluated against objective benchmarks and that is consistent with reliability objectives. Another benefit of capacity markets is that they are consistent with competitive wholesale electricity markets. Capacity markets address the incentives for resource adequacy issue directly and explicitly and therefore do not require ad hoc modifications to the definition of competition in the energy markets that, for example, would permit the exercise of market power in order to derive adequate market revenues. In large energy markets like PJM, a locational feature of the capacity markets will also address geographical differences in resource adequacy.

Since the need for a capacity market is fundamentally driven by reliability requirements, it is vital that the capacity market design provides consistency between capacity prices and reliability requirements. The current PJM capacity construct falls short of this fundamental requirement and this result has driven the need for development of the Reliability Pricing Model. RPM addresses the resource adequacy issue, providing signals to the market based on the locational and forward-looking need for generation resources to maintain system reliability in the context of a long-run competitive equilibrium in the energy markets. RPM also provides longer-term capacity price signals which are consistent with the lead-time requirements of generation installations and which therefore encourages competition from new entrants.

V. Market Power Mitigation Rules

RPM includes explicit rules governing market power mitigation in the capacity market. This is an important benefit of the RPM proposal, as PJM's existing capacity market does not include explicit market power mitigation rules. As I have concluded in the 2004 and prior State of the Market Reports, market power is endemic to the current capacity market design, yet there are no explicit rules limiting the exercise of market power in the capacity market. Given that, all else equal, RPM will increase market power, e.g through the creation of smaller, regional or LDA-based (Locational Deliverability Area) capacity markets, this explicit set of market power mitigation rules is central to the RPM construct. The RPM mitigation rules are required to make the RPM construct produce competitive outcomes. At the same time, the RPM market power mitigation rules are designed to minimize intervention in the capacity markets and to explicitly permit scarcity pricing as described below.

Section 6 of the RPM rules in proposed Attachment Y to the PJM Tariff contains the proposed market power mitigation rules for RPM. In general, the market power mitigation rules are narrowly targeted to specific market conditions that create the conditions for the potential exercise of market power. The unit-specific offer caps in the market power mitigation rules apply to LDAs only where an LDA is constrained and only where offers from new entrants are not required in order to clear the market. The market power mitigation rules also apply to the entire PJM region market but unit-specific mitigation would occur only if the market failed the market power tests and only where offers from new entrants are not required in order to clear the market. Mitigation is not applied to new entrants, rather competitive forces are relied upon to provide competitive prices when new entry is required. The RPM market power mitigation rules are based on the following principles:

- New entry is assumed to be competitive and mitigation based on unit-specific offer caps is therefore not necessary when new entry is required to clear any aggregate or local capacity market;

- Rational and accurate mitigation requires detailed unit-specific data. The preliminary market structure screen is intended only to determine whether more data should be provided by capacity owners;

- Proposed mitigation based on unit-specific offer caps is applied only in the situation where the relevant market structure fails the market structure tests and there is enough existing capacity to meet the demand for capacity in a constrained LDA or the PJM region. In addition, mitigation is applied only if the actual offers exceed the offer cap and if the offer would increase the market clearing price in the absence of mitigation;

- Proposed mitigation can never reduce a legitimate scarcity price. When existing capacity is not adequate to serve the load in a market, unit - specific mitigation is not applied. In this case the market clearing price is determined either by new entry and/or by the VRR Curve. As a result, the market clearing price will be greater than or equal to the CONE as determined by new entrant offers and the VRR Curve;

- Mitigation of offers from existing units is based on the incremental cost of such capacity, which is the competitive price of existing capacity. The incremental cost of existing capacity equals total annual avoidable costs less net revenue from other PJM markets. For existing capacity, a competitive offer covers the annual avoidable costs not recovered from other PJM markets. The incremental cost of existing capacity also includes the annual costs associated with any new investment in the unit required to maintain its viability as a generating unit. A rational seller will offer capacity into the capacity market at a price that covers its avoidable costs, net of energy and ancillary services revenues. It is profitable to sell at any price in excess of that price and it is not profitable to sell at any price less than that price;

- Physical withholding is a potentially profitable strategy for exercising market power in the aggregate market or in local markets. Market sellers must offer all of their PJM capacity resources (after adjustment for EFORd) to the market in all four seasons or they will not be permitted to sell any withheld capacity in any RPM auction. If this rule does not provide an adequate incentive to offer capacity resources to the market, withholding is addressed explicitly by including a 5 percent price trigger in all seasons. If withholding results in a market price increase of 5 percent or greater compared to the price absent withholding, a filing with FERC and a postponement of the final clearing of the auction are triggered.

A. Market Structure Screens

The market power mitigation rules include a preliminary market structure screen to determine whether additional generator data is required and a market structure test to determine whether non-competitive offers require mitigation, under defined circumstances.

1. Preliminary Screen to Determine Need for Data

The preliminary market structure screen is designed only to determine whether market structure conditions exist that could permit the exercise of market power. The screen is based on: the unforced capacity that is both located in a locational deliverability area ("LDA") and available for the relevant delivery year; the demand for capacity in the LDA (the reliability requirement); and firm obligations to sell unforced capacity from resources in the LDA. The screen is applied to the PJM region as a whole and also to each LDA. The logic of the screen as applied to LDAs is that, when transmission limits into the LDA are binding and no further imports are possible, the remaining capacity in the LDA forms the incremental supply curve that is capable of meeting the remaining demand for capacity. The market structure characteristics of this incremental supply curve therefore must be evaluated to determine whether there is a risk of market power in the LDA.

The preliminary market structure screen includes three measures: market shares of individual sellers; market concentration; and the extent to which suppliers are pivotal. Market shares are the proportion of generation owned by an individual entity. Consistent with Commission precedent, the market share screen is failed by an individual firm market share in excess of 20 percent. Market concentration is measured by the Herfindahl-Hirschman Index ("HHI"), calculated by summing the squares of the market shares of all sellers in the relevant market. This component of the screen is failed if the HHI exceeds 1800, consistent with the Commission's Merger Policy Statement that defines a highly concentrated market as one with an HHI greater than 1800.[9] Under the last component of the screen, suppliers are pivotal if the market cannot clear without the capacity of the identified suppliers. The residual supplier index ("RSI") is the measure of whether an identified group of suppliers are pivotal. Consistent with the market mitigation rules pending in Docket No. EL03-236, this aspect of the screen considers whether three suppliers are jointly pivotal. The screen is failed if the RSI is less than 1.0 for the three largest suppliers together.

The preliminary market structure screen is failed if any one of the three component screens is failed. In that event, capacity owners in the defined LDA or the entire market are required to submit data that will permit the PJM MMU to calculate the market structure test that will determine whether mitigation is required.[10]

2. Test to Determine Need for Mitigation

Consistent with the test proposed for the energy market in other proceedings now pending before the Commission, the market structure test includes only one measure, the

9 77 FERC 61,623, "Inquiry Concerning the Commission's Merger Policy under the Federal Power Act:: Policy Statement," Order No. 592, pp 64-70.

10 The referenced data is primarily the avoidable cost data described in the market power screen.

three pivotal supplier test. Only this test is needed because, if it is passed, no mitigation is needed regardless of the outcome of market share and HHI tests, whereas, if it is failed, mitigation is needed regardless of the outcome of other tests. If a market fails the market share test or the market concentration test, but passes the three pivotal supplier test, that indicates excess supply is available that would be considered adequate to offset the results of the market share and market concentration tests.[11] Conversely, if the market share and market concentration tests are passed, but the three pivotal supplier test is failed, the market would not be competitive, because the three dominant suppliers are required to clear the market, regardless of market shares or HHIs.

The market structure test will be applied to LDAs as the auction is cleared by PJM, in a manner similar to the operation of PJM's local market power mitigation rule. If a local constraint becomes binding in the optimization algorithm used to clear an RPM auction, then the market structure test is applied to that LDA. If the LDA fails the test, then the offers in that LDA that are required to solve the constraint and meet the remaining LDA load obligations are capped if necessary, as discussed below. In the PJM region market, the test will also be applied as the auction is cleared by PJM. If the PJM region market fails the market power test, offers will be capped if necessary as discussed below.

B. Market Seller Offer Caps

1. Basic Structure of the Cap

Market seller offer caps are intended to reflect competitive offers for capacity resources, recognizing that capacity in the RPM construct is fundamentally an annual product. At the most basic level, a competitive offer for an annual offer of capacity is the annual avoidable cost of the unit, less net revenues from other PJM markets, including the bilateral sale of any product from the unit. This is a competitive offer because it reflects the incremental cost of capacity for a year. If a unit has avoidable costs of $100 per MW-day and net revenues from other PJM markets of $30 per MW-day, the incremental cost of maintaining the unit for a year in order to sell capacity is the difference, $70 per MW-day. In a competitive market, this incremental cost is the competitive offer. (This assumes no opportunity cost as discussed below.)

A unit-specific revenue offset is used to determine the unit-specific offer caps. The unit-specific revenue offset is calculated on a unit-specific basis in contrast to the revenue offset in the net CONE calculation which is based on the Reference Resource.. Net revenues will vary by type of unit, e.g. steam, combined cycle and combustion turbine, and by the actual market conditions faced by the individual unit.

There are three additional complexities that are addressed in the definition of market seller offer caps: EFORd risk; opportunity cost; and firm obligations to sell.

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[11] This result differs from the preliminary screen because failure of any of the three components of the preliminary screen determines only the need for further data; whereas failure of this test determines the need for offer capping.

2. EFORd Risk

EFORd is the measure of the rate of forced outages and unit deratings used in PJM. The EFORd is an estimate of the probability of a unit failing to perform when called upon by PJM, based on historical data for each unit. A unit's EFORd can change over time, because PJM calculates EFORd using the unit's actual operating experience. Both the existing PJM capacity construct and RPM are based on "unforced capacity," where unforced capacity equals the installed capacity in MW adjusted for the EFORd of the unit. This is stated formulaically as [Unforced capacity = Installed capacity * (1 – EFORd)]. Thus, the higher the EFORd, the less unforced capacity available to sell in the market from a given unit. EFORd can act as an incentive to perform since decreases in EFORd translate into increases in unforced capacity to sell and corresponding increases in available revenue. For example, a 100 MW unit with an EFORd of 5 percent has 95 MW of unforced capacity available to be sold. If the capacity price is $80 per MW-day, the 95 MW of unforced capacity would be sold for $7,600 per day or $2,774,000 for the year. If the EFORd increases to 10 percent, then only 90 MW of unforced capacity can be sold. If the capacity price again is $80 per MW-day, the 90 MW of unforced capacity would be sold for $7,200 per day or $2,628,000 for the year, a reduction of $400 per day or $146,000 per year, i.e., about 5.3 percent. Based on the fact that EFORd is an historical measure, it is a relatively weak incentive for capacity resources to perform in the delivery year.

EFORd risk in RPM derives from the fact that an EFORd rate must be specified at the time an existing unit is offered into the RPM auction, while the amount of unforced capacity actually sold in the delivery year depends on the 12 month EFORd for a period ending three months prior to the delivery year. Specifically, the risk is that the EFORd used to calculate unforced capacity for the delivery year will increase compared to the EFORd used to determine the level of MW offered into the base residual auction. If the unit's offer in the base residual auction is based on an EFORd of 5 percent, but the EFORd increases to 10 percent prior to the actual delivery year, then the unit owner has to make up the additional MW of unforced capacity by purchasing it in the incremental auction or in a bilateral transaction. The risk faced by the seller at the time of the initial offer into the base residual auction is that the EFORd will increase and that the unit owner will have less unforced capacity than offered. If the EFORd decreases, the generation owner is better off and there is a benefit rather than a risk as the unit owner has more unforced capacity than offered.

The market seller offer caps address this risk by permitting an identified level of MW to be offered into the auction at a price that reflects the EFORd risk. The price is higher than the avoidable cost of the unit and equals the net CONE for the delivery year. The MW offered at the avoidable cost are termed the Base Offer Segment of the supply curve for a unit. The MW offered at the CONE are termed the EFORd Offer Segment. The EFORd Offer Segment is defined in Attachment Y, 6.7(c) (iii) as the unit's installed capacity level multiplied by the potential difference between the EFORd required to be used in the auction and the EFORd required to be used to define actual MW in the delivery year. In particular, to account for the possibility that EFORds are cyclical and that the 12-month EFORd may be low compared to the five-year average, the MW of unforced capacity in the EFORd Offer Segment may equal the positive difference between the five-year average EFORd and the 12-month average EFORd. In addition, if the unit is expected to undergo an anticipated degradation in EFORd performance, the

MW of unforced capacity in the EFORd Offer Segment may equal the positive difference between the documented expectation of EFORd performance as defined for the delivery year and the 12-month average EFORd.

The CONE is selected as the offer price for the EFORd Offer Segment to reflect the price risk to a generation owner that the EFORd applicable to the Delivery Year may exceed the EFORd used to determine the level of MW offered into the Base Residual Auction. In that case, the generation owner would have sold more unforced MW in the Base Residual Auction than it actually had available for the Delivery Year. In this case the generation owner would have to purchase the difference in the third or final incremental auction. The CONE is used to reflect the risk that the owner could face a high price for the EFORd related MW difference in the final incremental auction.

3. Opportunity Cost

Opportunity cost, in the context of market seller offer caps, refers to the documented price at which a PJM capacity resource could be sold in a market external to PJM. Any generation owner can submit an offer based on the opportunity cost available to a unit, provided that the opportunity cost is documented. PJM will construct a supply curve of opportunity cost offers, ordered by opportunity cost, and accept such offers to export starting with the highest opportunity cost, until the maximum level of such exports is reached. The maximum level of such exports is the lesser of PJM's ability to permit firm exports or the ability of the importing area(s) to accept firm imports or imports of capacity, taking account of relevant export limitations by location. For all units that do not have an accepted opportunity cost offer to export, their offers will be evaluated without the opportunity cost component.

This approach to opportunity costs provides a market-based mechanism for equilibrating RPM with external capacity and firm energy markets while limiting the ability to use potential exports as a method of physical withholding.

4. Firm Obligations to Sell

Generation owners may have firm obligations to sell their capacity. These obligations could take the form of a bilateral contract, the obligation of an integrated utility to meet load, or a provider of last resort obligation. Regardless of the exact nature of the obligation, if the market seller wishes its net capacity position to be used in the market power screens (rather than gross capacity position), the seller must self schedule or offer the capacity designated to serve the firm obligation at a zero price. Such sellers would receive the market clearing price for capacity.

5. Application of the Offer Cap

Sell offers by market sellers are subject to mitigation in specific LDAs only if there is a positive locational price adder in the auction and if the sell offers that are available to the PJM auction clearing algorithm to resolve the local constraint fail the market structure test. Sell offers would be subject to mitigation in the PJM regional market only if the market consisting of all sell offers to the RPM auction fails the market structure test. Mitigation will be applied only if the relevant sell offers are greater than the offer cap and only if, absent mitigation, the offer would increase the market clearing price. If the conditions for mitigation are met, the relevant sell offers are set equal to the market seller offer cap.

Sell offers of new entrants are not subject to mitigation, because new entry is assumed to be competitive. New generation resources may offer into a base residual auction, or an incremental auction, only if the owner has executed before such auctions, respectively, a facilities study agreement, or an interconnection service agreement. Accordingly, potential entrants must anticipate making an offer by the corresponding number of months in order to be entered into a queue and to have met the required milestones.

Offers of demand resources are not subject to mitigation because demand resources cannot set the clearing price in markets where mitigation is applied. While demand resources may offer at any price, the market clearing algorithm in markets where mitigation is applied will not let a demand resource set the clearing price. If demand resources were potential price setters, they would be subject to mitigation comparable to that applied to generation capacity sellers and demand resource avoidable costs would have to be identified. This raises a practical problem. The avoided cost formula in the tariff is designed for generation resources. Given the wide variety of demand resources, there is no defined standard approach for determining avoided costs for such resources. As a result, avoided cost would have to be determined on a case by case basis.

C. Withholding

Market power is generally exercised via either physical or economic withholding. The RPM auction rules need to address the potential for withholding to ensure that market power is not exercised and that the auction has an efficient solution. Economic withholding occurs when capacity is offered into the market at a price greater than its competitive price. The offer capping rules address the potential for economic withholding. Physical withholding occurs when capacity is not offered into the market. In order to address the potential for physical withholding, the RPM rules provide that if an existing generation resource in PJM does not offer its capacity into all the seasons of the base residual auction then it will be precluded from earning capacity revenues in PJM directly or indirectly for the that delivery year. This offer of capacity is at an unforced MW level using an EFORd less than or equal to the EFORd for the prior twelve months ended three months prior to the offer submission date. The associated EFORd risk is addressed via the inclusion of an EFORd offer segment in the capacity offer price as explained above. If the capacity resource does not clear in the base residual auction the same rules govern offers into each subsequent auction for all the seasons of the specified delivery year.

The only exceptions to the requirement that capacity resources must offer into the auction are capacity resources that are reasonably expected to be physically unable to participate in the market in the delivery year, capacity resources that have a physically firm commitment to an external sale of capacity and units that were originally interconnected to the transmission system as energy resources and remain energy resources.

If a capacity resource is not offered into the Base Residual Auction and subsequent capacity auctions for any of the seasons of a delivery year and does not qualify for any of the exceptions noted above, it may not be used to satisfy any entity's capacity obligation for any season of the specified delivery year in any manner, cannot receive payment for any season of the specified delivery year, and cannot be offered into any subsequent auctions for any season of the specified delivery year. Such capacity resource cannot be used as the basis for a bilateral capacity contract and it cannot be swapped with a capacity resource being exported so that it is effectively used to satisfy a capacity obligation for any season of the delivery year. The point of this rule is to make it clear that it is not possible to withhold in the base residual auction with the intent of increasing the clearing price and to then take advantage of that higher price via bilateral transactions or via sales into subsequent auctions for the same delivery year.

Notwithstanding these restrictions, there are still plausible incentives for market participants to withhold capacity resources. Therefore, the RPM rules provide that if withholding occurs, and would increase the clearing price in any auction for any season by more than five percent compared to the clearing price absent withholding, PJM will postpone clearing the auction and posting the results. In such cases, PJM will apply to FERC for an order compelling participation in the auction or for other appropriate relief. The ultimate enforcement authority on the issue of withholding lies with FERC.

D. Avoidable Cost Definition

As explained above, avoidable cost, net of other market revenues, is the incremental cost of capacity in an annual capacity market. Avoidable costs are the costs that the seller would avoid if the unit shut down. These are the costs that the seller incurs simply as a result of maintaining the unit's capability to participate in the energy market. A rational seller will offer capacity into the capacity market at a price that covers its avoidable costs, net of energy and ancillary services revenues. It is profitable to sell at any price in excess of that price and it is not profitable to sell at any price less than that price.

The proposed rules (Attachment Y Section 6.8) include a detailed formulaic definition of avoidable costs. In most respects, this definition is the same as the deactivation avoidable cost rate definition accepted by the Commission in connection with retiring units needed for reliability. The version of the formula used for RPM differs from the previously approved version only in its use of a ten percent adder; and its detailed provisions on incremental investments needed to maintain the resources as a capacity resource.

The ten percent adder is not intended to include a profit in the definition of avoidable costs, but to recognize the uncertainty associated with the exact measurement of avoidable costs for a period four years in the future. The 10 percent adder appropriately addresses such uncertainty.

The definition of avoidable costs also provides for the potential that an owner may need to make an incremental investment in a unit in order to maintain it as a capacity resource for the delivery year and for future years. The definition of avoidable costs provides for inclusion of the annual carrying costs of making such an investment (the capital recovery factors). These carrying costs include the return on and of capital including a rate of return and depreciation. The underlying financial model assumptions are identical to those used in PJM's definition of the CONE, with one important exception. The definition of avoidable costs explicitly recognizes that the useful life of a capacity investment in an existing unit is directly related to the age of the existing unit. It can reasonably be expected that an investment in a unit that is 20 years old will have a shorter useful life than an investment in a unit that is 5 years old. The capital recovery factors included in the definition of avoidable costs are therefore calculated on the basis of the age of the unit and therefore the expected remaining useful life. This provides an appropriate incentive to maintain and invest in existing capacity resources.

This completes my affidavit.

	)	Commonwealth of Pennsylvania
SS:	)	
	)	County of Montgomery

AFFIDAVIT OF JOSEPH E. BOWRING

Joseph E. Bowring, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Joseph E. Bowring on behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ Joseph E Bowring
Joseph E. Bowring

Subscribed and sworn to before me this 29th day of August, 2005.

/s/ April Mays-Parks
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
April Mays-Parks, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Sept. 8, 2008
Member, Pennsylvania Association Of Notaries

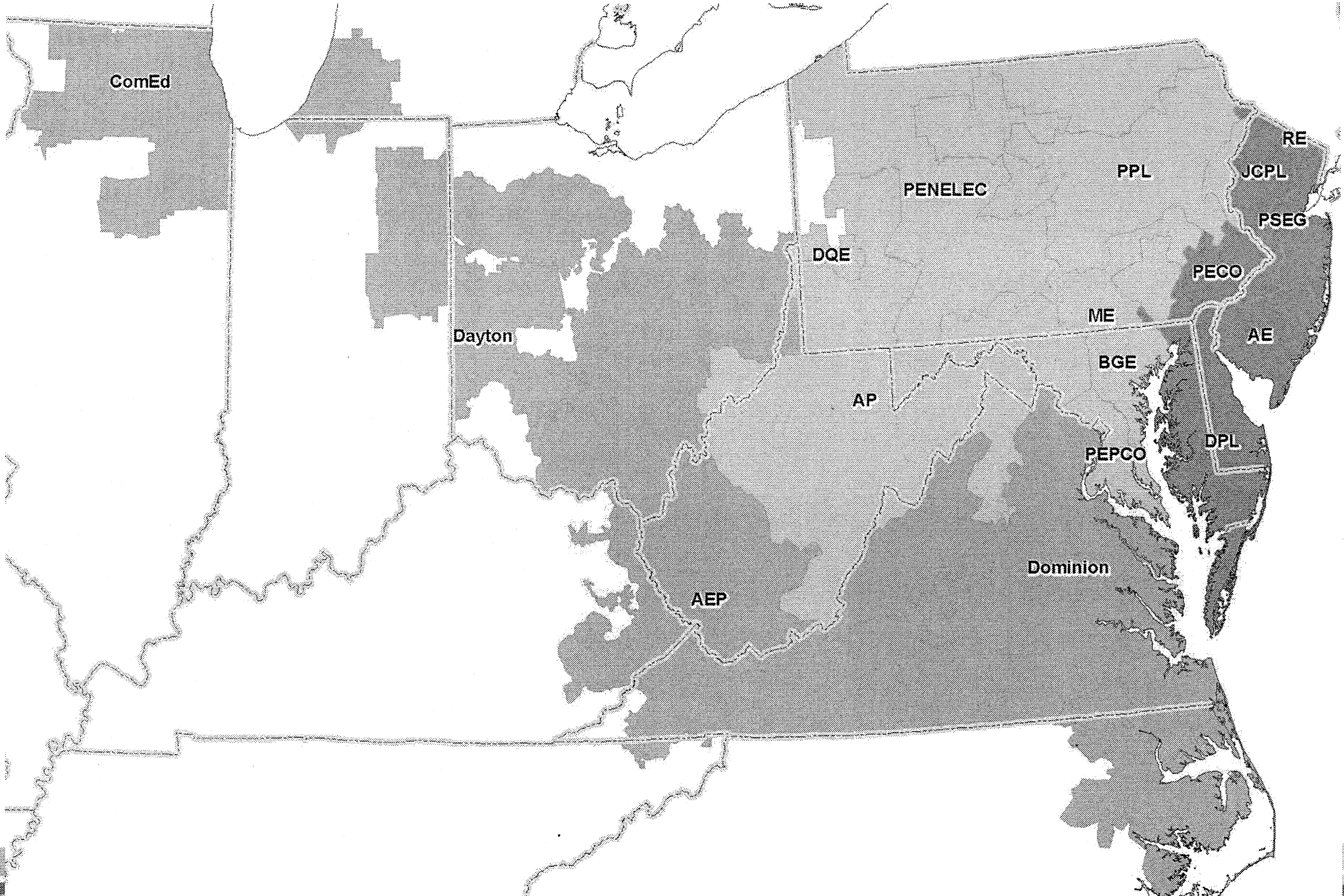
My Commission expires: 9/8/08

ATTACHMENT I – REACTIVE REVENUE REQUIREMENTS.

Generator(s)	Initial FERC Docket #	Total Annual Reactive Power Revenue Charge	CT FERC Filing Installed MW	$/MW-Y
AEP Big Sandy	ER04-1103-000	$525,904	300	$1,753
AEP Rolling Hills	ER04-1098-000$1,	100,000	800	$1,375
AEP Wolf Hills	ER04-1102-000	$442,023	250	$1,768
Armstrong County	ER03-229-000	$1,435,113	600	$2,392
CED Rock Springs	ER05-288-000	$766,570	335	$2,288
Commonwealth Cheasapeake	ER02-2520-000$1,	270,980	342	$3,716
Duke Lee	ER04-641-000	$1,500,000	640	$2,344
FPL MH50 (Marcus Hook)	ER01-1676-000	$393,182	50	$7,864
Handsome Lake	ER03-269-000	$370,304	250	$1,481
IMPA Anderson	ER05-971-000	$489,001	169	$2,893
ISG Sparrows Point	ER03-852-000	$319,464	153	$2,095
Ocean Peakings	ER05-289-000	$952,555	330	$2,887
Old Dominion Louisa	ER05-1229-000	$1,064,654	546	$1,951
Old Dominion Rock Springs	ER05-682-000	$654,639	672	$974
Pleasants Energy	ER03-451-000	$722,906	300	$2,410
PPL University Park	ER04-911-000	$1,504,414	540	$2,786
Reliant Aurora	ER04-1066-000	$2,183,895	873	$2,502
Reliant Twelvepole Creek	ER04-1166-000$1,	457,832	458	$3,183
Riverside	ER05-328-000	$1,702,765	820	$2,077
Westwood Joilet	ER02-2361-000	$203,901	30	$6,797
Total / Weighted Avg		$19,060,102	8,457	$2,254

Attachment II

Cost of New Entry (CONE) Regions



TAB H

Affidavit of Professor Benjamin F. Hobbs

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM Interconnection, L.L.C. Docket No. ER05-____-000

**AFFIDAVIT OF BENJAMIN F. HOBBS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

1. BIOGRAPHICAL INFORMATION

My name is Benjamin F. Hobbs, and I am a Professor in the Department of Geography & Environmental Engineering of the Whiting School of Engineering, The Johns Hopkins University, located in Baltimore, MD. I also hold a joint appointment in the Department of Applied Mathematics and Statistics in that institution. Previously, I was an Economics Associate at the National Center for Analysis of Energy Systems, Brookhaven National Laboratory, Upton, NY (1977-1979). From 1982-1984, I was a Wigner Fellow at the Energy Division of Oak Ridge National Laboratory. Between 1984 and 1995, I was on the faculty of the departments of Systems Engineering and Civil Engineering at Case Western Reserve University, Cleveland, OH. I have also been a visiting scientist or visiting professor at the Department of Civil Engineering at the University of Washington (1991-1992), the Systems Analysis Laboratory of the Helsinki University of Technology (2000), and the Policy Studies Unit of the Energy Center of the Netherlands (ECN (2001-2002). In the last ten years, I have been a consultant to the Maryland Power Plant Research Program (MPPRP); Planit Management, Ltd.; the Office of the Economic Advisor of the Federal Energy Regulatory Commission; the Energy Information Agency of the U.S. Dept. of Energy; The Analysis Group/Economics; Gas Research Institute; U.S. Army Corps of Engineers, Institute of Water Resources; Commonwealth Energy; the Electric Power Research Institute; Edison Source; Northeast Ohio Sewer District; BC Gas, Ltd.; Ontario Hydro; and BC Hydro. I presently serve as Scientific Advisor to ECN, as well as a member of the Public Interest Advisory Committee of the Gas Technology Institute. I am a member of the Market Surveillance Committee of the California Independent System Operator.

My Ph.D. was awarded in 1983 in environmental systems engineering from Cornell University, with minors in resource economics and operations research. I earned a B.S. from South Dakota State University in 1976, and a M.S. from the College of Environmental Science & Forestry of the State University of New York in 1978. I have published widely on electric utility regulation, economics, and systems analysis; and on environmental and water resources systems. These publications include over 80 refereed journal articles, and three books. A particular focus of my research is the use of engineering economy models to simulate electricity and emissions allowances markets, recognizing transmission and other technical constraints and imperfectly competitive behavior by market participants. My present research focuses on power market modeling, capacity market design, analysis of pollution policies under uncertainty and climate change, and decision analysis applications in ecological management. For example, I completed a comprehensive survey and simulation analysis of capacity market mechanisms for MPPRP in 2002. Current project sponsors include the U.S. Environmental Protection Agency, the National Science Foundation (NSF), MPPRP, and the PJM Interconnection.

Among my professional activities, I serve on the editorial boards of *Energy, The International Journal*; *IEEE Transactions on Power Systems*; *The Electricity Journal*; and the *Journal of Infrastructure Systems*. I am also Area Editor for Energy, Natural Resources, and the Environment for *Operations Research*, the premier journal in that field. I am former chairman of the Executive Committee of the Energy Division of the American Society of Civil Engineers (ASCE), and serve on the Systems Economics Committee and Working Group of the IEEE Power Engineering Society. I am a member of the National Research Council Committee on Changes in

New Source Review Programs for Stationary Sources of Air Pollutants. Among the honors I have earned are a NSF Presidential Young Investigator award (1986-1992), and best publication awards from the Decision Analysis Society (Institute for Operations Research and Management Science) and the Water Resources Planning & Management Division of ASCE.

2. PURPOSE AND SCOPE OF AFFIDAVIT

The PJM Interconnection has proposed a new mechanism to define the capacity obligations of Load Serving Entities (LSEs) and to clear the market for capacity needed to meet the obligations within PJM's territory. The proposed Reliability Pricing Model (RPM) will continue to use a target reserve margin designed to assure resource adequacy for the region as a whole, together with reliability requirements for sub-regions of PJM based on transmission constraints. Unlike the previous mechanism in which the reliability requirement is fixed, RPM considers the reliability requirement as a variable. It will do so by constructing demand curves that define higher capacity prices when the resources offered are less than the requirement, while gradually dropping capacity prices as resources increase beyond the requirement. I was hired by PJM to analyze the demand curve approach and to determine what shape of demand curve, and which parameters, would best achieve PJM's goals of continued future resource adequacy at a moderate cost for electricity customers with limited risk for generators.

Based on the analysis that follows, I conclude that there is a sloping demand curve that can be used to clear the PJM capacity market. This curve, the "Curve 4" described in Section 4, should set relatively stable capacity prices that will attract sufficient new capacity investment to meet PJM's target reserve margins. If its parameters are set appropriately, this curve will balance several related factors effectively – because the curve sets predictable prices for new capacity, it will lower prospective generators' risks enough so that the generators will accept lower prices and profits for their new generation; because enough new generation is built to meet reserve margin targets, energy and capacity prices to consumers will be lower because they pay a lower scarcity premium; and because more generation will be built, expected variability in actual reserve margins relative to uncertain future loads will be reduced and reliability will be improved. Under a wide variety of sensitivity analyses, the recommended curve produced a superior result – in terms of increased new generation investment, lower costs to consumers, and decreased variability in future reserve margins – compared to PJM's current ICAP method, which I characterize as a "no demand curve" or "vertical demand curve" method.

The purpose of this affidavit is to describe the assumptions, procedures, and results of a dynamic analysis of alternative demand curves (or "variable resource requirement", VRR) for the proposed reliability pricing model (RPM) system for the PJM market. In this affidavit, I will use the terms RPM, capacity market, and ICAP market interchangeably. A demand curve for installed capacity has the basic form shown in Figure 1(b): the market operator makes a capacity payment to generators that is a flat or decreasing function of the amount of capacity. The operator then collects those payments from load. (As I portray the curve here, capacity is measured as "unforced reserve margin", defined as the actual capacity less expected forced outages, then divided by the weather-normalized peak load.) In contrast, the present PJM system is equivalent to the vertical demand curve shown in Figure 1(a). The maximum payment results from deficiency charges applied to LSEs who are short of capacity credits (thus, those charges represent their maximum willingness to pay for capacity). But if there is more than enough capacity in the market to meet the target reserve, no one should be willing to pay anything for capacity, which is reflected in a zero price.

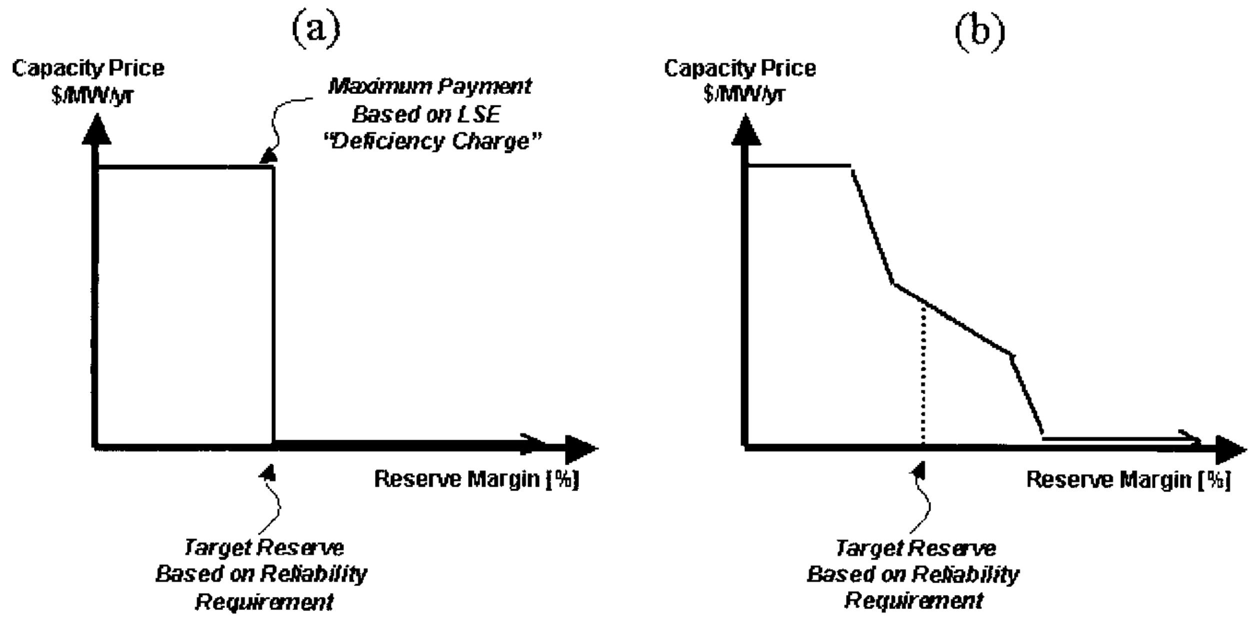


Figure 1. Demand Curves (Capacity Payments Expressed as a Function of Reserve Margin): (a) "Vertical" Case (Implicit in Present PJM System); (b) Downward Sloping Case (VRR)

The dynamic analysis addresses the following general questions:

1. How do different proposed demand curves (including the present vertical or "no demand" curve case) for the proposed four-year ahead auction compare in terms of average profits, capacity payments, energy and ancillary services revenues, reserve margins, and costs to consumers?
2. How do different curves compare in terms of the year-to-year variation in those indices?
3. How robust are those conclusions to changes in the shapes of the demand curve proposals, and to assumptions concerning the behavior and risk attitudes of investors in new generation?
4. How does changing from the present same-year auction system to a four-ahead system alter risks faced by generators?

The dynamic analysis considers the dynamic response of the market to incentives for construction of new generation. Further, it assesses how alternative assumptions concerning the risk attitudes and behaviors of builders of new generation could affect the performance of alternative demand curves under consideration for the RPM system. I have created a dynamic model that simulates generator investment over time in response to incentives in the energy, ancillary services, and capacity markets. Performance of different curves is gauged by three sets of indices: forecast reserve margin; generator revenues and profits; and consumer payments for capacity and scarcity rents. Average values for the simulated time periods are reported for these indices, as well as standard deviations that reflect variability over time in performance.

In the next section of the affidavit (Section 3), I provide background on the desirability of capacity market mechanisms and the general advantages of a demand curve approach. The advantages include the following: it is broadly reflective of the reality of an increasing social value of capacity as reserve margins shrink; it creates a stable investment environment—which reduces the cost of capital and saves consumers money; and it lessens incentives for exercise of market power in capacity markets. In Section 4, I summarize the assumptions and calculation procedures of the model. The detailed equations underlying the model are presented in the Appendix to this affidavit.

In Section 5 of the affidavit, I first compare five different demand curves for the four-year ahead auction (Section 5.1). These include a vertical demand curve in which there is a fixed \$/unforced megawatt/year (\$/unforced MW/yr) payment if capacity is below a target value, and zero payment if it is above that level (Figure 1(a)). (Below, I use the terms "vertical demand curve" and "no demand curve" interchangeably for this case.) Alternative curves are instead downward sloping (as in Figure 1(b)), and vary in terms of their slope and location relative to the PJM target reserve margin at which loss-of-load-probability equals 1 day in 10 years (the target reserve in the figure). I conclude that downward sloping curves result in more favorable performance in terms of average reserve margins, consumer costs, and year-to-year variations in these indices. Section 5.2 is devoted to an example that explains why boom-bust cycles can occur in capacity markets. In

Section 5.3, I describe a set of sensitivity analyses of these results. The selected curve should be robust relative to assumptions about the investors' degree of risk aversion, and their willingness to invest as a function of expected profits, because such behavioral characteristics are uncertain and subject to change.

I conclude that the advantages of the downward sloping demand curve recommended by PJM relative to the vertical demand curve prevail for wide variations in these and other model assumptions. The vertical demand curve (the present ICAP system) produces higher long-run consumer costs than the demand curve that PJM recommends for every set assumptions tested. That is, adding a slope to the demand curve, in the manner proposed by PJM, does not worsen costs to power consumers in the simulations and, under most assumptions, significantly decreases those costs.

In Section 5.4, I compare the effects of a four year-ahead auction with a same year auction. The primary difference between the two is that capacity prices are more uncertain in the latter case; as a result, if investors are risk averse, higher average returns may be required in order to induce investment. As a result, the dynamic analysis finds that for the case of no demand curve (the present PJM capacity market) and for the proposed PJM sloped demand curve, a same year auction yields lower average reserve margins and higher costs to consumers.

3. BACKGROUND

In normal commodity markets, the consumer buys just the commodity. For example, a car owner does not pay Exxon for gasoline, and in addition pay for "ancillary services" (e.g., separate charges for delivery trucks or gas pipeline maintenance) or capacity of refineries or oil wells. The gasoline buyer pays a per gallon charge, and the gasoline supplier then figures out how to arrange and pay for production, processing, and delivery. Even though gasoline consumers do not pay separately for, say, gas tanker trucks, this has not resulted in shortages. In normal commodity markets, much or all of the funding for capacity and storage required to meet peak demands is provided by higher than normal prices during those times. Why then are there repeated calls for separate capacity markets for electricity or other mechanisms to ensure that "enough" generation capacity is built?

There are several reasons why power markets do not conform to the assumptions of the perfect competition ideal. One reason is specific to electricity itself—because power is very capital-intensive to produce, yet cannot be produced at one time and stored for future use at another, it is very expensive to meet peaks demands that only occur a few hours per year. For instance, in PJM, the highest hourly load in most years is over 8% greater than the loads served in 99% of the hours (i.e., higher than the 1% exceedence level for loads). The marginal cost per MWh of building enough generation capacity to meet that highest load is several tens of thousands of dollars, compared to an average price that is three orders of magnitude smaller. This is based on the annualized capital cost of a combustion turbine, which is $61,000/installed MW/year (in annualized real dollars), as discussed later in this affidavit. The marginal cost during the peak hour is so high because the incremental capacity would be idle the other 8759 hours per year, making no contribution to capital costs. In other industries, this swing of marginal cost from off-peak to peak periods is less extreme for three reasons: some are less capital intensive, they have more ability to store and transfer commodities from one period to another, and finally they can often charge high prices to dampen demand during peak periods,

High peak marginal costs do not by themselves explain the need for capacity markets. The other consideration is the absent demand-side of the market. One failure of the demand-side is the presence of price caps or other sources of price rigidity that prevent prices from climbing anywhere near that high during peak periods. To pay for the carrying cost of a combustion turbine that operates only eight hours per year, prices must approach $10,000/MWh for those hours. In a competitive bulk power market, this would only happen if there is a capacity shortage such that operators had to curtail load in order to maintain sufficient operating reserves. However, in the PJM and other eastern US ISO markets, prices are capped at $1000/MWh. So when shortages loom, prices approach and can bump into the price cap, and generators fail to receive the high revenues that unrestrained price spikes would bring. When prices cannot spike to uncapped levels that reflect the true value of peak electricity consumption to customers, load cuts and near-shortages must occur several dozens of hours per year with prices approaching the cap of $1000/hr in order to justify constructing a combustion turbine. (This assumes (1) there is no capacity market and (2) energy prices otherwise do not exceed the running cost of turbines.) Market participants would view a system with such frequent shortages as unacceptably unreliable.

In current retail electric markets, price fluctuations in the bulk power market are not communicated to most retail customers, who pay a rate that is either constant or just seasonally adjusted. Those consumers then do not notice whether the price of bulk power is $10/MWh or $1000/MWh during a particular hour. Their consumption decisions would be unaffected by price spikes, unless they hear public conservation requests or they are among the minority that participate in utility interruptible rate or load control programs. In contrast, when consumers are subject to prices that fluctuate in real time, they can often respond by decreasing loads in peak periods, or shifting uses to off-peak periods. This reduces the need for expensive capacity. Economic theory shows that when real-time prices are faced by all market participants in a competitive market, the optimal amount of generation reserves can result. This is because market prices will express the consumers' willingness to pay for power during peak times—just as in other commodity markets. But price regulation and lack of hourly meters for most customers mean that this ideal is unattainable, at least in the near future.

The absence of demand response to real-time prices also means that consumers are vulnerable to the exercise of market power. If a generation market is concentrated, generation will benefit from tight supply conditions because suppliers can more easily raise price above marginal cost. This dampens the incentive for capacity construction by incumbent generators. In contrast, higher reserve margins benefit consumers by making the exercise of market power less likely.

As a result of these demand-side failures, generation capacity becomes a public good. That is, every electricity user in the market benefits from the addition of new capacity, but the owner of the capacity cannot capture all those benefits through higher revenues. Economic theory says that public goods tend to be undersupplied in markets, so demand-side failures tend to cause capacity under-investment. Recognizing the value of capacity, the North American Electric Reliability Council (NERC) has explicit standards for capacity adequacy that require that certain reserve margins be maintained.

Several alternative mechanisms have been proposed to correct these market failures and to respond to adequacy mandates. One approach is to directly address the market failures by widespread installation of real-time metering and removing the price caps on both electric demand and supply. A second approach is a regulatory requirement that those who sell power to consumers hold long-term contracts or options for energy, perhaps with a stipulation that the options be backed up by physical generation assets. A third approach is a fixed payment (price-based) mechanism, where the ISO provides a set payment per MW for capacity, subject perhaps to performance penalties.

A fourth approach is quantity-based methods, in which a market operator either procures reserve capacity directly or sets up a capacity market. There are several varieties of capacity markets currently implemented. However, each market has most or all of the following basic features:

- a target level of system generating reserves (commonly based on an adequacy criterion of capacity deficits occurring only once every decade);
- an allocation of responsibility for meeting that target by creating an obligation (either on the part of LSEs or the ISO itself) to acquire capacity or capacity credits;
- a system to assign credits to generators, based on their capacity and reliability, and also to load management programs that can diminish the need for capacity;
- a system that allows trading of credits so that those with credits beyond their needs can sell them to those who are short;
- a set of requirements defining how far ahead of time (days, months, or years) those responsible for obtaining capacity must contract for it; and
- a system of incentives to encourage availability of capacity when needed, and for penalizing LSEs who have insufficient credits.

The present PJM capacity market is of this general type, with most of the features mentioned in this paragraph.

A fifth approach is a hybrid of the third (price-based) and fourth (quantity-based) approaches. It involves the market operator creating a downward sloping demand curve that pays more for capacity if reserves are short, while providing smaller but nonzero payments for some capacity levels that exceed the nominal reliability target. (In a sense, the present PJM system can also be viewed as a hybrid, as the deficiency payment paid by LSEs who are short of capacity credits puts a cap on how much they are willing to pay for capacity. This translates into an effective demand curve with a horizontal segment equal to the deficiency payment to the left of the target reserve margin, a vertical segment at the target, and no payment to the right of the target. Because there is no slope to this "curve", I term this the "vertical demand curve" approach below.)

There are several general advantages of a sloped demand curve-based capacity mechanism relative to fixed payment and quantity-based systems. Compared to fixed payment systems, the downward sloping demand curve will signal a higher value for capacity if reserves are short, and a lower value if reserves are ample. On the other hand, compared to a pure quantity-based system, where prices for capacity are zero if there is 1 more MW than needed but are very high if there is 1 MW less than required (Figure 1(a), *supra)*, a demand curve will reflect the reality that additional capacity over and above a target reserve margin nevertheless has value. Additional capacity has value for two reasons. One is that in the face of varying load growth, weather, and capacity availability, the probability of available capacity being less than what is required to meet load and operating reserves never reaches zero, even for large reserve margins. Thus, reserves beyond the target are valuable for reducing the risk of capacity shortfalls. The second source of value is that reserves beyond the target lessen the risk of large suppliers being pivotal or otherwise able to exercise market power. Conversely, if reserves are below the target, a downward sloping demand curve provides increasing incentives for new capacity to the extent that the system is short, reflecting in a general way the greater risks of shortages and market power.

Another major advantage of a demand curve-based capacity market compared to the pure quantity-based system is that the stream of capacity payments received by generators will be more stable. In contrast, a capacity market with a fixed capacity requirement (no demand curve) can bounce between two extremes, depending on whether there is too little capacity or too much relative to the target. The resulting large swings in generator net revenues can exaggerate boom-bust behavior. Boom-bust cycles occur when a market adds too much capacity after a period of high prices, which results in a period of low or no capacity payments, which then dries up capacity additions until reserves are again short of target levels. Volatile revenues that cannot be hedged because of incomplete forward markets for energy and capacity increase risks to investors. Because investors in capital markets dislike risk, more volatile profits mean that higher rates of return will be required for new generation investments. In order to obtain the higher returns required by risk averse investors, shortages of capacity would have to happen more frequently, resulting in higher costs and risks to consumers. In comparison, as I show later in this affidavit, a demand curve-based system will lower the variation in generator revenues, especially for peak capacity. Further reductions of risk to investors result if capacity commitments are made years in advance, as opposed to the present PJM system. With advance capacity commitments, my market simulations show that if investors are risk averse, they will accept lower rates of return and be more willing to construct new capacity, ultimately decreasing costs and risks to consumers.

A third potential advantage of a downward sloping demand curve for capacity relative to a pure quantity-based capacity market (or vertical demand curve) is that the incentive to engage in either economic or physical withholding of capacity from the capacity market is reduced. This is because the slope of the demand curve causes a given reduction in capacity or increase in the capacity bid to have considerably less effect on the price of capacity than when the curve is vertical, as it effectively is for a quantity-based system. However, the presence of a "must-offer" requirement, backed by effective penalties, can also mitigate market power under either vertical or sloped curves.

4. DYNAMIC MODELING METHODOLOGY

4.1 Overview.

The purpose of the dynamic modeling methodology is to assess how the location and shape of the demand curve for capacity affect investments in generation adequacy. Because I focus on general adequacy issues, I do not represent capacity markets or payments for capacity differentiated by operating flexibility or location.

The fundamental idea of the methodology is that construction of generation capacity in a restructured electricity market represents a dynamic process with lags (due to construction lead times), short-sightedness (additions are based on recent energy and ancillary service market behavior, rather than perfect forecasts of future prices), and uncertain load growth. Thus, for instance, if it takes four years to bring a combustion turbine on-line in year *y*, the amount of turbine capacity installed in year *y* might be assumed to be some function of profits that such a turbine would have earned in, say, years *y*-4 and *y*-5. Profits, of course, are based on gross margins (revenues minus variable costs) earned in the energy and ancillary services (E/AS) markets, and any capacity payments. Investors may make construction decisions based on forecast profits, but since forecasts are generally based on past experience, construction decisions can therefore be represented as ultimately depending on the recent history of profits.

Investments based on recent profit histories can result in an unstable system exhibiting overshoot-type behavior. This behavior could result from an overreaction of merchant generation to high profit opportunities, resulting in a glut of capacity that then depresses prices, which then throttles capacity construction, leading subsequently to a shortage of capacity, and so forth. Instabilities can be exacerbated by load uncertainties. Because of variable economic growth, the growth in peak load (weather-normalized) can deviate from the expected value (that value being 1.7% per year for PJM), implying that realized reserve margins (with respect to weather-normalized peaks) will likely diverge from those forecasted in an advance ICAP auction. Further, variable weather adds volatility to E/AS gross margins. The resulting unstable profits lessen generators' willingness to invest. This is because investors are likely to be risk averse, in part because the market structure is new and changing, and in part because markets for financial hedges are inadequate for PJM E/AS and capacity markets.

Capacity markets should be designed to dampen boom-bust cycles, improve the stability and predictability of system adequacy, and minimize costs to consumers. It is reasonable to expect that the slope and location of a demand curve will affect the stability of the capacity market and, ultimately, prices and reliability. A good capacity market will also create some predictability and stability of generator profits, which is desirable to facilitate continued capital investment. My analysis focuses on those objectives.

There are tradeoffs between different market design objectives, so some judgment is needed.. On one hand, it is possible to essentially guarantee that the target capacity would be hit if a vertical demand curve (with an extremely high price to the left) was set at the target reserve level. But such a demand curve might result in more variation in consumer costs and profits and perhaps more market power than a sloped curve. So a choice requires consideration of those tradeoffs, and I use a dynamic model of capacity additions to quantify them.

Investment decisions are complex, and it is not possible to know or represent the precise decision processes of each potential generation investor. Therefore, my simulation modeling approach is intended to be a simple, reasonable, and transparent representation of the fundamental considerations that are affected by the demand curve and that contribute to stability or instability in the capacity market. These considerations include:

- uncertain load growth and E/AS revenues,
- generator risk aversion,
- forecasts of generator profits that depend on past profits, and
- willingness to invest in generation that increases as a function of forecast profit.

The models represent these considerations using simple functional forms with a minimum of parameters in order to facilitate alternative assumptions and improved understanding of the relationship of those assumptions to the results. A general principle of good modeling is Occam's razor: no more complex relationships should be used in a model than is necessary unless the additional complexity demonstrably increases the model's realism. Therefore, in the absence of evidence of more complex relationships or data to support their modeling, I have chosen to use simple functional forms in the models.

Because any model is necessarily a simplification of reality, and because many of the parameters of the model cannot be known with certainty, no single set of outputs should be treated as being definitive statements of the performance of a demand curve. Instead, I test several forms of the demand curve and conduct numerous sensitivity analyses around key parameters to determine the patterns of their influence on the model results, and the robustness of any conclusions about the relative performance of different curves. While the model necessarily simplifies capacity market decisions and impacts, the model is useful for the purpose of understanding qualitative dynamic effects such as whether a long-term capacity market is less likely to induce boom-bust cycles than a short-term capacity market, and whether the relative ranking of different alternatives is robust under a wide range of assumptions. The model is not accurate enough to make precise quantitative predictions, but its intent is to illuminate several qualitative decisions that must be made at the outset of the RPM.

Since no particular set of assumptions can be the "right" ones, sensitivity analyses are essential to assess the robustness of the comparisons. The model is designed to clearly show the implications of alternative assumptions concerning generator investment behavior and market conditions for the comparison of demand curves. A simple, transparent model that captures the basic features of the capacity market — uncertain loads, the dependency of forecast profits on past profits, generator risk aversion, increased investment in response to increased profits, and the effects of reserves upon energy and ancillary service market revenues and system reliability — is most likely to lead to useful insights and conclusions about the relative performance of different demand curves.

Models should produce sensible and consistent results. In particular, in the case of no uncertainty and risk neutral investors, the model should yield the expected equilibrium solution of enough capacity being added in each year to meet load growth, and generator revenues equaling costs, including a normal return to capital. Under these assumptions, a constant reserve margin—in an amount that depends on the location of the demand curve—should result. The model described below satisfies this consistency condition.

4.2. Model Assumptions

4.2.1. Flow of Model Execution

The dynamic model is a discrete time simulation, with an annual time step. Uncertainty is introduced in the form of both variations in economic growth and weather, which both affect the growth rate for the peak load. The model is implemented in EXCEL®.

Figure 2 summarizes the basic logic of the model for the case of the four-year ahead auction. An auction for ICAP in year *y* must take place at *y*-4, four years before that time. The following steps are executed in each year:

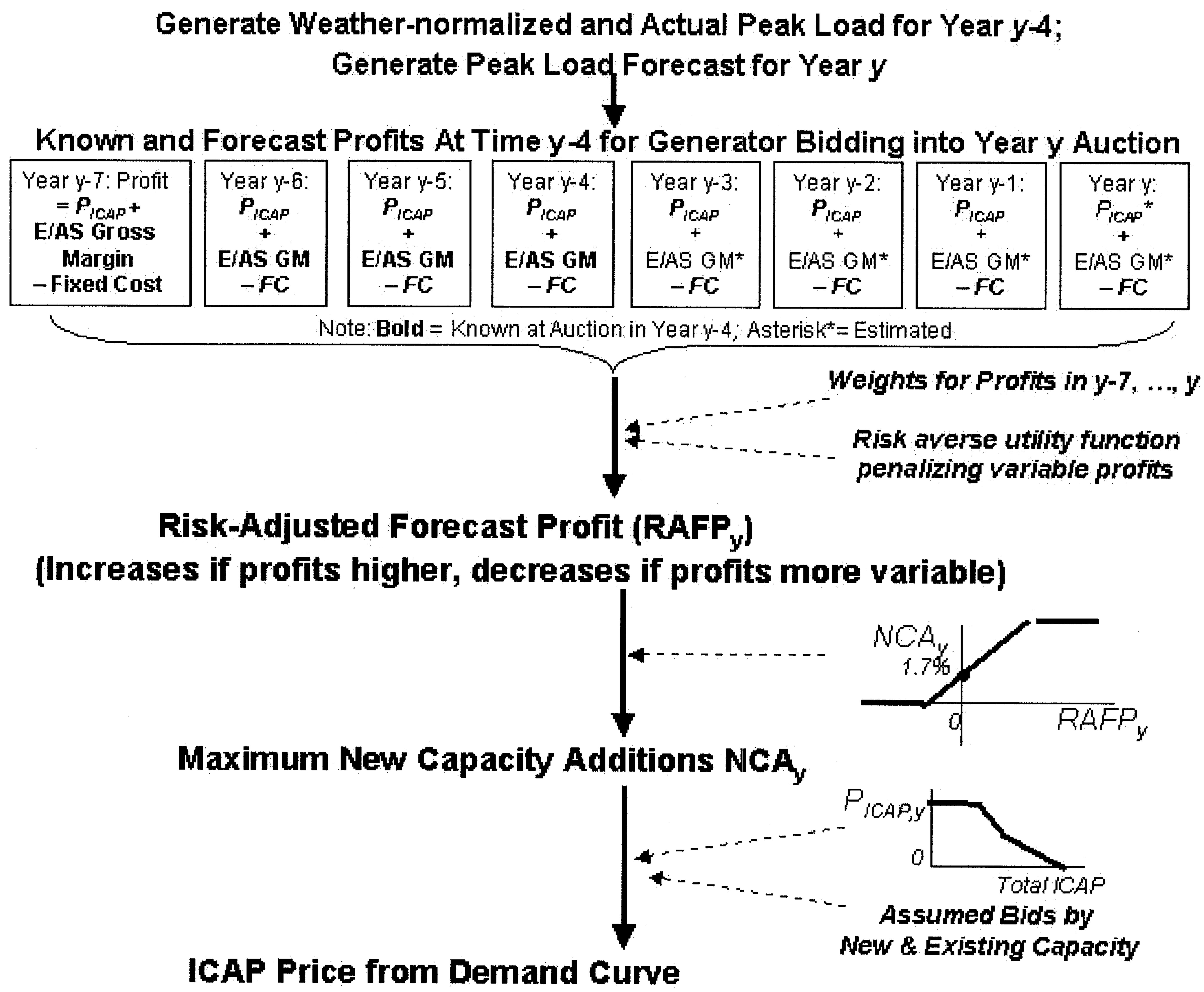


Figure 2. Flow Chart Showing Steps of Simulation

- Given the previous year *y*-5's weather-normalized peak load, and assuming random economic growth, the simulation model first generates a random weather-normalized peak for year *y*-4. The simulation then generates an actual peak load, accounting for random weather. E/AS gross margin, defined as E/AS revenue minus variable costs, is then calculated for a benchmark combustion turbine (having fixed annual cost *FC*) for year *y*-4. This margin is a function of the actual peak load and reserve margin in that year. Based on PJM experience, as I discuss below, tighter actual margins are associated with higher E/AS earnings. The E/AS gross margin plus the RPM revenues (determined in a previous auction) minus *FC* define the turbine's profit in that year. Then a forecast is made of the weather-normalized peak four years in the future (year *y*); this forecast is the basis of the demand curve in the auction held in year y-4.

- In the next step, companies who might build new generation assess profits for a combustion turbine in years y-7 to y. (Fewer or greater numbers of years could be chosen, but the relative performance of different demand curves would not be greatly affected.) Profits for some of those years (y-7 to y-4) are assumed to be already known, since those years have already passed (y-7 to y-5) or are in process (y-4) and can be fairly accurately projected. Profits for future years (y-3 to y) are not known, since E/AS revenues depend on loads, which in turn are unknown because of uncertain economic growth and variable weather. The ICAP price is known for y-3 to y-1 (thanks to prior auctions), but has to be estimated for this year's auction (y), which has not yet occurred.
- Then, given those profits, a risk-adjusted forecast profit $RAFP_y$ is calculated, which requires two inputs. One is a set of weights to be attached to the profits in years y-7 to y; for example, more weight might be given to recent profits. The other is a risk-preference function (called a "utility function" in decision theory) that incorporates attitudes towards risk. Basically, such a function penalizes bad outcomes in such a way that if there are two distributions of profits with the same average value, the more variable profit stream will be less attractive.
- In the next step, the risk-adjusted forecast profit is translated into a maximum amount of new capacity NCA_y that generators are willing to construct; it is assumed that higher risk-adjusted profits will increase the amount of capacity that generators are willing to build. The function shown embodies an assumption of 1.7%/year average load growth, and a maximum amount of capacity additions; I discuss these specific assumptions in more detail later in this affidavit.
- Then a supply curve for capacity is constructed, based on the amounts of existing and po-

tential new capacity and the assumed prices that each would bid. This supply curve is then combined with the demand curve to yield an ICAP price and committed amount of new capacity for year *y*. This committed amount might be less than the maximum amount if new capacity is assumed to bid a positive price.

After these steps are executed, the simulation then moves to the next year, and the process is repeated.

Because the model randomly samples economic growth and weather, good modeling practice requires that a large sample of years be simulated in order to obtain reliable estimates of the average long-run performance that are unaffected by sample error. In such so-called "Monte Carlo" simulations, it is typical to repeat the random draws many thousands or more times. I follow this standard practice by repeating the above process for 100 years, and then a new simulation is started. It is important to note that a particular simulation does not represent a prediction of the market's development over the next 100 years; rather it is one sample path which, when repeated a number of times, allows for a statistically precise estimate of the average long-run performance of a particular curve and set of assumptions. Altogether, twenty five simulations of 100 years apiece are run for each demand curve and set of assumptions tested. This results in a sample size of 2500 years that allows the long-run average and standard deviation of each of the four sets of performance indices to be calculated.

4.2.2. Specific Model Assumptions: Four-Year Ahead Auction Model

The model requires a number of parameters that characterize the market design, load, system reliability, E/AS gross margins, and generator responses to incentives. I summarize these below.

Inflation. All calculations are made in real (uninflated) dollars. All capital and operating costs are assumed to inflate at the general rate of inflation (no differential escalation). Prices defined by the demand curve are also assumed to be adjusted upwards by PJM at the rate of inflation.

Market design parameters. The model's simple characterization of the demand function for capacity includes maximum payment (the flat left portion of the curve in Figure 1) and location and slopes of the downward portions of the demand function. To focus on general resource adequacy issues, I do not consider the following complications: capacity payments differentiated by operating flexibility or location; possible backstop mechanisms if reserve margins are lower than acceptable for several years; and possible administrative adjustments to demand curves that are made in response to new information about capacity costs and revenues from energy and ancillary services revenues.

I do not consider how changes to an ICAP mechanism might affect administrative and transaction costs incurred by generators and load serving entities participating in the market. I also do not consider imports of capacity from outside PJM, or other seams issues.

Load parameters. Load is summarized by the annual peak load in each year. Three separate types of loads are considered: actual peak load, weather-normalized peak load (actual peak load adjusted for normal weather conditions), and forecast peak load (assuming normal weather conditions) for a future year. The growth in forecast peak load is assumed to be 1.7%/yr, consistent with the current official PJM forecast (see the February 2005 PJM Load Forecast Report), but below the PJM experience of 2.2% annual growth in weather-normalized peak load in the last decade. Year-to-year variations in the growth of weather normalized load are greatly influenced by economic growth in the PJM region; recent experience indicates that the growth rate has a standard deviation of 1%/year.[1] I model this variation in weather-normalized load growth by adding a normally distributed random component in each year to the 1.7%/yr expected growth.

[1] This 1% value is derived by comparing PJM four-year ahead forecasts with the experienced weather-normalized peaks over the 1995-2003 period. The standard deviation of the ratio of those two is 1.8%, which is consistent with the following set of assumptions: (1) a 0.9% random year-to-year error in weather-normalized growth, which I round off to 1%; (2) uncorrelated errors (from year to year) in that growth; and (3) an assumption that in the future, forecast load

Meanwhile, the actual peak load in a given year equals the weather-normalized peak plus an error reflecting year-to-year weather variations. Analysis of annual peaks from 1995-2003 for PJM and ISO-New England show that the ratio of actual to weather-normalized annual peaks has a standard deviation of about 4%, and I assume this value here.

Reserve Margins. Random economic growth and weather variability result in considerable instability in installed reserve margins, as well as in gross margins from E/AS sales which depend on those margins. Two different reserve margins are considered by the model: the forecast reserve margin, which is the basis of the capacity payment (Figure 1) and is based on forecast peak loads; and the actual reserve margin which depends on the actual load, including variation due to weather.

Generation Costs and Revenues. In the model, the focus is on combustion turbine additions, and investment decisions concerning baseload and cycling capacity are not modeled. More sophisticated assumptions about entry of other types of capacity can be made, but to simplify the simulations, we assume that incremental capacity is provided by benchmark combustion turbine (CT) capacity. This is based on the assumption that the price of capacity will be driven by the cost of turbines, net of their gross margins in the E/AS market, while other types of capacity receive most of their gross margins from the E/AS market. I have also conducted simulations of long-run equilibrium entry of coal plants, combined cycle facilities, and peaking plants for the PJM system.[2] Justifying my present focus on turbine investments, it turns out that those simulations show that the amount and mix of non-peaking capacity is not affected by the required reserve margin or the price of ICAP. Only the amount of peaking capacity is affected. However, all generating units are assumed to receive capacity payments, and consumer costs are calculated on that basis.

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growth rates (1.7%) are not biased up or down— that is, on average, the 4 year ahead forecast of the W/N peak will be correct.

[2]For a summary of the long run simulation approach and results, see B.F. Hobbs, J. Inon, and S. Stoft, "Installed Capacity Requirements and Price Caps: Oil on the Water, or Fuel on the Fire?", Electricity Journal, 14(6), August/Sept. 2001, 23-34. Since then I have updated the load duration curves and cost assumptions of the analysis, but the same basic result holds: capacity market mechanisms do not affect the quantity or mix of nonpeaking capacity added.

In reality, it is possible that in some years capacity additions for other types of plant will be undertaken while no turbines are being added. For example, if there are large shifts in relative fuel prices, as in the 1970s, generation additions beyond what is needed to meet reserve margin requirements might be justified in order to displace uneconomic fuels in the existing generation mix. For simplicity, I assume that these conditions are relatively infrequent, and that if capacity is being added, at least some of it will be in the form of combustion turbines, for which ICAP revenues will constitute a major part of their forecast profits.

All CT units are assumed to have the same marginal operating and capital costs (in real terms) in all years of the simulations, so technological progress and fuel price changes are not represented. I disregard real (after-inflation) changes in technology and costs in order to avoid having to make assumptions about escalation rates. The annualized capital and fixed operations cost is assumed to be \$61,000/installed MW/yr in annualized real dollars.[3] Accordingly, my model implicitly assumes that the second-year annualized capital cost will be higher than the first by a factor equal to the inflation rate, and the third-year figure will be higher than the second, and so on. It is my understanding that PJM is proposing a fixed CONE figure stated in its tariff that cannot be changed without a stakeholder process and regulatory approval, but that the proposed fixed CONE value also takes future inflation into account using a nominal levelized financial model, as explained by Joseph E. Bowring in his affidavit as witness for PJM.

With an assumed forced outage rate of 7%,[4] this translates into a cost of \$65,600/unforced MW/yr for a new turbine, again in real dollar terms. I assume that the marginal operating cost is \$79/MWh. I also assume that the lead time for CT construction is four years, including time re-

[3]See affidavit of Mr. Raymond M. Pasteris, witness for PJM. The difference between an annualized real dollar figure and an annualized nominal dollar figure is that a time series that is constant in real terms will escalate in nominal dollars at the rate of inflation, while a time series that is constant in nominal terms will have no inflation, i.e., the same "dollars of the day" in every year. See also the affidavit of Joseph E. Bowring for further explanation of the difference.

[4] The 7% forced outage rate is based on the latest NERC 5 year (1999-2003) class average (6.93%) for industrial type simple cycle combustion turbines over 50 MW in size, which is the closest publicly available fit for a GE Frame 7 machine. The corresponding value for the large aircraft-derivative units is almost identical at 6.91%.

quired for necessary regulatory approvals.[5] The willingness of investors to build new turbine capacity is assumed to depend on future profit forecasts, which in turn are assumed to depend on profits that would have been earned by such a CT in previous years, equal to the sum of ICAP revenues and E/AS gross margin, minus the annualized cost of CT capacity. Profits in previous years are important to consider because they provide a basis for forecasting the level and volatility of profits in the future.

The E/AS gross margin that a turbine would earn in each year is critical to its profitability, and therefore to investors' willingness to build capacity. Furthermore, as I document below, this gross margin varies greatly from year-to-year, depending strongly on the amount of capacity relative to the actual peak loads. The model therefore includes a relationship between market conditions (reserve margin) in a year, and the E/AS gross margin earned by a new turbine. This gross margin consists of two portions: a scarcity portion, which arises when price exceeds the marginal cost of the last generating unit (due either to a genuine shortage, or to exercise of market power), plus an assumed $10,000/MW/yr that is earned in ancillary service markets that I do not model or which results from margins earned when more expensive plants are on the margin.[6] Figure 3 shows the resulting total E/AS gross margin for a hypothetical new turbine (solid line), as well as the actual values that would have been experienced for such a turbine in years 1999-2004 (triangles), under the assumption that the turbine could operate in any hour in which price exceeded its

[5] This estimate is based on a typical time of up to two years to acquire necessary permits, in addition to an actual construction time of two years. The precise lead time required depends on location and the presence of complicating issues (such as non-attainment status for criterion air pollutants or land use restrictions).

[6] Within the model, this function could be calculated by an appropriately calibrated production costing submodel that represents all operating constraints. Instead, we estimate this function using the results of a simplified probabilistic production costing model for PJM in which the energy price paid to the generator is assumed to equal the marginal cost of generation unless load is within 8.5% of available capacity, at which point scarcity pricing is assumed to take place and the price of energy hits the cap ($1000/MWh). The simplified model has a capacity mix of baseload coal and gas-fired combined cycle and combustion turbine capacity, and a load distribution reflecting the combined PJM-East and PJM-West load shape. Subtracting the assumed marginal running cost of the CT yields the estimated scarcity rent. The scarcity rent is then added to an assumed minimum E/AS gross margin of $10,000/unforced MW/year. Although the particular assumptions of the production costing model are somewhat uncertain, Figure 3 shows that the resulting E/AS gross margin function is a reasonable approximation to actual PJM market conditions in the 19992004 period.

marginal running cost ("Perfect Economic Dispatch").[7] The actual data confirms the reasonableness of the E/AS function used. The figure shows that when the actual reserve margin equals the target installed reserve margin (IRM) (indicated by a ratio of 1 on the X axis), the E/AS gross margin is about $28,000/unforced MW/yr. This margin is generally consistent with the average E/AS margin for a new turbine for the period 1999-2004 under perfect dispatch assumptions, as reported in PJM's 2004 State of the Market Report.

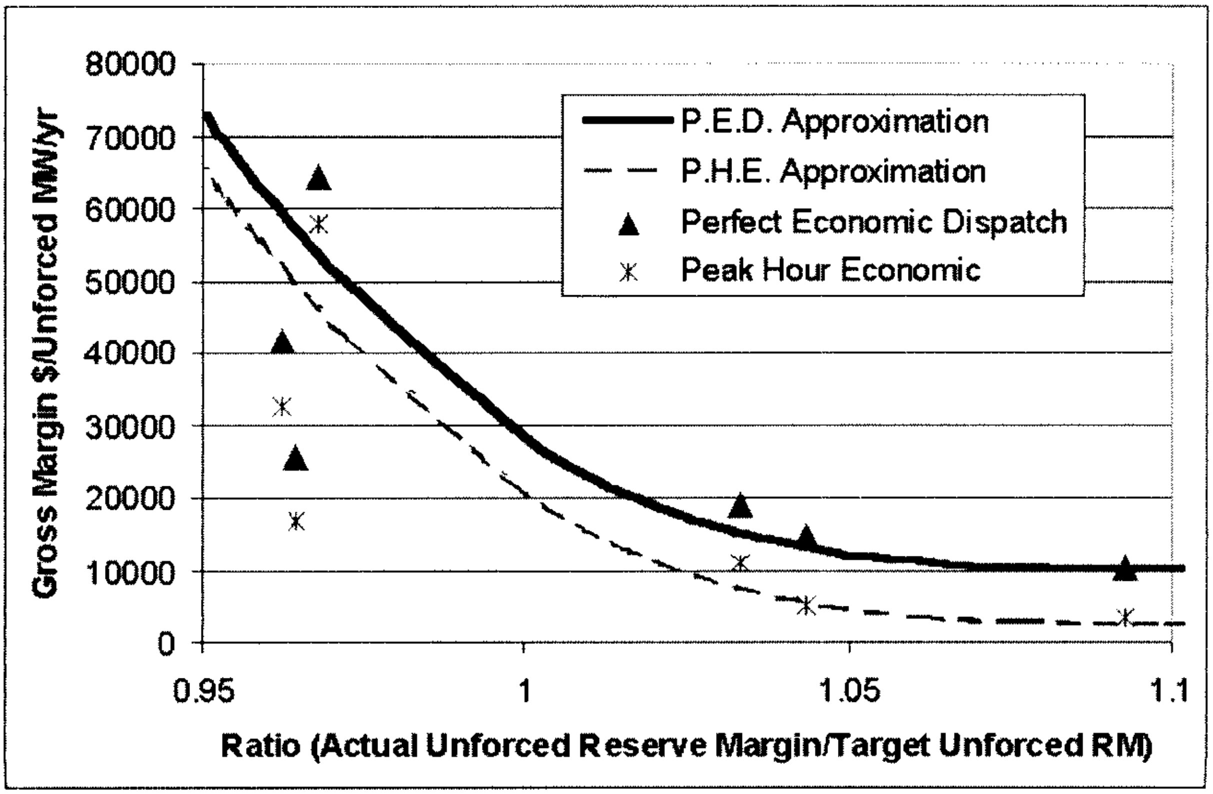

Figure 3. Relationship of E/AS Gross Margin to Unforced Reserve Margin Under Alternative Turbine Dispatch Assumptions, expressed as a Ratio With Respect to the Target Installed Reserve Margin for PJM

An alternative cost function results if a more conservative assumption is made about when the benchmark turbine could be operated. If its operation is limited to peak hours, thus omitting off-peak hours when prices exceed the turbine's running cost, E/AS revenues fall. For 1999-2004,

[7]Source: Table 2-34, 2004 PJM State of the Market Report. Values reported in that Table are adjusted upwards, accounting for forced outages, so that the values are expressed as $/unforced MW/yr.

the average E/AS revenue for the baseline turbine would then be about $21,000/MW/yr (*ibid.*); year-by-year results are shown in Figure 3 (asterisks, "Peak Hour Economic"). The cost curve in Figure 3 can be adjusted to fit those results by lowering the minimum E/AS gross margin from $10,000/MW/yr to $2400/MW/yr (see the dashed line in the figure). Later in this affidavit, I present the results of a set of sensitivity analyses based on this alternative cost function.

Since E/AS gross margins for years *y*-3 to *y* depend on actual peak loads which are not known in year *y*-4 (the year in which a commitment is made to constructing a turbine to be on-line in year *y*), these margins must be forecast. This is done in a simple fashion in the model by simply calculating the E/AS gross margin under the forecast loads for those years. Alternative, more sophisticated analyses are possible, such as considering a probability distribution of E/AS in each future year, but are unlikely to change the general results of the analysis.

Investment Behavioral Characteristics. As Figure 2 (on page 18) shows, there are four major sets of behavioral characteristics that are modeled: two sets are used to calculated risk-adjusted forecast profit (forecasting and risk aversion assumptions); another set is used to determine the maximum amount of new entry; and a fourth set includes the bid prices that capacity suppliers provide to the ICAP market. Since each set of characteristics is uncertain, I report a set of sensitivity analyses in Section 5.3, *infra*, that summarize the robustness of the model results to those assumptions.

The risk-adjusted forecast profit (*RAFP*) is defined as a certain profit that is viewed by investors in generation as being just as desirable as the actual stream of observed and estimated profits (the eight profits shown at the top of Figure 2). "Profit" is defined in the sense meant by economists: as profit over and above the cost of capital; so a zero profit signifies that capital costs are just being covered. The generator calculates a risk-adjusted profit for an investment in a combustion turbine by multiplying each profit (adjusted to account for risk aversion) by the probability of receiving that profit, accounting for the range and variability of observed and estimated profits. Generally speaking, if two endeavors offer the average profit, the riskier option is less desirable (has a lower risk-adjusted profit), and the options with the highest risk-adjusted profit will be most desirable. The adjustment for risk aversion is accomplished using a standard representation of risk preferences called a utility function, which I will call a risk-preference function in the remainder of this section. (Appendix A.2 below provides details.) The first step in calculating *RAFP* is to calculate the value of the risk-preference function for each year's profit.

Different degrees of willingness to take risks are captured by a single risk-aversion parameter in the risk-preference function. As I explain in Appendix A.2, *infra.*, a risk-aversion parameter value of 0.5 signals complete risk-neutrality—any investment with the same average return is valued the same, no matter how variable or risky the profits. Values of this parameter greater than 0.5 signal an increasing distaste for risky investments; a base-case value of 0.7, representing an intermediate degree of risk aversion, is assumed here. Because this behavioral characteristic cannot be known, I undertake a wide range of sensitivity analyses to see if the relative performance of the demand curves depends on the degree of investor risk aversion.

The second step in obtaining the *RAFP* is to calculate a weighted average of the eight years of risk-adjusted observed and estimated profits (Figure 2, page 18). The sum of the weights is 1. A simple form of such weights is the lagged formulation in which risk-adjusted profit in any year $y-1$ is a given fraction α of the weight assigned to the next year y's profits. The weights reflect the degree to which the history of profits is relevant to the generator forecasting profits; the greater the weight placed on previous years' profits (y-1, y-2, etc.), the less relative weight is placed on the ICAP price in the particular year y's auction. As a base case, we assume that the weight given profit in year y-1 is $\alpha = 80\%$ of the weight assigned the next year's profit. I subject this assumption to sensitivity analysis later in this affidavit.

The third step calculates the *RAFP* itself, defined as the single profit value whose perceived value to the investor is the same as the weighted average of the risk-adjusted observed and estimated profits.

The second set of behavioral characteristics concerns how investors in generation might react to different levels of *RAFP*. The maximum amount of new capacity additions (NCA) is calculated using a simple function with the following properties:

- If *RAFP* is zero (that is, capital costs are just covered), then the amount of capacity added is sufficient just to meet expected load growth (1.7%/yr, calculated as a fraction of existing capacity; see Figure 4). This is consistent with the assumption that in a growing market in which investors receive "normal" (zero economic) profit, adequate investment will occur.
- If *RAFP* equals the fixed cost of a combustion turbine (in annualized real terms), then entry of new capacity is highly profitable (not only is the cost of capital covered, but extra profits equal to the capital cost are also earned). I then assume that the amount of entry equals 7% of existing capacity (Figure 4). This value is based broadly on recent experience in the PJM market with capacity additions. In particular, the maximum capacity additions in the MAAC region since 2000 amounted to 3800 MW, equaling 6.3% of the 60,015 MW of capacity existing at that time.
- Capacity additions at other *RAFP* levels are an increasing function of *RAFP*, and follow a curve that is the same shape as the assumed risk-preference function (the upward sloped portion of Figure 4), with two exceptions. First, additions cannot be negative; retirements are not considered in this analysis. Second, additions are subject to a cap so that implausibly high levels of investment cannot occur in a single year. As a result, the *RAFP* function has the S-shape shown in Figure 2 (page 18), and reproduced in Figure 4.

Because this function cannot be known with any certainty, I report the results of sensitivity analyses of these assumptions.

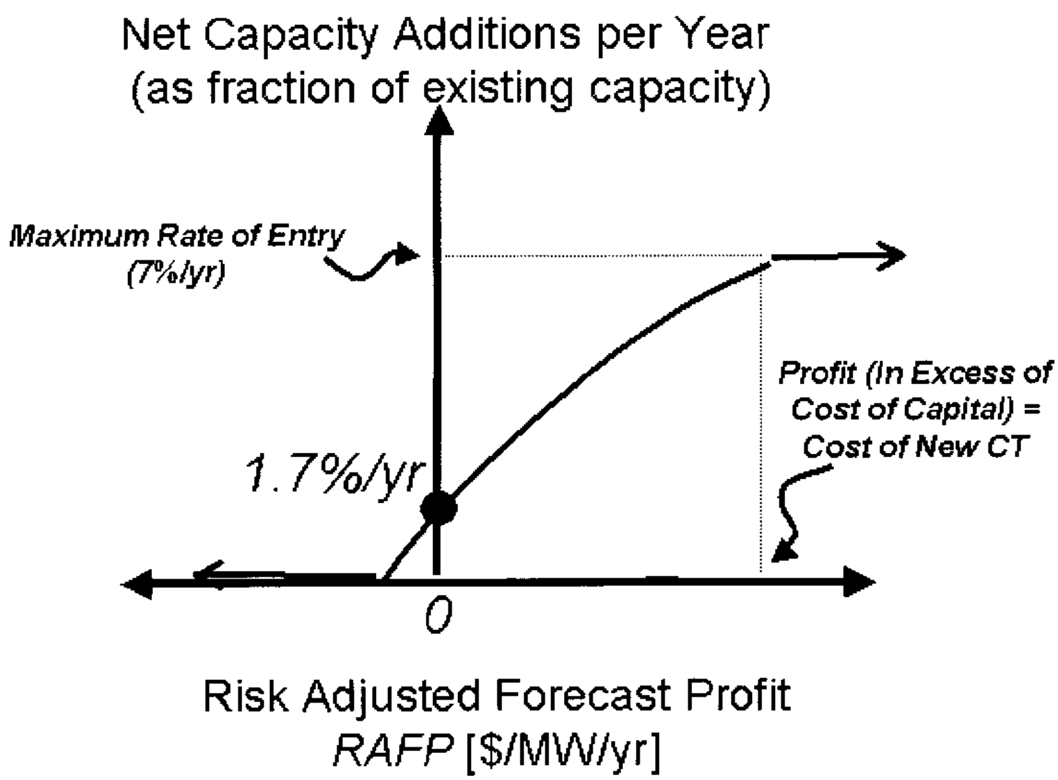

Figure 4. Relationship of Rate of New Capacity Construction (As Fraction of Existing Capacity) to Risk Adjusted Forecast Profit of New Combustion Turbine

The third set of behavioral characteristics in the model involves the assumed prices at which existing capacity and new capacity are bid into the ICAP auction. For simplicity, no retirements of existing capacity are considered. For the base cases, it is assumed that all capacity is bid in at $0/MW/yr; that is, generators are assumed to commit to maintaining or building certain quantities of capacity, and then bid in a vertical supply curve, which makes them price takers for the price of ICAP. Alternative assumptions are considered in our sensitivity analyses; the highest bid cases can be interpreted as an attempt to exercise market power. In all simulations, the bid price for existing capacity is assumed to be no more than for new capacity. Figure 5 shows how the resulting market clearing price and quantity of capacity are calculated. The new capacity that is offered but not accepted (the portion of the second step to the right of the point where the curves cross) is assumed to not be built.

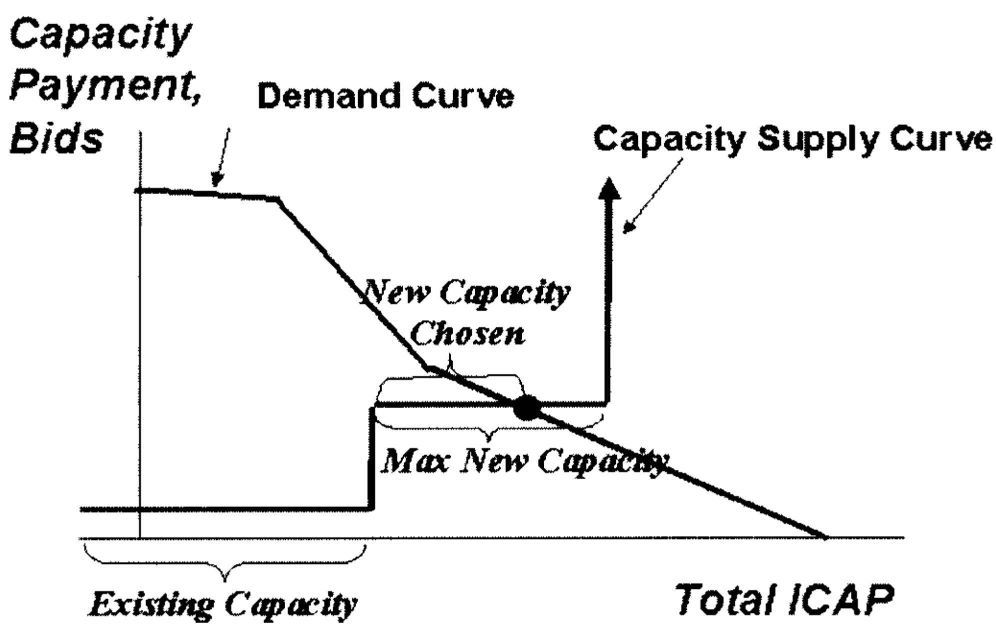

Figure 5. Determination of Price for Capacity Installed in year y

Performance Indices. The performance of a particular ICAP payment scheme is summarized by three sets of indices:

1. Reserve margin indices. One is forecast reserve margin, including its average and year-to-year standard deviation. Also calculated is the fraction of years in which the forecast margin is at or above the target installed reserve margin.
2. Indices regarding generator costs and profits. These include average values of profit for CTs, the price of ICAP, and E/AS revenues, as well as their year-to-year standard deviations. These are expressed in terms of \$/installed MW/yr of capacity for the benchmark CT.

3. An index of consumer cost. We calculate average and standard deviation (year-to-year) of customer payments ($/peak MW/year) for ICAP and for the scarcity rents earned by new turbines. It is assumed that other payments by consumers (including, e.g., energy produced during nonscarcity periods, wires charges, customer charges) are unaffected by the ICAP curve. A higher average cost can occur if chronically low reserve margins result in high ICAP prices and scarcity payments. Such conditions could persist if high market risks make generators reluctant to construct new plants unless average returns are large.

Both averages and standard deviations are reported, because the latter provide indications of the risk in the market for the market participants. For instance, two demand curves might provide the same average forecast reserve margin, but one policy might result in much more variation in that reserve.

5. RESULTS

5.1 Base Case Analyses

Five demand curves are considered in the base case analyses. Each of these curves is displayed in Figure 6. (The four parts of Figure 6 each show Curve 1, the "no demand curve case", superimposed upon Curves 2 through 5 respectively.) The X axis is expressed as a ratio of the unforced reserve margin to the target unforced reserve margin, so that a value of 1 signifies that the target is just met. Multiplying this ratio by the target and then subtracting 100% converts the X axis into the unforced reserve margin.

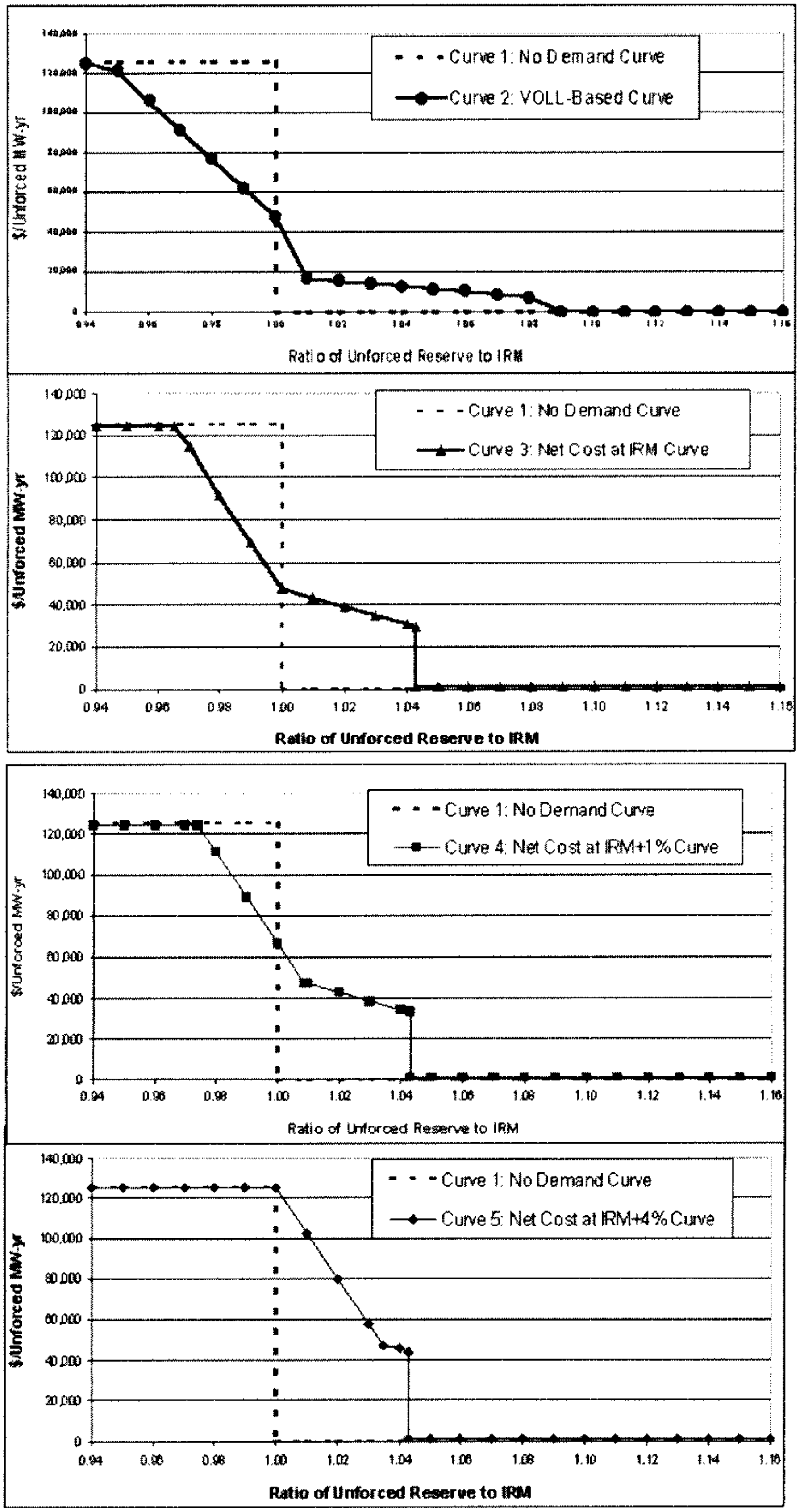

Figure 6. Five Alternative Demand Curves: ICAP Price Paid to Unforced Capacity as Function of Reserve Margin (Expressed as Ratio to Target Unforced Capacity)

The curves are defined as follows:

1. *No Demand Curve.* A vertical demand curve (also called the "no demand curve" case) yields an ICAP payment that is two times the fixed cost of a turbine ($144/kW/year, based on an annualized nominal dollar cost of $72/kW/yr) minus the average E/AS gross margin ($28/kW/yr) for values of forecast reserves that are less than the target installed reserve margin (IRM).[8] (The nominal dollar annualized cost is consistent with a $61/kW/yr real annualized cost and a 2.5% inflation rate.) (The capacity payment is expressed in terms of $/unforced MW/year. Therefore, the highest payment is actually (2*72-28) divided by 0.93 (1 minus the assumed 7% forced outage rate), or $124.7/unforced kW/yr.) The target reserve margin (shown as a ratio of 1 on the X axis of Figure 6) corresponds to a loss of load probability of 1 day in 10 years. If reserves exceed that level, then no capacity payment is made. This is analogous to the present PJM system in which load serving entities (LSEs) are willing to pay up to but no more than their deficiency payment for ICAP credits if they are short of credits, while if credits are in surplus, LSEs are assumed to be unwilling to pay for any more than their total ICAP obligation. As I noted *supra*, the average E/AS gross margin of $28,000/installed MW/yr is an average for the 1999-2004 period for the benchmark CT, as reported in PJM's 2004 State of the Market Report.

2. *VOLL-Based Curve.* A demand curve originally proposed by PJM in August, 2004 that is based upon an approximation of how the expected value of lost load VOLL (also called unserved demand) changes when average reserve margins diverge from PJM's target reserve margin (installed reserve margin IRM = 1.15). PJM's existing ICAP model, the capacity markets used by other northeastern ISOs, and the other curves evaluated in this affidavit, all are based on the fixed costs of a marginal capacity unit. Instead of looking at

[8] As I discuss later in this affidavit, sensitivity analyses using lower multipliers (i.e., 1.2 and 1.5) of a turbine's fixed costs, did not change the general result.

the cost of an increment of additional capacity, this VOLL-based curve attempts to approximate the value to the consumer of an increment of unserved load.

3. *"Alternative Curve with New Entry Net Cost at IRM" Curve.* As shown in the second part of Figure 6, this is a sloped demand curve with four segments: (a) a horizontal segment with an ICAP price equal to two times the fixed cost of a turbine if the reserves are less than 96% of the target reserves, minus the average E/AS gross margin, divided by one minus the forced outage rate ($124.7/unforced kW/yr); (b) another horizontal segment with a zero price if the installed capacity exceeds the target installed reserve margin of 15% by 5% or more (shown as occurring at 1.043 on the X axis in Figure 6, which is the ratio of 1.2 to the target installed reserve of 1.15); and (c) two linear downward sloping segment located between the other two, with the righthand one having a shallower slope.[9] The location where the slope changes is at a reserve margin equal to the IRM, and a price equal to the levelized nominal cost of the turbine ($72/kW/yr) minus the mean E/AS gross margin ($28/kW/yr, for the period 1999-2004), divided by 0.93, or $47.3/kW/yr. As a result, if capacity hits the IRM exactly, then the payment will equal the difference between the benchmark turbine's fixed cost and the average E/AS gross margin.

4. *"Alternative Curve with New Entry Net Cost at IRM +1%" Curve.* As seen in the third part of Figure 6, this curve is a version of Curve 3, except moved 1% to the right in installed capacity terms, but with the zero price still occurring at an installed reserve margin of 20%. (That is, if the X axis in Figure 6 was installed capacity rather than the ratio of installed capacity to the target IRM, the curve would be shifted 1%. In terms of the X axis of Figure

[9] Note that the capacity payment is expressed in terms of $/unforced MW/year. Therefore, as in the vertical curve, the highest payment is actually (2*72-28) divided by 0.93 (1 minus the assumed 7% forced outage rate), or $124.7/unforced kW/yr. Note also that the adjustment for E/AS gross margin is not adjusted year-to-year in the simulation, but reflects the 1999-2004 experience in PJM. The slope of the right hand sloped segment is defined by running a line from the inflection point (at the target IRM) to zero (at the target IRM plus 14% installed margin). That segment is then cutoff at IRM plus a 5% installed reserve margin, which is 1.043 times the IRM, as shown in Figure 6.

6, this shift is instead 1%/1.15.) Thus, at a given reserve margin, capacity will receive a higher ICAP payment than in Curve 3. As shown by the simulations summarized *infra*, this will tend to give additional incentive to invest in generation, and actual reserve margins will tend to be higher.

5. *"Alternative Curve with New Entry Net Cost at IRM +4%" Curve.* This is a version of Curve 3, except moved 4% to the right, and is shown in the last part of Figure 6. As in Curves 3 And 4, the capacity price falls to zero at an installed reserve margin of 20%, which is a factor of 1.043 higher than the target IRM.

In addition to this set of five curves, a second set of curves is also considered based upon an average E/AS gross margin of $21,100/MW/yr. As I noted earlier, and as explained in the 2004 State of the Market Report, this lower value results from an assumption that a benchmark turbine will only operate during peak hours. This assumption results in an upward shift in the left hand part of the curves, because the height of the curve in that region is based on the capital cost of a benchmark turbine minus this margin. In particular, the maximum capacity price increases by about $7400 (= $28,000-$21,100/MW/year, divided by 0.93), as does the location of the kink in the "Net Cost at IRM" curves.

A range of alternative assumptions is considered in the sensitivity analyses described in Section 5.3. I present my conclusions about the relative performance of the curves later in this section, but first some general observations are helpful in understanding the performance indices.

- The more capacity you get, the more likely you will exceed your IRM target, with less variability.
- The more capacity you get, the less scarcity there will be, so scarcity payments in the enrgy market will be lower.

- The sloped demand curves that PJM has proposed yield consistently higher capacity investment with consistently lower consumer costs than the other curves investigated. The vertical demand curve (Curve 1) pays the most for new capacity, but because it creates volatile and fast-changing signals to generators, it hits or exceeds the reserve margin target the least often.

Table 1 summarizes the averages and standard deviations of the performance indices for reserves, generation cost and profit, and consumer payments for the five demand curves summarized above. These results assume zero bids by existing and new capacity, moderate risk aversion (risk-preference function parameter of 0.7, see Appendix A.2), and moderately declining weights for profits in the *RAFP* calculation ($\alpha = 80\%$).

Table 1. Summary of Results Under Base Case Assumptions (All Curves under Four-Year Ahead Auction)

Curve	Forecast Reserve Indices: % Years Forecast Reserve Meets or Exceeds IRM	Forecast Reserve Indices: Average % Forecast Reserve over IRM (Standard Deviation)	Generation Profit, $/kW/yr (standard deviation [s.d.]) /IRR	Components of Generation Revenue: Scarcity Revenue $/kW/yr (s.d.)	Components of Generation Revenue: E/AS Fixed Revenue $/kW/yr	Components of Generation Revenue: ICAP Payment $/kW/yr (s.d.)	Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
1. No Demand Curve	39	-0.44 (1.92)	66/35.3% (113)	47 (85)	10	70 (57)	129 (121)
2. Original PJM Curve, Based on VOLL	54	-0.06 (0.74)	25/21.2% (73)	37 (70)	10	39 (14)	84 (78)
3. Alternative Curve with New Entry Net Cost at IRM	92	1.23 (0.87)	15/17.5% (53)	26 (52)	10	40 (4)	74 (55)
4. Alternate Curve with New Entry Net Cost at IRM+1%	98	1.79 (0.90)	12/16.6% (46)	21 (44)	10	42 (7)	71 (48)
5. Alternate Curve with New Entry Net Cost at IRM+4%	98	3.40 (1.05)	13/17.0% (41)	14 (31)	10	50 (20)	74 (43)

Some broad conclusions about Table 1's comparisons of the different demand curves are noted here, with further detail below.

1. The percentage of years that forecast reserves meet or exceed the IRM is related to the average reserve margin and its variability. For instance, Curve 4 exceeds the IRM in 98% of the years simulated.
2. Resource adequacy is also indicated by the average percent by which the forecast reserve exceeds the IRM, providing a safety margin. This is expressed in terms of unforced capacity. The standard deviation of this value indicates how much the forecast reserve varies from year to year.[10] Figure 7 provides an illustration of how the reserve margins vary over time, using data from sample 100-year simulations for two of the curves. Further explanation of the reasons for such variations is provided in Section 5.2. Under a given variability of the reserve margin (as measured by the year to year standard deviation), higher average reserve margins result in the IRM being achieved a greater percentage of the time. Comparing Curves 3 and 4, for example, Curve 4 has a higher average reserve margin (1.79% higher than the IRM, versus 1.23% for Curve 3), and therefore a higher percentage of years in which the IRM is met or exceeded (98% versus 92%).

[10] Note that the actual reserve margin will vary a good deal more, based as it is upon actual weather-influenced peak load. The forecast reserve, in contrast, is based on weather normalized load, growing smoothly at an expected rather than random growth rate.

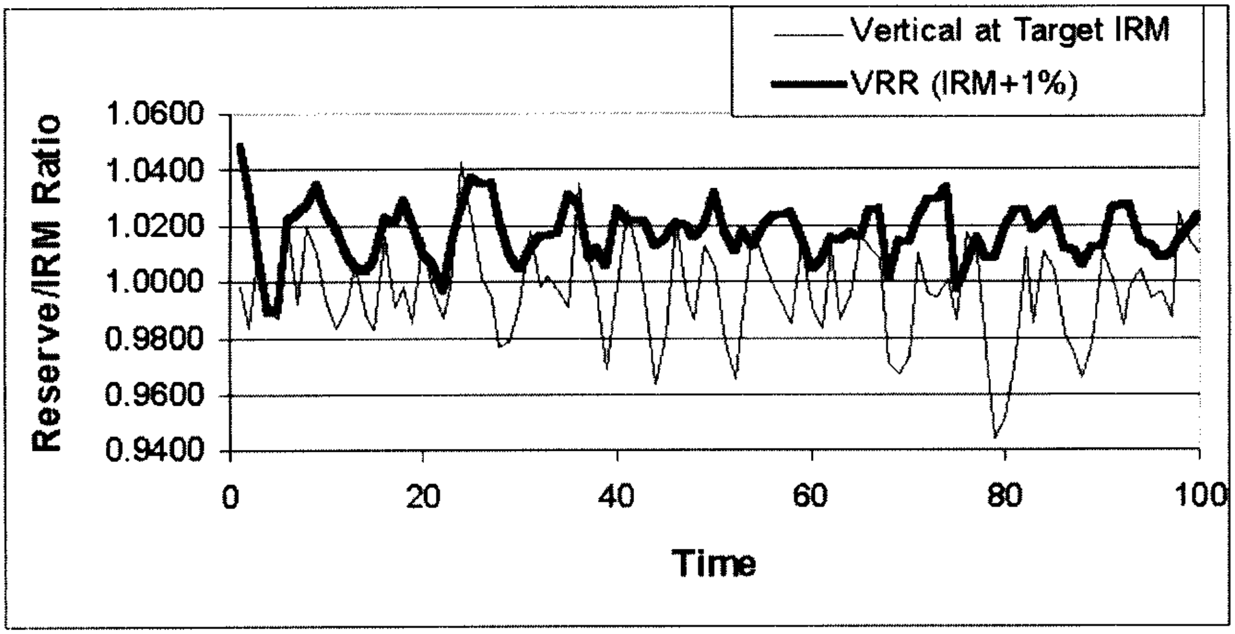

Figure 7. Time Series from Single Simulations of Ratios of Forecast Unforced Reserve Margin to Target Unforced Reserve, Curve 1 (No Demand Curve) and Curve 4 (Alternate Curve IRM+1%)

3. Generation profit is the net revenue that a potential entrant (baseline turbine) would earn over and above the assumed annualized fixed cost of construction. Larger values for this performance figure imply that investors are demanding a risk premium in exchange for higher levels of risks in ICAP revenues and E/AS gross margins. If there was no risk aversion and no risk in the market (from variations in load growth and weather), generators would, in theory, require zero profit, and the model gives this result. In general, lower reserve margins are associated with higher levels of risk and, therefore, higher required profits, because volatile E/AS revenues make up a higher portion of the revenues. This trend is clearly seen in comparing Curves 2 through 4; higher reserve margins are associated with lower average profits. (Curve 5 is an exception to this trend, because it is more vertical than Curves 3 and 4, as Figure 6 shows; this results in more volatile capacity revenues, which increases the profit that risk averse investors require in order to construct capacity.)

Profit is also expressed in terms of average internal rate of return (IRR) earned by owner's equity in combustion turbine capacity. Because the 61 \$/installed kW/yr levelized real cost of a new turbine is based on a nominal IRR of 12% (reflecting the after tax cost of equity capital in a relatively stable regulated rate-of-return environment), then an economic profit of \$0/kW-yr in the table would translate into an IRR of 12%. The modeling of risk aversion in this analysis reflects the general risk-return tradeoff apparent in capital markets in which higher risks are accepted by investors only if accompanied by higher average profits and IRR. Thus, simulations with higher investor risk result in higher costs of capital, as reflected in higher IRRs. Note, however, that these IRRs are a result of the risk aversion assumptions of the model which, when changed, yield different IRRs (see Section 5.3). The model is neither defining nor using a target IRR to drive investment; rather, the model merely calculates the IRR implied by particular levels of profits resulting from the risk aversion and other assumptions made.

4. The three components of baseline CT revenues include gross margins from the E/AS market (divided into scarcity revenues and the assumed fixed component, see Figure 2) and ICAP revenues, all expressed in [\$/installed MW/yr]. Subtracting the fixed cost of the CT (\$61/installed kW/yr in real dollar terms) yields profit. For instance, in the No Demand Curve case, revenues equal 47+10+70 = 127. Subtracting 61 for the real annualized fixed cost yields 66 for profit, as shown in the table. (Because of rounding, the profit may not precisely equal revenues minus cost for all curves.) Generally, the table shows that scarcity revenues are more important when the average reserve margin shrinks, because shortage conditions are more likely.

5. The consumer cost shown here includes only scarcity payments in the energy market along with ICAP payments, assuming that all other electricity costs paid by consumers are not

affected by the demand curve. The consumer cost equals the sum of total payments for energy scarcity and capacity, and is expressed in Table 1 as a ratio of the total ICAP and scarcity payments made by consumers divided by the peak load.[11] In general, consumer cost varies with generator profits; if investors require higher returns because of higher risks, then consumer costs will also be higher, as those higher profits result from higher ICAP prices and E/AS gross margins. However, the table shows that the relationship is not one-to-one (a $1 increase in profit does not translate into a $1 increase in consumer costs) in part because the profit is expressed on a $/installed MW/yr basis for a potential new turbine, while consumer costs have a different denominator (peak load).

From the table, the following conclusions concerning the relative performance of the different curves are apparent. First, the "no demand curve" case (Curve 1) has an average reserve margin that is less than the IRM (-0.39% less, to be exact), even though the vertical portion of the curve is located precisely at the IRM. Also, the variation in the reserve margin is higher (1.92% standard deviation, with the other curves having about half that variation or less). This comparison is illustrated in Figure 7. That figure shows a time series of forecast reserves for one of the sample 100 year simulations for Curve 1, as well as for one of the 100-year simulations for Curve 4 (Alternate Curve IRM+1%).[12] The curve shows that forecast reserve margins for the "No Demand Curve" fluctuate between 94% and 104% of the IRM, while those for Curve 4 not only meet or exceed the target more often, but also fluctuate in a tighter range, i.e., between 99% and 105% of the IRM.

Furthermore, average profits and consumer payments are higher for Curve 1 (no demand curve) than for the other curves. Profits are higher because the risks to investors are greater; by

[11] This can be expressed in other ways, also; for example, if the annual load factor is 60%, then a $80/peak kW/yr consumer cost would be equivalent to $15.2/MWh (= 80*1000/(0.6*8760)).

[12] As explained earlier, I performed twenty-five 100-year simulations for each combination of a curve and set of assumptions.

assumption, risk averse investors in generation require higher average returns in order to compensate them for higher risks, and so, on average, generators must earn higher profits if they are to invest. Therefore, generators who are in the market are earning higher average profits. This higher profit does not mean that generators are better off; rather, the higher profits are needed to offset the greater risks, which will be reflected in a higher cost of capital. The greater risk is indicated by the standard deviation of profits (113 \$/Peak kW/yr), which for Curve 1 (vertical) is considerably larger than for the other curves. This greater variation occurs in part because the vertical curve results in more variation in ICAP costs from year to year; in essence, ICAP prices bounce between zero and the maximum level on the curve (\$124.7/kW/yr, Figure 6) depending on whether existing capacity plus new additions is greater or less than the IRM. Figure 8 shows an example of the wide variation in capacity payments from a 100 year simulation of Curve 1 (no demand curve). This variation is reflected in that curve's relatively high standard deviation for ICAP revenues (57 \$/kW/yr, much higher than for the other curves, as shown in Table 1). In contrast, Figure 7 shows that the variation in capacity payments is much more stable for Curve 4 (Alternate Curve IRM+1%).

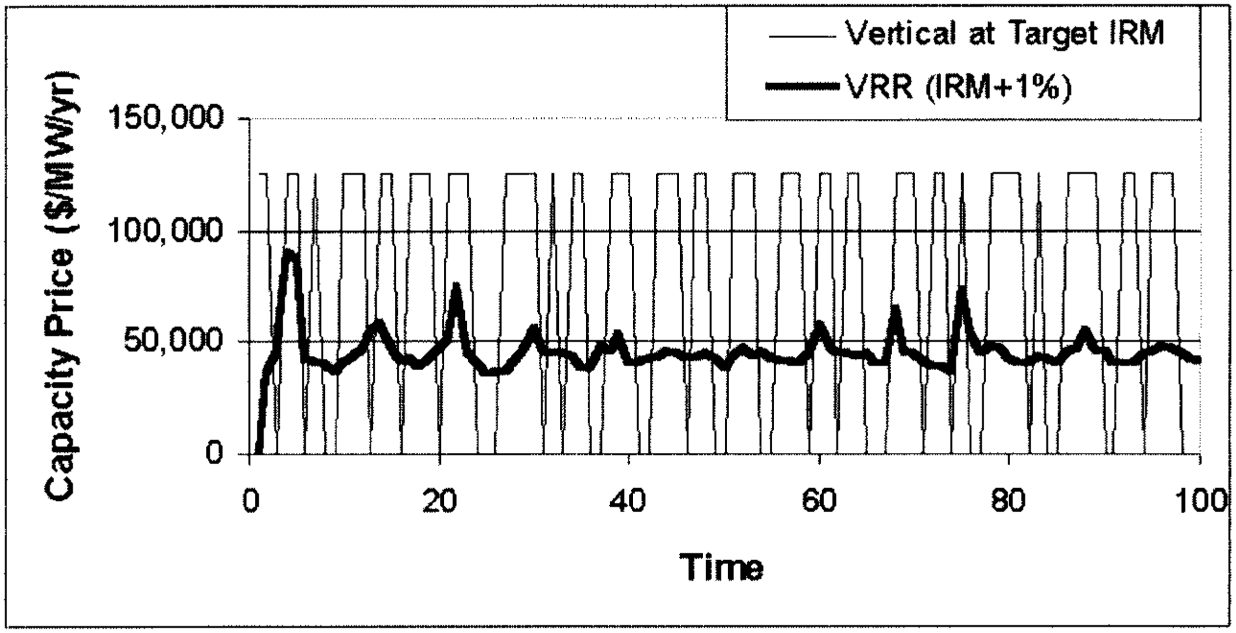

Figure 8. Time Series of Capacity Prices from Single Simulations, Curve 1 (No Demand Curve) and Curve 4 (Alternate Curve IRM+1%)

However, fluctuating ICAP prices are not the only cause of highly variable profits in Curve 1. Energy and ancillary service gross margins also vary more for Curve 1 than for the other curves (with a standard deviation of 85 in Curve 1, and smaller values for the other curves, as seen in Table 1). The reason is that the fluctuating forecast reserves mean that there are a number of years of low reserves; if such years also correspond to hot weather and/or higher than anticipated economic growth, actual reserves are pushed even lower. At such times, E/AS gross margins can be high (see Figure 3).

Because Curve 1 (no demand curve) results in high consumer costs and relatively low reserve margins, the other curves appear more attractive by these metrics. Improved performance of the "no curve" case occurs if it is shifted to the right, which increases reserve margins and somewhat lowers risks to investors and costs to consumers, or if it is assumed that new generation submits a nonzero bid. These and other sensitivity analyses are discussed in more detail in Section 5.3, *infra.* However, the lack of a slope for Curve 1 means that relatively high variations in ICAP prices and, thus, profits persist under alternative assumptions. As a result, required profits remain higher than for the other curves and so do consumer costs. Therefore, I conclude that the sloped curves are more desirable from a consumer perspective.

Comparing the sloped curves (Curves 2 through 5 in Figure 6, page 32), they differ in their reserve margins, generator profits, and consumer costs. Curves 2 and 3 result in lower probabilities of meeting or exceeding the IRM, as well as higher consumer costs than Curve 4, which represents a variant of Curve 3 in which the curve has been shifted to the right. These low probabilities and high consumer costs mean than Curve 4 is more desirable from those perspectives. Curve 5 represents a further shift, although the truncation to zero price occurs at the same location as Curves 3 and 4. The result is a higher average reserve margin, but Curve 5's more vertical characteristics result in more variation in revenues, profits, and reserves than Curve 4. As a result, required profits and thus consumer costs are higher than in Curve 4, and the probability of reaching the target IRM is the same for those two curves.

As the curves are shifted further to the right, a greater proportion of the gross margin for generators comes from the ICAP market, and less from E/AS scarcity revenues. (For example, generators in Curve 3 gain 26 $/kW/yr from scarcity revenues, on average, and about 50% more from ICAP. However, in Curve 5, where the curve has been shifted to the right by 4%, scarcity revenues are approximately 70% smaller than ICAP revenues.) The standard deviations in Table 1 indicate that ICAP revenues tend to be less volatile (varying by only a few tens of dollars per kW per year) relative to E/AS revenues (which can vary tenfold or more, depending on weather and other variations). As a result, risks are less for generators, and the profit required to justify investment is smaller; this is reflected in the lower equilibrium profit for Curve 4 compared to Curves 2 and 3. The lower required profit translates directly into lower consumer payments. (Curve 5 has slightly higher profit requirements than Curve 4, however, because Curve 5 is closer to vertical, so that revenues are more volatile and the required internal rate of return is higher.)

I should caution, however, that this dynamic analysis is better suited to comparing the relative performance of curves than it is to fine-tuning the "optimal" location of the demand curve. Although Curve 4 has lower average consumer costs than curves to its left (Curve 3) or right (Curve 5), under other possible assumptions, this might not be so. However, as the sensitivity analyses in Section 5.3 show, the general conclusion that Curve 4 is preferable in terms of reserve margin, lower variance of generation profits, and lower consumer payments compared to Curves 1-3 is robust with respect to a wide range of assumptions concerning behavior of generators. In contrast, the precise location of the demand curve that minimizes consumer payments is more sensitive to these assumptions.

5.2 Example of Cycles in Reserve Margins

In Figure 8, the forecast reserve margin exhibits cyclical behavior in which reserves periodically fall below the target (IRM) level. The swings in reserve margins are larger under some curves and assumptions than under others, but are always present in the simulations. In this section, I give some reasons for this behavior with the help of an example. The example is a fourteen year excerpt of a simulation of Curve 1 (no demand curve), and illustrates how random fluctuations in load growth and weather can cause variations in forecast reserve margins. The example represents a situation in which low load growth dampens profits and investment, which then results in shortages of capacity, which in turn increases profits and, after a lag, investment. As a result, a period of low forecast reserve margins is followed by one of high margins.

Figure 9 shows the sequence of weather-normalized and actual peaks for years 12-25 from one simulation. The peaks are expressed as a multiple of the four-year ahead forecast peaks for those years. Early on, the weather-normalized peaks around year 16 are several percentage points below the forecast peaks. Furthermore, cool weather in some years depresses actual peaks even further. Turning to Figure 10, we see that those low loads translate into higher than normal actual reserve margins in those years, relative to the reserves that were forecast four years before. The bottom of that figure shows that those higher reserves depress gross margins through year 18, mainly by lowering E/AS revenues (as actually occurred in PJM in 2003 and 2004). This series of depressed profits, in turn, translates into forecasts of low profits, which in turn depresses investment. By years 18 and 19, Figure 11 shows that investment in new capacity has dried up completely.

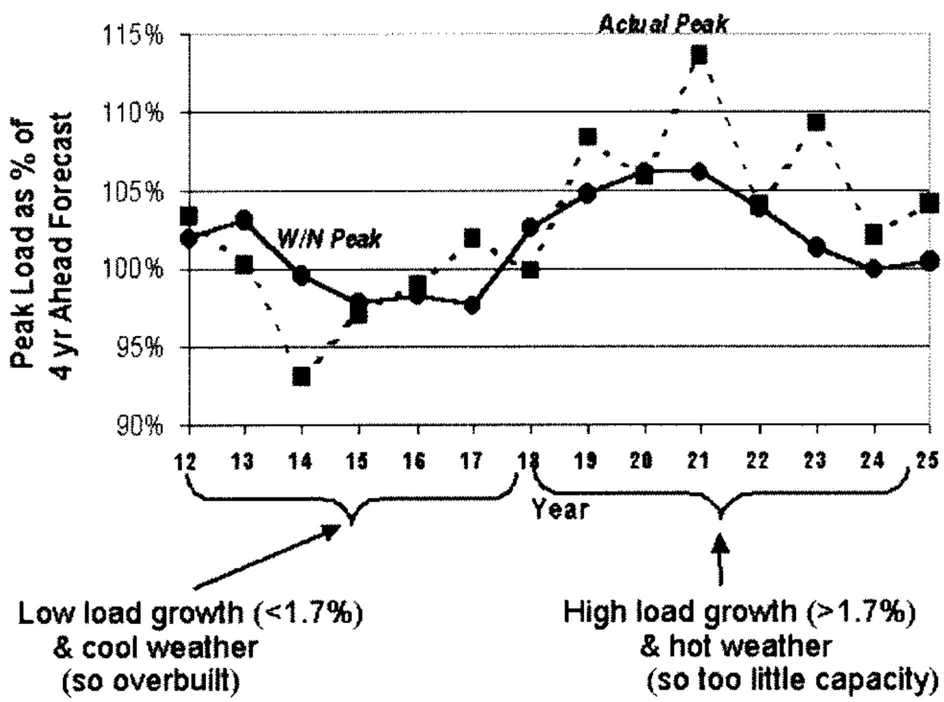

Figure 9. Analysis of Capacity Cycle: Weather-Normalized and Actual Peaks

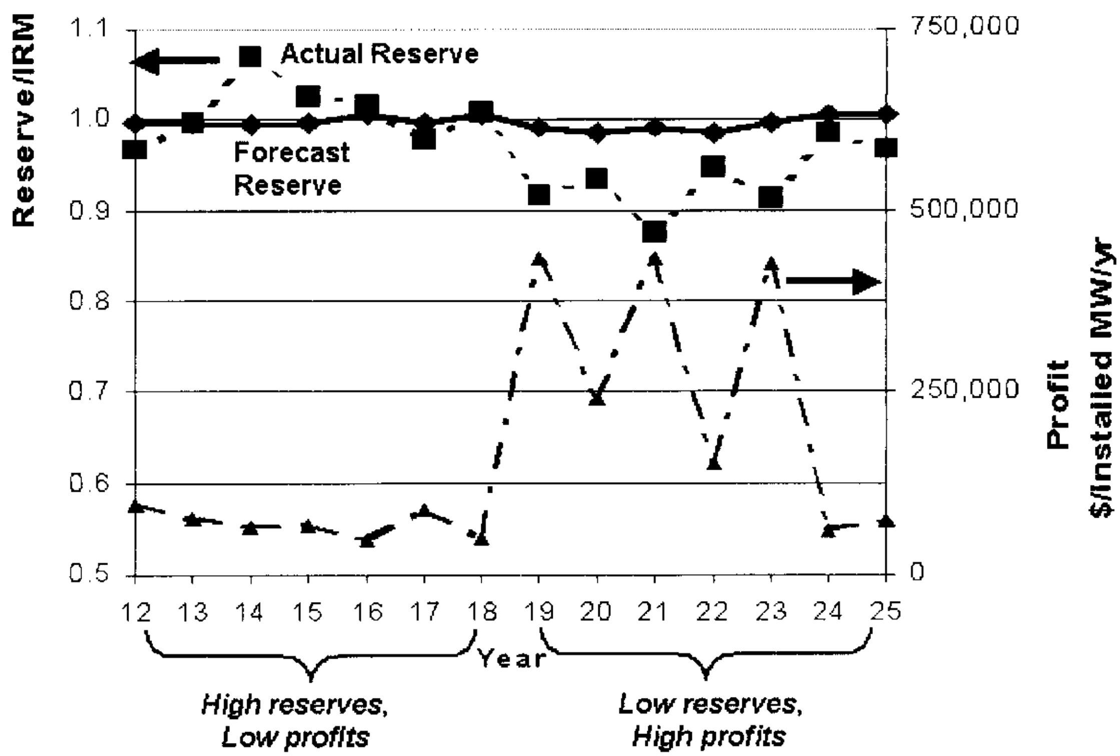

Figure 10. Analysis of Capacity Cycle: Low Profits in Early Years, High Profits Later

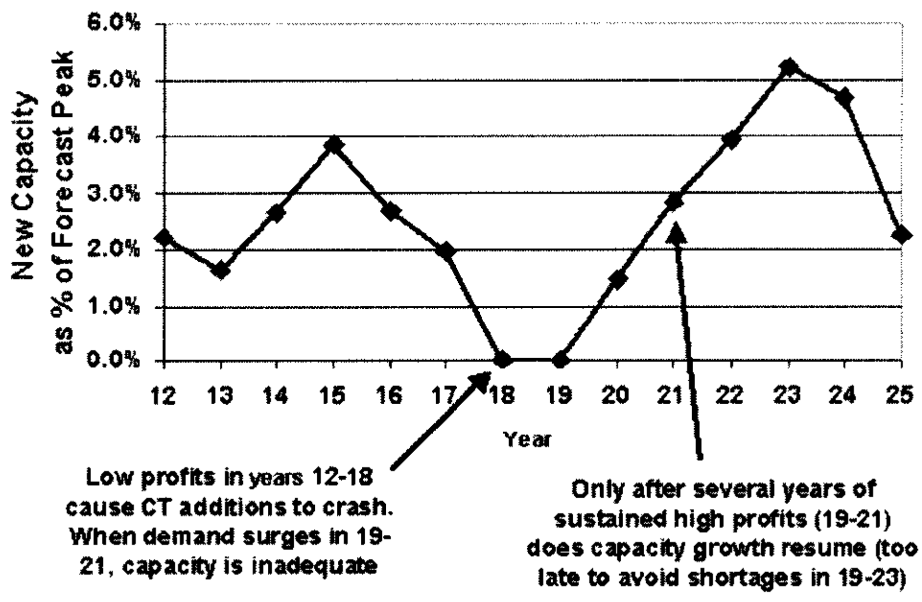

Figure 11. Analysis of Capacity Cycle: Capacity Additions Lag Profitability

The lack of new capacity in years 18 and 19 causes forecast reserve margins to dip below the IRM after year 18 (Figure 10). At the same time, hot weather in years 19 and 21 results in abnormally high actual peak loads (Figure 9) and very low actual reserve margins (Figure 10), causing E/AS revenues to spike (Figure 10). After the generators see some years of high profits, their profit forecasts and subsequent willingness to invest recover, and high investment levels are seen after year 21. Eventually, forecast reserve margins climb back up to the IRM in year 23. This completes the cyclical variation in reserve margins induced by low load growth and cool weather.

5.3 Sensitivity Analyses for the Four-year Ahead Auction

The dynamic model is designed based on simple relationships and a minimal number of parameters that describe the behavior of generators, while still capturing the fundamental phenomena of risk aversion and increased entry in response to increased profits. This is done in order to maximize model transparency and to facilitate sensitivity analyses, since the correct values of the parameters are not known. Hence, it is important that the relative performance of the demand curves not be overly sensitive to these parameters.

In this section, sensitivity analyses are performed relative to my assumptions concerning the four sets of behavioral characteristics. In addition, sensitivity analyses are performed relative to two parameters of the demand curves. Table 2 summarizes those assumptions. The demand curve parameters that I vary and report extensive results for are as follows:

1. The highest ICAP price in the curve. In the base cases, it is assumed to be two times the levelized nominal capital cost of a turbine, minus the expected E/AS gross margin of \$28/kW/yr. Lower values are tested to see if they affect the results significantly (Sensitivity Runs #1,2).
2. The level at which the price of ICAP is assumed to fall to zero. This is done by cutting off the curves entirely at 10% above the IRM (measured in terms of installed capacity), rather than at 5% as in the base case (Sensitivity Run #3). The 10% cutoff affects only Curves 2-5; in Curves 3-5, this assumption has the effect of lengthening the right-hand tail of the curve. This is done by extending the second (rightmost) sloped segment linearly until the

10% cutoff. In Sensitivity Run #4, Curves 3-5 are not chopped off at all; rather, the last (rightmost) downward sloping segment is extended until it hits a zero price. For Curve 3, this occurs at an installed reserve margin of 28% (13% above the IRM target of 15%); for Curves 4 and 5, these points occur at installed reserves of 29% and 32% respectively (14% and 17%, respectively, above the target IRM).

The behavioral assumptions that I change and provide detailed results for include the following:

1. Variations in how much capacity is bid into the market (NCA_y) and built when profits (risk-adjusted forecast) are high. Low amounts mean that the market does not respond quickly to profit signals, while higher amounts mean greater responsiveness. In our base case, we assume that if risk-adjusted forecast profit (net of all costs, including annualized capital cost) for a benchmark combustion turbine equal 100% of the cost of the turbine, then capacity amounting to 7% of existing capacity would be added. Alternative assumptions of 5% and 9% are considered (Sensitivity Runs #5 and 6, respectively).
2. Variations in the level of bids ($/unforced MW/year) submitted by existing and potential new capacity. Zero bids were assumed as a base case. This was based upon the assumption that generators would commit to building and maintaining a certain amount of capacity that depends on forecast profits, and would bid that capacity into the ICAP market in a price-taking manner. Various levels of positive bids, up to $44/kW/yr are considered in the sensitivity analyses. The highest bid considered exceeds the net cost of a benchmark turbine (approximately $36/unforced kW/yr, equal to the real levelized capital cost of $61 minus the expected E/AS revenues of $28, divided by one minus the forced outage rate,) (Sensitivity Runs #7-10).
3. Various degrees of risk aversion, ranging from weaker risk neutrality to extreme risk aversion (Sensitivity Runs #11 and 12, respectively). Sensitivity Run #11a is the case of

complete risk neutrality (linear risk-preference function, resulting from a risk-preference parameter of 0.5), in which risk is not penalized at all. Meanwhile, Sensitivity Run #11b is risk averse, but less so than the base case. These sensitivity cases are summarized in terms of the risk-preference parameter explained in Appendix A.2 (see Table 2 and Figure 4).

4. Various relative weightings for recent profits versus profits further in the past in the risk-adjusted forecast profit calculations (Sensitivity Runs #13, 14). In the base case, profit in a given year is assumed to be given only 80% of the weight assigned to profit in the following year.

In addition to those sensitivity analyses of demand curve and behavioral characteristics, I also examine the effect of assuming lower E/AS gross margins (Sensitivity Run #15). As I explained *supra*, confining the baseline turbine's operation to peak hours lowers the average E/AS gross margin to $21/kW/yr (compared to the base case assumption of $28/kW/yr). I simulate this assumption by shifting the demand curve upwards to account for the lower E/AS revenues, and by lowering the E/AS gross margin curve (Figure 3) by the same amount.

Tables 3-12 show the results of Sensitivity Runs #1-15 for all five demand curve cases. Both the average and standard deviations (across the sample of 2500 years) are shown for the performance indices.

Finally, I also briefly report on sensitivity analyses concerning the slope of the demand curves and the assumed year-to-year variation in growth rates for weather-normalized peak loads.

Table 2. Summary of Sensitivity Analysis Assumptions

Sensitivity Run #	Sensitivity Analysis Case	Explanation
1	Max Price = Net Cost multiplied by 1.5	Highest price on demand curve is (1.5*72-28)/(1-.07) [$/kW/yr] = 86 [$/kW/yr] (Base Case = multiplied by 2, 124.7 [$/kW/yr])
2	Max Price = Net Cost multiplied by 1.2	Highest price on demand curve is (1.2*72-28)/(1-.07) [$/kW/yr] = 62.8 [$/kW/yr]
3	Price drops to zero at IRM+10%	Right tail of demand curve is reduced to zero at IRM+10%. Only applicable to Curves 2-5
4	Curves 3-5 long tails; no chopoff	No chopoff of tail; rightmost sloped segment extended linearly to X axis. Only applicable to Curves 3-5
5	Low Percent CT added when profit is equal to cost	If CT profit equals annualized nominal capital cost (72 $/kW/yr), then 5% of existing capacity is added. (Base case = 7%)
6	High Percent CT added when profit is equal to cost	If CT profit equals annualized capital cost, then 9% of existing capacity is added.
7	10,000 bids for new capacity	$10,000/unforced MW/yr is bid submitted for new capacity in four-year ahead auction ("New" includes only capacity for which a commitment is made 4 years ahead of auction). All other capacity bid in at $0. (Base case = $0 bid for both new and old capacity)
8	25,000 bids for new capacity	$25,000/unforced MW/yr is bid submitted for new capacity in four-year ahead auction
9	44,000 bids for new capacity	$44,000/unforced MW/yr is bid submitted for new capacity in four-year ahead auction
10	44,000 bids for new, 20,000 for existing capacity	$44,000/unforced MW/yr is bid submitted for new capacity in four-year ahead auction; $20,000 bid for all other ca acity. p
11a	Low risk aversion 0.5	Risk neutral (linear risk-preference function for new generation profit); Risk-preference parameter set to 0.5 (Base case = 0.7)
11b	Low risk aversion 0.6	Low risk averse; Risk-preference parameter set to 0.6
12	High risk aversion 0.9	Highly risk averse (strongly concave utility function for new generation profit, see Appendix A.2); Risk-preference parameter set to 0.9
13	High rate of decay in weights	Weight assigned to profit in year *Y*-1 equal to 60% of weight given to profit in year *Y* in *RAFP* calculation. This emphasizes more recent profits more than earlier profits. (Base case = 80%)
14	Low decay in weights	Weight assigned to profit in year *Y*-1 equal to 90% of weight given to profit in year *Y* in *RAFP* calculation. This places nearly equal emphasis on profits from all eight years in Figure 2.
15	Lower E/AS margins	Confine turbine operation to peak hours

Table 3. Summary of Sensitivity Analyses of Curve I (No Demand Curve), Average Values

Sensitivity Run	Reserve Indices: % Years Meet or Exceed IRM	Reserve Indices: Average % Reserve over IRM	Generation Profit, $/kW/yr /IRR	Components of Generation Revenue: Scarcity Revenue $/kW/yr	Components of Generation Revenue: E/AS Fixed Revenue $/kW/yr	Components of Generation Revenue: ICAP Payment $/kW/yr	Consumer Payments for Scarcity + ICAP $/Peak kW/yr
1. Max Price = Net Cost multiplied by 1.5	35	-0.58	49/29.5%	49	10	52	110
2. Max Price = Net Cost multiplied by 1.2	29	-0.91	43/27.3%	52	10	41	103
3. Price drops to zero at IRM+10%	not applicable (na)	na	na	na	na	na	Na
4. Price drops to zero at higher IRM	na	na	na	na	na	na	Na
5. Low Percent CT added when profit is equal to cost	36	-0.50	68/35.9%	45	10	74	131
6. High Percent CT added when profit is equal to cost	42	-0.32	63/34.1%	47	10	67	125
7. 10,000 bids for new capacity	46	-0.59	60/33.2%	45	10	66	123
8. 25,000 bids for new capacity	63	-0.31	45/28.0%	41	10	55	106
9. 44,000 bids for new capacity	4	-0.13	33/23.9%	38	10	46	93
10. 44,000 bids for new, 20,000 for existing capacity	4	-0.07	29/22.7%	37	10	43	89
11a. Low risk aversion 0.5	69	1.03	12/16.7%	29	10	34	70
11b. Low risk aversion 0.6	53	0.28	39/25.9%	37	10	53	99
12. High risk aversion 0.9	21	-3.53	158/67.5%	118	10	92	226
13. High rate of decay in weights	49	0.21	44/27.9%	38	10	58	106
14. Low decay in weights	36	-0.77	76/38.7%	53	10	73	139
15. Lower E/AS margins	39	-0.39	68/36.0%	45	10	74	131

Table 4. Sensitivity Analyses of Curve 1 (No Demand Curve), Standard Deviations

Sensitivity Run	Reserve Indices	Generation Profit, $/kW/yr (s.d.)	Components of Generation Revenue		Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
	Average % Reserve over IRM (s.d.)		Scarcity Revenue $/kW/yr (s.d.)	ICAP Payment $/kW/yr (s.d.)	
1. Max Price = Net Cost multiplied by 1.5	1.84	101	86	38	108
2. Max Price = Net Cost multiplied by 1.2	1.67	98	90	26	105
3. Price drops to zero at IRM+10%	na	na	na	na	na
4. Price drops to zero at higher IRM	na	na	na	na	na
5. Low Percent CT added when profit is equal to cost	1.48	105	79	56	112
6. High Percent CT added when profit is equal to cost	2.25	112	83	57	120
7. 10,000 bids for new capacity	0.81	102	80	53	110
8. 25,000 bids for new capacity	0.64	91	74	45	97
9. 44,000 bids for new capacity	0.43	75	69	22	79
10. 44,000 bids for new, 20,000 for existing capacity	0.29	70	67	15	74
11a. Low risk aversion 0.5	1.74	85	58	53	93
11b. Low risk aversion 0.6	1.42	100	71	57	108
12. High risk aversion 0.9	4.02	166	144	47	174
13. High rate of decay in weights	1.70	100	71	58	108
14. Low decay in weights	2.21	120	92	56	128
15. Lower E/AS margins	1.85	111	82	60	120

Table 5. Sensitivity Analyses of Curve 2 (VOLL Curve), Average Values

Sensitivity Run	Reserve Indices		Generation Profit, $/kW/yr /IRR	Components of Generation Revenue			Consumer Payments for Scarcity + ICAP $/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue $/kW/yr	E/AS Fixed Revenue $/kW/yr	ICAP Payment $/kW/yr	
1. Max Price = Net Cost multiplied by 1.5	48	-0.01	25/21.0%	37	10	38	84
2. Max Price = Net Cost multiplied by 1.2	47	-0.07	25/21.0%	38	10	38	84
3. Price drops to zero at IRM+10%	na	na	na	na	na	na	na
4. Price drops to zero at higher IRM	na	na	na	na	na	na	na
5. Low Percent CT added when profit is equal to cost	56	0.06	25/21.1%	36	10	39	84
6. High Percent CT added when profit is equal to cost	51	0.08	24/20.9%	36	10	39	83
7. 10,000 bids for new capacity	54	0.06	25/21.2%	37	10	39	84
8. 25,000 bids for new capacity	61	0.10	23/20.4%	36	10	38	82
9. 44,000 bids for new capacity	95	0.09	25/21.2%	35	10	41	84
10. 44,000 bids for new, 20,000 for existing capacity	95	0.09	25/21.2%	35	10	41	84
11a. Low risk aversion 0.5	66	0.84	14/17.4%	32	10	33	72
11b. Low risk aversion 0.6	63	0.20	21/19.7%	35	10	37	79
12. High risk aversion 0.9	30	-1.83	91/44.1%	78	10	64	155
13. High rate of decay in weights	55	0.12	21/19.9%	35	10	37	80
14. Low decay in weights	50	-0.02	27/22.0%	38	10	40	87
15. Lower E/AS margins	58	0.19	25/21.3%	36	10	41	85

Table 6. Sensitivity Analyses of Curve 2 (VOLL Curve), Standard Deviations

Sensitivity Run	Reserve Indices	Generation Profit, $/kW/yr (s.d.)	Components of Generation Revenue		Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
	Average % Reserve over IRM (s.d.)		Scarcity Revenue $/kW/yr (s.d.)	ICAP Payment $/kW/yr (s.d.)	
1. Max Price = Net Cost multiplied by 1.5	0.75	72	69	12	76
2. Max Price = Net Cost multiplied by 1.2	0.81	71	69	11	76
3. Price drops to zero at IRM+10%	na	na	na	na	na
4. Price drops to zero at higher IRM	na	na	na	na	na
5. Low Percent CT added when profit is equal to cost	0.59	70	68	12	74
6. High Percent CT added when profit is equal to cost	0.92	72	68	16	76
7. 10,000 bids for new capacity	0.74	73	70	14	78
8. 25,000 bids for new capacity	0.54	69	67	11	74
9. 44,000 bids for new capacity	0.17	64	64	3	68
10. 44,000 bids for new, 20,000 for existing capacity	0.16	64	64	3	68
11a. Low risk aversion 0.5	1.85	71	65	17	75
11b. Low risk aversion 0.6	0.65	69	66	13	74
12. High risk aversion 0.9	3.13	139	119	36	147
13. High rate of decay in weights	0.84	68	65	16	72
14. Low decay in weights	1.00	76	71	17	80
15. Lower E/AS margins	0.82	72	67	18	77

Table 7. Sensitivity Analyses of Curve 3 (New Entry Net Cost at IRM), Averages

Sensitivity Run	Reserve Indices		Generation Profit, $/kW/yr /IRR	Components of Generation Revenue			Consumer Payments for Scarcity + ICAP $/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue $/kW/yr	E/AS Fixed Revenue $/kW/yr	ICAP Payment $/kW/yr	
1. Max Price = Net Cost multiplied by 1.5	90	1.20	15/17.6%	26	10	40	74
2. Max Price = Net Cost multiplied by 1.2	88	1.16	15/17.7%	26	10	40	74
3. Price drops to zero at IRM+10%	92	1.23	15/17.5%	26	10	40	74
4. Price drops to zero at IRM+13%	92	1.23	15/17.5%	26	10	40	74
5. Low Percent CT added when profit is equal to cost	89	1.18	15/17.7%	26	10	40	74
6. High Percent CT added when profit is equal to cost	95	1.26	14/17.3%	25	10	40	73
7. 10,000 bids for new capacity	92	1.23	15/17.5%	26	10	40	74
8. 25,000 bids for new capacity	92	1.23	15/17.5%	26	10	40	74
9. 44,000 bids for new capacity	99	0.78	18/18.8%	28	10	41	77
10. 44,000 bids for new, 20,000 for existing capacity	99	0.78	18/18.8%	28	10	41	77
11a. Low risk aversion 0.5	88	1.63	10/15.9%	24	10	38	69
11b. Low risk aversion 0.6	91	1.35	13/17.0%	25	10	39	72
12. High risk aversion 0.9	92	1.02	17/18.4%	27	10	41	76
13. High rate of decay in weights	100	1.16	14/17.2%	25	10	40	73
14. Low decay in weights	82	1.28	17/18.4%	27	10	41	76
15. Lower E/AS margins	99	2.00	11/16.4%	20	10	42	71

Table 8. Sensitivity Analyses of Curve 3 (New Entry Net Cost at IRM), Standard Deviations

Sensitivity Run	Reserve Indices	Generation Profit, $/kW/yr (s.d.)	Components of Generation Revenue		Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
	Average % Reserve over IRM (s.d.)		Scarcity Revenue $/kW/yr (s.d.)	ICAP Payment $/kW/yr (s.d.)	
1. Max Price = Net Cost multiplied by 1.5	0.92	53	53	4	56
2. Max Price = Net Cost multiplied by 1.2	0.98	54	53	4	57
3. Price drops to zero at IRM+10%	0.88	53	52	4	55
4. Price drops to zero at IRM+13%	0.88	53	52	4	55
5. Low Percent CT added when profit is equal to cost	0.94	52	51	5	55
6. High Percent CT added when profit is equal to cost	0.82	52	51	4	55
7. 10,000 bids for new capacity	0.87	53	52	4	55
8. 25,000 bids for new capacity	0.88	53	52	4	55
9. 44,000 bids for new capacity	0.21	53	53	1	56
10. 44,000 bids for new, 20,000 for existing capacity	0.21	53	53	1	56
11a. Low risk aversion 0.5	1.58	51	49	10	54
11b. Low risk aversion 0.6	1.04	51	50	5	54
12. High risk aversion 0.9	0.77	55	54	5	58
13. High rate of decay in weights	0.37	49	49	1	51
14. Low decay in weights	1.40	58	55	11	61
15. Lower E/AS margins	0.89	42	41	4	44

Table 9. Sensitivity Analyses of Curve 4 (New Entry Net Cost at IRM + 1%), Averages

Sensitivity Run	Reserve Indices		Generation Profit, $/kW/yr /IRR	Components of Generation Revenue			Consumer Payments for Scarcity + ICAP $/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue $/kW/yr	E/AS Fixed Revenue $/kW/yr	ICAP Payment $/kW/yr	
1. Max Price = Net Cost multp lied by 1.5	97	1.73	13/16.8%	22	10	42	72
2. Max Price = Net Cost multiplied by 1.2	95	1.64	13/16.9%	23	10	41	72
3. Price drops to zero at IRM+10%	99	1.82	12/16.6%	21	10	42	71
4. Price drops to zero at IRM+14%	99	1.82	12/16.6%	21	10	42	71
5. Low Percent CT added when profit is equal to cost	98	1.77	13/16.8%	22	10	42	72
6. High Percent CT added when profit is equal to cost	98	1.80	12/16.5%	22	10	41	71
7. 10,000 bids for new qpa aci	99	1.79	12/16.6%	21	10	42	71
8. 25,000 bids for new qca acit	99	1.80	12/16.6%	21	10	42	71
9. 44,000 bids for new capacity	100	1.55	13/17.0%	22	10	42	72
10. 44,000 bids for new, 20,000 for existing capacity	100	1.55	13/17.0%	22	10	42	72
11a. Low risk aversion 0.5	97	2.12	9/15.3%	20	10	40	67
11b. Low risk aversion 0.6	99	1.90	11/16.2%	21	10	41	70
12. High risk aversion 0.9	92	1.31	24/20.7%	29	10	46	84
13. High rate of decay in pwei hty	100	1.71	11/16.3%	21	10	41	70
14. Low decay in gwei hts	87	1.72	19/19.1%	25	10	45	79
15. Lower E/AS marpins y	99	2.50	11/16.1%	18	10	44	70

Table 10. Sensitivity Analyses of Curve 4 (New Entry Net Cost at IRM + 1%), Standard Deviations

Sensitivity Run	Reserve Indices: Average % Reserve over IRM (s.d.)	Generation Profit, \$/kW/yr (s.d.)	Components of Generation Revenue: Scarcity Revenue \$/kW/yr (s.d.)	Components of Generation Revenue: ICAP Payment \$/kW/yr (s.d.)	Consumer Payments for Scarcity + ICAP \$/Peak kW/yr (s.d.)
1. Max Price = Net Cost multiplied by 1.5	0.92	47	46	5	49
2. Max Price = Net Cost multiplied by 1.2	0.99	47	47	4	50
3. Price drops to zero at IRM+10%	0.89	45	44	5	47
4. Price drops to zero at IRM+14%	0.89	45	44	5	47
5. Low Percent CT added when profit is equal to cost	0.94	45	44	7	48
6. High Percent CT added when profit is equal to cost	0.87	46	45	7	49
7. 10,000 bids for new capacity	0.88	45	44	6	47
8. 25,000 bids for new capacity	0.88	45	44	6	47
9. 44,000 bids for new capacity	0.36	44	43	2	46
10. 44,000 bids for new, 20,000 for existing capacity	0.36	44	43	2	46
11a. Low risk aversion 0.5	1.40	45	42	11	47
11b. Low risk aversion 0.6	0.99	44	43	7	47
12. High risk aversion 0.9	1.54	67	60	15	71
13. High rate of decay in weights	0.39	42	42	1	44
14. Low decay in weights	1.64	60	53	17	64
15. Lower E/AS margins	0.95	40	38	8	42

Table 11. Sensitivity Analyses of Curve 5 (New Entry Net Cost at IRM + 4%), Averages

Sensitivity Run	Reserve Indices: % Years Meet or Exceed IRM	Reserve Indices: Average % Reserve over IRM	Generation Profit, $/kW/yr /IRR	Components of Generation Revenue: Scarcity Revenue $/kW/yr	Components of Generation Revenue: E/AS Fixed Revenue $/kW/yr	Components of Generation Revenue: ICAP Payment $/kW/yr	Consumer Payments for Scarcity + ICAP $/Peak kW/yr
1. Max Price = Net Cost multiplied by 1.5	97	3.13	12/16.6%	15	10	48	72
2. Max Price = Net Cost multiplied by 1.2	94	2.75	12/16.5%	17	10	46	72
3. Price drops to zero at IRM+10%	100	3.87	7/14.8%	11	10	47	67
4. Price drops to zero at IRM+17%	100	3.87	7/14.7%	11	10	47	67
5. Low Percent CT added when profit is equal to cost	98	3.32	14/17.5%	14	10	52	75
6. High Percent CT added when profit is equal to cost	95	3.16	18/18.8%	16	10	53	79
7. 10,000 bids for new capacity	99	3.49	11/16.1%	13	10	49	71
8. 25,000 bids for new capacity	100	3.57	9/15.5%	12	10	48	69
9. 44,000 bids for new capacity	100	3.72	8/15.2%	12	10	47	69
10. 44,000 bids for new, 20,000 for existing capacity	100	3.75	7/14.9%	11	10	47	68
11a. Low risk aversion 0.5	100	3.92	5/13.9%	12	10	44	65
11b. Low risk aversion 0.6	100	3.60	9/15.5%	12	10	48	69
12. High risk aversion 0.9	53	0.12	90/43.7%	60	10	81	155
13. High rate of decay in weights	100	3.60	8/15.2%	12	10	47	69
14. Low decay in weights	90	2.78	27/22.0%	20	10	59	89
15. Lower E/AS margins	96	3.26	21/19.8%	15	10	57	83

Table 12. Sensitivity Analyses of Curve 5 (New Entry Net Cost at IRM + 4%), Standard Deviations

Sensitivity Run	Reserve Indices	Generation Profit, $/kW/yr (s.d.)	Components of Generation Revenue		Consumer Payments for Scarcity + ICAP $/Peak kW/yr (s.d.)
	Average % Reserve over IRM (s.d.)		Scarcity Revenue $/kW/yr (s.d.)	ICAP Payment $/kW/yr (s.d.)	
1. Max Price = Net Cost multiplied by 1.5	1.13	38	32	14	40
2. Max Price = Net Cost multiplied by 1.2	1.35	40	37	10	42
3. Price drops to zero at IRM+10%	0.94	26	23	9	27
4. Price drops to zero at IRM+17%	0.95	26	23	9	27
5. Low Percent CT added when profit is equal to cost	1.04	39	30	19	42
6. High Percent CT added when profit is equal to cost	1.78	53	35	31	57
7. 10,000 bids for new capacity	0.72	33	27	14	35
8. 25,000 bids for new capacity	0.58	29	26	10	30
9. 44,000 bids for new capacity	0.71	29	25	10	30
10. 44,000 bids for new, 20,000 for existing capacity	0.61	26	23	8	27
11a. Low risk aversion 0.5	1.67	34	24	20	37
11b. Low risk aversion 0.6	0.90	33	27	16	35
12. High risk aversion 0.9	4.26	130	107	43	137
13. High rate of decay in weights	0.68	30	25	13	31
14. Low decay in weights	2.09	65	46	34	70
15. Lower E/AS margins	1.58	53	33	33	58

First considering the effects of the demand curve changes, my conclusions about the sensitivity analyses are as follows:

1. Lowering the maximum price in the demand curve from $124.7/kW/yr to $86 or $62.8/kW/yr (Sensitivity Runs #1, 2) improves the performance of the no demand curve case (Curve 1) in terms of consumer payments (from $129/peak kW/yr to $110 or $103), but worsens its average reserve margin. Consumer payments decrease because the lowered maximum ICAP price lowers the variability of total CT revenues, somewhat lowering risk and, thus, the profit required for new entry. However, Curve 1 remains considerably more expensive for consumers than the other curves. For all the other curves, there are no advantages to lowering the maximum price, as the average reserve margins deteriorate slightly and consumer payments stay approximately the same.
2. Dropping the right tail of Curves 3 or 4 to zero at a point further to the right rather than at IRM+5% (Sensitivity Runs #3, 4) has negligible effect on the results, because the forecast reserve margin is rarely in that range for either of those curves. On the other hand, the performance of Curve 5 (IRM+4%) improves (lower consumer cost, higher reserves), because these changes eliminate the vertical character of that curve.

In addition to the above sensitivity analyses concerning the curves, I also examined the effect of alternative slopes of the demand curves by compressing or expanding their range. In general, I find that changing the slopes of the curves makes much less difference in the results than shifting their location left or right. For instance, taking Curve 4 (IRM+1%) in Table 1 and shifting it left by 1% (Curve 3, Table 1) or right by 1% (not shown) changes the percent of years that the IRM is achieved from 98% to 92% and 99%, respectively. (Such a shift is equivalent to changing the target reserve margin you want to achieve and how much you're willing to pay for it.) On the other hand, decreasing the absolute value of the slopes of Curve 4 by 33% (while keeping the kink of the curve centered at IRM+1% and $47/kW/yr) or increasing it by 50% changes that percentage from 98% to 94% and 98%, respectively. This is a smaller effect. The changes in consumer costs show a similar pattern. These left and right shifts of Curve 4 change the consumer costs from the base value of 71 $/peak kW/yr to 74 and 70 $/peak kW/yr, respectively. The decreased and increased slopes, meanwhile cause a somewhat smaller change, from 71 $/peak kW/yr to 73 $/peak kW/yr in both cases. Therefore, the decision about the location of the curve is more important than decisions about its slope.

Turning to the behavioral characteristics, I reach the following basic conclusion: the performance of Curve 1 (no demand curve) is more sensitive to these assumptions than the sloped demand curves, sometimes dramatically so. However, under no assumptions is the "no demand curve" case found to be preferable, in terms of reserve margins or consumer payments. to the sloped curves. Concerning each individual set of behavioral characteristics, my conclusions are as follows:

1. The greater the amount of entry that occurs in response to a given profit, the better the performance of all curves in terms of the reserve indices and consumer payments (Sensitivity Runs #5, 6). This is because supply can more quickly adjust to unexpectedly high economic and, thus, demand growth. However, the changes in the performance of the curves as a result of changes in this assumption generally small relative to the effects of changes in some other behavioral assumptions (especially risk aversion and forecast weights).
2. Bidding positive amounts, whether just by new capacity or both new and old capacity (Sensitivity Runs #7-10), stabilizes ICAP prices and thus profits for Curve 1 (no demand curve), while having relatively little or no impact on sloped Curves 2-4. (Curve 5 experiences more impact, because it is more vertical than the other curves.) As a result,

generators face less risk and are more willing to enter the market in Curve 1 (and Curve 5), which yields improved reserve margins and consumer payments. Under the most extreme assumptions (new capacity bids $44/kW/yr, and existing capacity bids $20/kW/yr, Sensitivity Run #10), Curve 1's average reserves improve from 0.44% below IRM on average to 0.07% below IRM, while the standard deviation of reserves falls from 1.92% to 0.29%.[13] The standard deviation of ICAP payments in Curve 1 is more than halved (from $57/kW/yr to $15/kW/yr), because ICAP prices now occur frequently at intermediate values where bids intercept the demand curves rather than just the extremes of $0 and $124.7/kW/yr. The resulting lowered profit risk lowers the required returns, so equilibrium profit falls from $66/kW/yr to $29/kW/yr, with consumer payments for scarcity and capacity correspondingly dropping from $129/peak kW/yr to $89/peak kW/yr. This increases the relative attractiveness of the vertical demand curve, but its performance (in terms of the consumer payments) is still undesirable relative to the sloped demand curves. For example, under Curve 4 (IRM+1%), consumer payments are $71 or $72/peak kW/yr under all bidding assumptions.

3. The degree of risk aversion (Sensitivity Runs #11, 12) has a marked influence on all the results; this is the most important behavioral characteristic, as gauged by the sensitivities shown in Tables 3-12. On one hand, strict risk neutrality causes consumer payments for all curves to fall to the range of 65 to 70 $/peak kW/yr (Sensitivity Run #11), as the risk neutral producers are willing to accept much lower profits. Curves 4 and 5 still have lower consumer costs than the other curves, although not to as a great degree. Required profits are still positive because of nonlinearities elsewhere in the model (in particular, in the response of entry to risk-adjusted forecast profit, see Figure 2). If additional uncertainties

[13] It should be noted that these bidding levels are much higher than daily ICAP prices observed in the PJM market between 1999 and 2004; see the PJM State of the Market Report, Figure 4-9.

in load, attributed to economic growth and weather, are eliminated, then the required profits fall to zero or nearly so, as they should in a riskless world with no variations in profits. On the other hand, a high aversion to risk (strongly curved risk-preference function, see Appendix A.2) results in very high profit requirements, particularly for the case with no demand curve, greatly increasing its consumer payments relative to the other curves.

4. The weighting assumptions for profits in different years (Sensitivity Runs #13, 14) in the risk-adjusted forecast profit calculation make some difference in the consumer payments and reserves, but do not change the conclusion that Curve 1 (no demand curve) is inferior.

Finally, in Sensitivity Run 15, I compared the results of the demand curves developed under the assumption that the benchmark turbine earns an average \$21,100/MW/yr E/AS gross margin rather than \$28,000 (see Figure 3 and the associated discussion, *supra*). This lower value is based on an assumption that the turbine operates only during peak hours, rather than during any hour in which price exceeds its running cost. This assumption means that the E/AS gross margin offset for the curves is smaller, so that the maximum payments defined by the curves are higher by about \$7000 (after adjustments for forced outage rates). The simulations are done using a correspondingly lower curve relating E/AS gross margin to reserve margins (the dashed line in Figure 3). Comparing Sensitivity Run #15 (\$21,100 assumption) with the base case in Table 1 (\$28,000 assumption) shows that under the base case assumptions for other parameters, there is little change in the reserve margins resulting from the curves. However, there are small changes in the profits that investors require and the resulting consumer payments, and these changes are positive for some curves and negative for others. The relative standing of the various curves does not change: the alternative sloped curves (Curves 3-5) still result in lower consumer payments and higher reliability than the no demand curve case (Curve 1).

I also examined alternative assumptions concerning the year-to-year variation in growth rates for the weather-normalized peak. Instead of the base case value of 1% for the standard deviation of that growth rate, I also examined 0.5% and 1.5%. These assumptions did have significant impacts on the specific numerical performance of the five curves, but not on their general performance relative to each other. For instance, standard deviations of 0.5% and 1.5% resulted in consumer costs of 121 and 136 $/peak kW/yr, respectively, for Curve 1 (no demand curve), compared to the base case value of 129 (Table 1). More variable load growth results in both greater risks and greater potential rewards for entry; my assumption of risk-aversion then translates into a higher required profit in order for entry to occur. In contrast to Curve 1, for Curve 4 (sloped curve centered at IRM+1%), the 0.5% and 1.5% values yielded consumer costs of 62 and 78, compared to the base case of 71. The sloped curves continue to have relatively lower costs than the vertical curve.

Although the conclusion regarding the desirability of sloped curves (especially Curves 4 and 5) relative to Curve 1 (no demand curve) is robust with respect to these assumptions, the precise financial consequences (ICAP prices, generator profits, and consumer payments) do depend on the assumptions made. Therefore, the conclusion I draw is that there is significant uncertainty regarding the future effects of capacity mechanisms on consumers, but that risks are lower if a sloped demand curve is used.

5.4 Comparison of Four-Year Ahead with Same-Year Auction

An investor in generation capacity has less information on future capacity prices in the present year-ahead ICAP auction than under the proposed four-year ahead RPM system. Referring to Figure 2, the investor knows at year *y-4* the ICAP price in years *y*-3, *y*-2, and *y*-1 in the RPM system, because the auctions for capacity in those years have already been held. As a result, the investor has a firm basis for projecting capacity prices in subsequent years. But in the present

ICAP system, this information is not available. Even though the generation capacity that will be on line in those years might be estimated, based on capacity that already exists or is under construction, the investor does not know the weather-normalized peaks upon which the demand curves for those years will be based. Furthermore, there is also more uncertainty in the ICAP price for year *y* in the present ICAP system, because the location of the demand curve for that year is not known at the time that the investor commits to construction, unlike the RPM system.

To represent this additional risk, the four year-ahead auction model is modified to consider twelve profits rather than the eight shown in Figure 2. The additional four profit terms enable me to represent uncertainty in the ICAP price in years *y*-3, *y*-2, *y*-1, and *y* using two possible values for profits for each of these years. The two values, high and low, represent the cases where load growth results in relatively low and high reserve margins, respectively, in those years. This results in greater variation in profits and thus risk for the generator. The values of the low and high reserve margins result from modeling the uncertain evolution of weather-normalized load growth in future years, resulting from variations in economic growth. As I explained earlier in this affidavit, economic growth uncertainties are assumed to result in a 1% (standard deviation) uncertainty in year-to-year growth in the peak load, and, for simplicity, this uncertainty is assumed to be normally distributed and independent from year to year. Based on that assumption, a normal probability distribution for weather-normalized peaks for years *y*-3, *y*-2, *y*-1, and *y* can be described, conditioned on the peak in year *y*-4, which is already known; two equally probable values for each year are chosen to approximate the distribution. The two values, low and high, are chosen so that their average is the mean of the distribution and their standard deviation is the same as the actual distribution. Then for each of these weather-normalized peaks, a demand curve is created, resulting in two equally probable demand curves for capacity in each of those years.

These curves, together with the amount of existing and new capacity in each year, determine two capacity prices in each year that, together with E/AS gross margins, determine two profits in each year. For instance, for investment commitments being made in year y-4, given the weather-normalized peak in that year and investment commitments in previous years, the model might show a 50% probability of an ICAP payment of $80,000/MW/yr and a 50% probability of $30,000/MW/yr in year y-1.

In general, this distribution of capacity payments represents greater risk to the generator investor, and can lower the risk-adjusted forecast profit in the simulation model. I focus here on the effect on Curve 1 (no demand curve), since that is the system that is presently in place, while also mentioning results for Curve 4 (the PJM proposal). For Curve 1, the effect of introducing uncertainty into ICAP prices in years y-3, y-2, y-1, and y (simulating a same-year auction rather than four years-ahead auction) is to lower the average reserve margin by 0.5%, and to increase the required profit by 9 $/kW/yr and consumer payment by 11 $/peak kW/yr. The target reserve margin is met in 3% fewer of the years. These calculations use the base case assumptions. This result quantifies the effect of subtracting several years from the auction's lead time (from four to same year), assuming no change in the vertical demand curve or in bidding behavior.

For Curve 4, the effect is not as large, but still indicates a positive benefit to suppliers for introducing more certainty to capacity prices. In particular, the impact of a same-year auction rather than a timing of four years-ahead (simulated by introducing uncertainty into ICAP prices in years y-3, y-2, y-1, and y) is a decrease in the average reserve margin of 0.2%. Required profit goes up by 5 $/kW/yr, as do consumer payments.

In summary, multiyear lead times for power plants together with risk aversion means that more certain capacity prices are worth something to investors.

APPENDIX: MODEL EQUATIONS

This appendix summarizes the equations and notation used in my dynamic model of the four year-ahead RPM auction.

A.1. Assumptions

Let $P_{ICAP}(r_{F,y})$ be the demand curve for capacity, showing the price [in $/unforced MW/yr] paid for unforced capacity during year y as a function of unforced capacity reserve $r_{F,y}$. The F subscript indicates that the reserve margin is calculated based on the forecast peak load (at the time of the ICAP auction).

Load is summarized by the annual peak load in year y, designated L_y in the model. There are three separate types of loads that are considered: forecast peak load $L_{F,y}$, weather-normalized peak load $L_{WN,y}$, and actual peak load $L_{A,y}$.

The growth in weather-normalized load $L_{WN,y}$ is assumed to be 1.7%/yr on average. Uncertain growth in this load is assumed to be independent from year to year (random walk). Thus, the simulation is a Monte Carlo simulation, in which random trajectories of $L_{WN,y}$ are drawn:

$$L_{WN,y+1} = L_{WN,y}\,(1+ERR_{WN}) \qquad (1)$$

where ERR_{WN} is an independently distributed normal random variable with mean zero and standard deviation of 1%, consistent with PJM experience. The forecast peak load in year $y+4$ is related to the actual load in year y by the following forecasting formula:

$$L_{F,y+4} = L_{WN,y}\,(1.017)^4 \qquad (2)$$

This assumes that 4-year ahead forecasts are used in the ICAP auction, and that 1.7%/yr expected load growth is the basis of the forecast.

The actual peak load in year y equals the weather-normalized peak plus an error reflecting year-to-year weather variations. Analysis of annual peaks from 1995-2003 for PJM and ISO-NE show that the ratio of actual to weather-normalized annual peaks has a standard deviation of about

4%. The formula is:

$$L_{A,y} = L_{WN,y}\,(1+ERR_A) \qquad (3)$$

where ERR_A is an independently distributed normal error with mean zero and standard deviation of approximately 4%.

Random economic growth and weather variability results in considerable instability in installed reserve margins and gross margins from E/AS sales. Actual reserve margin $r_{A,y}$ in a particular year is calculated as follows:

$$r_{A,y} = (1\text{-}FOR)X_y/L_{A,y} \qquad (4)$$

where X_y is the installed capacity in the given year, and FOR is its average forced outage rate. Forecast reserve margin is calculated as:

$$r_{F,y} = (1\text{-}FOR)X_y]/L_{F,y} \qquad (5)$$

A.2 Model of Generation Capacity Bidding

Let Y be a particular year, which means that in the four-year ahead design of the PJM auction, the commitment to construct capacity for that year is made in the ICAP auction in year Y-4. The addition of CT capacity in year Y depends not only on the ICAP price $P_{ICAP,Y}$ in the auction held in year Y-4, but also on the anticipated E/AS gross margin in year Y, GM_Y, as well as profits $\pi_y = P_{ICAP,y} + GM_y - FC$ in years y previous to Y. FC is the annualized fixed cost of constructing a new combustion turbine, in real annualized terms. (Note that π_y, $P_{ICAP,y}$, GM_y, and FC are all expressed in compatible units of [$/unforced MW of capacity/year].)

Profits in previous years provide the basis for forecasting the level and volatility of profits in the future. The E/AS gross margin in each of those years is assumed to be a function of the market conditions in a year, summarized by the actual reserve margin. That is, $GM_y = GM_y(r_{A,y})$, as shown in Figure 2, *supra*. A function of the form $GM_y(r_{A,y}) = \text{EXP}(a_0 + a_1 r_{A,y} + a_2 r_{A,y}^2 + a_3 r_{A,y}^3)$ was found to represent an excellent fit to the output of the production costing model used to estimate gross margins.

An installed capacity bid curve for an auction held in year *Y*-4 for capacity to be installed in year *Y* has the general shape shown in Figure 1. The simulation model creates such a curve in each year. Existing capacity is assumed to be bid in at price B_E, while the maximum potential incremental capacity NCA_Y is assumed to be bid in at assumed bid of B_N. The ICAP price is then calculated as the intersection of that capacity bid curve with the demand curve. NCA_Y is based on generator's anticipated profits, which reflect both the levels and variability of recent profits, along with an adjustment to account for generator's aversion to risk.

The following are the steps involved in construction of a capacity bid curve in each year.

1. The anticipated or actual profit π_y for a new CT for each of several years $y = Y, Y\text{-}1, Y\text{-}2, \ldots, Y\text{-}7$ is calculated. (Other ranges of years can be considered; a total of eight is considered in these simulations.) Profits in years *Y*-4, *Y*-5, *Y*-6, and *Y*-7 are assumed to be known exactly, since ICAP and A/ES prices in those years have been observed or can be fairly well estimated by the time the auction in *Y*-4 takes place. Profits in years *Y*-1, *Y*-2, and *Y*-3 can be estimated based on the known $P_{ICAP,y}$ and a projection of gross margin based on the forecast reserve margin $GM_y \cong GM_y(r_{F,y})$. Profit in year *Y* is more difficult to forecast, because $r_{F,Y}$ is not yet known (since the auction has not yet taken place). So an estimate is obtained by assuming that enough capacity would be added in *Y* so that the forecast reserve margin in that year would be the same as in the previous year $r_{F,Y\text{-}1}$. The ICAP demand curve in year *Y* (used in the auction held in *Y*-4) is then used to estimate $P_{ICAP,Y}$ for that year based on that guess of the forecasted reserve, and GM_Y is projected using the same guess.
2. The value of the utility function $U(\pi_y)$ (*i.e.*, the risk-preference function I discuss in the body of this affidavit) of the anticipated or actual profit π_y for $y = Y, Y\text{-}1, Y\text{-}2, \ldots, Y\text{-}7$ is then calculated. $U(\pi_y)$ is a concave nonlinear utility function that represents attitudes towards

risk.[14] The simplest possible risk averse utility function is the negative exponential form $U(\pi_y) = a\text{-}be^{-c\pi y}$, which is standard in decision analysis; the risk attitude can be summarized in one risk aversion parameter c. The constants a, b, and c are calibrated so that zero profit results in zero utility; a utility of 1 results if $\pi_y = FC$ (i.e., a gross margin, including ICAP payments, equal to double the fixed cost); and $\pi_y = 0.5FC$ results in a utility of 0.7 (indicating a somewhat but not extreme risk aversion). Other degrees of risk aversion can be readily simulated. For instance, $U(0.5FC) = 0.5$ defines a linear utility function, which represents risk neutrality; then the generator is assumed to care only about average profits, and not their volatility.

3. A risk-adjusted forecast profit $RAFP_Y$ for capacity added in year Y is calculated. This is accomplished by first obtaining a weighted utility of the observed and estimated profits:

$$WU_Y = \Sigma_{y=Y,\, Y-1,\, \ldots,\, Y-7}\, W_{Y-y}\, U(\pi_y) \qquad (6)$$

where W_{Y-y} is a weight assigned to profits that occur Y-y years before the on-line date for new capacity in that auction. The sum of the weights is 1. A simple form of such weights is the lagged formulation $W_{y-1} = \alpha\, W_y$, with $\alpha<1$; a value of $\alpha=0.8$ is used in the simulations here. From the weighted utility, $RAFP_Y$ is calculated by inverting the utility function $U(RAFP_Y) = WU_Y$:

$$RAFP_Y = -\ln((a-WU_Y)/b)/c \qquad (7)$$

4. The maximum amount of capacity additions NCA_Y based on $RAFP_Y$ is calculated using a function with the following properties: (a) if $RAFP_Y$ is zero, then the amount of capacity added is 1.7% of the existing capacity (so that if all profits in every year are zero, then capacity growth would be just enough to meet the assumed average load growth of 1.7%);

[14] Note that the term "utility" in "utility function" has nothing to do with the utility in "electric utility"; rather, decision analysis use the term to refer to a notion of value that is quantified under conditions of uncertainty.

(b) if $RAFP_Y = FC$, then the amount of entry equals $\beta > 1.7\%$ of existing capacity (here, assumed to be 7%); and (c) capacity additions at other risk-adjusted profit levels are an increasing function of $RAFP_Y$, and follow a curve that is the same shape as the utility function. These assumptions yield the following relationship between the maximum additions in Y and the risk-adjusted forecast profit:

$$NCA_Y = X_{Y-1}*\mathrm{MAX}(0,0.017+\lambda\ (WU_Y-U(0)) \qquad (8)$$

where: $\lambda = (\beta\text{-}0.017)/(U(FC)\text{-}U(0))$, and X_{Y-1} is the installed capacity in the previous year. Because the utility function has a negative exponential form, there is a maximum amount of capacity that can be added in a given year (that is, even if expected profits were extremely high, there is a limited amount of capacity that would be constructed).

Given the existing capacity X_{Y-1} and its bid B_E, and the maximum increment in capacity NCA_Y and the assumed bid B_N associated with it, the resulting ICAP price and quantity for year Y can then be calculated, as shown in Figure 2.

The utility function plays a key role in this analysis, and so I explain it further here. The utility function is an increasing and downward bending (concave) function that reflects an assumed risk averse attitude; this is a standard method used in decision analysis and economics to represent risk acceptance behavior by individuals and companies. The more concave the function, the more risk averse generating companies are assumed to be; i.e., the more that undesired outcomes and profit variations are penalized. A negative exponential form, which is standard in decision analysis, is used so that the risk attitude can be summarized by a single risk aversion parameter. In the base case analyses reported in Table 1, *supra.*, the constants of the function are calibrated so that zero profit results in zero utility; a utility of 1 results if profit equals the fixed cost FC of the turbine (i.e., gross margin, including ICAP payments, equals double the fixed cost, measured in real annualized terms); and a profit of $0.5FC$ results in a utility of 0.7 (indicating a somewhat but not extreme risk aversion). Other degrees of risk aversion can be readily simulated, and are considered in the sensitivity analyses of Section 5.3. For instance, if a profit of 0.5*FC* is instead assumed to have a utility of 0.5, then a linear utility function results, which represents risk neutrality. In that case, the generator is assumed to care only about average profits, and not their volatility.

Figure 12 illustrates how a risk averse utility function penalizes riskier profit streams. The higher the average utility, the more attractive investors are assumed to view an investment opportunity. Comparing two distributions of profits—distribution A which has \$1 occurring for sure, and distribution B which has a 50:50 chance of \$0.50 and \$1.50—we see that the concave (downward bending) form of the utility function means that the average utility of B is lower than the utility of A. So the riskier investment is less desirable, even though its average profit is the same.

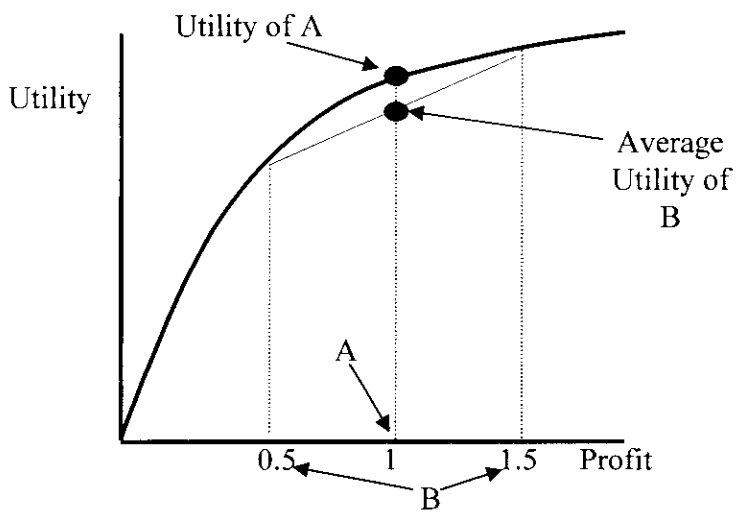

Figure 12. A Risk-Averse Utility Function Results in Lower Average Utility for Riskier Alternatives

Because the utility function is concave, if there is a lot of variation in profits, then RAFP is lower. For example, consider an actual stream of observed and estimated profits that varies over time and has average X. Then *RAFP* will generally be less than X because the risk averse investor prefers a certain profit to a variable one, and so is willing to give up some average return in order to reduce the risk. The riskier a stream of profits is and the more risk averse (concave) the utility function is, the lower *RAFP* will be relative to X.

A.3 Model Execution

Each year *y* of the simulation calculates the following:

1. Random forecast errors (due to economic growth and weather) are drawn, and used to obtain the actual and weather-normalized peak loads (1),(3). The forecast load in *y*+4 is also calculated (2).
2. The ICAP auction is simulated in the manner described in Section A.2, yielding the ICAP price and amount of capacity that will be installed in year *y*+4.
3. Statistics on the simulation results are compiled for calculating performance indices.

Because the emphasis of the simulation is upon steady-state behavior of the ICAP system, the first 10 years of each simulation are discarded to avoid biases due to starting conditions. One hundred more years are simulated, and then the 110 year simulation is repeated twenty five times, giving 2500 years of output as the basis for the calculation of the performance indices.

This concludes my affidavit.

AFFIDAVIT OF BENJAMIN F. HOBBS

Benjamin F. Hobbs, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Benjamin F. Hobbs on behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/______________________________
Benjamin F. Hobbs

Subscribed and sworn to before me this the 5th day of August, 2005.

/s/______________________________
Notary Public

My Commission expires: ____________

AFFIDAVIT OF BENJAMIN F. HOBBS

Benjamin F. Hobbs, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Benjamin F. Hobbs on behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ [signature]
Benjamin F. Hobbs

Subscribed and sworn to before me this the 5th day of August, 2005.

/s/ Elizabeth E. Weber
Notary Public

My Commission expires: 1/7/09

ELIZABETH E. WEBER
Notary Public
Baltimore City
MARYLAND
My Commission Expires January 07, 2009

TAB I

Affidavit of Ray L. Pasteris

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER05-______

AFFIDAVIT OF RAYMOND M. PASTERIS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.

My name is Raymond M. Pasteris, and I am the President of Strategic Energy Services, Inc. ("Strategic"). I am submitting this affidavit in support of PJM's proposed Reliability Pricing Model ("RPM"), in particular the estimated cost of new entry generator used by PJM for RPM.

In August of 2004 PJM retained Strategic to determine the type of generator to use for the estimated cost of new entry ("CONE"), an appropriate configuration and technology for that generator, and its resulting fixed revenue requirements, expressed in $/MW-Year or $/MW-Day. The CONE revenue requirements are based on the total project capital cost and annual fixed operations and maintenance ("O&M") expenses of a combustion turbine ("CT") simple cycle peaker power plant addition. Strategic prepared separate CONE estimates for three PJM subregions: New Jersey, Maryland and Illinois.

The results of Strategic's analysis are set forth in the attached report, "Independent Study to Determine Cost of New Entry Combustion Turbine Power Plant Revenue Requirements For PJM Interconnection, LLC.," which was prepared under my direction and supervision. My qualifications and experience, as well as that of Strategic, are set forth in Addendum No. 3 to the report. Strategic retained The Wood Group, a power plant design build firm with CT construction, operation, and maintenance experience, to develop the plant proper capital cost estimates and certain plant startup and annual O & M expenses for the CT plants considered.

As explained in the report, Strategic evaluated plant configurations based on two types of combustion turbine units: General Electric's 45 MW LM 6000 Sprint aero-derivative CT and the 170 MW GE Frame PG7241 ("7FA") industrial frame CT. Recent CT plants installed in the PJM control region as well as other control regions have incorporated both these units. Our analysis found that the Frame CT plant required significantly lower fixed revenue requirements than that of the Aero CT plant. Accordingly, we have recommended to PJM that the Frame CT plant be used as the basis for the CONE estimates for all three sub regions of PJM.

The resulting CONE, on a nominal levelized basis, is $72,207/MW-Year for New Jersey; $74,117/MW-Year for Maryland; and $73,866/MW-Year for Illinois. These results are lower than (but consistent with) the results of similar Cost of New Entry studies recently performed for the New York ISO and ISO-New England. The CT capital costs and weighted average cost of capital estimated in our study also are consistent with the capital costs and cost of capital of CT plants that achieved commercial operation in the PJM region between June 2001 and July 2003, as reported to FERC in reactive service revenue requirement filings.

The attached report also includes our professional assessment of the likely development schedule of a combustion turbine plant. As detailed in the report, we estimate the entire development of a greenfield CT plant from initial concept through site selection, interconnection studies, environmental permits, and construction to commercial operation to be four years.

Although not reflected in the attached report, Strategic performed two other tasks in support of PJM's RPM submission. First, Strategic assisted PJM's witness Professor Benjamin Hobbs with calculations of the internal rates of return ("IRR") implied by the generator profit forecasts in the dynamic modeling he performed for PJM. For this purpose, I used the same working financial model described in the attached CONE report. Professor Benjamin Hobbs requested nineteen sensitivities of increased capacity revenues be run on the financial model to determine the resulting increased IRR. These IRR results were used in his dynamic modeling.

Second, I supplied PJM's witness Dr. Joseph E. Bowring with estimates of the variable operations and maintenance ("VOM") expenses likely to be incurred by the GE Frame 7FA plant configuration. While I did not need this figure for my estimate of the fixed capital and O&M costs of the plant, Dr. Bowring uses VOM in connection with his discussion of the net energy and ancillary service revenues likely to be earned in the PJM market by the CONE plant configuration. That CONE CT plant VOM was estimated at $5.00/MWh. Strategic relied upon a General Electric Company ("GE") public document GER-3620K (12/04) "Heavy-Duty Gas Turbine Operating and Maintenance Considerations" to perform its VOM estimate. This document is available to the public for PDF download from the GE website at www.gepower.com Technical Library, GE Reference Documents (GERs).

This concludes my affidavit.

AFFIDAVIT OF RAYMOND M. PASTERIS

Raymond M. Pasteris, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Raymond M. Pasteris on behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ Raymond M. Pasteris
Raymond M. Pasteris

Subscribed and sworn to before me this 25 day of August, 2005.

/s/ Peter M. Molnar
Notary Public

My Commission expires: 1/18/09

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Peter M. Molnar, Notary Public
Lower Makefield Twp., Bucks County
My Commission Expires Jan. 18, 2009
Member, Pennsylvania Association of Notaries

Independent Study to Determine Cost of New Entry Combustion Turbine Power Plant Revenue Requirements

For

PJM Interconnection, LLC.

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August 30, 2005

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Executive Summary

Introduction

In August of 2004 PJM retained Strategic Energy Services, Inc. ("Strategic") to determine the cost of a new entry ("CONE") generator, its technology and its resulting fixed revenue requirements expressed in \$/MW-Year or \$/MW-Day. The CONE revenue requirements are based on the total project capital cost and annual fixed operations and maintenance expenses ("O&M") of a combustion turbine ("CT") simple cycle peaker power plant addition in three PJM regions. These regions are New Jersey, Maryland and Illinois. This evaluation only considered capital and fixed O&M costs. Net revenues from the sale of energy and ancillary services are not included in this report and were determined by PJM using CONE CT performance information contained is this report.

Choice of Generation Technology

Recent CT plants installed in the PJM control region as well as other control regions have incorporated multiple aero-derivative units of approximate 40 MW to 50 MW per unit and/or multiple industrial frame units of 40 MW to 170 MW units. Newly constructed CT power plants have primarily incorporated General Electric's 45 MW LM 6000 Sprint aero-derivative CT and the 170 MW GE Frame PG7241 ("7FA") industrial CT. Accordingly, it was decided to evaluate both these GE CT units. Levitan & Associates, Inc. and Concentric Energy Advisors, Inc. also evaluated these technologies for the CONE and ICAP demand curve studies for ISONY and ISONE, respectively.

Evaluation Methodology

Two CT power plant design configurations, one consisting of two GE LM 6000 units, the other consisting of two GE Frame 7FA units were evaluated initially at the New Jersey regional location. The CT power plant emerging with the lowest fixed revenue requirements, expressed in \$/MW-Year or \$/MW-Day, would be further evaluated for the Maryland and Illinois regions.

The Wood Group, a power plant design build firm with CT construction and O&M experience was contracted by Strategic to develop the plant proper capital cost estimates for the Frame CT and Aero CT plants. The Wood Group assembled these estimates based on major equipment quotations, balance of plant material costs and man-hours based on prevailing union labor rates in the designated region. The plant proper estimate is an engineering, procurement and construction ("EPC") turnkey proposal as if contracted to the Wood Group to fully implement the project "turnkey" in 2004 dollars. The Wood Group operations division also provided assistance in determining plant startup, capitalized spare parts, O&M staffing, and annual maintenance expenses. Strategic determined other development expenses such as land, environmental permitting, legal, project management and interest during construction. Strategic utilized PJM's capital cost database to estimate electric interconnection and system upgrade costs. Strategic determined the annual property tax payments and insurance premiums.

Proforma Analysis

A twenty (20) year after tax discounted cash flow ("ATDCF") economic model was used to determine the revenue requirements for the CONE CT project to cover capital recovery, annual fixed O&M expenses and earn the target internal rate of return ("IRR") for the investor/owner. The mid-year convention was used to account for revenues and expenses incurred continuously throughout each year in the 20-year project evaluation. This ATDCF methodology for evaluating new power generation investments is the most commonly used by power plant owners and developers. Accordingly, the financial results of this study will be consistent with the financial results obtained by owners and developers when applying the study capital costs, annual O&M expenses and financial criteria. The model only accounted for the capital costs to build the plant and annual fixed O&M expenses over the 20-year project life. It includes fixed revenue, fixed O&M expense, debt service, depreciation, income taxes and after tax cash flow. Variable operating expenses such as fuel and variable operations and maintenance ("VOM") expenses were not included in the financial model.

Financial Criteria

Target Internal Rate of Return ("IRR")

A target IRR of 12% was chosen for the proforma evaluation and is based on achieving this IRR over a 20-year project life. Applying this 12% discount rate to the net present value ("NPV") of the 20-year after tax cash flow, including the equity investment in year one, the NPV would equal zero. This investment hurdle rate represents a mature and properly functioning capacity market, which provides appropriate and reasonably stable capacity revenues. Concentric Energy Advisors, Inc. used a 12% target IRR for the CONE study for ISONE. Strategic has reviewed this report and agrees with the basis of the 12% target IRR.

Debt to Equity Ratio

A 50% debt to 50% equity ratio was assumed in the proforma model evaluation. This ratio is consistent with the financial structure of a creditworthy integrated electric utility company or independent power company ("IPP"). This would be a reasonable financial structure for the CONE CT plant project.

Debt Term and Interest Rate

Consistent with the financial structure of a creditworthy integrated electric utility company or IPP a long term, 20-year, bond with an interest rate of 7.0 % was used in the proforma model. A mortgage style loan was used which provides for increasing principal payment and decreasing interest payments over the loan term.

Tax Depreciation

The federal tax code allows for CT only power plants to utilize Modified Accelerated Cost Recovery System ("MACRS") over a 15 year tax life on the qualifying portions of the total project cost.

Federal and State Income Taxes

A 35.0% federal income tax rate was used in the proforma model. The state tax rate for New Jersey was 9.0 %, Maryland, 7.0% and Illinois 7.3%.

Escalation

An annual escalation rate of 2.5% was assumed for all fixed O&M expenses over the entire project life.

CONE Revenue Requirement Results

The resulting CONE CT revenue requirements of the Aero CT plant and the Frame CT plant may be found on Table 1 below. The Frame CT plant required significantly lower fixed revenue than that of the Aero CT plant. Accordingly, it is the conclusion of Strategic that the Frame CT plant is the lowest cost CT plant. It is Strategic's recommendation to PJM that the Frame CT plant be utilized by PJM as the CONE CT for all regions of PJM.

Table 1
CONE CT REVENUE REQUIREMENTS
FRAME AND AERO CT PLANT

SUMMARY		
REGION	New Jersey	New Jersey
CT Model	GE Frame 7FA	GE LM 6000
Number of CTs	2	2
Net Capacity (MW)	336.1	94.1
Heat Rate (BTU/kWh) (HHV)	10,826	9,902
Capital Cost ($Million)	$156.636	$79.597
Capital Cost ($/kW)	$466.04	$845.45
2004 ($/MW-Year)	$58,752	$110,203
2004 ($/MW-Day)	$160.96	$301.93
2006 ($/MW-Year)	$61,726	$115,782
2006 ($/MW-Day)	$169.11	$317.21
Total Levelized ($/MW-Year)	$72,207	$135,442
Total Levelized ($/MW-Day)	$197.83	$371.07
FINANCIAL CRITERIA		
Project Evaluation (Years)	20	
Percent Equity	50%	
Percent Debt	50%	
Internal Rate of Return (%)	12.0%	
Loan Term (Years)	20	
Loan Interest Rate (%)	7.00%	
MACRS Depreciation Schedule (Yrs)	15	
GENERAL ASSUMPTIONS		
Ambient Temperature (F)	92.0	
Ambient Wet Blub Temperature (F)	78.0	

In Tables 1 and 2 revenue requirements are presented in $/MW-Year and $/MW-Day for the years 2004 and 2006 and non-escalated nominal levelized. The 2004 value represents the current revenue requirements of the CONE CT assuming the revenue requirements and fixed expenses escalate at 2.5% annually over the project life. The 2006 value represents the first year of plant operation revenue requirements with the 2004 revenue requirement escalated at 2.5% annually for the two years between 2004 and 2006. The nominal levelized value represents constant, non-escalating annual revenues over the 20-year project life beginning in 2006 having the same NPV as the 20-year revenue requirements escalating at 2.5% starting in 2006.

The results of evaluating the CONE CT revenue requirements of the Frame CT plant for the New Jersey, Maryland and Illinois regions of PJM are found on Table 2. The differences in revenue requirements are primarily a result of construction labor rates, O&M labor rates, land costs, property taxes and state income tax rates. Strategic reviewed FERC reactive filings of nine (9) recently constructed multiple frame CT peaker power projects in PJM regions. These power plants, totaling 4,792 MW, began commercial operation between June 2001 and July 2003. The average all-in project capital cost for these power plants was $399.92/kW. See Table 15 for further details on newly constructed frame CT power plants. The design of these plants did not include SCR emissions controls and duel fuel capability which adds $40.00/kW and $11.00/kW, respectively yielding an adjusted capital cost of $450.92/kW. This compares closely with the CONE regional capital cost range of $466.04/kW to $475.30/kW found in Table 2 below.

Table 2
CONE CT REVENUE REQUIREMENTS
PJM REGIONAL FRAME CT PLANT

SUMMARY			
PJM REGION	**New Jersey**	**Maryland**	**Illinois**
Capital Cost ($Million)	$156.636	$158.527	$159.749
Capital Cost ($/kW)	$466.04	$471.67	$475.30
2004 ($/MW-Year)	$58,752	$60,305	$60,102
2004 ($/MW-Day)	$160.96	$165.22	$164.66
2006 ($/MW-Year)	$61,726	$63,359	$63,144
2006 ($/MW-Day)	$169.11	$173.59	$173.00
Total Levelized ($/MW-Year)	$72,207	$74,117	$73,866
Total Levelized ($/MW-Day)	$197.83	$203.06	$202.37
FINANCIAL CRITERIA			
Project Evaluation (Years)	20		
Percent Equity	50%		
Percent Debt	50%		
Internal Rate of Return (%)	12.0%		
Loan Term (Years)	20		
Loan Interest Rate (%)	7.00%		
MACRS Depreciation Schedule (Yrs)	15		
GENERAL ASSUMPTIONS			
CT Model	GE Frame 7FA		
Number of CTs	2		
Ambient Temperature (F)	92.0		
Ambient Wet Blub Temperature (F)	78.0		
Net Capacity (MW)	336.1		
Heat Rate (BTU/kWh) (HHV)	10,826		

1.0 Plant Design

1.1 GE Frame 7FA Plant

Since its introduction to the markets more than ten years ago the GE Frame 7FA has been a technically and commercially successful combustion turbine in simple and combined cycle operation. The particular model used in this study is the PG7241. Many of these specific unit models have been installed in the PJM system in simple and combined cycle configuration. There are greater then thirty GE Frame 7FA units currently installed and operating in the PJM region.

The Frame CT plant design for this CONE study consists of two GE Frame 7FA units. This is consistent with the majority of new CT plants constructed in PJM having two or more GE Frame 7FA units. The primary fuel is natural gas with No. 2 oil as liquid fuel backup. It is assumed that pipeline gas is available at adequate pressure to be utilized by the CT without on site fuel gas compression. The minimum fuel gas pressure requirement of the GE Frame 7FA is 450 PSIG.

The Frame 7FA, when firing natural gas, utilizes dry low NOx ("DLN") combustor technology to reduce NOx emissions to 9.0 PPM at 15% O_2. Selective Catalytic Reduction ("SCR") technology has been added to further reduce emissions from the stack to 2.5 PPM at 15% O_2. Due to the high exhaust temperatures of the Frame CT, which are greater than 1,100° F, cooling air is introduced upstream of the SCR to lower and control the exhaust temperatures to an acceptable range for the SCR operation. Cooling air fans and associated ductwork are included in the Frame CT plant scope and capital cost. A hot SCR catalyst design is incorporated. 9.0 PPM emissions from one CT are approximately 62.0 pounds per hour of NOx. Reducing the NOx level to 2.5 PPM through the SCR reduces the emissions to approximately 17.2 pounds per hour per CT. Assuming two CT units both operating 1,500 hours annually the NOx emissions are 25.8 Tons per year.

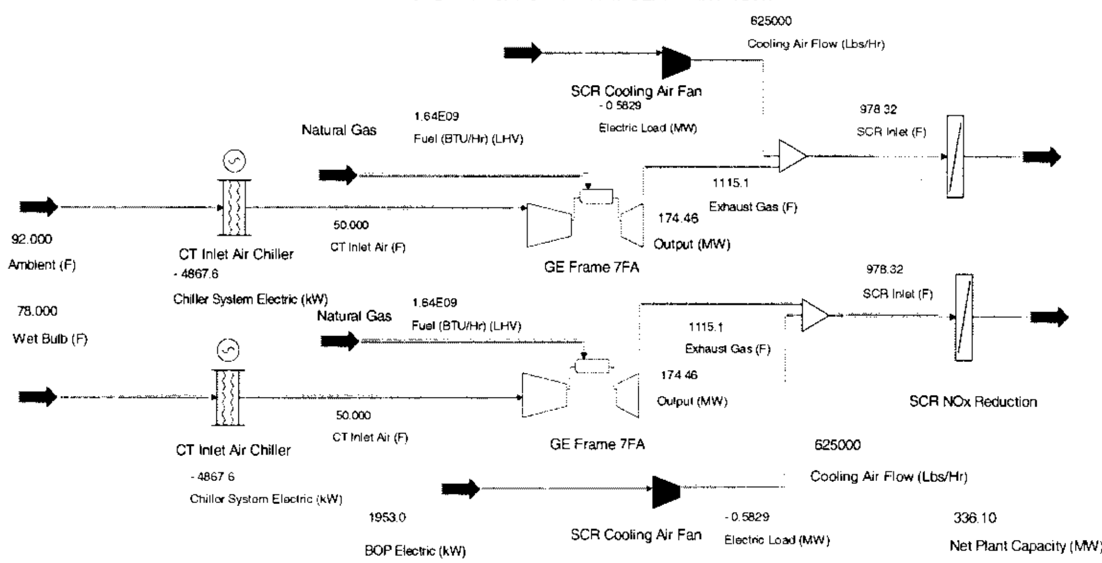
While firing distillate fuel water injection is used to reduce emissions from the CT to 42 PPM. At this NOx level entering the SCR achieving a stack NOx level of 2.5 PPM would not be expected. Accordingly, the plant may be limited to a specified, not to exceed annual operating hours on oil.

The unit is not designed with black start capability. Because of the large mass of the rotating elements of the GE Frame 7FA, windings in the electric generator are used to start the unit. Smaller CT units typically use an external motor driven hydraulic system for startup. Accordingly, it was deemed impractical to consider black start for the GE Frame 7FA. No black start ancillary service revenues are available from the Frame CT plant.

Turbine inlet air-cooling to 50° F is included in the Frame CT plant design. Motor driven mechanical chillers chill water to approximately 40° F. The chilled water is pumped through a heat exchange coil located upstream of the CT compressor inlet and cools the compressor inlet air. The CT electric output and heat rate are equal to that of a 50° F ambient day in spite of actual ambient temperatures greater than 50° F. Figure 1 provides details of the Frame CT plant under ambient conditions of a 92° F dry bulb temperature and a 78° F wet bulb temperature. The net electric capacity of the Frame CT plant is 336.1 MW. This capacity is net of the chiller system parasitic load of 9,735 kW. Each CT output is 174.46 MW. Without turbine inlet cooling the net electric capacity is 297.33 MW with each CT output only 150.21 MW. The net plant capacity increase due to inlet air-cooling is 38.8 MW. Evaporative cooling was evaluated and would yield a net plant capacity of 312.0 MW at the same ambient conditions. Each CT output would be 157.54 MW. Mechanical refrigeration provides a net plant capacity gain of 24.1 MW over evaporative cooling. The incremental capital cost of the mechanical chiller system is approximately $8.4 Million. This investment increases capacity by 38.8 MW making the cost of inlet air cooling only $216.50/kW. This is well below the plant proper cost of $391.00/kW without inlet cooling. Accordingly, the inlet air cooling investment lowers the overall plant proper cost to $370.90/kW.

Figure 1

PJM CONE Combustion Turbine Study
Two GE Frame 7FA At 92 F Ambient



1.2 GE LM 6000 Aero – Derivative Plant

The GE LM 6000 has also been a technically and commercially successful combustion turbine in simple and combined cycle operation. The LM 6000 CT is an aero-derivative type unit. The particular model used in this study is a GE LM 6000 PC with Sprint. Many of these units have been installed in the PJM system in simple cycle only. There are more than ten GE LM 6000 units currently in operation in the PJM system.

The Aero CT plant design for this CONE CT study consists of two GE LM 6000 units. The primary fuel is natural gas with No. 2 oil as liquid fuel backup. It is assumed that pipeline gas is available at adequate pressure to be utilized by the CT without on site fuel gas compression. The minimum fuel gas pressure requirement of the GE LM 6000 is 650 PSIG.

The LM 6000, when firing natural gas, utilizes water injection to reduce NOx emissions to 25 PPM at 15% O_2. Selective Catalytic Reduction ("SCR") technology further reduces emissions from the stack to 2.5 PPM at 15% O_2. Cooling air fans and associated ductwork are not required for the SCR. The LM 6000 exhaust, at approximately 850° F, is at an acceptable temperature for hot SCR operation. 25 PPM emissions from one CT results in approximately 36.0 pounds per hour of NOx. Reducing the NOx level to 2.5 PPM through the SCR reduces the emissions to approximately 3.6 pounds per hour. Assuming two CT units both operating 1,500 hours annually the NOx emissions would be 5.4 tons per year.

While firing distillate fuel water injection continues to be used to reduce emissions from the CT to 42 PPM. At this NOx level entering the SCR achieving a stack NOx level of 2.5 PPM would not be expected. Accordingly, the plant may be limited to a specified, not to exceed annual operating hours on oil.

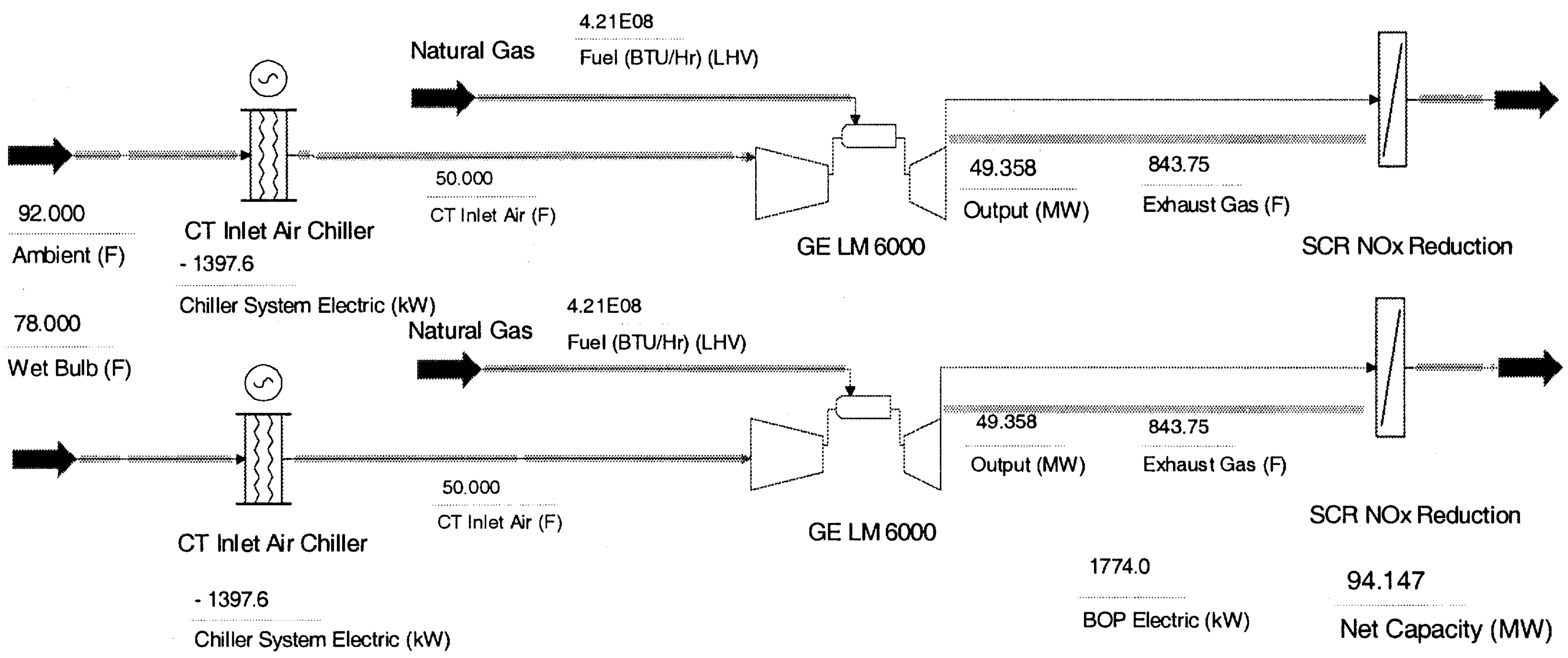
The GE LM 6000 unit is designed with black start capability. These units are commonly supplied with black start capability. Accordingly, black start ancillary service is available from the Aero CT plant.

Turbine inlet air-cooling to 50° F is included in the Aero CT plant design and is a common option when purchased from GE. The chiller system is similar to that described for the Frame CT plant. Figure 2 below provides details of the Aero CT plant at ambient conditions of a 92° F dry bulb temperature and a 78° F wet bulb temperature. The net electric capacity of the Aero CT plant is 94.15 MW. This is net of 2,795 kW of chiller system parasitic load. Each CT output is 49.36 MW.

Without turbine inlet cooling the net electric capacity is 74.11 MW with each CT output at 37.94 MW. The net plant capacity increase is 20.04 MW with turbine inlet cooling.

Figure 2

PJM CONE Combustion Turbine Study
Two GE LM 6000 At 92 F Ambient



2.0 Construction Scope and Capital Cost

2.1 Plant Proper Capital Cost

The Wood Group, a power plant design build firm with CT plant design and construction experience, was retained by Strategic to develop the plant proper capital cost estimates for the Frame CT and Aero CT plants. The Wood Group assembled capital cost estimates based on equipment quotations, materials, and man-hours based on prevailing union labor rates in the designated PJM regions. The plant proper estimate is an engineering, procurement and construction ("EPC") turnkey cost as if contracted to the Wood Group to complete in 2004 dollars. The Frame CT plant proper cost for New Jersey was estimated at $124.648 Million, for Maryland at $125.293 and for Illinois at $126.528. The Aero CT plant proper cost for New Jersey was estimated at $66.681 Million.

2.2 Construction and Draw Down Schedules

The Wood Group also provided construction and draw down schedules. The construction schedule for the Frame CT plant is 18 months and 15 months for the Aero CT plant. The construction and draw down schedule were used by Strategic to determine interest during construction.

2.3 Black Start Capability

The Aero CT plant is capable of black start services and black start facilities have been included in the capital cost. Black start capability is not included in the Frame CT plant as the unit is not started via a separate motor driven hydraulic system but utilizes the generator winding as a motor to start the unit using electric from the system.

2.4 Duel Fuel Capability

Both the Aero CT and the Frame CT plants are capable of natural gas and No. 2 oil operation and the necessary equipment including on site fuel oil storage and transfer have been included in the plant proper capital cost.

3.0 Other Project Capital Costs

3.1 Electric Interconnection

In the normal process of power project development within PJM the PJM Transmission Planning Department develops the capital cost for plant direct interconnection to the PJM system as well as the capital cost of PJM system upgrades. For the CONE CT study 111 power plant interconnection and system upgrade capital costs were available in the PJM database for proposed, in construction and recently completed power plant projects. Project installed capacities ranged from 2 MW to 765 MW. The database was sorted into the 100 MW to 400 MW capacity range that represented the range of the CONE CT projects under evaluation. This capacity range produced 13 projects with an average direct interconnection cost of $12.70 per kW and $8.06 per kW for PJM system upgrades. This produced a total interconnection cost of $21.76 per kW of installed net plant capacity. This value was increased to a value of 22.30 per kW net plant capacity to include power lines from the CONE CT plant proper to the PJM interconnection point.

3.2 Natural Gas Interconnection

PJM does not compile a database of natural gas interconnection costs. The Wood Group provided estimates for the natural gas metering station at the plant site. These costs were estimated at $500,000 for the Aero CT plant and $1,000,000 for the Frame CT plant. Based on further input from The Wood Group and review of other available information a cost of $21.00 per net kW capacity was utilized to represent the total cost of natural gas interconnection that includes the metering stations and a gas pipeline outside the plant proper. The pipeline distance from the plant to the high-pressure gas interconnection point is assumed to be 5 miles or less. The CONE CT evaluation assumes that natural gas is available at a pressure level adequate to be used directly in the CT without on site fuel gas compression. For the Aero CT plant this pressure is assumed to be 650 PSIG and for the Frame CT plant this pressure is assumed to be 450 PSIG.

3.3 Plant Mobilization and Startup Costs

As a power plant nears construction completion the owner begins to mobilize for the commissioning, testing and startup. These costs are typically capitalized and include hiring, relocation expenses, labor costs for the O&M staff 5 to 6 month before startup, training, production of O&M manuals, special tools and office equipment and furnishings. Startup consumables were also capitalized which include purchased electricity, fuel, water and chemicals.

The Wood Group operations division provided the mobilization costs for the Aero CT plant and the Frame CT plant. The Wood Group operations division provides startup, operations and maintenance services for CT based power plants. The mobilization cost for the Aero CT plant was estimated by the Wood Group to be $1,139,279. The mobilization cost for the Frame CT plant was estimated at $1,505,426.

Fuel, water and electric costs were assumed to include 72 hours of CT full load testing and 3,600 hours or 5 months of plant parasitic electric load purchased from the local utility. No credit was taken for electric sales revenues during plant testing. The consumable expenses for the Aero CT plant were estimated by Strategic at $553,194. The consumable expenses for the Frame CT plant were estimated at $1,992,909.

3.4 Initial Capitalized Spare Parts Inventory

The Wood Group estimated the spare parts inventory consistent with their estimate for startup and O&M services provided to the CONE CT plants. The capitalized spare parts for the Aero CT plant were estimated at $553,725 while the capitalized spare parts for the Frame CT plant were estimated at $2,000,000.

3.5 Project Development Costs

Owner or developer internal and contracted expenses for professional services can be capitalized. These costs include, development, legal, financial and technical professionals during the development, construction and startup of the project. Strategic, having experience in power project development, estimated these costs. The development costs for the Aero CT plant was estimated at $1,800,000 while the development costs for the Frame CT plant was estimated at $2,250,000.

Environmental and regulatory professional services and application fees to obtain air, land use and FERC permits were estimated at $1,000,000 for the Aero CT plant and $1,500,000 for the Frame CT plant.

3.6 Land Costs

Costs of property for the siting of the CONE CT plants were obtained by contacting real estate agencies in south New Jersey, Maryland and northern Illinois. The current average cost for New Jersey property is $20,000 per acre, for Maryland property, $40,000 per acre and for northern Illinois property, $40,000 per acre.

The Wood Group provided a plot plan for each CONE CT plant. The plant proper foot print for the Aero CT plant was 3.25 acres while the plant proper foot print for the Frame CT plant was 6.75 acres. A land buffer area was added surrounding plant proper foot print equal to 8 times the plant proper foot print. The total purchased property for the Aero CT plant was 29.25 acres while the total purchased property for the Frame CT plant was 60.75 acres.

3.7 Interest During Construction

Interest during construction ("IDC") was determined based on the construction and monthly draw down schedules provided by The Wood Group. An interest rate of 3.50% was utilized for the calculation of IDC.

3.8 Owner's Contingency

An owner's contingency was added to the total project capital cost of 2.5% of the plant proper engineering, procurement and construction cost.

Details of the CT plant scope, capital costs, schedule, startup and annual O&M costs, plant performance and plant drawings provided by the Wood Group may be found in the attached Addendum No. 1. The Wood Group qualifications, experience and references may be found in the attached Addendum No. 2. The capital cost buildup for the Frame CT plant and the Aero CT plant may be found on Table 3 and Table 4, respectively.

Table 3

**FRAME CT CAPITAL COST
BY REGION**

PJM Region	New Jersey		Maryland		Illinois	
	$000	$/kW	$000	$/kW	$000	$/kW
Plant Proper EPC	$124,648	$370.9	$125,293	$372.8	$126,528	$376.5
Electric Interconnect	$7,482	$22.3	$7,482	$22.3	$7,482	$22.3
Gas Interconnect	$6,978	$20.8	$6,978	$20.8	$6,978	$20.8
Equipment Spares	$2,000	$6.0	$2,000	$6.0	$2,000	$6.0
Owners Contingency	$3,116	$9.3	$3,132	$9.3	$3,163	$9.4
Mobilization and Startup	$3,498	$10.4	$3,498	$10.4	$3,498	$10.4
Land Purchase	$1,212	$3.6	$2,424	$7.2	$2,424	$7.2
Development Expenses	$1,500	$4.5	$1,500	$4.5	$1,500	$4.5
Legal Fees	$750	$2.2	$750	$2.2	$750	$2.2
Interest During Construction	$3,825	$11.4	$3,842	$11.4	$3,874	$11.5
Air, EIS, Land Use & FERC Permits	$1,500	$4.5	$1,500	$4.5	$1,500	$4.5
Emissions Reductions Credits	$125	$0.4	$125	$0.4	$50	$0.1
Total Project Cost	$156,636	$466.1	$158,525	$471.7	$159,749	$475.3

Table 4

AERO CT CAPITAL COST

PJM Region	New Jersey	
	$000	$/kW
Plant Proper Contract	$66,681	$708.3
Electric Interconnect	$2,073	$22.0
Gas Interconnect	$1,974	$21.0
Equipment Spares	$554	$5.9
Owners Contingency	$1,667	$17.7
Mobilization and Startup	$1,692	$18.0
Land Purchase	$586	$6.2
Development Expenses	$1,200	$12.7
Legal Fees	$600	$6.4
Interest During Construction	$1,528	$16.2
Air, EIS, Land Use & FERC Permits	$1,000	$10.6
Emissions Reductions Credits	$41	$0.4
Total Project Cost	$79,597	$845.5

4.0 Plant Performance

4.1 Plant Net Capacity and Heat Rate

Strategic utilized GE Energy Services GateCycle power plant performance software to determine the performance of the CONE CT plant at ambient temperatures from 20° F to 100° F. The performance evaluation also included detailed determinations of the plant parasitic loads for CT inlet air cooling, SCR cooling air and the balance of plant loads. Table 5 and Table 6 below summarize the plant performance for the Frame CT and Aero CT plants, respectively.

Table 5

PJM CONE CT PLANT PERFORMANCE
TWO GE FRAME 7FA CT UNITS WITH CT INLET AIR CHILLING TO 50 F

AMBIENT AND OTHER OPERATING CONDITIONS									
Ambient Temperature (F)	**20.0**	**30.0**	**40.0**	**50.0**	**60.0**	**70.0**	**80.0**	**90.0**	**100.0**
Relative Humidity (%)	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
Electric Chiller Status	Off	Off	Off	Off	On	On	On	On	On
CT Inlet Air Temperature (F)	20.0	30.0	40.0	50.0	50.0	50.0	50.0	50.0	50.0
Chiller System Efficiency (kW/Ton)	NA	NA	NA	NA	0.80	0.80	0.80	0.80	0.80
SCR Cooling Air Flow (Lbs/Hr)	625,000	625,000	625,000	625,000	625,000	625,000	625,000	625,000	625,000
SCR Inlet Temperature (F)	950.3	957.6	965.8	973.8	975.1	976.3	977.2	978.0	978.6
PLANT GROSS CAPACITY									
CT 1 Gross Capacity (MW)	183.323	180.938	177.701	174.464	174.464	174.464	174.464	174.464	174.464
CT 2 Gross Capacity (MW)	183.323	180.938	177.701	174.464	174.464	174.464	174.464	174.464	174.464
Plant Gross Capacity (MW)	366.646	361.876	355.401	348.927	348.927	348.927	348.927	348.927	348.927
PLANT PARASITIC LOADS									
CT 1 Chiller System Load (kW)	0	0	0	0	-567	-1,569	-3,091	-4,954	-7,264
CT 2 Chiller System Load (kW)	0	0	0	0	-567	-1,569	-3,091	-4,954	-7,264
CT 1 SCR Cooling Air Fan Load (MW)	-0.502	-0.513	-0.524	-0.535	-0.546	-0.557	-0.569	-0.581	-0.594
CT 2 SCR Cooling Air Fan Load (MW)	-0.502	-0.513	-0.524	-0.535	-0.546	-0.557	-0.569	-0.581	-0.594
BOP Parasitic Load (kW)	1,953	1,953	1,953	1,953	1,953	1,953	1,953	1,953	1,953
PLANT NET CAPACITY									
Net Capacity (MW)	**363.689**	**358.897**	**352.401**	**345.905**	**344.749**	**342.723**	**339.654**	**335.904**	**331.257**
PLANT FUEL CONSUMPTION AND HEAT RATE									
CT 1 Fuel (MMBTU/Hr) (LHV)	1,721.0	1,697.7	1,670.7	1,643.5	1,643.5	1,643.5	1,643.5	1,643.5	1,643.5
CT 2 Fuel (MMBTU/Hr) (LHV)	1,721.0	1,697.7	1,670.7	1,643.5	1,643.5	1,643.5	1,643.5	1,643.5	1,643.5
Total Plant Fuel (MMBTU/Hr) (LHV)	3,441.9	3,395.4	3,341.4	3,287.1	3,287.1	3,287.1	3,287.1	3,287.1	3,287.1
Total Plant Fuel (MMBTU/Hr) (HHV)	3,810.2	3,758.7	3,698.9	3,638.8	3,638.8	3,638.8	3,638.8	3,638.8	3,638.8
Net Plant Heat Rate (BTU/kWh) (HHV)	**10,476**	**10,473**	**10,496**	**10,520**	**10,555**	**10,617**	**10,713**	**10,833**	**10,985**
CT Only Gross Heat Rate (BTU/kWh) (LHV)	9,388	9,383	9,402	9,421	9,421	9,421	9,421	9,421	9,421

Table 6

PJM CONE CT PLANT PERFORMANCE
TWO GE LM 6000 CT UNITS WITH CT INLET AIR CHILLING TO 50 F

AMBIENT AND OTHER OPERATING CONDITIONS									
Ambient Temperature (F)	**20.0**	**30.0**	**40.0**	**50.0**	**60.0**	**70.0**	**80.0**	**90.0**	**100.0**
Relative Humidity (%)	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%	60.0%
Electric Chiller Status	Off	Off	Off	Off	On	On	On	On	On
CT Inlet Air Temperature (F)	20.0	30.0	40.0	50.0	50.0	50.0	50.0	50.0	50.0
PLANT GROSS CAPACITY									
CT 1 Gross Capacity (MW)	50.484	50.848	50.466	49.701	49.358	49.358	49.358	49.358	49.358
CT 2 Gross Capacity (MW)	50.484	50.848	50.466	49.701	49.358	49.358	49.358	49.358	49.358
Plant Gross Capacity (MW)	100.968	101.696	100.932	99.402	98.716	98.716	98.716	98.716	98.716
PLANT PARASITIC LOADS									
CT 1 Chiller System Load (kW)	0	0	0	0	-163	-451	-889	-1,425	-2,089
CT 2 Chiller System Load (kW)	0	0	0	0	-163	-451	-889	-1,425	-2,089
BOP Parasitic Load (kW)	1,774	1,774	1,774	1,774	1,774	1,774	1,774	1,774	1,774
PLANT NET CAPACITY									
Net Capacity (MW)	**99.194**	**99.922**	**99.158**	**97.628**	**96.616**	**96.040**	**95.164**	**94.092**	**92.763**
PLANT FUEL CONSUMPTION AND HEAT RATE									
CT 1 Fuel (MMBTU/Hr) (LHV)	422.4	427.6	429.0	424.0	421.1	421.1	421.1	421.1	421.1
CT 2 Fuel (MMBTU/Hr) (LHV)	422.4	427.6	429.0	424.0	421.1	421.1	421.1	421.1	421.1
Total Plant Fuel (MMBTU/Hr) (LHV)	844.8	855.3	858.0	848.1	842.1	842.1	842.1	842.1	842.1
Total Plant Fuel (MMBTU/Hr) (HHV)	935.2	946.8	949.8	938.8	932.3	932.3	932.3	932.3	932.3
Net Plant Heat Rate (BTU/kWh) (HHV)	**9,428**	**9,475**	**9,579**	**9,617**	**9,649**	**9,707**	**9,796**	**9,908**	**10,050**
CT Only Gross Heat Rate (BTU/kWh) (LHV)	8,367	8,410	8,501	8,532	8,531	8,531	8,531	8,531	8,531

4.2 NOx Emissions Controls

The Frame CT plant utilized dry low NOx ("DLN") combustor technology to control NOx at 9 PPM exiting the CT while firing natural gas. While firing No. 2 oil, water injection is used to control the NOx level at 42 PPM. Selective Catalytic Reduction ("SCR") technology was employed to further reduce NOx to 2.5 PPM exiting the stack.

The Aero CT plant utilized water injection technology to control NOx at 25 PPM exiting the CT while firing natural gas. While firing No. 2 oil, the NOx level is controlled at 42 PPM. Selective Catalytic Reduction ("SCR") technology was employed to further reduce NOx to 2.5 PPM exiting the stack.

4.3 Ancillary Services

Both CONE CT plant configurations are capable of supplying reactive power as an ancillary service. No additional capital cost is included for this service as leading power factor capability is standard design for the electric generators. The Aero CT plant is capable of black start services and the cost of black start equipment has been included in the capital cost. Black start capability is not included in the Frame CT plant as the unit is not started via a separate motor driven hydraulic system but utilizes the generator winding as a motor to start the unit using electric from the system.

5.0 Annual Fixed Operating Expenses

5.1 Operations and Maintenance Staffing

The Wood Group operations division provided assistance in determining the O&M staffing of the CONE CT plants. The staffing profile for the Frame CT plant and Aero CT plant are summarized in Table 7 and Table 8, respectively.

A 37% benefits burden has been added to the base hourly rate as well as 20% overtime hours above the base 2,080 hours at a time and one half hourly rate. This results in a 2004 fully loaded annual labor expense of $1,206,494 or $100,541 per person per year for the Frame CT plant. The 2004 fully loaded annual labor expense of for the LM 6000 plant is $675,678 or $96,525 per person per year.

Table 7

FRAME PLANT STAFFING

PLANT WORK FORCE						
Shift Number	1	2	3	4	Swing	Total
Direct Management						
Facility Manager	1					1
Operations						
O&M Supervisor	1					1
Shift Supervisor	1	1	1	1		4
A Operator	1	1	1	1	0	4
B Operator	0	0	0	0	0	0
Maintenance						
Maintenance Supervisor	0					0
Toolroom/Warehouse	0					0
Mechanic/Welder	0					0
Electrician/I&C	1					1
Administrative						
Secretary/Administration	1					1
Accounting/Purchasing	0					0
TOTAL LABOR						12

Table 8

AERO PLANT STAFFING

PLANT WORK FORCE						
Shift Number	1	2	3	4	Swing	Total
Direct Management						
Facility Manager	1					1
Operations						
O&M Supervisor	0					0
Shift Supervisor	0	0	0	0		0
A Operator	1	1	1	1	0	4
B Operator	0	0	0	0	0	0
Maintenance						
Maintenance Supervisor	0					0
Toolroom/Warehouse	0					0
Mechanic/Welder	0					0
Electrician/I&C	1					1
Administrative						
Secretary/Administration	1					1
Accounting/Purchasing	0					0
TOTAL LABOR						7

5.2 Contract Parts and Labor

The Wood Group provided the annual contract parts and labor expenses for both the Frame CT plant and the Aero CT plant, which were $232,000 and $205,000, respectively.

5.3 Insurance Expenses

Overall power plant annual insurance premiums were estimated to be 1.0% of the assets being insured. In the CONE CT study insurance was extended to the plant proper, the electric interconnection, the gas interconnection and capitalized spare parts. Coverage included general liability, property, boiler and machinery and business interruption. This amounts to approximately $1.4 Million annual premium for the Frame CT plant and $713,000 annual premium for the Aero CT plant. Guidelines for the determination of insurance premiums were provided by Marsh Insurance, Inc.

5.4 Property Tax

Property taxes were determined for each region-- New Jersey, Maryland and Illinois-- by obtaining public information on actual taxes paid by recently constructed power plants. This information was obtained from FERC filings or directly from the township or county tax assessors. These rates for power plants were compared with statutory tax rates in the counties and townships where the plants were constructed as well as surrounding counties and townships. In all cases the power plant tax rates were lower then the statutory rates indicating that development/enterprise zone tax relief was made available or payments in lieu of taxes ("PILOT") were negotiated. The averages of the actual tax rates incurred by the power plants surveyed in each region were used in this study. For New Jersey the tax rate was $2.53 per $1,000 of assessed value, for Maryland the tax rate was $4.50 per $1,000 of assessed value and for Illinois the tax rate was $2.09 per $1,000 of assessed value. The assessed value was determined to be all fixed assets based on the plant proper construction capital cost and all interconnection costs plus net current assets which would include capitalized spare parts. In many townships and counties property taxes are only assessed against the value of the buildings and property not power generation equipment values. This also contributed to reduced property tax expenses.

5.5 General and Administrative Expenses

General and administrative expense cover any technical, legal, accounting and permitting fees incurred on an annual basis. G&A expenses were estimated at $161,000 for the Frame CT plant and $157,000 for the Aero CT plant.

The annual fixed O&M expenses for the first year of operation for the Frame CT plant and the Aero CT plant are summarized on the following Table 9 and Table 10, respectively.

Table 9

**FRAME CT FIRST YEAR ANNUAL FIXED O&M EXPENSES
BY REGION**

PJM Region	New Jersey		Maryland		Illinois	
	$000	$/MW-Year	$000	$/MW-Year	$000	$/MW-Year
Site O &M Labor	$1,268	$3,772	$1,344	$3,998	$1,470	$4,375
O&M Contract Parts & Labor	$232	$689	$232	$689	$232	$689
Electric Purchases	$200	$595	$200	$595	$200	$595
Training-Employee Expenses	$74	$220	$74	$220	$74	$220
O & M Management Fee	$250	$744	$250	$744	$250	$744
Property, Machinery, B I Insurance	$1,411	$4,199	$1,418	$4,218	$1,430	$4,255
G&A	$161	$478	$161	$478	$161	$478
Property Taxes	$395	$1,177	$713	$2,121	$333	$991
Total	$3,991	$11,874	$4,390	$13,064	$4,150	$12,348

Table 10

AERO CT FIRST YEAR ANNUAL FIXED O&M EXPENSES

PJM Region	New Jersey	
	$000	$/MW-Year
Site O &M Labor	$710	$7,540
O&M Contract Parts & Labor	$205	$2,174
Electric Purchases	$100	$1,062
Training-Employee Expenses	$44	$462
O & M Management Fee	$250	$2,655
Property, Machinery, B I Insurance	$713	$7,571
G&A	$157	$1,667
Property Taxes	$201	$2,135
Total	$2,379	$25,268

6.0 Financial Criteria

6.1 Proforma Analysis

A twenty (20) year after tax discounted cash flow ("ATDCF") economic model was used to determine the real levelized and nominal levelized revenue requirements for the CONE CT project. Revenue requirements covered capital recovery, annual fixed O&M expenses and earn the target internal rate of return ("IRR") for the investor/owner. The mid-year convention was used to account for revenues and expenses incurred continuously throughout each year in the 20-year project evaluation. This methodology for evaluating power generation investments is the most commonly used by owners and developers. Accordingly, the financial results of this study will be consistent with the financial results obtained by developers when applying the CONE CT study capital costs, annual O&M expenses and financial criteria. The model only accounted for the capital costs to construct the plant and annual fixed operation and maintenance ("O&M") expenses over the 20-year project life. It includes fixed revenue, annual fixed O&M expense, debt service, depreciation, income taxes and after tax cash flow. Variable operating expenses such as fuel and variable operations and maintenance expenses ("VOM") where not included in the model.

6.2 Financial Criteria

Target Internal Rate of Return ("IRR")

A target IRR of 12% was chosen for the proforma evaluation and is based on achieving this IRR over a 20 year project life. Applying this 12% discount rate to the net present value ("NPV") of the 20 year after tax cash flow steam, including the equity investment in year one, the NPV will be zero. This investment hurdle rate represents a mature and properly functioning capacity market, which provides appropriate and reasonably stable capacity revenues. Concentric Energy Advisors, Inc. used a 12% target IRR for the CONE study for ISONE. Strategic has reviewed this report and agrees with the basis of the 12% target IRR.

Debt to Equity Ratio

A 50/50 debt to equity ratio was assumed in the proforma model evaluation. This ratio is consistent with the financial structure of a creditworthy integrated electric utility company or independent power company ("IPP"). This would be a reasonable financial structure for a CONE CT project.

Debt Term and Interest Rate

Consistent with the financial structure of a creditworthy integrated electric utility company a long term, 20-year, bond with an interest rate of 7.0 % was used in the proforma model. A mortgage style loan was used which provides for increasing principal payment and decreasing interest payments over the loan term.

Tax Depreciation

The federal tax code allows for CT only power plants to utilize Modified Accelerated Cost Recovery System ("MACRS") over a 15 year tax life on the qualifying portions of the total project cost.

Federal and State Income Taxes

A 35.0% federal income tax rate was used in the proforma model. The state tax rate for New Jersey was 9.0 %, Maryland, 7.0% and Illinois 7.3%.

Escalation

An annual escalation rate of 2.5% was assumed for all fixed expenses over the entire project life.

Reporting of Revenue Requirements

Revenue requirements are presented in $/MW-Year and $/MW-Day for the year 2004, 2006 and total nominal levelized. The 2004 value represents the current revenue requirements of the CONE CT assuming the annual revenue requirements and fixed O&M expenses escalate at 2.5% annually over the project life. The 2006 value represents the first year of operation with the 2004 revenue requirement escalated at 2.5% annually for the two years between 2004 and 2006. The total nominal levelized value represents constant, non-escalating annual revenues over the 20-year project life beginning in 2006 having the same NPV as the 20-year annual revenue requirements escalating at 2.5% starting in 2006.

6.3 Proforma Evaluation Methodology

Initially an estimated real levelized (escalating at 2.5%) annual revenue requirement was input into the proforma model. Next the project capital cost and 2004 estimates of fixed O&M expenses were input into the proforma model and allowed to escalate at 2.5% annually to 2006, the first year of operation, and for the 20-year project life. Included with these expenses were MACRS tax depreciation and debt interest payments. The difference between revenues and expenses provided the annual taxable income to which the federal income tax and appropriate state taxes were applied. This yielded after tax income. To the after tax income line the loan principal payments were subtracted and depreciation was added back to determine annual after tax cash flow. The equity placement of 50% of the total project cost was added as a negative cash flow on January 1, 2006 of the first operating year while annual after tax cash flow was assigned a mid-year convention of July 1 for each year in the project life. This 20-year after tax cash flow stream was used to calculate IRR via the MS Excel function XIIR. The real levelized annual revenue requirement input was adjusted until the target 12.0% IRR was achieved.

PJM requested Strategic to determine the non-escalating or nominal levelized annual revenue requirements for the CONE CT project under the same financial criteria. The nominal levelized value represents constant, non-escalating annual revenues over the 20-year project life beginning in 2006 having the same NPV as the 20-year revenue requirements escalating at 2.5% starting in 2006.

7.0 PJM CONE Comparison to ISONY and ISONE CONE Studies

7.1 ISONY Study Overview

The New York ISO retained Levitan & Associates, Inc. located in Boston to determine the CONE generator for three regions of the New York ISO. These regions were New York City, Long Island and the rest of state ("ROS"). For making meaningful comparisons New York ROS region only was compared to the PJM CONE CT results.

Levitan relied upon DMJM+ Harris, an engineering firm with gas turbine experience in New York City and Long Island, to provide power plant capital costs, start up, testing and spare parts costs, owner's development costs and plant staffing levels and other fixed O&M expenses. Levitan's in house experience contributed to interconnection costs, start up, testing and spare parts costs, owner's development cost and property taxes. Levitan's report was completed and issued in August 2004.

Levitan, as did Strategic, focused on the GE LM 6000 Aero CT and the GE Frame 7FA Frame CT technologies in their evaluation. Each technology was evaluated employing a two CT plant configuration. The plant design for NYISO was natural gas only, included SCR for NOx control but did not include turbine inlet air-cooling. Plant capacity ratings in the Levitan study used ISO conditions at 59° F. Strategic rated the CONE CT plant capacity at 92° F consistent with the PJM summer plant capacity rating procedures.

7.1 ISONE Study Overview

The New England ISO had two CONE CT studies performed. e-Acumen, Inc. completed a study in June 2002 and Concentric Energy Advisors, Inc. completed the most recent study in August of 2004.

e-Acumen relied upon four separate studies of hypothetical marginal CT power plants. e-Acumen obtained the results of simple cycle CT power plant studies performed by developers of combined cycle power plants in the New England region. Evaluating a hypothetical marginal CT power plant was part of the risk analysis performed by the developers of these combined cycle power plants. All the CT studies employed the GE Frame 7FA units. e-Acumen used the weighted average cost of capital expressed in \$/kW and fixed O&M expenses expressed in \$/kW-Year to determine their study Frame CT plant's capital cost and fixed O&M expenses. To determine the fixed revenue requirements e-Acumen used the average of the four studies' financial criteria. A comparison of the various studies' financial criteria can be found in Table 14.

Detailed plant design information was not available in the e-Acumen report. Accordingly, it is not known if the plant included dual fuel capability, SCR for NOx control or turbine inlet air-cooling. Plant capacity ambient rating conditions were also not known.

In conducting their study for ISONE, Concentric Energy Advisors, Inc. reached out to developers, AE firms, equipment suppliers, environmental firms, investors, gas supply and transmission companies and state and federal environmental officials to obtain cost data. Detailed information obtained formed the basis of the cost estimates. Summary quality information was used to check their final results.

Concentric, as did Levitan and Strategic, focused on the GE LM 6000 Aero CT and the GE Frame 7FA Frame CT technologies for their evaluation. However, Concentric evaluated a single unit Frame CT plant. Concentric evaluated a two unit Aero CT plant as did Levitan and Strategic. The ISONE plant design included natural gas and distillate fuel capability, SCR for NOx control but did not include turbine inlet air-cooling. Plant capacity ratings used ISO conditions at 59° F. Concentric concluded that the Frame CT plant should be used as the CONE CT plant as it yields the lowest fixed revenue requirements. Since the Concentric study utilized only one Frame 7FA unit, Strategic provided the single CT plant results and adjusted the costs to reflect a two unit Frame CT power plant to make a more direct comparison to the Strategic, Levitan and e-Acumen results.

7.2 Profroma Comparison Conclusions

The Strategic economic proforma model yielded the same \$/MW-Year revenue requirements as Levitan, e-Acumen and Concentric when the same capital costs, fixed O&M expenses and financial criteria were utilized. It can then be concluded that all study proformas were comparable and consistent in structure.

7.3 Study Comparison Results

Table 11 provides a detailed comparison of the capital costs of each study. The largest cost variances centered on equipment cost estimates, construction labor and interconnection costs.

Exhibit IMM-00011
Docket No. EL21-91-000, -003

Table 11

CONE CT ISO COMPARISON
FRAME CT PLANT CAPITAL COSTS

(Using Concentric Cost Categories)

PLANT/SITE CHARACTERISTICS					
ISO	PJM	NY	NE	NE	NE
Source	Strategic	Levitan	Concentric	Concentric	e-Acumen
Location	New Jersey	ROS	Maine	Maine	Multiple
CT Technology	Frame x 2	Frame x 2	Frame x 1	Frame x 2	Frame
Environmental Controls	with SCR	with SCR	with SCR	with SCR	NA
Fuel Capability	Dual	Gas	Dual	Dual	NA
Capacity- (MW)	336.1	336.5	170.0	340.0	198.5
Site Size (Acres)	60.61	NA	5	10	NA
INSTALLATION ($000)					
Equipment (Including CT and SCR Delivered to Site)	$83,056	$118,000	$38,600	$77,200	NA
Pipeline & Transmission Interconnection	$14,537	$14,211	$11,100	$22,200	NA
Non-Labor EPC (Plus Inventory, Startup & Testing)	$37,285	$38,555	$22,500	$45,000	NA
Owner's (Permitting, Legal, Community Support, Fees)	$7,700	$15,084	$4,700	$7,050	NA
Construction Labor	$9,730	$15,606	$13,206	$26,412	NA
Project Contingency	$3,116	$0	$3,806	$7,611	NA
Per Acre Land Cost	$20	$0	$250	$250	NA
Land and Land Rights	$1,212	$0	$1,250	$2,500	NA
Total Capital Costs - Depreciable Portion	$155,424	$201,456	$93,912	$185,473	NA
Total Capital Costs - Non-Depreciable Portion (Land)	$1,212	$0	$1,250	$2,500	NA
Total Capital Costs	**$156,636**	**$201,456**	**$95,162**	**$187,973**	**$82,030**
Total Capital Costs ($/kW)	**$466.04**	**$598.68**	**$559.77**	**$552.86**	**$413.25**

Table 12 provides a detailed comparison of the annual fixed O&M expenses. The largest expense variances centered primarily on property taxes.

Table 12

CONE CT ISO COMPARISON
FRAME CT PLANT FIXED O&M EXPENSES

FIXED O&M EXPENSES ($000)					
ISO	PJM	NY	NE	NE	NE
Source	Strategic	Levitan	Concentric	Concentric	e-Acumen
Location	New Jersey	ROS	Maine	Maine	Multiple
CT Technology	Frame x 2	Frame x 2	Frame x 1	Frame x 2	Frame
Labor - Location Cost	$1,268	$0	$435	$870	NA
Property Tax Rate ($/$000 Value)	$2.52	$25.96	$15.00	$15.00	$14.99
Value Used for Property Taxes	$156,511	$201,456	$95,162	$187,973	$82,030
Total Annual Property Taxes	$395	$5,229	$1,427	$2,820	$1,230
Other (Insurance, Materials, G&A Etc.)	$2,328	$1,487	$1,670	$3,340	$1,824
Total Fixed O&M	**$3,991**	**$6,717**	**$3,532**	**$7,030**	**$3,054**
Total Fixed O&M ($/kW-Year)	**$11.87**	**$19.96**	**$20.78**	**$20.68**	**$15.39**
RESULTS					
Total Capacity Payment ($/kW-Year)	**$58.752**	**$87.000**	**$87.220**	**$86.296**	**$73.810**
Capital Capacity Payment ($/kW-Year)	**$46.878**	**$67.040**	**$66.441**	**$65.621**	**$58.425**

Table 13 provides a detailed reconciliation of the Strategic, Concentric and Levitan study capital costs and fixed O&M expenses expressed in $/kW-Year.

Table 13

CONE CT ISO COMPARISON
FRAME CT PLANT
RECONCILIATION OF REVENUE REQUIREMENTS

RECONCILIATION ($/kW-Year)			
ISO	NE	PJM	NY
Source	Concentric	Strategic	Levitan
Location	Maine	NJ	ROS
CT Technology	Frame x 2	Frame x 2	Frame x 2
Total Capacity Payment ($/kW-Year)	**$86.296**	**$58.752**	**$87.000**
Equipment	$2.044	$0.000	($11.629)
Pipeline & Transmission Interconnection	($2.675)	$0.000	$0.108
Non-Labor EPC	($2.693)	$0.000	($0.423)
Owner's Costs	$0.227	$0.000	($2.457)
Construction Labor	($5.824)	$0.000	($1.955)
Project Contingency	($1.569)	$0.000	$1.037
Land and Land Rights	($0.450)	$0.000	$0.403
Total Capital Adjustments	($10.940)	$0.000	($14.915)
Operating Labor	$1.171	$0.000	$3.768
Total Annual Property Taxes	($7.132)	$0.000	($14.367)
Other (Insurance, Materials, G&A Etc.)	($2.976)	$0.000	$2.498
Total O&M Adjustments	($8.937)	$0.000	($8.100)
Total Adjustments	**($19.877)**	**$0.000**	**($23.015)**
Other Aggregate Financial Adjustments	($7.667)	$0.000	($5.233)
Adjusted Capacity Payment ($/kW-Year)	**$58.752**	**$58.752**	**$58.752**

Table 14 provides a detailed comparison of each study's financial criteria. Note that the use of levelized principal payments increases revenue requirements by $3.00/kW-Year.

Table 14

CONE CT ISO COMPARISON
FINANCIAL CRITERIA

ISO	PJM	NY	NE	NE
Source	Strategic	Levitan	Concentric	e-Acumen
Annual Inflation Rate	2.5%	3.0%	2.5%	2.5%
Federal Income Tax Rate	35.00%	35.00%	35.00%	35.00%
State Income Tax Rate	9.00%	7.50%	9.38%	7.00%
Total Effective Income Tax Rate	40.85%	39.88%	41.10%	39.55%
Equity Percent	50%	50%	50%	50%
Debt Percent	50%	50%	50%	50%
Cost of Debt	7.00%	7.50%	7.00%	8.78%
Debt Term	20	20	20	15
After-Tax Internal Rate of Return	12.0%	12.5%	12.0%	14.13%
Debt Structure	Mortgage	Fixed Principal	Fixed Principal	Mortgage
Interest Rate During Construction	3.5%	5.0%	3.5%	NA
Project Life	20	20	20	15
MACRS Tax Life - Years	15	15	15	15

8.0 PJM CONE CT Development Schedule

8.1 Schedule Overview

The entire development of a greenfield CT plant from initial concept through site selection, interconnection studies, environmental permits, construction to commercial operation is estimated to be four (4) years.

An owner/developer considering the construction of a CT based power plant would begin by evaluating multiple plant sites. Concurrently with the site selection process the owner/developer would be conducting conceptual plant design and engineering. Key factors in this evaluation are proximity of high pressure natural gas supply, high voltage substations and power transmission lines, water supply, interconnection costs, equipment transportation, air emission thresholds, property cost and local property taxes. The selection of a site is estimated to take nine (9) months. Multiple sites may be evaluated concurrently with multiple PJM Interconnection Feasibility Studies being conducted.

Once a site is selected the property may be purchased or secured with an executed purchase option. Environmental permit applications would be prepared and submitted. The permit approval process, which would include public hearings, is estimated to take twelve (12) months but could extend to eighteen (18) months depending on site complexity and the results of public hearings. Concurrently with the permit process the PJM System Impact Study and the Generation and Transmission Interconnection Facilities Study would be completed. Each study is completed by PJM within a four (4) month period. See Figure 3 below for a Gant Chart on the overall development schedule.

During the permit process the owner/developer would conduct a competitive bidding process for the plant engineering, procurement and construction ("EPC") and select the EPC firm. During this period the owner/developer would also be arranging for the placement of debt and equity for the plant financing. This would include a construction loan and term loan. Financing and approved permits would have to be in place prior to a "Notice to Proceed" given to the EPC firm.

The construction of the Frame CT plant is estimated to take eighteen (18) months to mechanical competition. Three (3) months is estimated for commissioning, startup and testing of the power plant prior to the commercial operation date.

Figure 3

PJM CONE CT PROJECT SCHEDULE

YEAR	1				2				3				4			
QUARTER	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
Conduct Conceptual Plant Design																
Identify Potential Plant Sites																
Submit and Conduct PJM Interconnect Feasibility Studies (30 Day Study)																
Secure Final Plant Site **Milestone**																
Submit and Obtain Air Permits																
PJM System Impact Study (30 Days Submit) (120 Day Study) (30 Day Review)																
PJM Interconnection Facilities Study (120 Day Study w/ 60 Day Review)																
Signed Interconnection Service Agreement With PJM **Milestone**																
Tender Bids and Select EPC Firm																
Tender and Secure Financing																
Financial Closing **Milestone**																
Construction																
Mechanical Completion **Milestone**																
Startup, Commissioning and Testing																
Commercial Operation Date **Milestone**																

9.0 Cost of Recently Constructed CT Projects

9.1 Overview

Using the information available in recent FERC filings for reactive revenues, technical, capital cost and financial information was obtained on nine (9) CT plants which have achieved commercial operation between June 2001 and July 2003. The average capacity of the CT plants is 532 MW and seven of the plants utilized the GE Frame 7FA or the Siemens-Westinghouse equivalent F technology. All plants incorporated multiple CT units, with the capacity of all nine plants totaling 4,800 MW.

9.2 Capital Cost Comparison

The capital cost information obtained from the FERC reactive filings may be found in Table 15 below. The average all-in project capital cost for these power plants was \$399.92/kW. The design of these plants did not include SCR emissions controls and duel fuel capability which adds \$40.00/kW and \$11.00/kW, respectively, for an adjusted capital cost of \$450.92/kW. This capital cost compares closely with the CONE regional cost range found in Table 2 and Table 15 of \$466.04/kW to \$475.30/kW.

Table 15
Recently Constructed CT Plants
Capital Cost Comparison

PJM CONE CT						
Project Name	**Location**	**Owner**	**CT Type**	**Capacity (MW)**	**Capital ($)**	**Cost ($/kW)**
PJM CONE CT	NJ	NA	GE Frame 7FA	336	$156,636,000	**$466.04**
PJM CONE CT	Maryland	NA	GE Frame 7FA	336	$158,527,000	**$471.67**
PJM CONE CT	Illinois	NA	GE Frame 7FA	336	$159,749,000	**$475.30**
FERC FILINGS OF PJM MEMBER FRAME CT PLANTS						
Project Name	**Location**	**Owner**	**CT Type**	**Capacity (MW)**	**Capital ($)**	**Cost ($/kW)**
Rock Springs	Rising Sun, MD	ConEd	GE Frame 7FA	335	$145,908,555	$435.55
Ocean Peaking	Lakewood, NJ	ConEd	GE Frame 7FA	330	$135,110,335	$409.43
Duke Lee County	Lee County, IL	Duke	GE Frame 7EA	640	$254,293,000	$397.33
Rock Springs	Rising Sun, MD	Dominion	GE Frame 7FA	336	$140,604,453	$418.47
Rolling Hills	Wilkesville, Ohio	Dynegy	Siemens-Westinghouse 501F	973	$351,742,000	$361.50
Armstrong	Armstong, Co., PA	Dominion	GE Frame 7FA	600	$234,404,000	$390.67
Pleasants	St. Mary's, WV	Dominion	GE Frame 7FA	300	$119,985,000	$399.95
Twelvepole Creek	Wayne Co., WV	Reliant	GE Frame 7EA	458	$175,520,025	$383.25
Riverside	Catlettsburg, KY	Dynergy	Siemens-Westinghouse 501F	820	$326,178,000	$397.78
Total/Average				532	$1,883,745,368	**$399.32**

9.3 Weighted Average Cost of Capital Comparison

The financial structure of recently constructed CT projects was also obtained from the FERC reactive filings and may be found in Table 16 below. The financial structure of the CONE CT using 50% debt at 7.0% interest rate and 50% equity at a target IRR of 12.0% yields a weighted average cost of capital ("WACC") of 9.5%. The average financial structure of the same nine CT projects listed in Table 16 compares closely with that of the CONE CT. The average debt amount was 49.5% at a rate of 7.3%. The average equity amount was 50.5% at a rate of 11.4%. The overall WACC of all nine projects is 9.25%. This is very close to the 9.5% WACC used in the CONE CT financial structure.

Table 16
Recently Constructed CT Plants
Weighted Average Cost of Capital Comparison

FERC FILINGS OF PJM MEMBER FRAME CT PLANTS									
Project Name	Location	Owner	Debt %	Debt Rate	Preferred %	Preferred Rate	Equity %	Equity Rate	Project WACC
Rock Springs	Rising Sun, MD	ConEd	49.40%	7.63%	4.60%	4.89%	46.00%	11.50%	9.28%
Ocean Peaking	Lakewood, NJ	ConEd	23.60%	7.26%	3.09%	8.42%	73.31%	9.60%	9.01%
Duke Lee County	Lee County, IL	Duke	52.89%	8.10%	5.50%	8.16%	41.60%	12.50%	9.93%
Rising Sun	Rising Sun, MD	Dominion	77.03%	6.42%	0.00%	0.00%	22.97%	10.00%	7.24%
Rolling Hills	Wilkesville, Ohio	Dynegy	54.00%	7.70%	0.00%	0.00%	46.00%	13.50%	10.37%
Armstrong	Armstrong, Co., PA	Dominion	48.00%	7.37%	7.10%	6.57%	44.90%	11.00%	8.94%
Pleasants	St. Mary's, WV	Dominion	48.00%	7.37%	7.10%	6.57%	44.30%	11.00%	8.88%
Twelvepole Creek	Wayne Co., WV	Reliant	46.15%	7.94%	6.41%	6.55%	47.44%	11.75%	9.66%
Riverside	Catlettsburg, KY	Dynegy	46.15%	5.73%	6.41%	5.50%	47.44%	11.75%	8.57%
Average/Total			49.47%	7.28%	4.47%	5.18%	46.00%	11.40%	9.10%

Addendum No. 1

Wood Group Capital Cost Estimates

TABLE OF CONTENTS

Section 1.0 Capital Cost Estimates

The Capital Cost Estimates for Proxy No. 1 (two each GE LM 6000 Gas Turbine Generator Packages) and Proxy No. 2 (two each GE Frame VII FA Gas Turbine Generator Packages) are attached. These cost estimates are based on the following assumptions along with the plants as described on the drawings located in Section 10.

1.1 Location – The location for the plants is estimated to be in Pennsylvania and New Jersey.
1.2 Organized Labor – The cost estimates are based on utilizing Union Labor.
1.3 Work Week – The cost estimates are based on a 50 hour work week
1.4 Freight – Freight for both the Gas Turbine Packages and the Balance of Plant equipment is included.
1.5 Sales Tax – Sales Tax is included for the BOP equipment but not the Gas Turbine Packages. Sales Tax can be added to the cost estimates if you desire.
1.6 Mark Ups – Mark ups for the BOP is shown as 17%. This can range from 12% to 18%. Mark up for the EPC Contractor to furnish a performance wrap on the entire plant is shown as 7%. This can range from 7% to 10%.
Note: These markups can be adjusted if desired.
1.7 Capital Cost Breakdown – The Capital Cost Breakdown is presented in the WGPS Cost Estimating Form. This can be grouped as you desire.
1.8 The Cost Estimates for earthwork and concrete foundations are based on 1500 to 2000 psf soil with no rock or water.
1.9 The cost of any permits, local taxes, fees, etc. is not included.

See attached Cost Breakdowns for Proxy No. 1 and No. 2.

Wood Group Power Solutions, Inc.
Job Description: Two LM 6000's w/ SCR

WOOD GROUP

Two GE LM6000's COST ESTIMATE
(1,000's)

Project Name:	**Strategic PJM Proxy Plant No 1**	**Date:**	**September 9, 2004**
Customer:	**Strategic Energy**	**Job No.**	**#0415 - 1**
Location:	**Pennsylvania**	**Est By:**	WTS
Bid Due Date:	**September 13, 2004**		

I - BALANCE OF PLANT

1.0 Civil - Structural		
1.1 Site Preparation	100	
1.2 Excavation - Fill	71	
1.3 Concrete Foundations	1,092	
1.4 Concrete Piers	-	
1.5 Paving Asphalt - Concrete	207	
1.6 Gravel - Sand	169	
1.7 Structural Steel	170	
1.8 Fencing	80	
1.9 Architectural Treatment	50	
	1,939	1,939
2.0 Buildings		
2.1 Various Bldgs	1,024	
	-	
	-	
	1,024	1,024
3.0 Mechanical		
3.1 Major Mechanical Equipment	8,838	
3.2 Pipelines	-	
3.3 Mechanical Subcontractor	1,635	
	10,473	10,473
4.0 Electrical		
4.1 Major Electrical Equipment	1,610	
4.2 Substation Equipment	1,669	
4.3 Plant Electrical Subcontractor	1,421	
4.4 Substation Subcontractor	341	
	5,042	5,042

Recap of Estimate Cont'd

5.0 Instrumentation		
5.1 Cems	260	
5.2 Plant Instrumentation	205	
	465	465
6.0 DCS System PBX and Public Address		
6.1 Hardware	170	
6.2 Software	197	
	367	367
7.0 Plant Erection		
7.1 Plant Erection	1,669	
	1,669	1,669
8.0 Equipment Rental		
8.2 Plant Equipment Rental	717	
	717	717
9.0 Painting	600	600
10.0 Transportation		-
10.1 Transportation BOP	903	
10.2 LM 6000's Gas Turbine to Job Site	600	
	-	
	1,503	1,503
11.0 Site Costs	300	300
12.0 Engineering		
12.1 EPC Eng Labor	795	
12.2 Local Eng/Arch Labor	40	
12.3 Eng Travel & Per Diem	52	
	886	886
13.0 Project Management		
13.1 Project Mgt Labor	1,236	
13.2 PM Travel & Per Diem	371	
	1,607	1,607

RECAP OF COST CONT'D

14.0 On Site Tech Reps			
14.1 GE	90 @ 2000	180	
14.2 SCR	60 @ 1500	90	
14.3 Chillers	30 @ 1500	45	
14.4 Water Treatment	15 @ 1500	23	
14.5 Fire H2o	15 @ 1500	23	
		361	361
15.0 Testing			
15.1 Concrete		35	
15.2 X-ray		55	
15.3 Environmental Emissions		25	
15.4 Environmental Noise		15	
15.5 Performance and Parasitic		90	
15.6 Black Start, Reliability		10	
15.7 Relay		30	
		260	260
16.0 Legal		30	30
17.0 Insurance		350	350
18.0 Contingency 3%		845	845
19.0 Project Finance Carrying Costs		-	-
	Total Cost of BOP		28,437
	Markup BOP	0.170	4,834
	Total BOP Sales Price w/ FRT		33,272

II - GAS TURBINE PACKAGE (2 Units)

2.1 Two ea GE LM 6000 Gas Turbine Generators w/o Freight w/o Sales Tax			29,000
2.2 Sales Tax		0.08	2,320
	Total Cost 2 Each LM6000		31,320
	Markup LM 6000's	0.07	2,192
	TOTAL SALES PRICE 2 Ea LM6000		33,512

III - TOTAL PLANT SALES PRICE 2 EA. LM6000 & BOP	66,784

Wood Group Power Solutions, Inc.
Job Description: Two GE VII FA's w/SCR

Two VII FA's COST ESTIMATE
(1,000's)

Project Name:	**Strategic PJM Proxy Plant No 2**	**Date:**	**September 9, 2004**
Customer:	**Strategic Energy**	**Quote No:**	**#0415 - 2**
Location:	**Pennsylvania**	**Est By:**	WTS
Bid Due Date:	**September 13, 2004**		

I - BALANCE OF PLANT

1.0 Civil - Structual		
1.1 Site Preparation	150	
1.2 Excavation - Fill	172	
1.3 Concrete Foundations	1,608	
1.4 Concrete Piers	-	
1.5 Paving Asphalt - Concrete	252	
1.6 Gravel - Sand	171	
1.7 Structual Steel	290	
1.8 Fencing	103	
1.9 Architectual Treatment	0	
	2,747	2,747
2.0 Buildings		
2.1 Various Bldgs	872	
	-	
	-	
	872	872
3.0 Mechanical		
3.1 Major Mechanical Equipment	20,598	
3.2 Pipelines	-	
3.3 Mechanical Subcontractor (25,200hrs)	1,578	
	22,175	22,175
4.0 Electrical		
4.1 Major Electrical Equipment	3,027	
4.2 Substation Equipment	3,953	
4.3 Plant Electrical Subcontractor	1,950	
4.4 Substation Substation Subcontractor	468	
	9,399	9,399

Recap of Estimate Cont'd

5.0 Instrumentation		
5.1 Cems	260	
5.2 Plant Instrumentation	500	
	760	760
6.0 DCS System, PBX and Public Address		
6.1 Hardware w/ Tel and Public Add Systm	214	
6.2 Software	186	
	400	400
7.0 Plant Erection		
7.1 Plant Erection	2,384	
	2,384	2,384
8.0 Equipment Rental		
8.2 Plant Equipment Rental	2,872	
	2,872	2,872
9.0 Painting	905	905
10.0 Transportation		-
10.1 Transportation BOP	1,349	
10.2 Transportation of GE VII FA's	1,200	
	-	
	2,549	2,549
11.0 Site Costs	599	599
12.0 Engineering		
12.1 EPC Eng Labor	1,332	
12.2 Local Eng/Arch Labor	105	
12.3 Eng Travel & Per Diem	76	
	1,513	1,513
13.0 Project Management		
13.1 Project Mgt Labor	2,130	
13.2 Travel & Per Diem	425	
	2,555	2,555

RECAP OF COST CONT'D

14.0 On Site Tech Reps			
14.1 GE erection and comn		3,000	
14.2 Control System	70 @ 2000	140	
14.3 Fire Water	30 @ 1500	45	
14.4 Water Treatment	15 @ 1500	23	
14.5 SCR	90 @ 1500	135	
		-	
		3,343	3,343
15.0 Testing			
15.1 Concrete		80	
15.2 Xray		120	
15.3 Environmental Emissions		45	
15.4 Environmental Noise		35	
15.5 Performance and Parasitic		150	
15.6 Black Start, Reliability		15	
15.7 Relay		30	
		475	475
16.0 Legal		50	50
17.0 Insurance and Bonds		500	500
18.0 Contingency 3%		1,700	1,700
19.0 Project Finance Carrying Costs		-	-
	Total Cost of BOP		55,797
	Markup BOP	0.170	9,486
	Total BOP Sales Price w/ FRT		65,283
II - Gas Turbine Package (2 Units)			
2.1 Two ea GE Frame VII FA Gas Turbine Generators w/o Freight w/o Sales Tax			52,000
	Markup on GTG's	0.07	3,640
	Total Sales Price 2 ea Frame VII FA's		55,640
III - Total Plant Sales Price 2ea Frame VII FA's & BOP			120,923

Wood Group Power Solutions, Inc.

Job Description: Two GE VII FA's w/SCR

Two VII FA's COST ESTIMATE
(1,000's)

Project Name:	**Strategic PJM Proxy Plant No 4**	**Date:**	**January 5, 2005**
Customer:	**Strategic Energy**	**Quote No:**	**#0415 - 2**
Location:	**Maryland**	**Est By:**	KKM
Bid Due Date:	**January 5, 2005**		

I - BALANCE OF PLANT

1.0 Civil - Structual		
1.1 Site Preparation	150	
1.2 Excavation - Fill	172	
1.3 Concrete Foundations	1,608	
1.4 Concrete Piers	-	
1.5 Paving Asphalt - Concrete	252	
1.6 Gravel - Sand	171	
1.7 Structual Steel	290	
1.8 Fencing	103	
1.9 Architectual Treatment	0	
	2,747	2,747
2.0 Buildings		
2.1 Various Bldgs	872	
	-	
	-	
	872	872
3.0 Mechanical		
3.1 Major Mechanical Equipment	20,598	
3.2 Pipelines	-	
3.3 Mechanical Subcontractor (25,200hrs)	1,674	
	22,271	22,271
4.0 Electrical		
4.1 Major Electrical Equipment	3,027	
4.2 Substation Equipment	3,953	
4.3 Plant Electrical Subcontractor	2,068	
4.4 Substation Substation Subcontractor	604	
	9,653	9,653

Recap of Estimate Cont'd

5.0 Instrumentation		
5.1 Cems	260	
5.2 Plant Instrumentation	500	
	760	760
6.0 DCS System, PBX and Public Address		
6.1 Hardware w/ Tel and Public Add Systm	214	
6.2 Software	186	
	400	400
7.0 Plant Erection		
7.1 Plant Erection	2,564	
	2,564	2,564
8.0 Equipment Rental		
8.2 Plant Equipment Rental	2,872	
	2,872	2,872
9.0 Painting	905	905
10.0 Transportation		-
10.1 Transportation BOP	1,349	
10.2 Transportation of GE VII FA's	1,200	
	-	
	2,549	2,549
11.0 Site Costs	599	599
12.0 Engineering		
12.1 EPC Eng Labor	1,332	
12.2 Local Eng/Arch Labor	105	
12.3 Eng Travel & Per Diem	76	
	1,513	1,513
13.0 Project Management		
13.1 Project Mgt Labor	2,130	
13.2 Travel & Per Diem	425	
	2,555	2,555

RECAP OF COST CONT'D

14.0 On Site Tech Reps			
14.1 GE erection and comn		3,000	
14.2 Control System	70 @ 2000	140	
14.3 Fire Water	30 @ 1500	45	
14.4 Water Treatment	15 @ 1500	23	
14.5 SCR	90 @ 1500	135	
		-	
		3,343	3,343
15.0 Testing			
15.1 Concrete		80	
15.2 Xray		120	
15.3 Environmental Emissions		45	
15.4 Environmental Noise		35	
15.5 Performance and Parasitic		150	
15.6 Black Start, Reliability		15	
15.7 Relay		30	
		475	475
16.0 Legal		50	50
17.0 Insurance and Bonds		500	500
18.0 Contingency 3%		1,700	1,700
19.0 Project Finance Carrying Costs		-	-
	Total Cost of BOP		56,328
	Markup BOP	0.170	9,576
	Total BOP Sales Price w/ FRT		65,904
II - Gas Turbine Package (2 Units)			
2.1 Two ea GE Frame VII FA Gas Turbine Generators w/o Freight w/o Sales Tax			52,000
	Markup on GTG's	0.07	3,640
	Total Sales Price 2 ea Frame VII FA's		55,640
	No. 2 Oil Capability Adder		3,749
III - Total Plant Sales Price 2ea Frame VII FA's & BOP			$ 125,293

Wood Group Power Solutions, Inc.
Job Description: Two GE VII FA's w/SCR

Two VII FA's COST ESTIMATE
(1,000's)

Project Name:	**Strategic PJM Proxy Plant No 3**	**Date:**	**January 5, 2005**
Customer:	**Strategic Energy**	**Quote No:**	**#0415 - 2**
Location:	**Chicago**	**Est By:**	KKM
Bid Due Date:	**January 5, 2005**		

I - BALANCE OF PLANT

1.0 Civil - Structural		
1.1 Site Preparation	150	
1.2 Excavation - Fill	172	
1.3 Concrete Foundations	1,608	
1.4 Concrete Piers	-	
1.5 Paving Asphalt - Concrete	252	
1.6 Gravel - Sand	171	
1.7 Structual Steel	290	
1.8 Fencing	103	
1.9 Architectual Treatment	0	
	2,747	2,747
2.0 Buildings		
2.1 Various Bldgs	872	
	-	
	-	
	872	872
3.0 Mechanical		
3.1 Major Mechanical Equipment	20,598	
3.2 Pipelines	-	
3.3 Mechanical Subcontractor (25,200hrs)	1,827	
	22,424	22,424
4.0 Electrical		
4.1 Major Electrical Equipment	3,027	
4.2 Substation Equipment	3,953	
4.3 Plant Electrical Subcontractor	2,515	
4.4 Substation Substation Subcontractor	604	
	10,100	10,100

Recap of Estimate Cont'd

5.0 Instrumentation		
5.1 Cems	260	
5.2 Plant Instrumentation	500	
	760	760
6.0 DCS System, PBX and Public Address		
6.1 Hardware w/ Tel and Public Add Systm	214	
6.2 Software	186	
	400	400
7.0 Plant Erection		
7.1 Plant Erection	2,980	
	2,980	2,980
8.0 Equipment Rental		
8.2 Plant Equipment Rental	2,872	
	2,872	2,872
9.0 Painting	905	905
10.0 Transportation		-
10.1 Transportation BOP	1,349	
10.2 Transportation of GE VII FA's	1,200	
	-	
	2,549	2,549
11.0 Site Costs	599	599
12.0 Engineering		
12.1 EPC Eng Labor	1,332	
12.2 Local Eng/Arch Labor	105	
12.3 Eng Travel & Per Diem	76	
	1,513	1,513
13.0 Project Management		
13.1 Project Mgt Labor	2,130	
13.2 Travel & Per Diem	425	
	2,555	2,555

RECAP OF COST CONT'D

14.0 On Site Tech Reps			
14.1 GE erection and comn		3,000	
14.2 Control System	70 @ 2000	140	
14.3 Fire Water	30 @ 1500	45	
14.4 Water Treatment	15 @ 1500	23	
14.5 SCR	90 @ 1500	135	
		-	
		3,343	3,343
15.0 Testing			
15.1 Concrete		80	
15.2 Xray		120	
15.3 Environmental Emissions		45	
15.4 Environmental Noise		35	
15.5 Performance and Parasitic		150	
15.6 Black Start, Reliability		15	
15.7 Relay		30	
		475	475
16.0 Legal		50	50
17.0 Insurance and Bonds		500	500
18.0 Contingency 3%		1,700	1,700
19.0 Project Finance Carrying Costs		-	-
	Total Cost of BOP		57,343
	Markup BOP	0.170	9,748
	Total BOP Sales Price w/ FRT		67,092
II - Gas Turbine Package (2 Units)			
2.1 Two ea GE Frame VII FA Gas Turbine Generators w/o Freight w/o Sales Tax			52,000
	Markup on GTG's	0.07	3,640
	Total Sales Price 2 ea Frame VII FA's		55,640
	No. 2 Oil Capability Adder		3,797
III - Total Plant Sales Price 2ea Frame VII FA's & BOP			126,528

Section 2.0 Cost for Electrical and Gas Interconnect

The cost estimate for the Electrical and Gas Interconnect is not included as we previously stated due to the extreme cost variance based on local factors. The Owner or someone knowledgeable as to local conditions is much better prepared to furnish this.

Section 3.0 Adder for Black Start Capability

The price adder for Black Start Capability for the two options is outlined below:

3.1 Black Start for Proxy No. 1 (two GE LM 6000's)
Cost adder for Black Start utilizing
1 – 750 KW Generator $ 463,000

3.2 Black Start for Proxy No. 2 (two GE Frame VII FA's)
Cost adder for Black Start utilizing
3 – 3 MW Generators $7,440,000

Section 4.0 Adder for No. 2 Diesel Firing

The price adder for equipping the plant with No. 2 diesel fuel capabilities is outlined below:

4.1 Dual fuel capabilities for Proxy No. 1 (two LM 6000's)
Cost adder for dual fuel $1,920,000

4.2 Dual fuel capabilities for Proxy No. 2 (two Frame VII FA's)
Cost adder for dual fuel $3,720,000

III. Cost Estimate for Black Start Capability

			Chicago	Maryland
3.1 Black Start for Proxy No. 1 2ea LM 6000's				
1ea 750 KW Diesel Generator		220		
1 lot Sw Gear		70		
1 lot Installation		80		
		370		
Mark Up	0.25	93		
Sales Price		463		
3.2 Black Start for Proxy No. 2 2ea Fr VIIFA's				
3ea 3 MW Diesel Generators		4800	4800	4800
3ea Sw Gr		900	900	900
3ea Installations		500	580	530
		6200	6280	6230
Mark Up	0.2	1240	1256	1246
Sales Price		7440	7536	7476

IV. Cost Estimate for No 2 Diesel Adder

4.1 Proxy No. 1 2ea LM 6000's				
1 lot Fuel Tank Pumps etc		450		
1 lot Installation		150		
2ea Dual Fuel Adder for GTG		1000		
		1600		
Mark Up	0.2	320		
Sales Price		1920		
4.2 Proxy No. 2 2ea FR VIIFA's				
1 Lot of Fuel Tanks Pumps etc		700	700	700
1 lot Installation		400	464	424
2ea Dual Fuel Adder for GTG		2000	2,000	2,000
		3100	3,164	3,124
Mark Up	0.2	620	632.8	624.8
Sales Price		3720	3,797	3,749

VI. Cost for Wood Group Start Up Services

5.1 The commissioning is included in the BOP pricing of the plant. This also includes the various Tech Reps.

Section 5.0 Construction Draw Down Financial Schedule

5.1 Proxy No. 1 (2ea LM6000 GTG's)

Month 1	10%
Month 2	3%
Month 3	2%
Month 4	2%
Month 5	14%
Month 6	6%
Month 7	3%
Month 8	3%
Month 9	15%
Month 10	2%
Month 11	25%
Month 12	5%
Month 13	3%
Month 14	2%
Month 15	5%

5.2 Proxy No. 2 (2ea Frame VII FA GTG's)

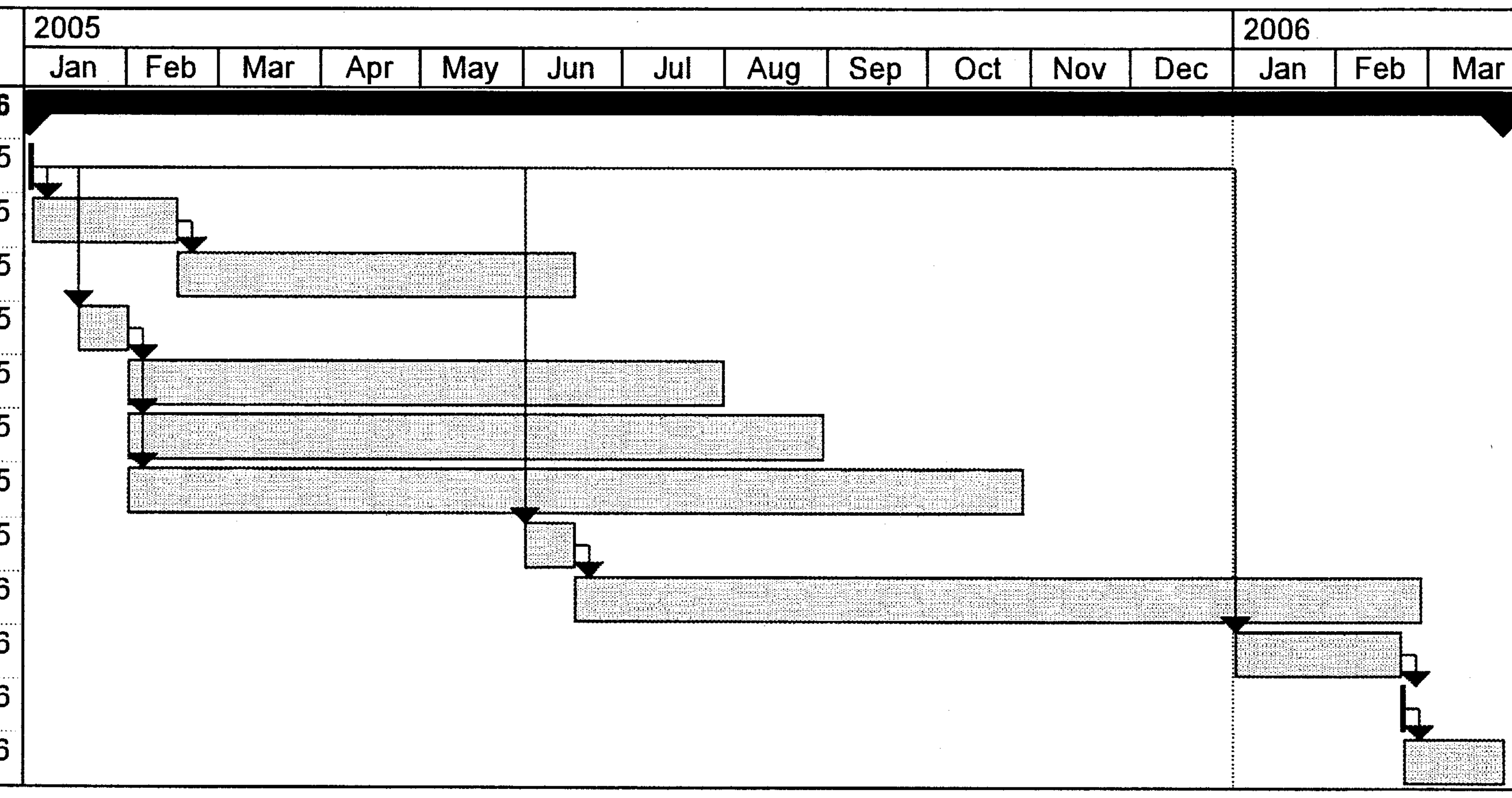
Month 1	10%
Month 2	3%
Month 3	2%
Month 4	2%
Month 5	10%
Month 6	10%
Month 7	3%
Month 8	3%
Month 9	10%
Month 10	2%
Month 11	10%
Month 12	5%
Month 13	8%
Month 14	6%
Month 15	2%
Month 16	7%
Month 17	2%
Month 18	5%

Section 6.0 Schedule

On the following pages please find schedules for Proxy No. 1 and Proxy No. 2.

Strategic PJM
Proxy No. 1 Peaker Plant
2 LM 6000 GTG's
WGPS Project #0415

ID		Task Name	Duration	Start	Finish
1		**Proxy No. 1 (2 LM 6000 GTG's)**	**445 days**	**Mon 1/3/05**	**Thu 3/23/06**
2		Contract Signed	1 day	Mon 1/3/05	Mon 1/3/05
3		Conceptual Engineering	44 days	Tue 1/4/05	Wed 2/16/05
4		Detailed Engineering	120 days	Thu 2/17/05	Thu 6/16/05
5		Procure Major Equipment	15 days	Tue 1/18/05	Tue 2/1/05
6		BOP Equipment to Site	180 days	Wed 2/2/05	Sun 7/31/05
7		SCR's to Site	210 days	Wed 2/2/05	Tue 8/30/05
8		LM 6000 GTG's to Site	270 days	Wed 2/2/05	Sat 10/29/05
9		Mobilize to Site	15 days	Thu 6/2/05	Thu 6/16/05
10		Construction	255 days	Fri 6/17/05	Sun 2/26/06
11		Commission and Startup	50 days	Mon 1/2/06	Mon 2/20/06
12		Sync to Grid	1 day	Tue 2/21/06	Tue 2/21/06
13		Plant Testing	30 days	Wed 2/22/06	Thu 3/23/06



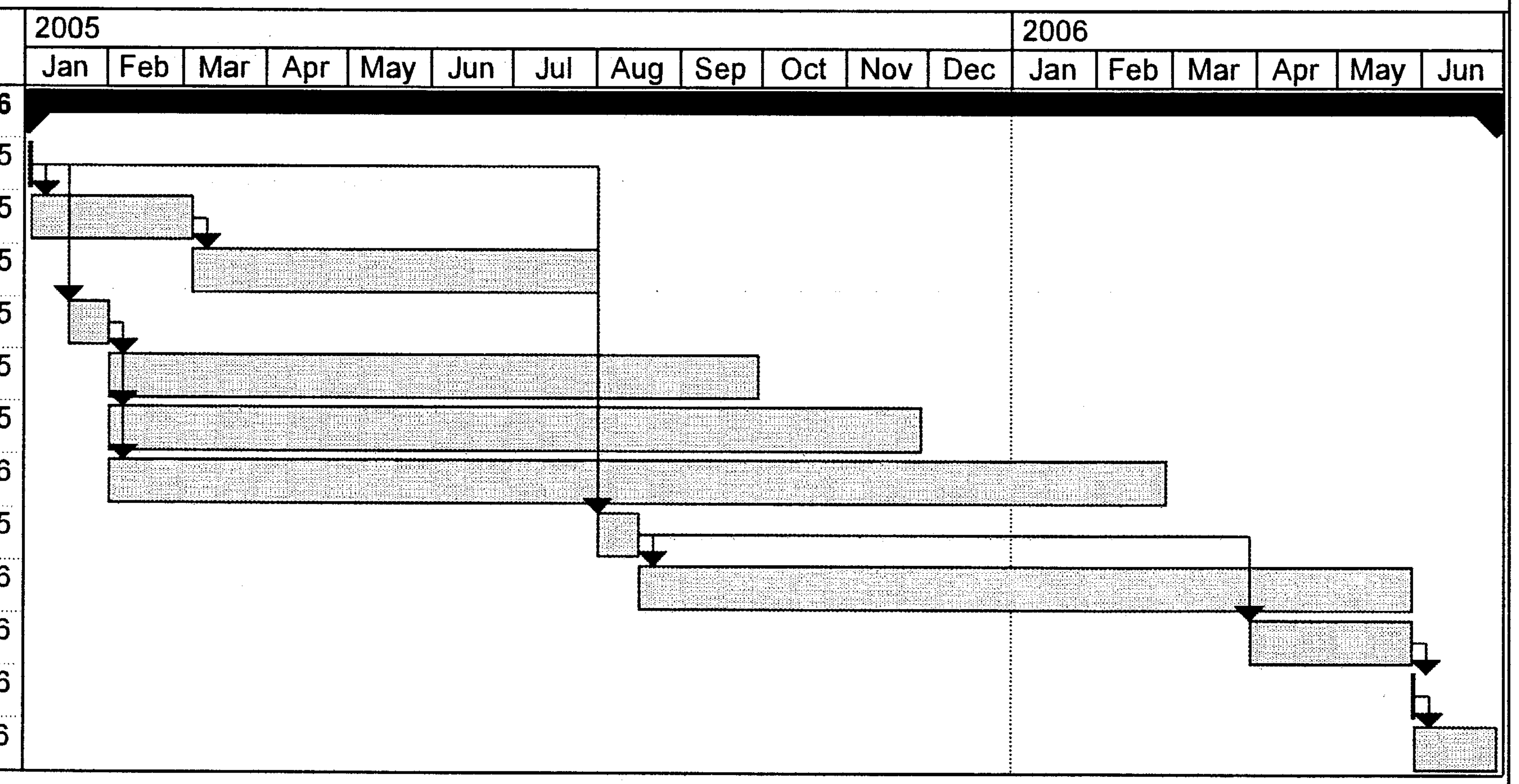
Project: \\Wgusokdc01\shareddata\Pro
Date: Mon 9/13/04

Task | Split | Progress | Milestone | Summary | Rolled Up Task | Rolled Up Split | Rolled Up Milestone | Rolled Up Progress | External Tasks | Project Summary | External Milestone | Deadline

WOOD GROUP

Strategic PJM
Proxy No. 2 Peaker Plant
2 Frame VII FA GTG's
WGPS Project #0415

ID		Task Name	Duration	Start	Finish
1		**Proxy No. 2 (2 Frame VII FA GTG's)**	**542 days**	**Mon 1/3/05**	**Wed 6/28/06**
2		Contract Signed	1 day	Mon 1/3/05	Mon 1/3/05
3		Conceptual Engineering	60 days	Tue 1/4/05	Fri 3/4/05
4		Detailed Engineering	150 days	Sat 3/5/05	Mon 8/1/05
5		Procure Major Equipment	15 days	Tue 1/18/05	Tue 2/1/05
6		BOP Equipment to Site	240 days	Wed 2/2/05	Thu 9/29/05
7		SCR's to Site	300 days	Wed 2/2/05	Mon 11/28/05
8		Frame VII FA GTG's to Site	390 days	Wed 2/2/05	Sun 2/26/06
9		Mobilize to Site	15 days	Tue 8/2/05	Tue 8/16/05
10		Construction	285 days	Wed 8/17/05	Sun 5/28/06
11		Commission and Startup	60 days	Thu 3/30/06	Sun 5/28/06
12		Sync to Grid	1 day	Mon 5/29/06	Mon 5/29/06
13		Plant Testing	30 days	Tue 5/30/06	Wed 6/28/06



Project: \\Wgusokdc01\shareddata\Pro
Date: Mon 9/13/04

Task
Split
Progress
Milestone
Summary
Rolled Up Task
Rolled Up Split
Rolled Up Milestone
Rolled Up Progress
External Tasks
Project Summary
External Milestone
Deadline

Section 7.0 Start Up Services

The cost of Start Up Services by Wood Group Powers Solutions is included in the Cost Estimates of Proxy No. 1 and Proxy No. 2.

Wood Group Power, Inc

Cost Plus O&M Estimates for a 2 X GE 7FA
Power Facility Located at NJ, United States for PJM

Six Year Summary

Annual Escalation 2.5%

Annual O&M	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Service Hours	750	750	750	750	750	750
Labor	$1,267,572	$1,299,261	$1,331,743	$1,365,036	$1,399,162	$1,434,141
Consumables	$68,946	$70,670	$72,436	$74,247	$76,103	$78,006
Chemicals & Water Treatment	$184,854	$189,475	$194,212	$199,068	$204,044	$209,145
Office & Administration	$58,500	$59,963	$61,462	$62,998	$64,573	$66,187
Training	$74,000	$75,850	$77,746	$79,690	$81,682	$83,724
Contract Services	$97,550	$99,989	$102,488	$105,051	$107,677	$110,369
Miscellaneous Operating Expenses	$25,676	$26,318	$26,976	$27,650	$28,341	$29,050
Maintenance & Minor Repairs	$65,214	$66,844	$68,515	$70,228	$71,984	$73,784
Insurance	$19,000	$19,475	$19,962	$20,461	$20,972	$21,497
Freight	$0	$0	$0	$0	$0	$0
Duties & Nationalization	$0	$0	$0	$0	$0	$0
Handling Charge	$57,474	$58,911	$60,384	$61,893	$63,441	$65,027
Other Costs & Credits	$0	$0	$0	$0	$0	$0
Operator Management Fee	$250,000	$256,250	$262,656	$269,223	$275,953	$282,852
Foreign Tax Adjustment on Fee	$0	$0	$0	$0	$0	$0
Sub-Total O&M Only	$2,168,786	$2,223,006	$2,278,581	$2,335,545	$2,393,934	$2,453,782
Gas Turbine Major Maintenance	$0	$0	$0	$0	$0	$0
Total O&M Costs	$2,168,786	$2,223,006	$2,278,581	$2,335,545	$2,393,934	$2,453,782

Mobilization Period (6 Month Period)	Cost
Labor Costs	$633,786
Hiring, Relocation, Administration & Support	$321,527
Equipment & Specialty Tools	$213,300
Office Equipment and Furnishings	$73,325
WGPO Provided Manuals	$86,000
Handling Charge	$42,988
Freight, Duties & Nationalization	$0
Insurance	$9,500
Operator's Fee with Tax Adjustment	$125,000
Total Mobilization Cost	$1,505,426

Estimated Initial Inventory	Cost
Initial Inventory	$2,000,000
Freight	$0
Duties & Nationalization	$0
Total Mobilization Cost	$2,000,000

Wood Group Power, Inc

Cost Plus O&M Estimates for a 2 X LM6000sc
Power Facility Located at NJ, United States for PJM

Six Year Summary

Annual Escalation 2.5%

Annual O&M	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6
Service Hours	750	750	750	750	750	750
Labor	$709,884	$727,631	$745,822	$764,467	$783,579	$803,169
Consumables	$35,456	$36,342	$37,251	$38,182	$39,137	$40,115
Chemicals & Water Treatment	$63,076	$64,653	$66,269	$67,926	$69,624	$71,365
Office & Administration	$52,000	$53,300	$54,633	$55,998	$57,398	$58,833
Training	$43,500	$44,588	$45,702	$46,845	$48,016	$49,216
Contract Services	$122,605	$125,670	$128,812	$132,032	$135,333	$138,716
Miscellaneous Operating Expenses	$43,757	$44,851	$45,972	$47,122	$48,300	$49,507
Maintenance & Minor Repairs	$46,657	$47,823	$49,019	$50,244	$51,501	$52,788
Insurance	$14,000	$14,350	$14,709	$15,076	$15,453	$15,840
Freight	$6,450	$6,611	$6,777	$6,946	$7,120	$7,298
Duties & Nationalization	$0	$0	$0	$0	$0	$0
Handling Charge	$40,705	$41,723	$42,766	$43,835	$44,931	$46,054
Other Costs & Credits	$0	$0	$0	$0	$0	$0
Operator Management Fee	$250,000	$256,250	$262,656	$269,223	$275,953	$282,852
Foreign Tax Adjustment on Fee	$0	$0	$0	$0	$0	$0
Sub-Total O&M Only	$1,428,090	$1,463,792	$1,500,387	$1,537,897	$1,576,344	$1,615,753
Gas Turbine Major Maintenance	$0	$0	$0	$0	$0	$0
Total O&M Costs	$1,428,090	$1,463,792	$1,500,387	$1,537,897	$1,576,344	$1,615,753

Mobilization Period (6 Month Period)	Cost
Labor Costs	$295,787
Hiring, Relocation, Administration & Support	$315,403
Equipment & Specialty Tools	$196,300
Office Equipment and Furnishings	$71,725
WGPO Provided Manuals	$72,000
Handling Charge	$44,260
Freight, Duties & Nationalization	$12,971
Insurance	$5,833
Operator's Fee with Tax Adjustment	$125,000
Total Mobilization Cost	$1,139,279

Estimated Initial Inventory	Cost
Initial Inventory	$535,000
Freight	$18,725
Duties & Nationalization	$0
Total Mobilization Cost	$553,725

Section 9.0 Performance Tables and Curves

On the following pages please find:

9.1 Performance Calculation Proxy Plant No. 1 (2- LM6000) and Plant No. 2 (2-Frame 7FA)

9.2 Proxy Plant No. 1, Power vs. Compressor Inlet Temperature, Chilled Inlet

9.3 Proxy Plant No. 1, Power Output vs. Heat Rate

9.4 Proxy Plant No. 2, Power vs. Compressor Inlet Temperature, Chilled Inlet

9.5 Proxy Plant No. 2, Heat Rate vs. Plant Output

Exhibit IMM-00011
Docket No. EL21-91-000, -003

Performance Calculations, PJM Strategic Energy
Project 0415
10-Sep-04

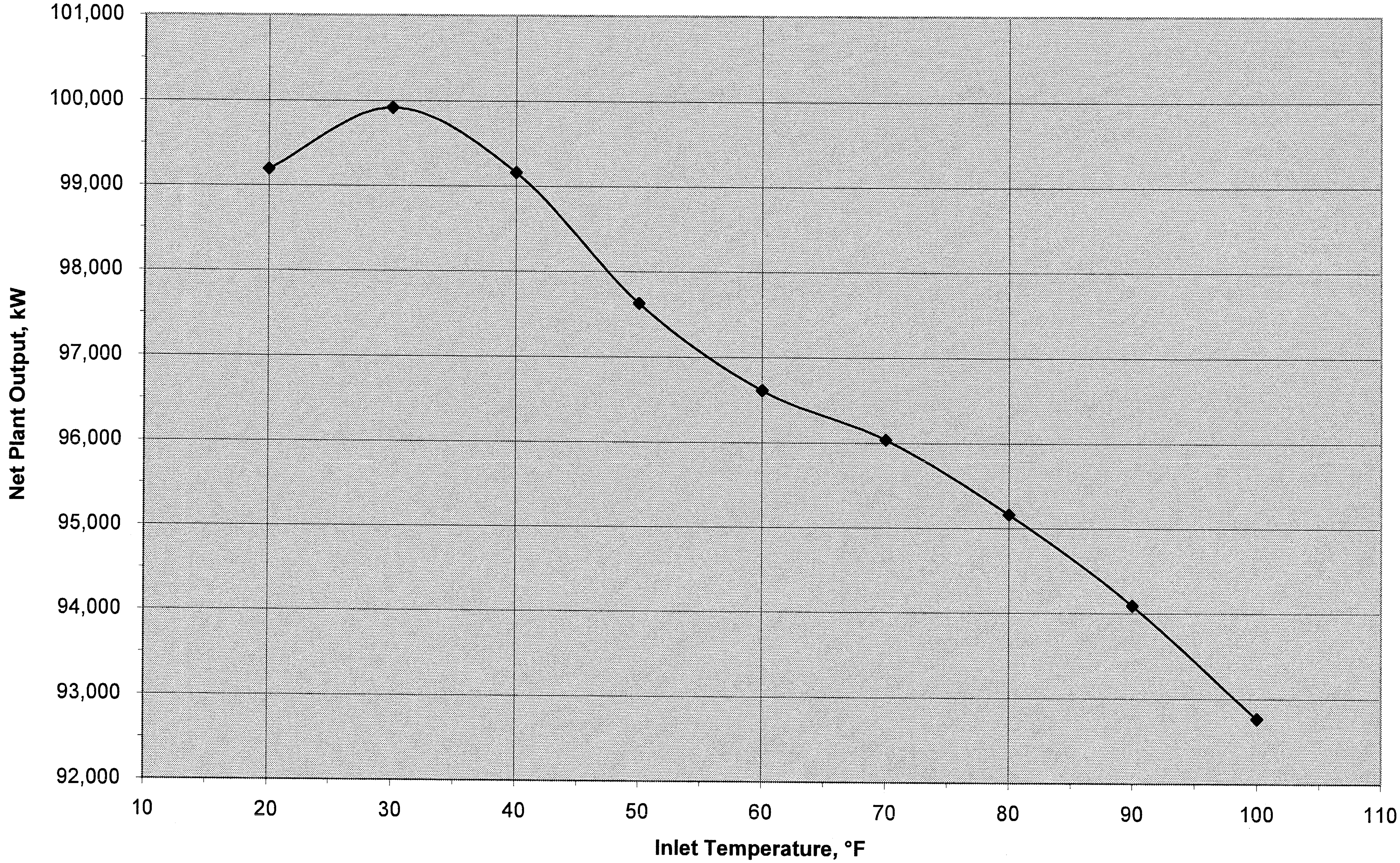
Proxy Plant No. 1 - 2 LM6000 in Simple Cycle, Chilled Inlet

Item	Temperature, °F								
	20	30	40	50	60	70	80	90	100
Output, Single unit, Kw	50,484	50,848	50,466	49,701	49,358	49,358	49,358	49,358	49,358
Heat rate, btu/kw	8,367	8,410	8,501	8,532	8,531	8,531	8,531	8,531	8,531
Plant Output, Gross, kW	100,968	101,696	100,932	99,402	98,716	98,716	98,716	98,716	98,716
Parasitic Load, kW,	1,774	1,774	1,774	1,774	1,774	1,774	1,774	1,774	1,774
Chiller Load, Tons					408	1,128	2,223	3,563	5,223
Chiller Load, kW					326	902	1,778	2,850	4,178
Total Parasitic Load, kW	1,774	1,774	1,774	1,774	2,100	2,676	3,552	4,624	5,952
Net Plant Heat Rate, btu/kW	8,517	8,559	8,653	8,687	8,716	8,769	8,849	8,950	9,078
Net Plant Output,. kW	99,194	99,922	99,158	97,628	96,616	96,040	95,164	94,092	92,764

Proxy Plant No. 2 - 2 Frame 7FA in Simple Cycle, Chilled Inlet

Item	Temperature, °F								
	20	30	40	50	60	70	80	90	100
Output, Single unit, Kw	183,323	180,938	177,701	174,464	174,464	174,464	174,464	174,464	174,464
Heat rate, btu/kw	9,388	9,383	9,402	9,421	9,421	9,421	9,421	9,421	9,421
Plant Output, Gross, kW	366,646	361,876	355,402	348,928	348,928	348,928	348,928	348,928	348,928
Parasitic Load, kW,	1,953	1,953	1,953	1,953	1,953	1,953	1,953	1,953	1,953
Chiller Load, Tons					1,418	3,923	7,728	12,385	18,160
SCR Cooling Air Fan Load, kW	1,004	1,026	1,048	1,070	1,092	1,114	1,138	1,162	1,188
Chiller Load, kW					1,134	3,138	6,182	9,908	14,528
Total Parasitic Load, kW	2,957	2,979	3,001	3,023	4,179	6,205	9,273	13,023	17,669
Net Plant Heat Rate, btu/kW	9,464	9,461	9,482	9,503	9,535	9,592	9,678	9,786	9,924
Net Plant Output,. kW	363,689	358,897	352,401	345,905	344,749	342,723	339,655	335,905	331,259

Proxy Plant No. 1- 2 LM6000PC, Power vs. Compressor Inlet Temperature, Chilled Inlet



Proxy Plant No. 1 - 2 LM6000, Power Output vs. Heat Rate

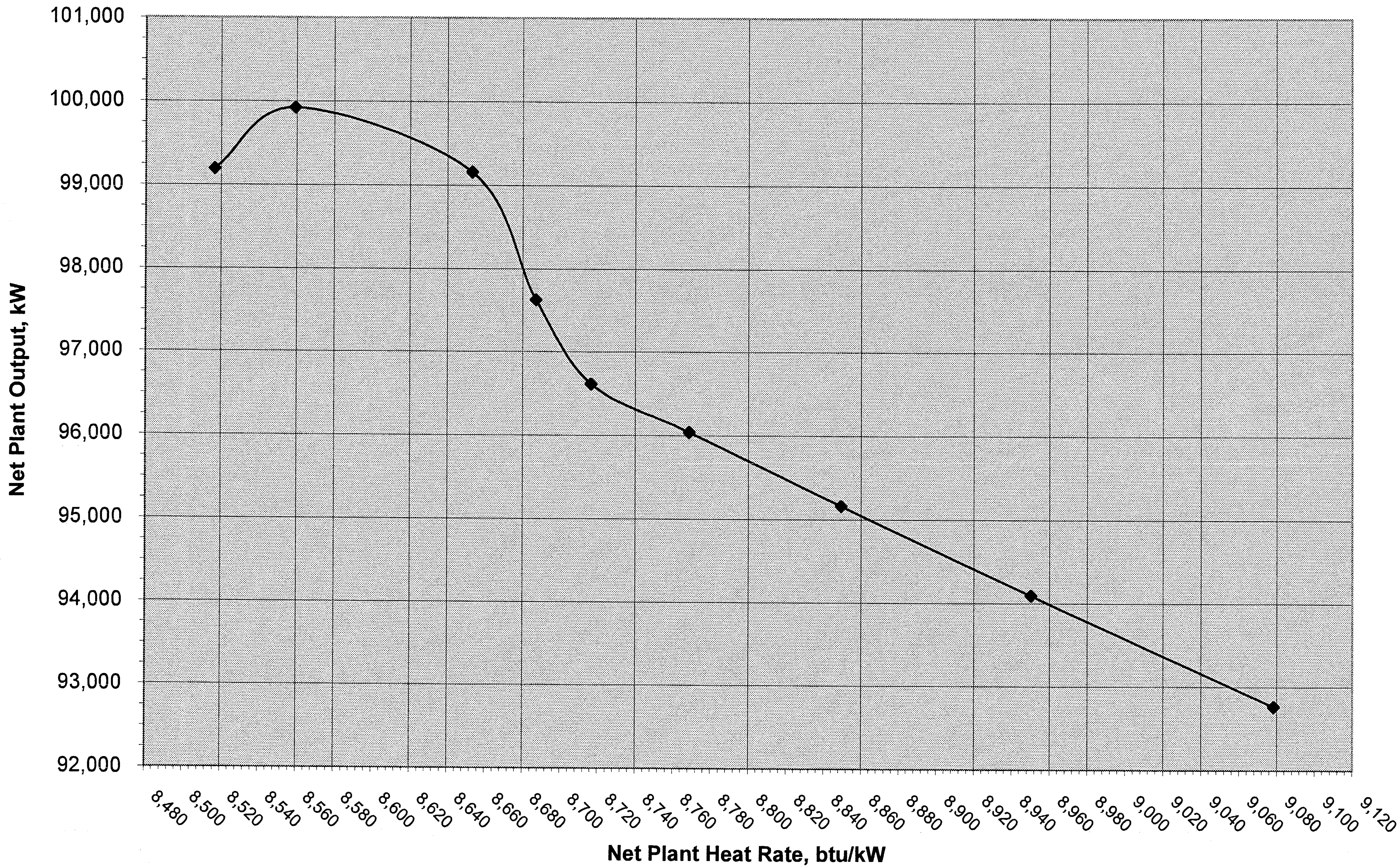
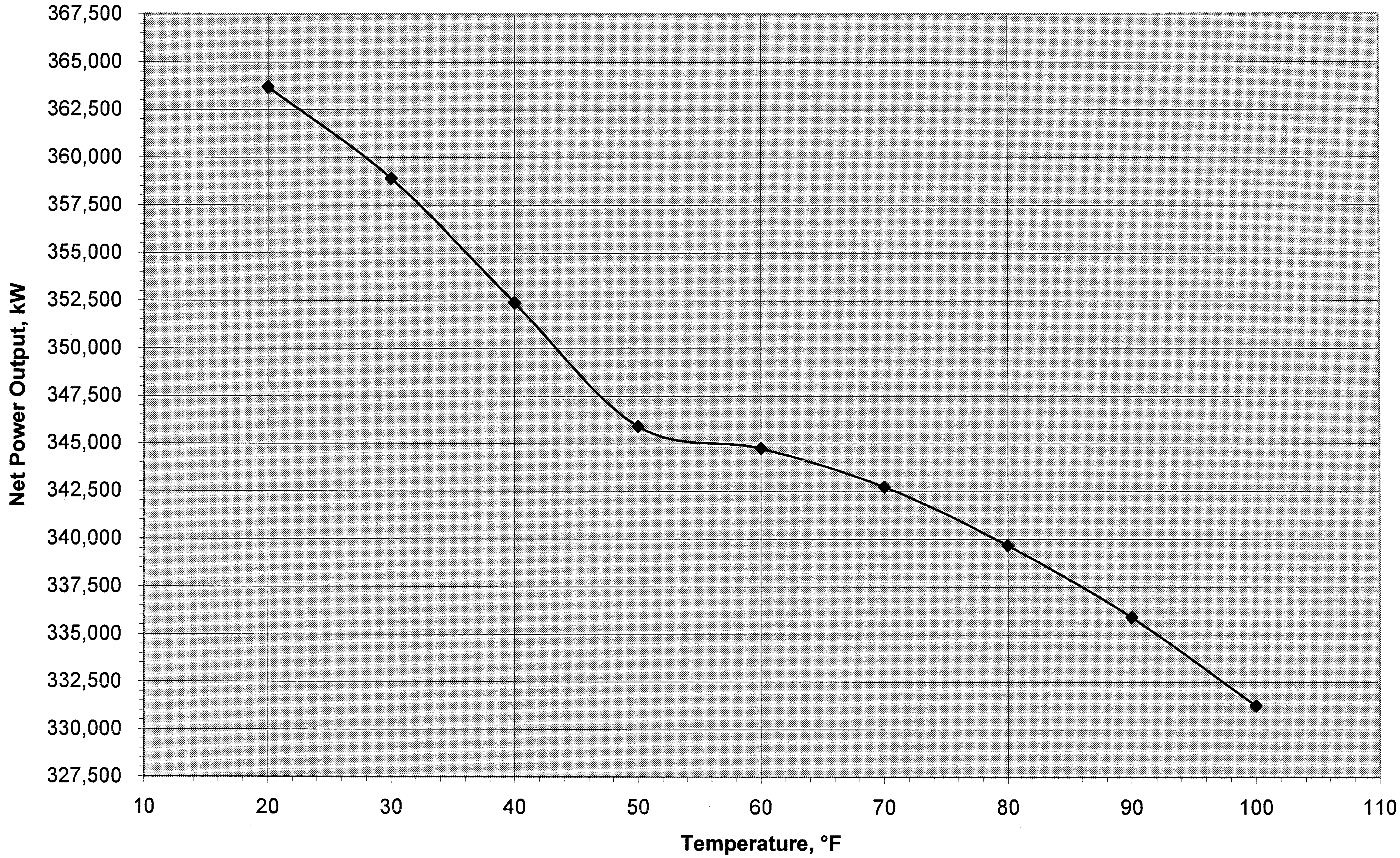
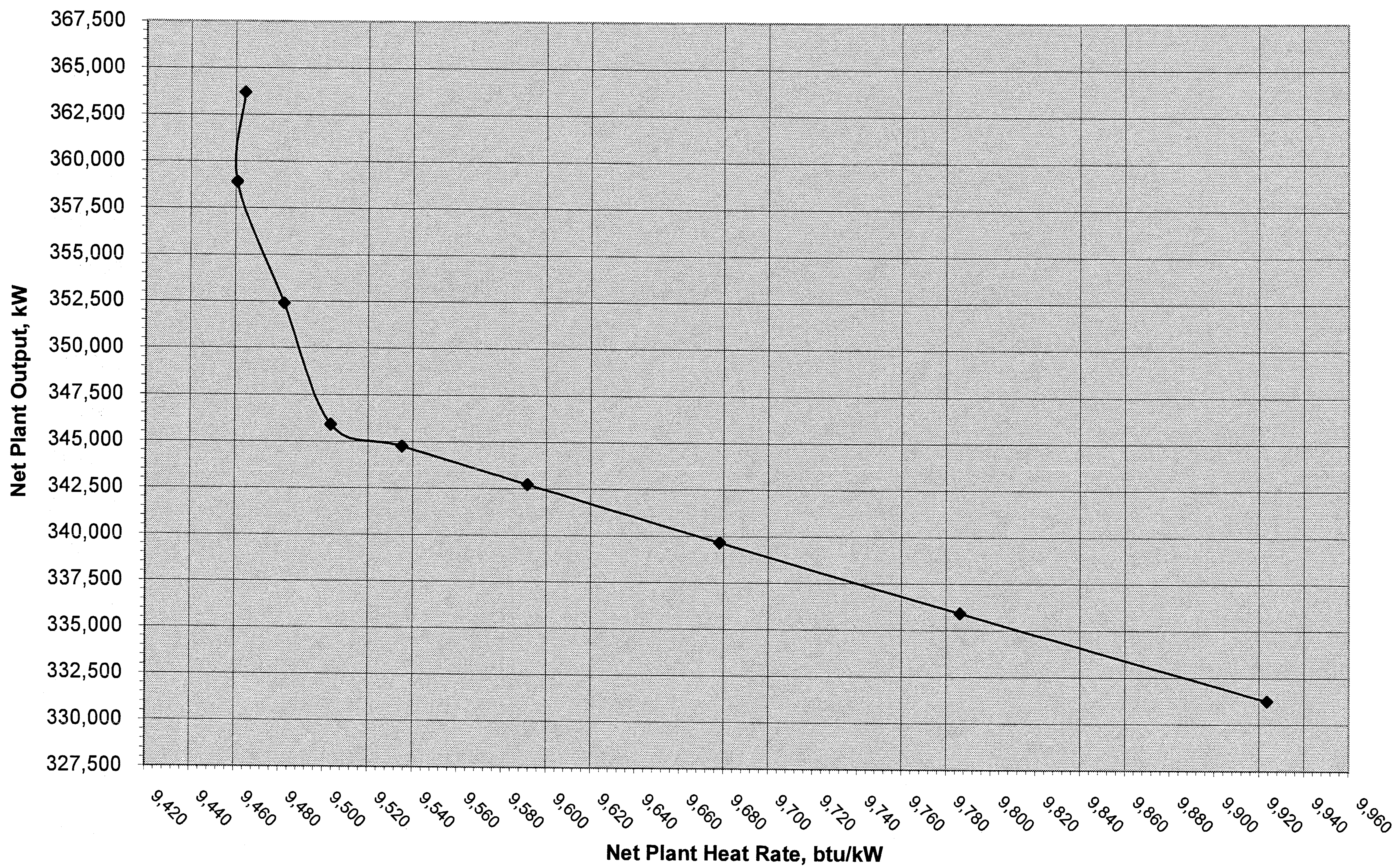


Exhibit IMM-00011
Docket No. EL21-91-000, -003

Proxy Plant No. 2 - 2 Frame 7FA, Power vs. Compressor Inlet Temperature, Chilled Inlet



Proxy Plant No. 2 - 2 Frame 7FA, Heat Rate vs. Plant Output

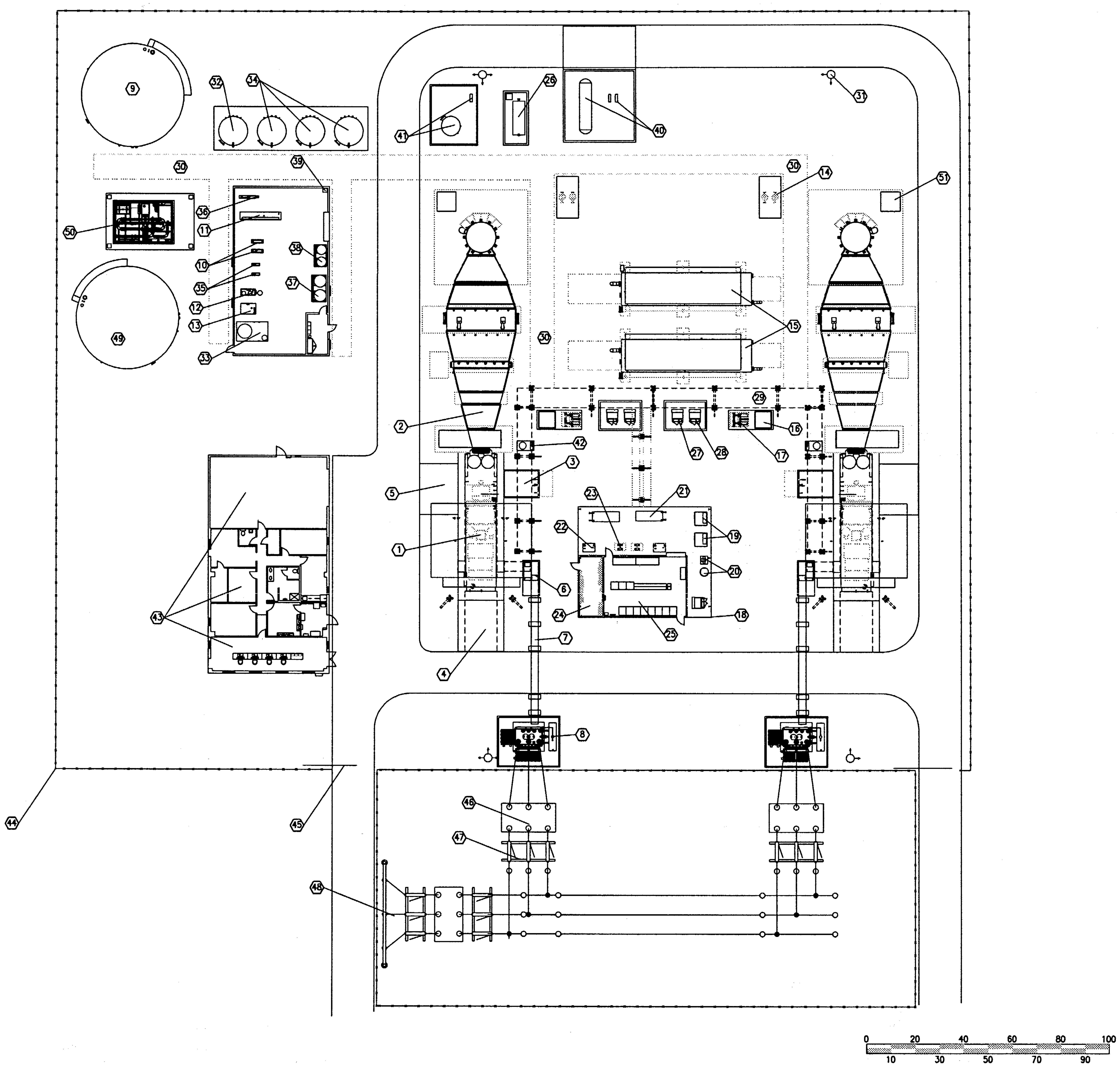


Section 10.0 Drawings

Drawing Number	Title
415-10-100 Sh 1	Plot Plan Proxy No. 1
415-10-200 Sh 1	Plot Plan Proxy No. 2
415-50-100 Sh 1	Process Flow Diagram LM6000's
415-50-100 Sh 2	Process Flow Diagram LM6000's
415-50-200 Sh 1	Process Flow Diagram Frame VII FA's
415-50-200 Sh 2	Process Flow Diagram Frame VII FA's
415-60-100 Sh 1	One Line Diagram LM6000's
415-60-100 Sh 2	One Line Diagram LM6000's
415-60-100 Sh 3	One Line Diagram LM6000's
415-60-200 Sh 1	One Line Diagram Frame VII FA's
415-60-200 Sh 2	One Line Diagram Frame VII FA's
415-60-200 Sh 3	One Line Diagram Frame VII FA's

LEGEND OF SYMBOLS:

1. LM6000 GAS TURBINE GENERATORS
2. SCR
3. AUX SKIDS
4. GEN REMOVAL PADS
5. TURBINE REMOVAL PADS
6. 15 KV SWITCHGEAR
7. 15 KV CABLE TRAY
8. STEP-UP TRANSFORMERS
9. RAW WATER TANK (500,000 GALS)
10. RAW WATER FORWARDING PUMPS
11. RO UNIT
12. SOFTENER SKID
13. EDI SKID
14. FUEL GAS / FILTER SKIDS
15. CHILLER / COOLING TOWER ASSEMBLIES
16. CHEMICAL INJECTION SKIDS
17. LUBE OIL COOLING SKIDS
18. CONTROL / UTILITY BUILDING
19. AIR COMPRESSOR PACKAGE
20. DRYER & RECEIVER TANK
21. WATER INJECTION SKIDS
22. SPRINT SKIDS
23. DEMIN FILTER SKIDS
24. BATTERY ROOM (BATTERIES & CHARGERS)
25. TCP / MCC AREA
26. OILY WATER SEPARATOR
27. AUX TRANSFORMERS (480 V)
28. AUX TRANSFORMERS (4160 V)
29. PIPE RACKS
30. PIPE WAYS
31. LIGHT POLES
32. RO STAORAGE TANK (21,000 GALS)
33. RO FORWARDING PUMPS
34. DEMIN STORAGE TANK (3 - 21,000 GALS)
35. DEMIN FORWARDING PUMPS
36. IN LINE FILTER SKID
37. MULTI MEDIA SKID
38. ACTIVATED CARBON SKID
39. EYE WASH STATION
40. AMMONIA STORAGE & OFF LOAD AREA (15,000 GALS)
41. WASTE OIL TANK & OFF LOAD PUMP (5,000 GALS)
42. CONDENSATE TANK & PUMP
43. CONTROL ROOM, OFFICE AREA, & WAREHOUSE
44. FENCE
45. GATE
46. SF6 BREAKER
47. DISCONNECT
48. DEADEND TOWER
49. FIREWATER TANK (350,000 GALS)
50. FIREWATER SKID
51. CEMS



WOOD GROUP POWER SOLUTIONS, INC
GENERAL ARRANGEMENT PLOT PLAN
2 LM-6000S W/ SCR
STRATEGIC PJM PROXY PLANT NO. 1
PHILADELPHIA PENNSYLVANIA

DRAWN	LES	9/8/04	
CHECK			
DESIGN			
PROJ ENGR			
PROJ MGR			
QA MGR		JOB. NO. 0415	DWG NO. 10-100
SCALE	1"=20'	SIZE E	SH NO. 1	REV A

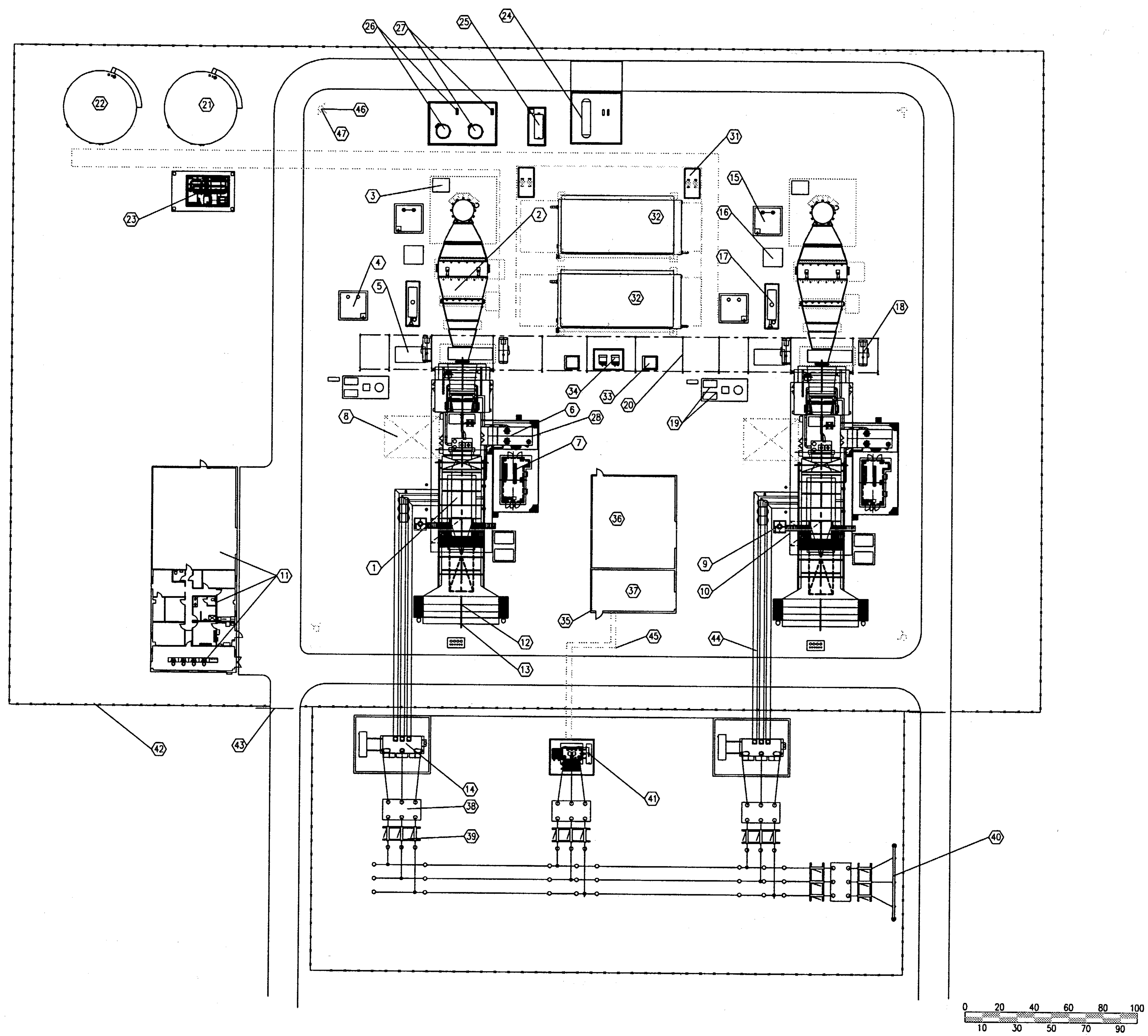
REVISIONS

NO.	DATE	BY	CHK'D	APP'D	DESCRIPTION

WOOD GROUP

SYMBOLS LEGENDS

1. GE FRAME 7
2. SCR
3. CEMS
4. OILY WATER SUMP
5. WATER WASH SKID
6. ACCESSORY MODULE
7. PEECC
8. ROTOR REMOVAL AREA
9. COOLER REMOVAL AREA
10. ROTOR REMOVAL AREA
11. CONTROL , OFFICE & WAREHOUSE BUILDING
12. REMOVABLE WALL PANEL
13. CTG AIR INLET
14. STEP-UP XFMR
15. WASTE WATER SUMP
16. GAS FILTER SKID
17. GAS HEATER
18. CO2 TANK
19. AIR COMPRESSORS
20. PIPE RACK
21. FIRE WATER TANK (350,000 GALS)
22. RAW WATER STORAGE (500,000 GALS)
23. FIRE WATER SKID W/ SHED
24. AMMONIA STORAGE & OFF LOAD AREA (15,000 GALS)
25. OILY WATER SEPARATOR
26. WASTE OIL TANK & OFF LOAD PUMP (5,000 GALS)
27. WASTE WATER TANK & OFF LOAD PUMP (5,000 GALS)
28. FIN FANS FOR LUBE OIL COOLING
29. SURGE TANK
30. COOLING WATER FORWARDING PUMPS
31. NATURAL GAS FILTER / SCRUBBER
32. CHILLER / COOLING TOWER ASSEMBLY
33. CHEMICAL INJECTION
34. AUX TRANSFORMER
35. UTILITY BUILDING
36. PUMP ROOM & MISC EQUIPMENT
37. ELECTRICAL ROOM
38. SF6 BREAKER
39. DISCONNECT
40. DEAD END TOWER
41. AUX TRANSFORMER
42. FENCE
43. GATE
44. ISO PLASE BUS
45. UNDERGROUND DUCT BANK
46. 1000 WATT LIGHTS
47. 50' LIGHT POLES



NO.	DATE	BY	CHK'D	APP'D	DESCRIPTION

REVISIONS

DRAWN	LES	9/12/04
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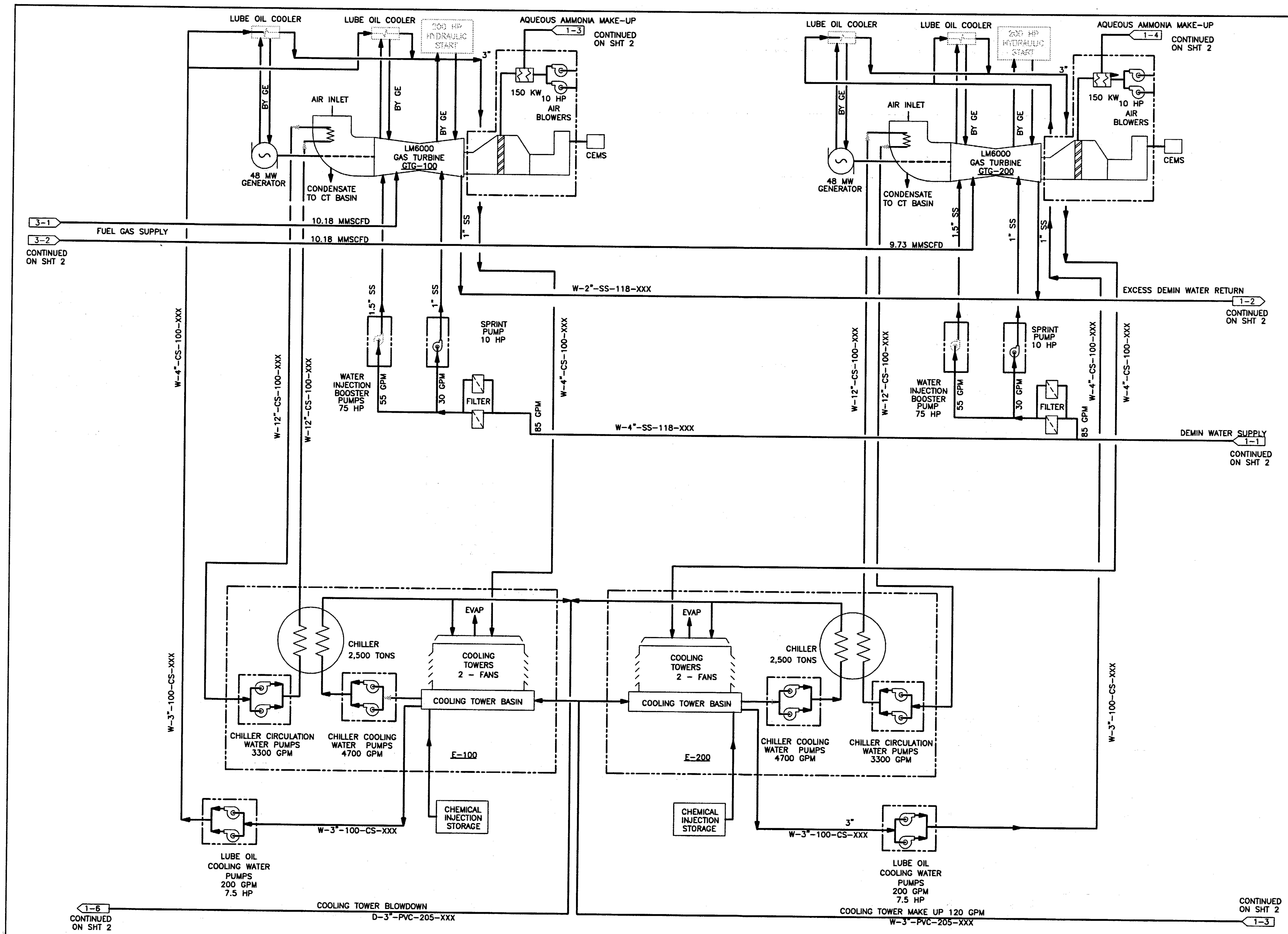
DESIGN		
PROJ ENGR		
PROJ MGR		
QA MGR		
SCALE	1"=30'	SIZE E

WOOD GROUP POWER SOLUTIONS, INC

GENERAL ARANGEMENT PLAN
2 GE FRAME 7FA W/ SCR
STRATEGIC PJM PROXY PLANT NO. 2
PHILADELPHIA PENNSYLVANIA

JOB. NO.	DWG NO.	SH NO.	REV
0415	10-200	1	A

WOOD GROUP



WOOD GROUP POWER SOLUTIONS, INC

PROCESS FLOW DIAGRAM
LM6000 UNITS GTG-100, GTG-200,
STRATEGIC PJM PROXY PLANT NO. 1

PHILADELPHIA PENNSYLVANIA

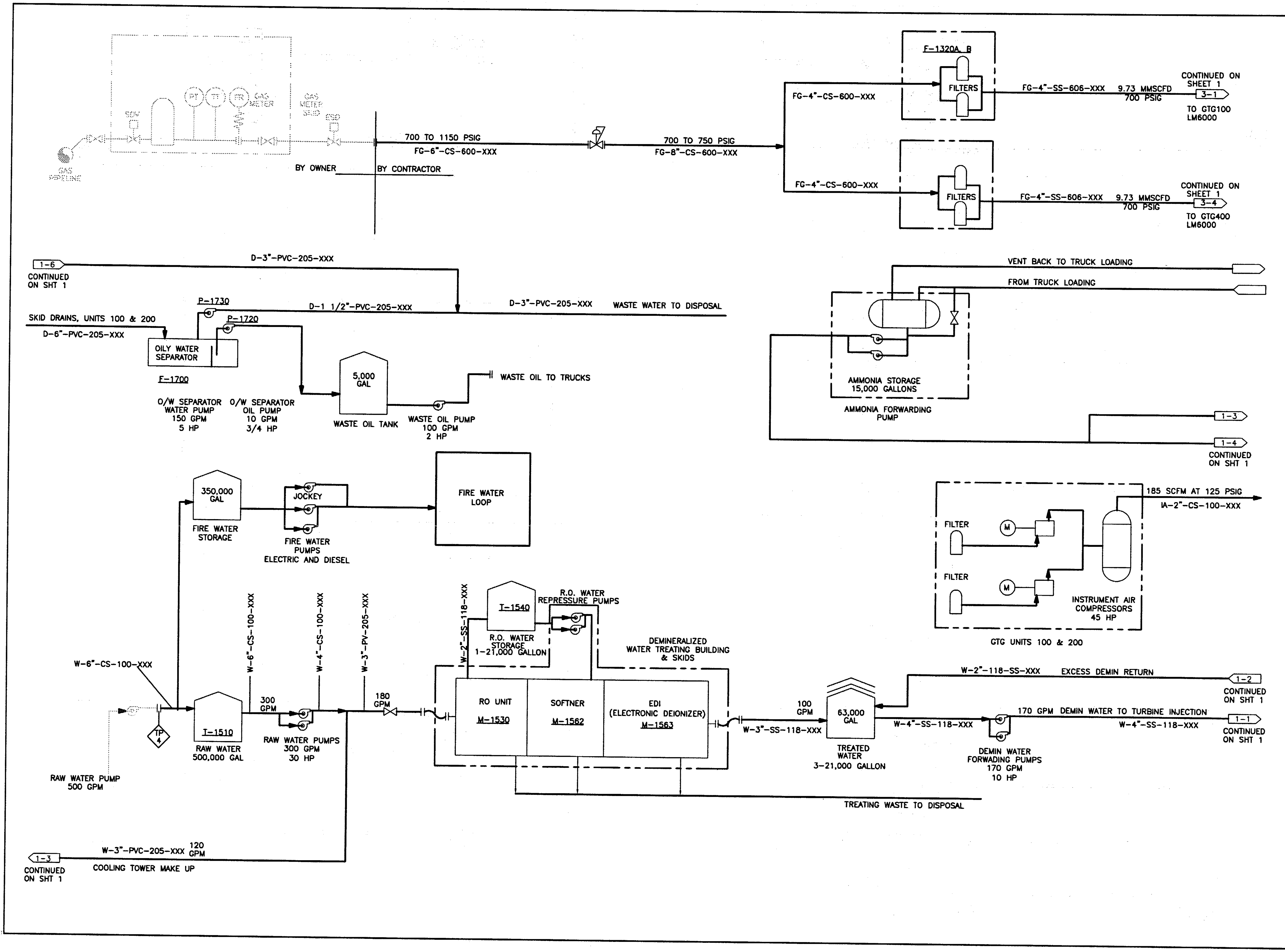
JOB. NO.	DWG NO.	SH NO.	REV
0415	50-100	1	A

DRAWN	RWC	9/8/04
CHECK		
DESIGN		
PROJ ENGR		
PROJ MGR		
QA MGR		
SCALE	NONE	SIZE E

REVISIONS

NO.	DATE	BY	CHK'D	APP'D	DESCRIPTION
A	9/8/04	RWC			ISSUED FOR TSD

WOOD GROUP



NO.	DATE	BY	CHK'D	APP'D	DESCRIPTION
A	9/8/04	RWC			ISSUED FOR TSD

REVISIONS

DRAWN	RWC	9/8/04
CHECK		
DESIGN		
PROJ ENGR		
PROJ MGR		
QA MGR		
SCALE	NONE	SIZE E

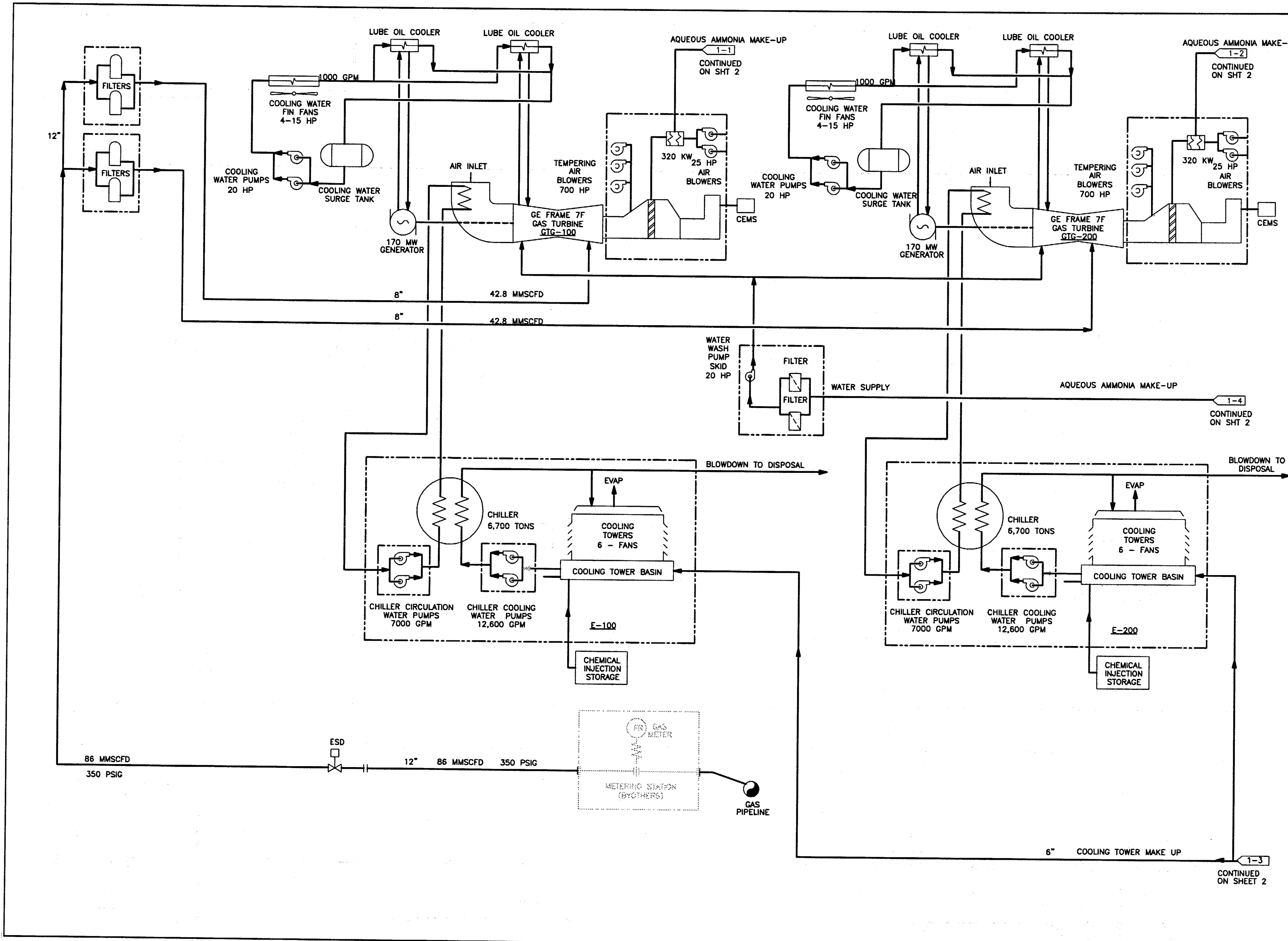
WOOD GROUP POWER SOLUTIONS, INC

PROCESS FLOW DIAGRAM
UTILITIES – WATER, AIR, WASTE HANDLING
STRATEGIC PJM PROXY PLANT NO. 1

PHILADELPHIA PENNSYLVANIA

JOB. NO.	DWG NO.	SH. NO.	REV
0415	50-100	2	A

WOOD GROUP



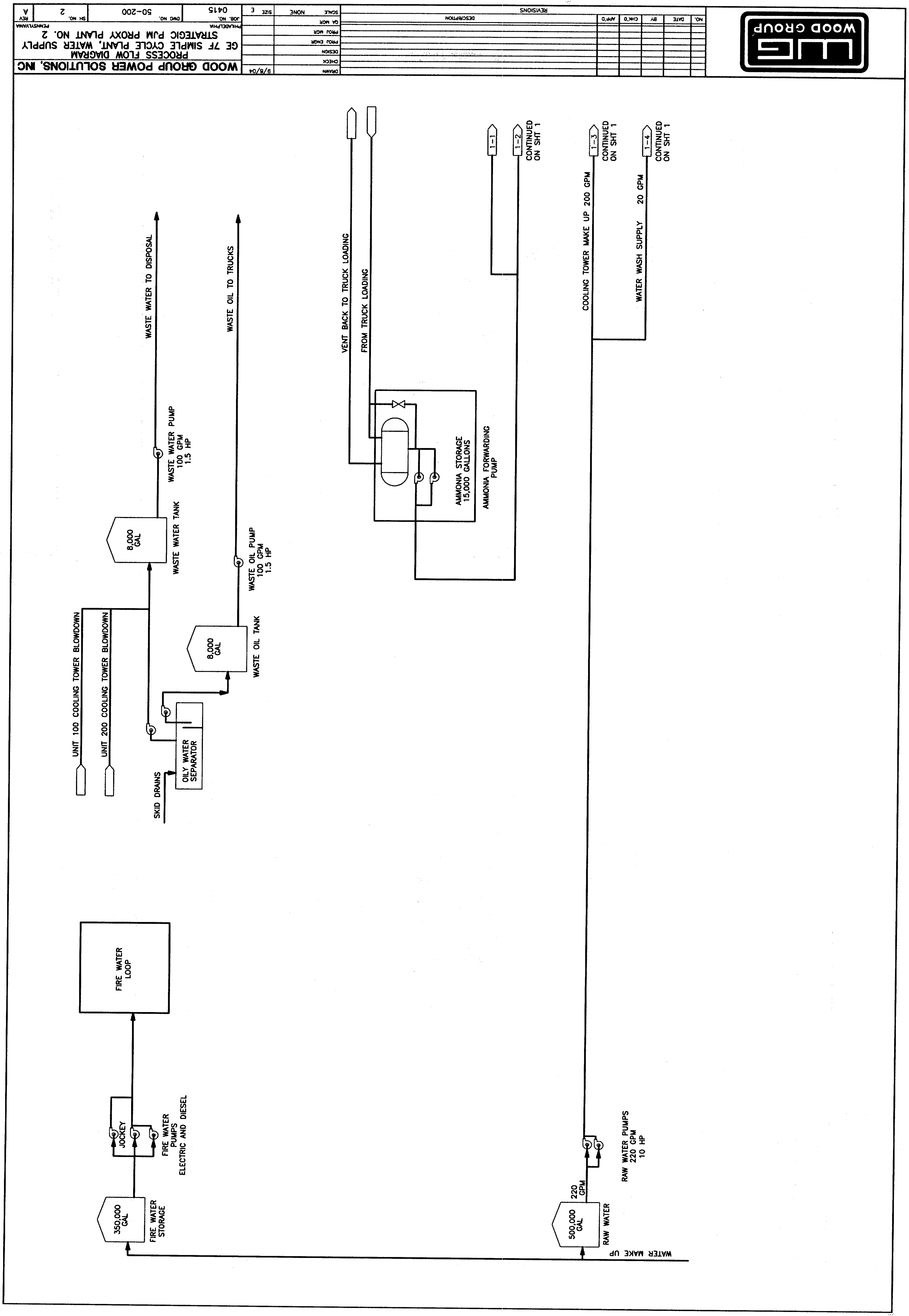
WOOD GROUP POWER SOLUTIONS, INC
PROCESS FLOW DAGRAM
GE FRAME 7F PLANT GTG100, GTG200
STRATEGIC PJM PROXY PLANT NO. 2
PHILADELPHIA PENNSYLVANIA

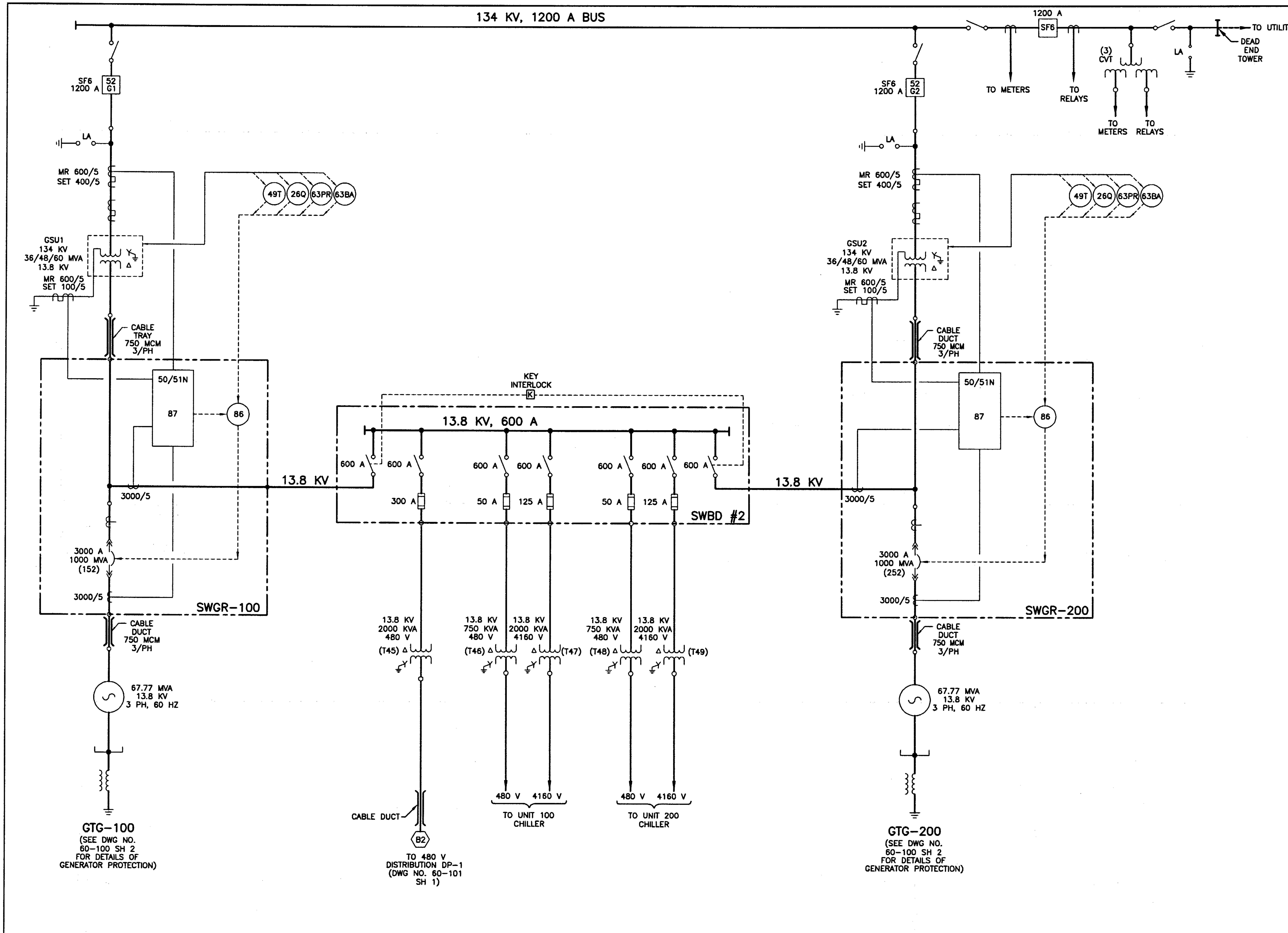
DRAWN	9/8/04
CHECK	
DESIGN	
PROJ ENGR	
PROJ MGR	
QA MGR	
SCALE	NONE
SIZE	E
JOB. NO.	0415
DWG NO.	50-200
SH NO.	1
REV	A

REVISIONS

NO.	DATE	BY	CHK'D	APP'D	DESCRIPTION
A	9/8/04	RWC			ISSUED FOR TSD

WOOD GROUP


WOOD GROUP POWER SOLUTIONS, INC
PROCESS FLOW DIAGRAM
GE 7F SIMPLE CYCLE PLANT, WATER SUPPLY
STRATEGIC PJM PROXY PLANT NO. 2
PHILADELPHIA
PENNSYLVANIA
JOB. NO. 0415
DWG NO. 50-200
SH NO. 2
REV A
SCALE NONE
SIZE E
DRAWN 9/8/04
CHECK
DESIGN
PROJ ENGR
PROJ MGR
QA MGR
REVISIONS
NO. DATE BY CHK'D APP'D DESCRIPTION
WOOD GROUP
WASTE WATER TO DISPOSAL
WASTE OIL TO TRUCKS
VENT BACK TO TRUCK LOADING
FROM TRUCK LOADING
1-1
1-2
CONTINUED ON SHT 1
1-3
CONTINUED ON SHT 1
1-4
CONTINUED ON SHT 1
COOLING TOWER MAKE UP 200 GPM
WATER WASH SUPPLY 20 GPM
WASTE WATER PUMP
100 GPM
1.5 HP
8,000 GAL
WASTE WATER TANK
AMMONIA STORAGE
15,000 GALLONS
AMMONIA FORWARDING PUMP
WASTE OIL PUMP
100 GPM
1.5 HP
8,000 GAL
WASTE OIL TANK
UNIT 100 COOLING TOWER BLOWDOWN
UNIT 200 COOLING TOWER BLOWDOWN
OILY WATER SEPARATOR
SKID DRAINS
FIRE WATER LOOP
JOCKEY
FIRE WATER PUMPS
ELECTRIC AND DIESEL
350,000 GAL
FIRE WATER STORAGE
RAW WATER PUMPS
220 GPM
10 HP
220 GPM
500,000 GAL
RAW WATER
WATER MAKE UP



WOOD GROUP POWER SOLUTIONS, INC

ONE LINE DIAGRAM
LM-6000 UNIT 100 & UNIT 200
STRATEGIC PJM PROXY PLANT NO. 1

PHILADELPHIA PENNSYLVANIA

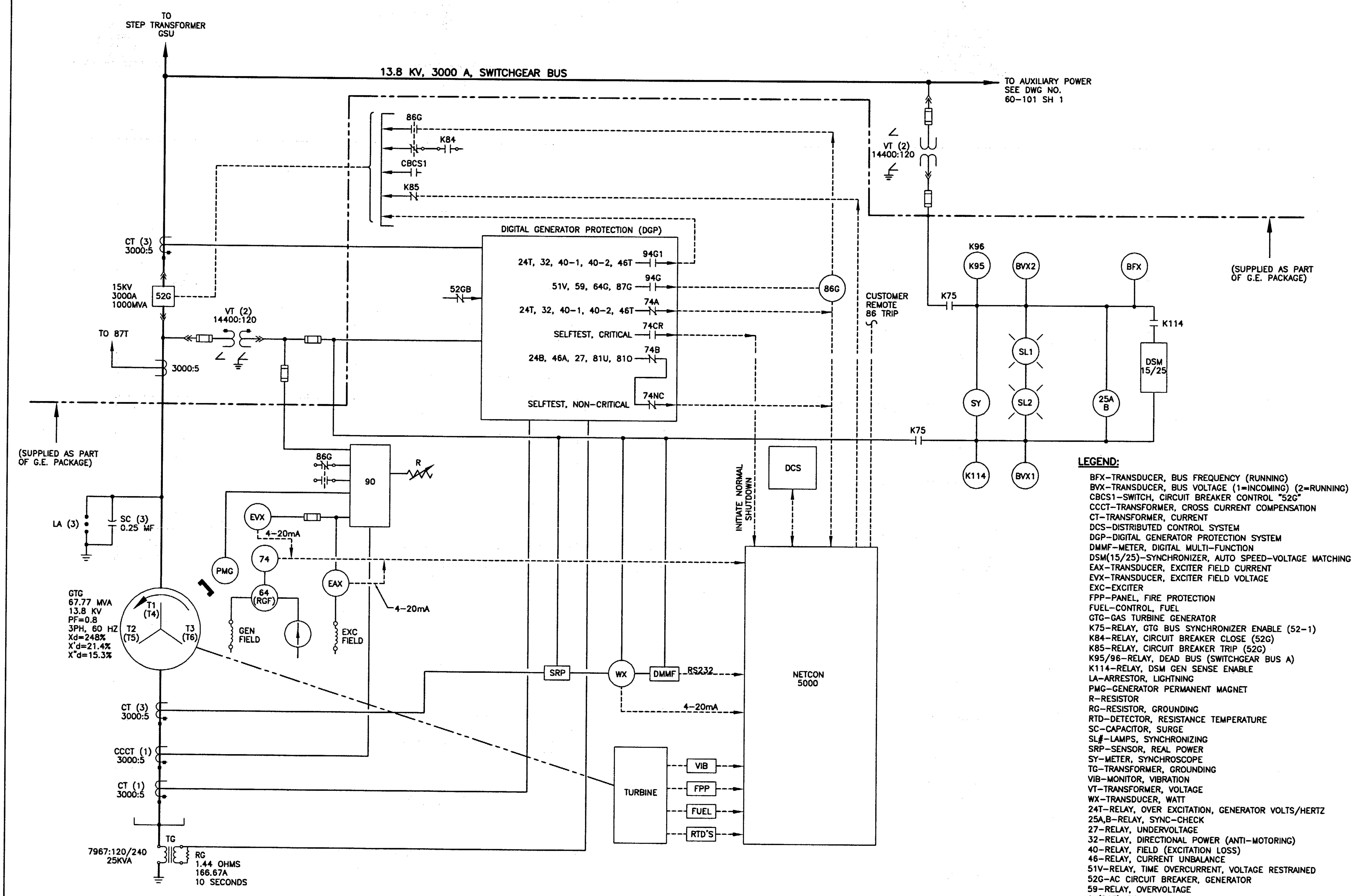
DRAWN	SL	9/08/04
CHECK		
DESIGN		
PROJ ENGR		
PROJ MGR		
QA MGR		
SCALE	NONE	SIZE E

JOB NO.	DWG NO.	SH NO.	REV
0415	60-100	1	A

REVISIONS

NO.	DATE	BY	CHK'D	APP'D	DESCRIPTION

WOOD GROUP



LEGEND:

BFX-TRANSDUCER, BUS FREQUENCY (RUNNING)
BVX-TRANSDUCER, BUS VOLTAGE (1=INCOMING) (2=RUNNING)
CBCS1-SWITCH, CIRCUIT BREAKER CONTROL "52G"
CCCT-TRANSFORMER, CROSS CURRENT COMPENSATION
CT-TRANSFORMER, CURRENT
DCS-DISTRIBUTED CONTROL SYSTEM
DGP-DIGITAL GENERATOR PROTECTION SYSTEM
DMMF-METER, DIGITAL MULTI-FUNCTION
DSM(15/25)-SYNCHRONIZER, AUTO SPEED-VOLTAGE MATCHING
EAX-TRANSDUCER, EXCITER FIELD CURRENT
EVX-TRANSDUCER, EXCITER FIELD VOLTAGE
EXC-EXCITER
FPP-PANEL, FIRE PROTECTION
FUEL-CONTROL, FUEL
GTG-GAS TURBINE GENERATOR
K75-RELAY, GTG BUS SYNCHRONIZER ENABLE (52-1)
K84-RELAY, CIRCUIT BREAKER CLOSE (52G)
K85-RELAY, CIRCUIT BREAKER TRIP (52G)
K95/96-RELAY, DEAD BUS (SWITCHGEAR BUS A)
K114-RELAY, DSM GEN SENSE ENABLE
LA-ARRESTOR, LIGHTNING
PMG-GENERATOR PERMANENT MAGNET
R-RESISTOR
RG-RESISTOR, GROUNDING
RTD-DETECTOR, RESISTANCE TEMPERATURE
SC-CAPACITOR, SURGE
SL#-LAMPS, SYNCHRONIZING
SRP-SENSOR, REAL POWER
SY-METER, SYNCHROSCOPE
TG-TRANSFORMER, GROUNDING
VIB-MONITOR, VIBRATION
VT-TRANSFORMER, VOLTAGE
WX-TRANSDUCER, WATT
24T-RELAY, OVER EXCITATION, GENERATOR VOLTS/HERTZ
25A,B-RELAY, SYNC-CHECK
27-RELAY, UNDERVOLTAGE
32-RELAY, DIRECTIONAL POWER (ANTI-MOTORING)
40-RELAY, FIELD (EXCITATION LOSS)
46-RELAY, CURRENT UNBALANCE
51V-RELAY, TIME OVERCURRENT, VOLTAGE RESTRAINED
52G-AC CIRCUIT BREAKER, GENERATOR
59-RELAY, OVERVOLTAGE
64(RGF)-RELAY, GROUND FAULT
64G-RELAY STATOR GROUNDING
74-RELAY ALARM
81O/U-RELAY, OVER/UNDER FREQUENCY
86*-RELAY, CUSTOMER LOCKOUT
86G-RELAY, LOCKOUT (SHOWN RESET), GENERATOR
94-RELAY, TRIP

NO.	DATE	BY	CHK'D	APP'D	DESCRIPTION

REVISIONS

WOOD GROUP

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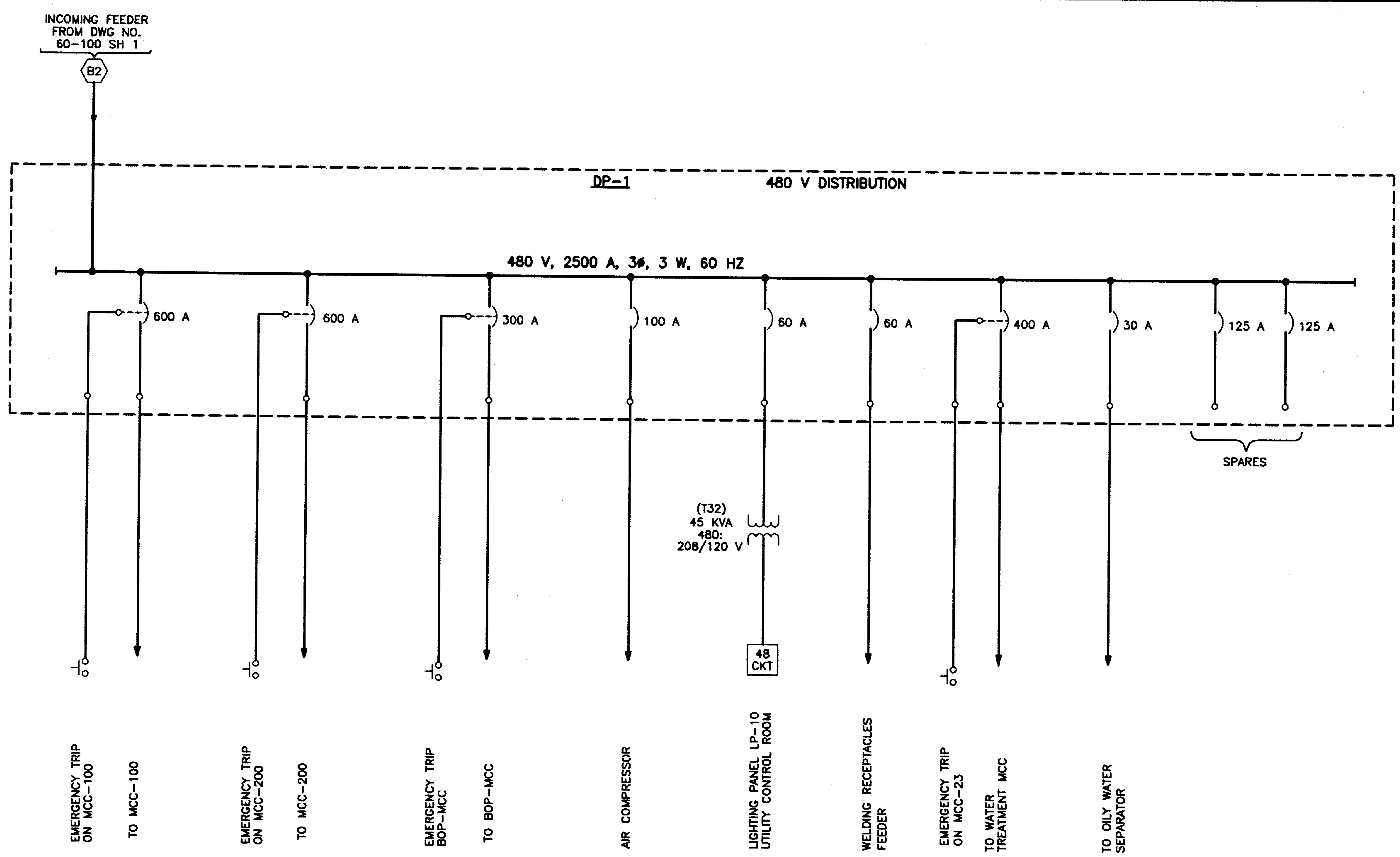
DESIGN	
PROJ ENGR	
PROJ MGR	
QA MGR	
SCALE	NONE
SIZE	E

WOOD GROUP POWER SOLUTIONS, INC
PHILADELPHIA PENNSYLVANIA

TYPICAL GENERATOR PROTECTION
LM-6000
STRATEGIC PJM PROXY PLANT NO. 1

JOB NO.	DWG NO.	SH NO.	REV
0415	60-100	2	A



REFERENCE DRAWINGS:

60-100 SH 1 - ONE LINE DIAGRAM OVERALL SYSTEM

LEGEND:

- COMBINATION STARTER (BREAKER WITH MOTOR OVER LOADS) — SCHEMATIC NO.
- COMBINATION CONTACTOR (BREAKER NO MOTOR OVER LOADS) — SCHEMATIC NO.
- HOA - HAND-OFF-AUTO SWITCH
- 1 - MOTOR HORSEPOWER (HP)
- R - INDICATING LIGHT COLOR
- TCP - TURBINE CONTROL PANEL
- MOTOR SPACE HEATER
- XX - DRAWING CONTINUATION POINT

NO.	DATE	BY	CHK'D	APP'D	REVISIONS DESCRIPTION

DRAWN	SL	9/08/04
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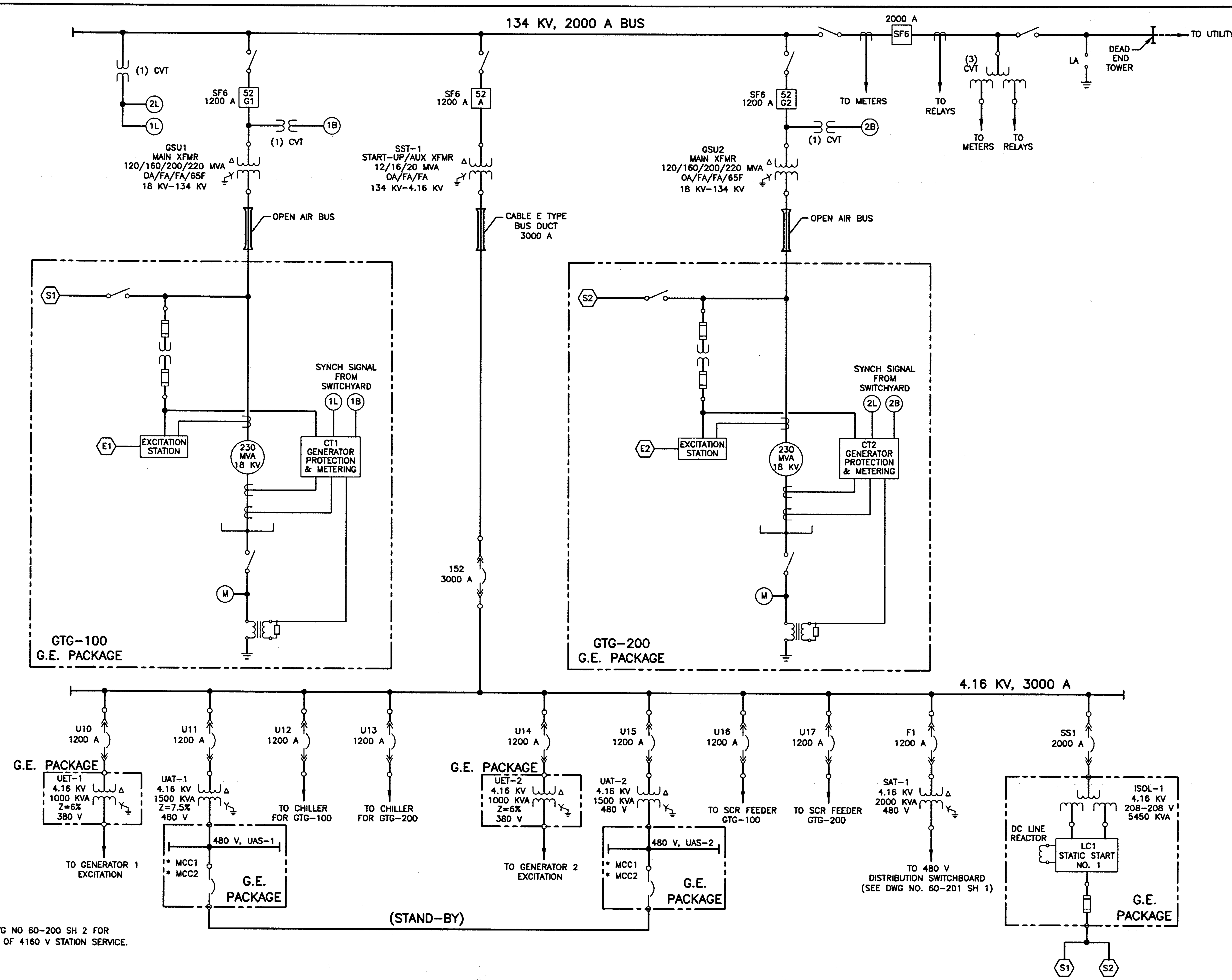
DESIGN		
PROJ ENGR		
PROJ MGR		
QA MGR		
SCALE	NONE	SIZE E

WOOD GROUP POWER SOLUTIONS, INC

ONE LINE DIAGRAM
480 V DISTRIBUTION
STRATEGIC PJM PROXY PLANT NO. 1
PHILADELPHIA, PENNSYLVANIA

JOB. NO.	DWG NO.	SH NO.	REV
0415	60-100	3	A

WOOD GROUP



NOTES:

- SEE DWG NO 60-200 SH 2 FOR DETAILS OF 4160 V STATION SERVICE.

NO.	DATE	BY	CHK'D	APP'D	DESCRIPTION

REVISIONS

WOOD GROUP

WOOD GROUP POWER SOLUTIONS, INC

SYSTEM ONE LINE DIAGRAM
FRAME VII FA GTG-100 AND GTG-200
STRATEGIC PJM PROXY PLANT NO. 2

PHILADELPHIA PENNSYLVANIA

DRAWN	SL	9/08/04
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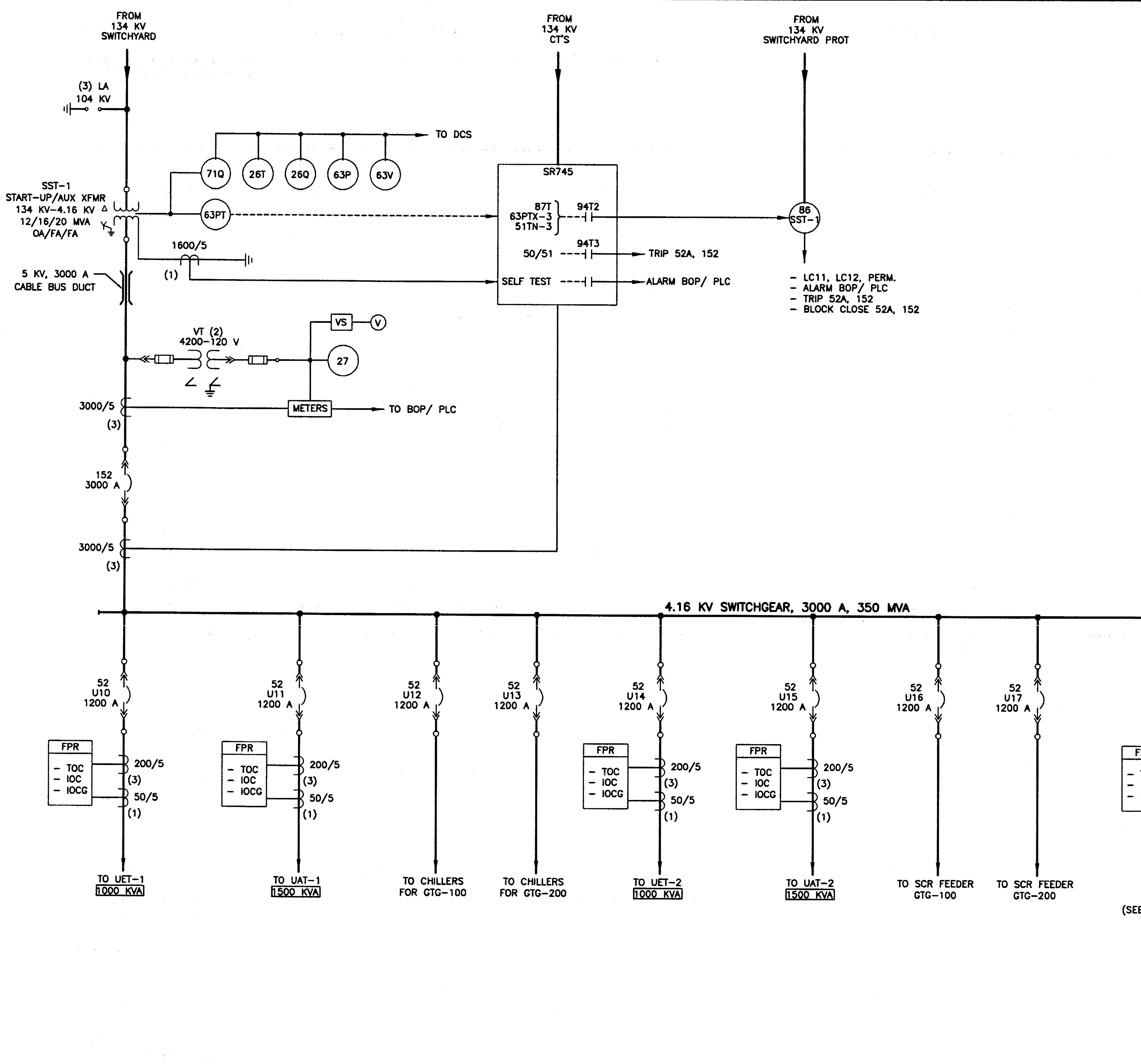
DESIGN		
PROJ ENGR		
PROJ MGR		
QA MGR		
SCALE	NONE	SIZE E

JOB. NO.	DWG NO.	SH NO.	REV
0415	60-200	1	A



NOMENCLATURE:

V	- VOLMETER
A	- AMMETER
VS	- VOLTMETER SWITCH
AS	- AMMETER SWITCH
VT	- VOLTAGE TRANSFORMER
UAT (1, 2)	- UNIT AUXILIARY TRANSFORMER
UET (1, 2)	- UNIT EXCITATION TRANSFORMER
SAT (1, 2)	- STATION AUXILIARY TRANSFORMER
ISOL (1, 2)	- STATIC START ISOLATION TRANSFORMER

RELAY LEGEND:

FPR	- FEEDER PROTECTION MULTI-LIN MDP012DA
MPR	- MOTOR PROTECTION RELAY MULTI-LIN 269
25B	- HOT BUS TRANSFER SYNCH CHECK RELAY
26Q	- LIQUID TEMPERATURE ALARM RELAY
26T	- LIQUID TEMPERATURE TRIP RELAY
27	- UNDERVOLTAGE RELAY
50/51	- TIME OVERCURRENT SR-745
51N	- TRANSFORMER NEUTRAL OVERCURRENT SR-745
63P	- TRANSFORMER TANK PRESSURE ALARM
63PT	- TRANSFORMER FAULT PRESSURE RELAY
63PTX	- TRANSFORMER FAULT PRESSURE AUX. RELAY SR-745
63V	- TRANSFORMER VACUUM ALARM
71Q	- TRANSFORMER LIQUID LEVEL ALARM
86SST-1,2	- LOCK-OUT RELAY TYPE LOR
87SST-1, 2	- TRANSFORMER DIFFERENTIAL RELAY SR-745

NOTES:

1. MPR IS MULTI-FUNCTION MOTOR PROTECTIVE RELAY AND CONSISTS OF THE FOLLOWING PROTECTIVE FUNCTIONS:
   - OVERLOAD
   - PHASE IMBALANCE
   - OPEN PHASE
   - GROUND FAULT
   - OVER TEMPERATURE
2. FPR IS MULTI-FUNCTION FEEDER PROTECTIVE RELAY AND CONSISTS OF THE FOLLOWING PROTECTIVE FUNCTIONS:
   - TOC: TIME OVERCURRENT
   - IOC: INSTANTANEOUS OVERCURRENT
   - IOCG: INSTANTANEOUS GROUND FAULT PROTECTION.

WOOD GROUP POWER SOLUTIONS, INC

SYSTEM ONE LINE DIAGRAM
4160 V STATION SERVICE
STRATEGIC PJM PROXY PLANT NO. 2

PHILADELPHIA PENNSYLVANIA	
JOB. NO.	0415
DWG NO.	60-200
SH NO.	2
REV	A
DRAWN	SL 9/08/04
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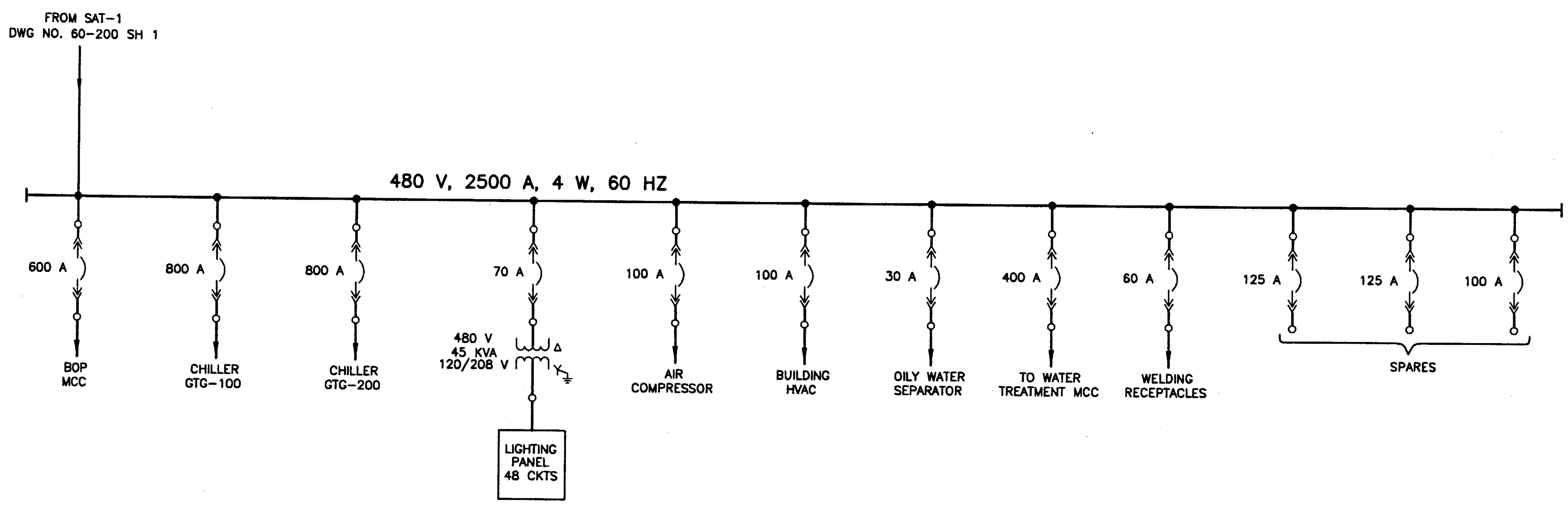
DESIGN	
PROJ ENGR	
PROJ MGR	
QA MGR	
SCALE	NONE
SIZE	E

NO.	DATE	BY	CHK'D	APP'D	DESCRIPTION

REVISIONS

WOOD GROUP

Docket No. EL21-91-000, -003



NO.	DATE	BY	CHK'D	APP'D	DESCRIPTION

REVISIONS

WOOD GROUP

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DESIGN	
PROJ ENGR	
PROJ MGR	
QA MGR	
SCALE	NONE
SIZE	E

WOOD GROUP POWER SOLUTIONS, INC

400 V ONE LINE DIAGRAM
BALANCE OF PLANT (BOP)
STRATEGIC PJM PROXY PLANT NO. 2
PHILADELPHIA PENNSYLVANIA

JOB. NO.	DWG NO.	SH NO.	REV
0415	60-200	3	A

Addendum No. 2

Wood Group Qualifications, Experience and References

QUALIFICATIONS, EXPERIENCE AND REFERENCES

QUALIFICATIONS:

John Wood Group PLC is an international energy services company with $2.2 billion sales, employing more than 14,000 people worldwide and operating in 36 countries. The Group has three Businesses - Engineering & Production Facilities, Well Support, and Gas Turbine Services - providing a range of engineering, production support, maintenance management, and industrial gas turbine overhaul and repair services to the oil & gas, and power generation industries worldwide.

The **Well Support** group continued international expansion programs and in 2002 contributed revenues of $360 million.

The **Engineering & Production Facilities** group employs over 2,500 engineers in the Houston, Texas area. They also have significant off-shore deep water facilities engineering and design support responsibilities. In 2002 WG Engineering & Production Facilities increased revenues to $993 million.

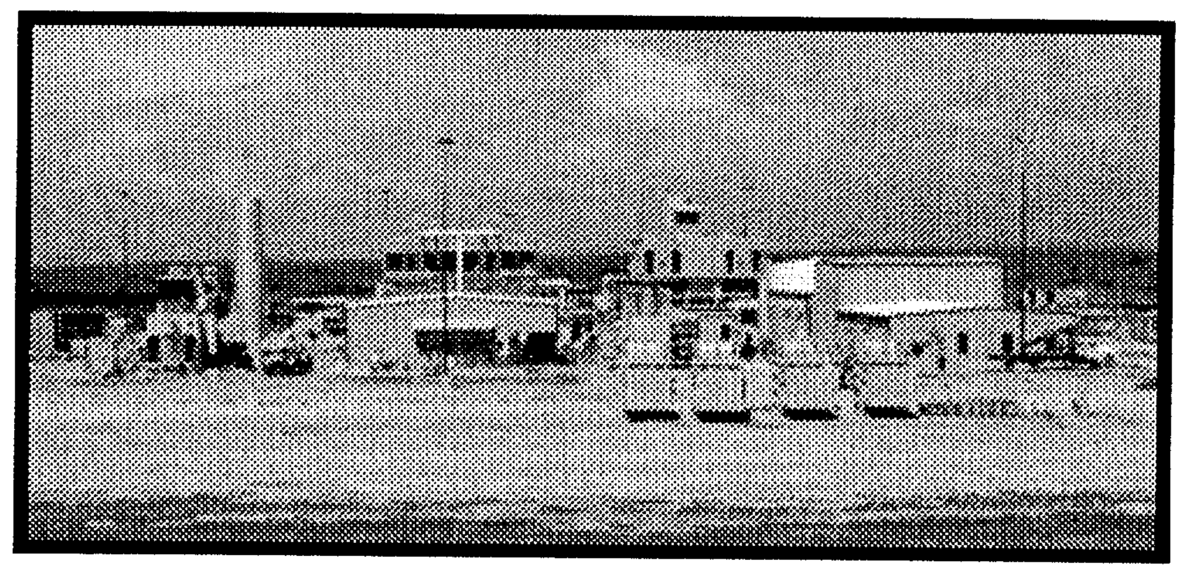
Wood Group Gas Turbine Services is a leading independent provider of maintenance, repair and overhaul services for light industrial, aero-derivative, and heavy industrial gas turbines, steam turbines, generators, and other high-speed rotating equipment, including pumps and compressors. WG Gas Turbine Services also repairs gas turbine accessories and components for industrial and aero customers. Gas Turbine Services significantly increased its 2002 revenues to $352 million.

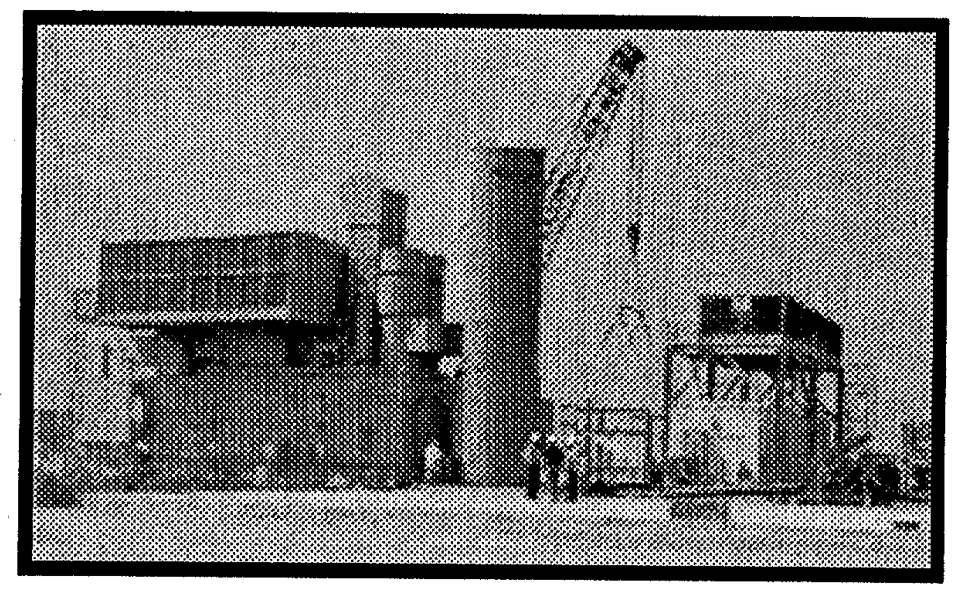
Wood Group Power Solutions, Inc. (WGPS) is a subsidiary of Wood Group Gas Turbine Services. Our mission is to provide turnkey EPC services to customers.

WGPS provides turnkey services for the power generation industry, having successfully completed work for Rural Electric Cooperatives, Municipalities, and Investor Owned Utilities. Experience within our company totals over 40 years in the power generation industry. The staff has been involved in many national and international projects (some as large as 300MW) that include the installation of large gas turbines to serve as prime movers for base load generation, cogeneration, and peaking service. WGPS employees have participated in the installation of over 23 GE LM5000 or LM6000 gas turbine generator units. This includes test stands for GE in Houston and TransCanada Turbines in Canada. WGPS' services vary from initial feasibility studies through preparation of detailed equipment specifications and procurement to the supervision of installation and commissioning.

On the following pages you will find brief descriptions of projects in which WGPS' staff has participated as the EPC contractor.

PROJECT HISTORY:





Project: **Pribbenow Mine Power Project**

Client: Drummond Ltd.

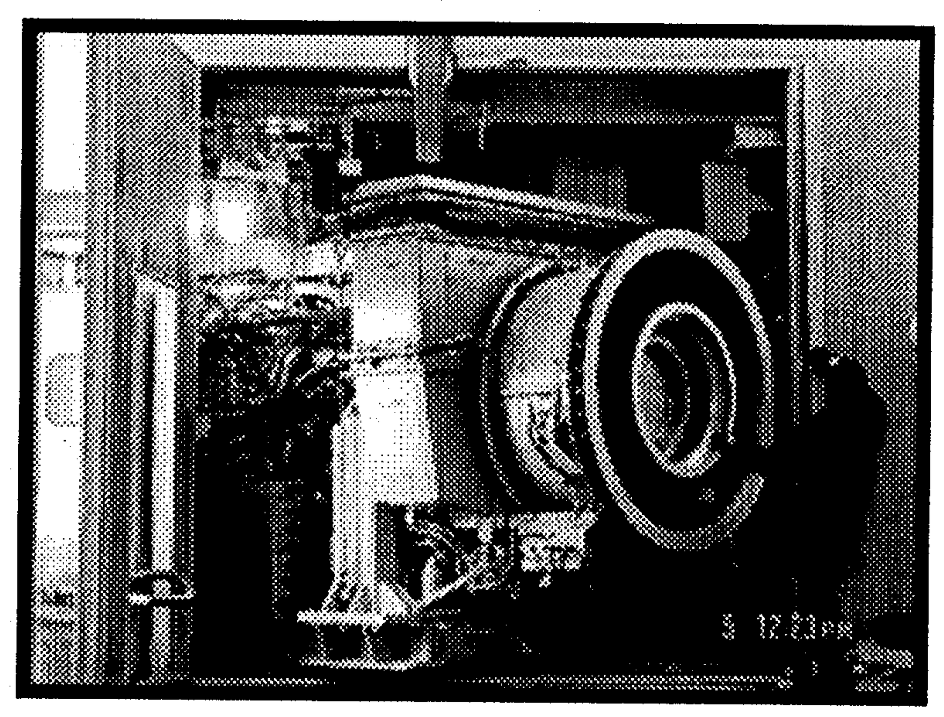
Date: November 2003 to May 2004

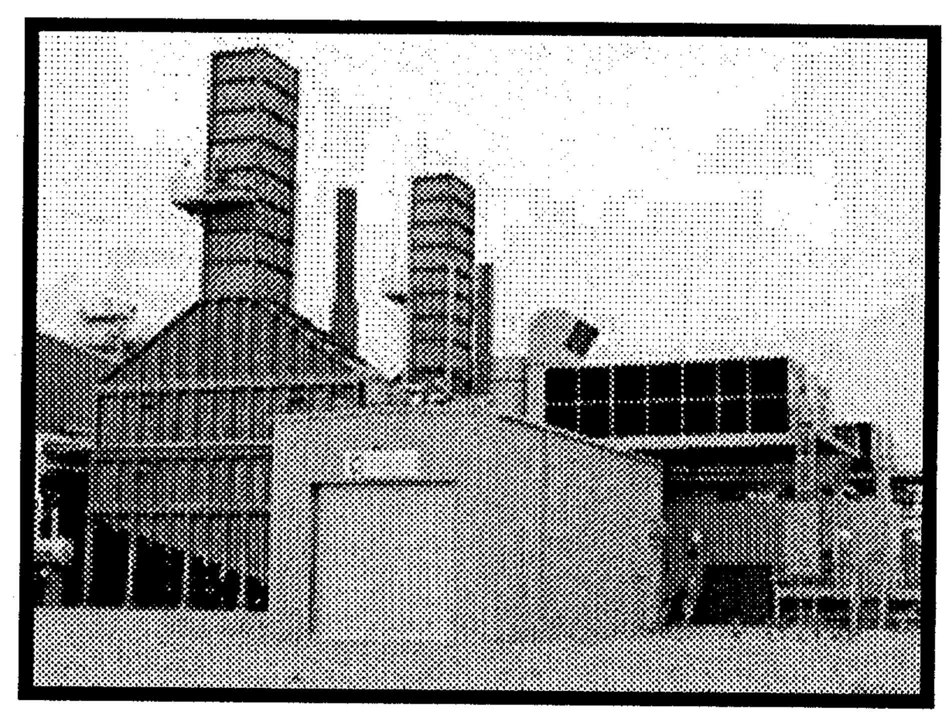
Location: La Loma Cesar, Colombia S.A.

Equipment: LM6000 and LM2500

Megawatts: 67 MW

Scope of Work: WGPS provides turbines, Balance of Plant equipment, installation, start-up, and commissioning for the turbine on a turnkey contract basis.





Project: **TCT Test Cell**

Client: TransCanada Turbines

Date: 2003

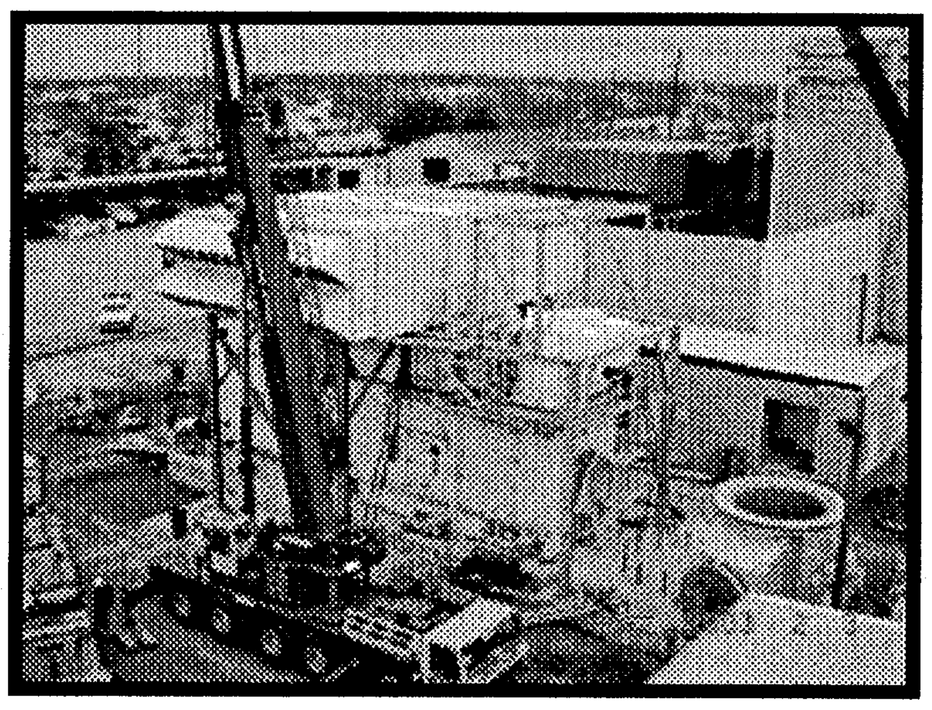
Location: Calgary, Alberta Canada

Equipment: LM6000 PC & PA

Megawatts: ±40 MW

Scope of Work: Incorporate into existing commercial plant; skids, quick connects, and software systems to allow TCT to test refurbished turbines once a week. (2 day period)

Wood Group Power Solutions, Inc.
Qualifications, Experience and References



Project: **OMPA – Ponca City Unit #4**

Client: Oklahoma Municipal Power Authority (OMPA)

Date: 2003

Location: Ponca City, Oklahoma USA

Equipment: The installation of one (1) LM6000 next to an existing unit along with associated control systems with associated balance of plant equipment.

Megawatts: 42 MW

Scope of Work: WGPS provides the turbine, Balance of Plant equipment, installation, start-up, and commissioning for the turbine on a turnkey contract basis.

RECENT PROJECTS – LM2500, LM5000 AND LM6000 EXPERIENCE:

Date	Client	Project	Location	Equipment	MW	Scope of Work
2004-2005	Drummond Co	Pribbenow Mine Phase 2	Colombia	Two (2) GE LM6000 gas turbine generators	90	Turnkey engineering, design, construction, start-up and commissioning for turbine generators and balance of plant systems all integrated into owners existing system.
2004	Duro Felguera S.A. Energia	Fiumesanto Power Project	Italy	Two (2) GE LM6000 50 Hz gas turbine generators, DCS System, balance of plant equipment		50 Hz Conversion, engineering, procurement, and delivery to Port of Houston
2002	Williams	Williams-Hazleton Power Project	Hazleton, PA	Three (3) GE LM5000 simple cycle gas turbine generators with associated control systems with associated balance of plant systems including 69kV step-up transformer and utility tie-in.	105	Turnkey engineering, design, construction, start-up and commissioning for turbine generators and balance of plant systems all integrated into owners existing system.

Wood Group Power Solutions, Inc.
Qualifications, Experience and References

Date	Client	Project	Location	Equipment	MW	Scope of Work
2002	City of Burbank CA	Burbank Power Project	Burbank, CA	One (1) GE LM6000 PC 45MW simple cycle gas turbine generators with associated control systems, chillers, cooling towers, SCR, fuel gas compressors and balance of plant systems.	45	Turnkey engineering, design, construction, start-up and commissioning for turbine generators and balance of plant systems integrating with existing owner's power plant facility.
2000	Oklahoma Gas and Electric (OG+E)	Horseshoe Lake Power Project	Harrah, OK	Two (2) GE LM6000 PC 45MW simple cycle gas turbine generators with associated control systems, chillers, cooling towers, inlet heating boilers, etc.	90	Balance of plant detail design, engineering, procurement, construction, installation and commissioning for turbine generators and balance of plant systems.
2000	Cornerstone, Grady County and Three Notch Rural Electric Cooperatives	SOWEGA Power Project	Baconton, GA	Two (2) GE LM6000 PC 45MW simple cycle gas turbine generators with associated control systems, chillers, cooling towers, pipe header system for six (6) units and balance of plant systems.	90	Turnkey engineering, design, construction, start-up and commissioning for turbine generators and balance of plant systems with dual fuel capability, firewater system, and demin water supplied by truck mounted water treatment.
2001	Cornerstone and Coral Energy	Baconton Power Project	Baconton, GA	Four (4) GE LM6000 PC 45MW simple cycle gas turbine generators with associated control systems, chillers, cooling towers, inlet heating boilers, water treatment, and auxiliary bus	180	Included the dismantling of three (3) units in Argentina, packaging for shipment to U.S., turnkey engineering, design, construction, reassembly of gas turbine generator packages on site start-up and commissioning for turbine generators and balance of plant systems including the required 230KV substation extension. A new owner supplied fourth unit was also installed.

Wood Group Power Solutions, Inc.
Qualifications, Experience and References

Client	Location	Description
Stewart & Stevenson / Guam Power Authority	Guam Island	Two (2) GE LM2500 22 MW simple cycle gas turbine generators with associated 34KV substations, water treatment, fuel treatment, and control systems. Included Balance of Plant detailed design procurement and construction.
Brown-Boveri / Colt / Canadian U.L.	Canada	One (1) Brown-Boveri 42MW generator, base load. Included all installation engineering and supervision for plant only.
Public Service Company of Oklahoma	Oklahoma	Three (3) Worthington 70MW peaking power and base loaded generators, installed in three (3) locations. Performed feasibility studies, prepared purchase specifications and bid evaluation, along with conceptual installation engineering in association with Fern.
General Electric	Florida	Twelve (12) GE Frame 7, 60MW generators, base loaded, preparation of construction specifications and bid documents to solicit large general contractor bids in association with Fern.
Worley / Mobil Oil Company	North Sea	Three (3) GE Frame 5, 25MW generators, base loaded, in one (1) location. Preparation of feasibility studies and electrical design for large Mobil Beryl "C" offshore platform.
Ruston / Petro Peru	Peru – Petro-Peru Pipeline	Sixteen (16) packaged generation stations consisting of two (2) each Ruston TB turbine generators with associated 5KV switchgear and substation. Responsibility included total turnkey engineering and construction of modules, housing, switchgear, and substations along with procurement and project management.
Gulf Oil / Chevron	Cabinda-Angola	Power Generation Module weighing 480 tons consisting of two (2) Solar Centaur 2.5 MW gas turbines with all ancillaries. Responsibilities included complete engineering, procurement, fabrication, testing, and load-out of the 480 ton module.

Client	Location	Description
HRSG PROJECT EXPERIENCE:		
Anderson Lithograph, Inc.	Los Angeles, California	Completed the commissioning and start up of a combined cycle 5.2 MW gas turbine power plant with Allison KB5, 3.5 MW, HRSG with supplementary burner, 1.7 MW steam turbine, 1100 tons absorption chilling, chilled water / steam process system, SCR, substation and DCS control system with CEMS. Scope of work included detailed engineering, procurement, and construction.
Stewart & Stevenson / UNOCAL Oil Company	California – Ventura	One (1) Allison 501 KB5 3.5 MW gas turbine with waste heat boiler to furnish process heat to UNOCAL Roncon Plant (Crude Treating, CO2 Processing, LTS, and Gas Compression). Responsibilities included turnkey design, procurement, and installation of the power plant.
Abu Dhabi Petroleum	Persian Gulf	Five (5) GEC EASI 1 and 2, 13 MW and 26 MW generators with waste heat boilers, baseload, in three (3) locations. Performed feasibility studies, complete installation, engineering, procurement, project management, and commissioning.
Solar / Dansk Boreselskab	North Sea – "Gorm Field" Denmark	Design and procurement of Balance of Plant for three (3) 900 ton modules including power generation, gas compression, and gas re-injection. The power generation module consisted of four (4) Solar 2.6 MW turbine-driven generator sets with waste heat boilers. The

Client	Location	Description
		gas compression module consisted of five Solar 3600 HP turbine-driven compressors with waste heat boilers. The gas re-injection module consisted of two (2) Nuevo Pignone 6000 HP turbine-driven compressors.
Williams Company / Agrico	Oklahoma	One (1) GE Frame 3 turbine-driven compressor with waste heat boiler. Responsibility included complete engineering, procurement, and construction of the cogeneration plant.
Stewart & Stevenson / Daquing Petroleum Company	China – Daquing	Twelve (12) Allison 501 gas turbines driving high pressure injection water pumps with waste heat boilers. Responsibilities included site survey, complete feasibility studies with preliminary design and bills of material for four (4) water injection stations.
Stewart & Stevenson / Qinghai Petroleum Company	China – Qinghai	Five (5) Allison 501 gas turbines driving pipeline pumps with waste heat boilers and associated ancillaries. Responsibilities included detailed feasibility studies, technical meetings, preliminary design, and bills of materials for complete pump station.
Joint Venture of Central & South West Utility and Ark Energy	California – Bakersfield	Upgrade one (1) 37 MW LM5000 gas turbine to 50 MW. Includes modification of waste heat boiler, STIG steam injection into gas turbine, new computerized gas turbine control system, new safety systems, and new balance of plant control system. Responsibilities included turnkey design, procurement and installation.

FRAME PROJECT EXPERIENCE:

Hitachi / PRWRA	Puerto Rico	Twenty one (21) GE Frame 5 20MW peaking power and base load generators installed in five (5) locations. Scope of project included all design engineering, installation supervision and commissioning for turbine generators and substations (13.8KV to 138KV) in association with Fern.
Hitachi	San Salvador	One (1) GE Frame 5 20 MW generator base loaded. Included all installation engineering, project management and commissioning for plant and associated substation in association with Fern.
Hitachi / GE / Cadafe	Venezuela	One (1) GE Frame 7, 55MW and two GE Frame 5, 20MW generators, base loaded, in three (3) locations. Included complete installation engineering for plants, substations, transmission lines, with associated relay coordination, supervisory and carrier equipment in association with Fern.

LIST OF KEY PERSONNEL:

Wood Group Power Solutions' management team consists of:

David Whisenhunt	President
W.T. Stewart	Vice President
Kent McAllister	VP Turnkey Sales
Craig DeWees	VP Operations
Lee Fields	Sr. Project Manager
Ron Carr	Sr. Process/Mechanical Consultant
JD Patten	Sr. Electrical Engineering Consultant
Bob Eynon	Sr. Civil/Structural Engineering Consultant
Les Pry	Engineering Manager
Kathryn Baulis	Controller
Lisa Angleton	Project Administrator
Brandi Tracy	Marketing/Office Management

This key management team is supplemented with staff personnel. In addition, a portion of WGPS' detailed engineering is subcontracted to EDG International, Inc. (EDG) of Tulsa, Oklahoma. Like WGPS, EDG is located in Tulsa, Oklahoma. The staff of WGPS and EDG has worked together for over 40 years providing detailed engineering and project management.

Wood Group Power Solutions, Inc.
Qualifications, Experience and References

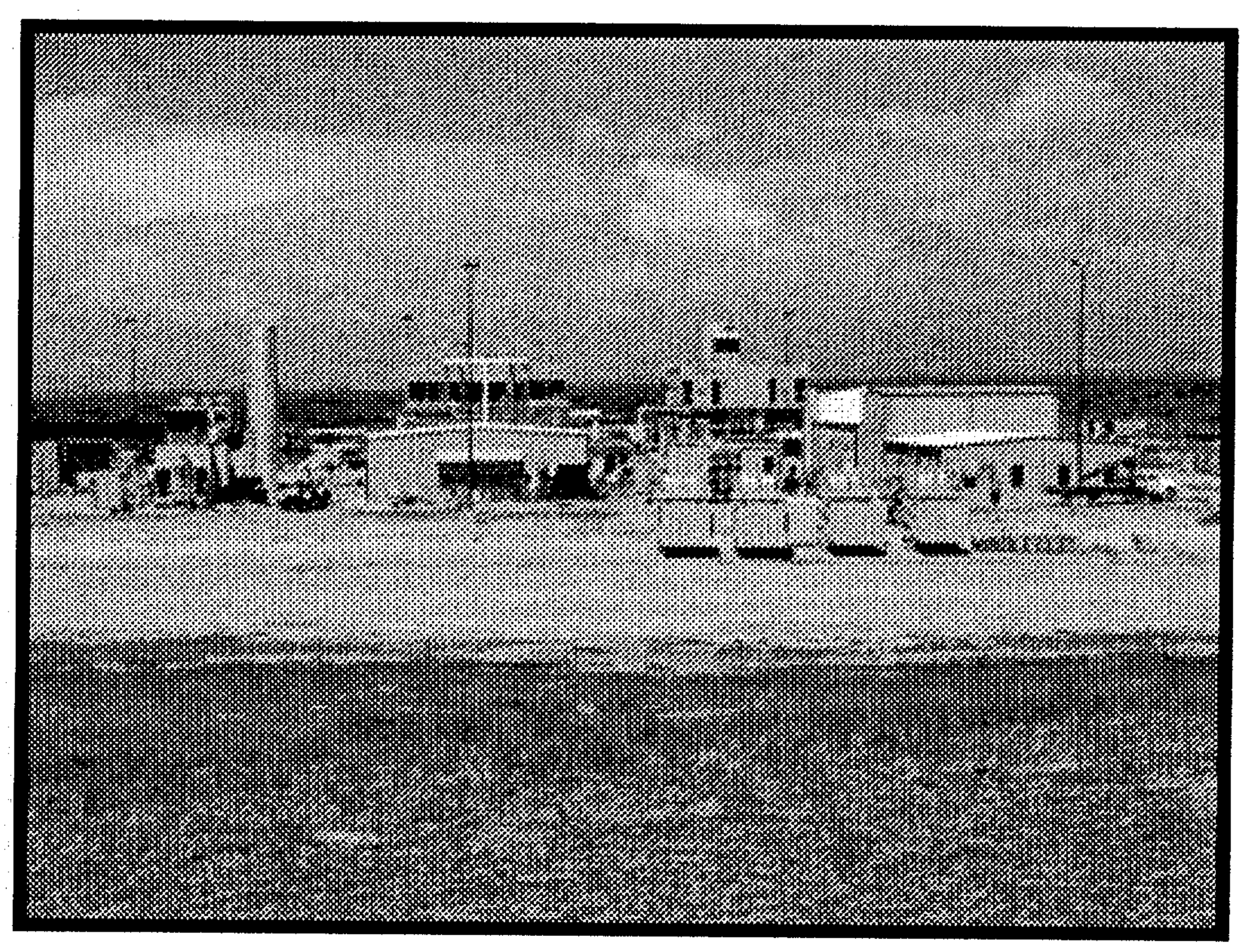
PROJECT EXPERIENCE:

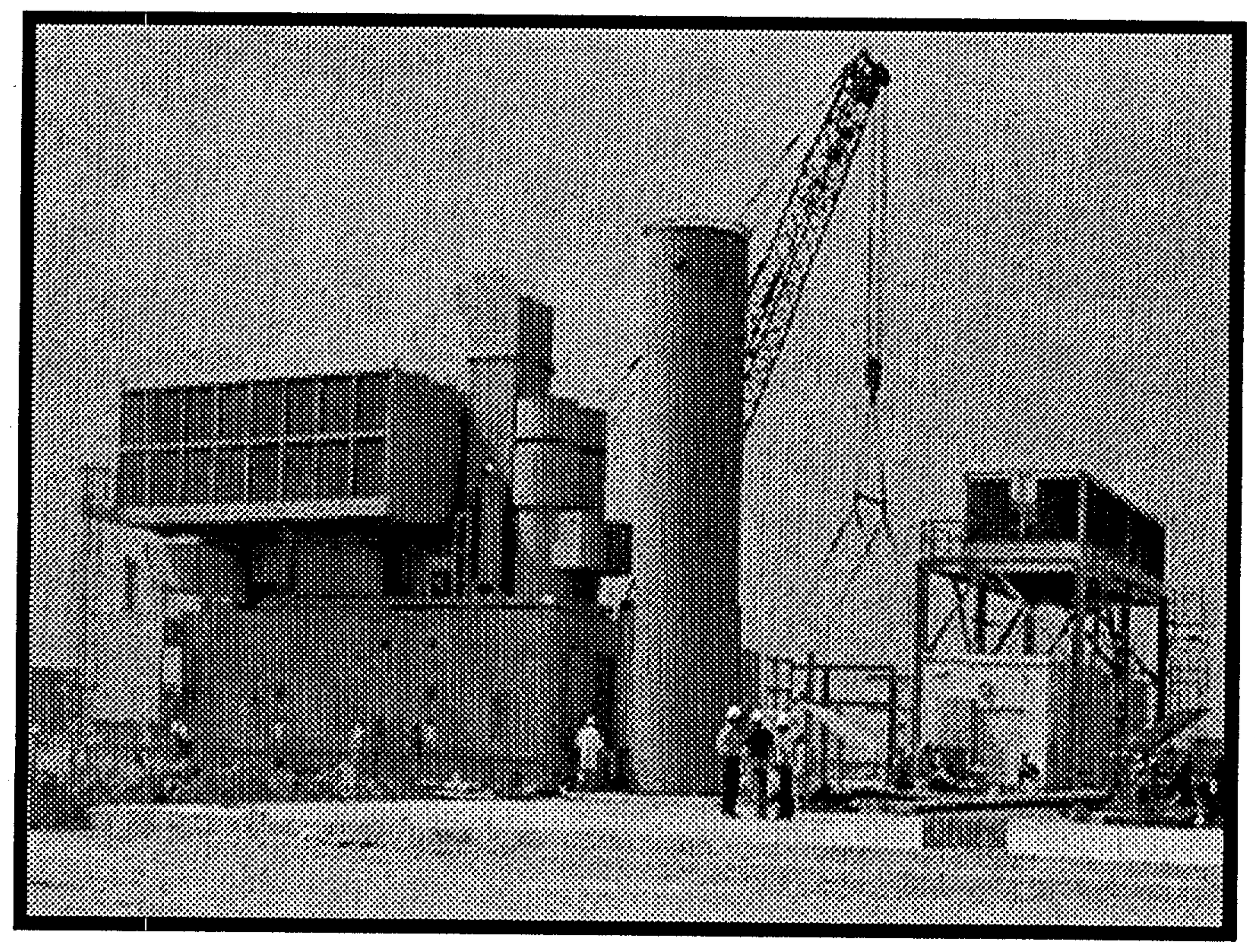
For Wood Group Power Solutions, Inc there are several recent LM6000 projects, which have been successfully completed by our team, that demonstrate our turnkey EPC contract capability.

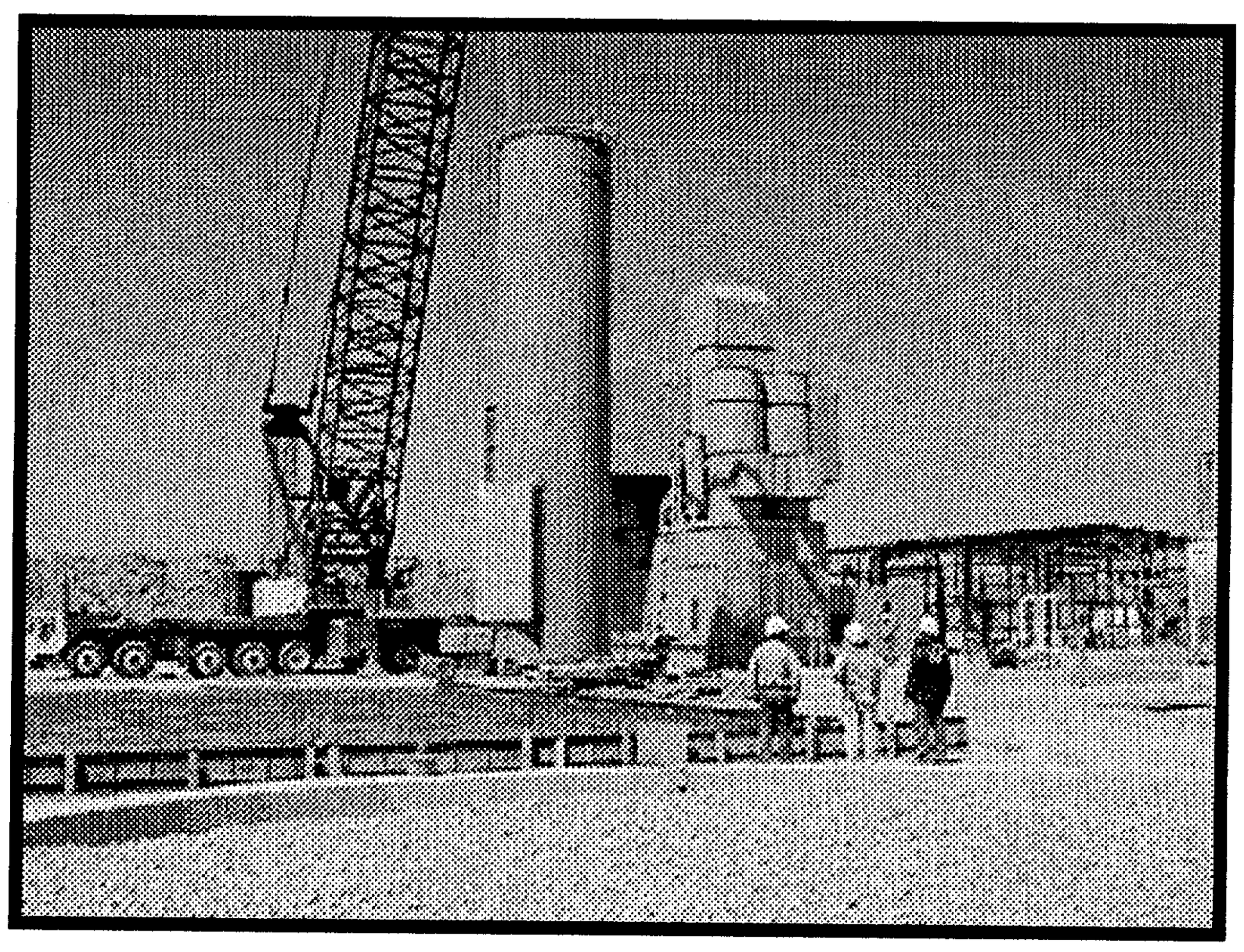
Drummond Ltd. – Pribbenow Mine Project

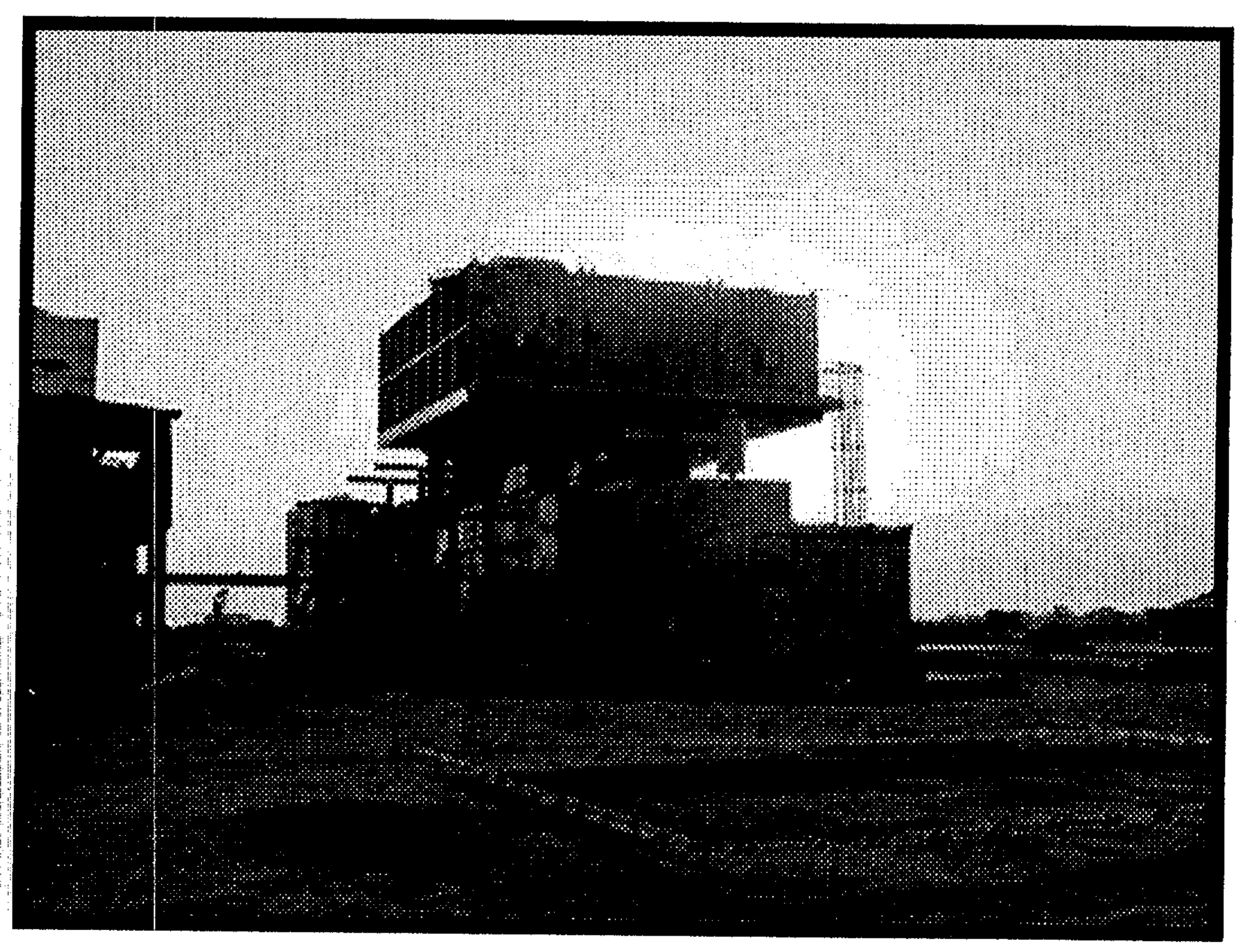
Wood Group Power Solutions, Inc. signed this $30 million EPC contract with Drummond Ltd. to provide a 65 MW power plant designed to generate electricity for the company's expanded coal mining operations in northern Colombia.

Under the contract, WGPS is responsible for the design, procurement, installation and commissioning of the power plant, consisting of one General Eelctric LM6000PC gas turbine and one General Electric LM2500 gas turbine, at the Pribbenow Coal Mine in Colombia's Cesar Coal Basin. Drummond Ltd has the mining rights to Pribbenow and supplies its coal to the electric utility industry worldwide. The project achieved commercial operation during the second quarter of 2004.



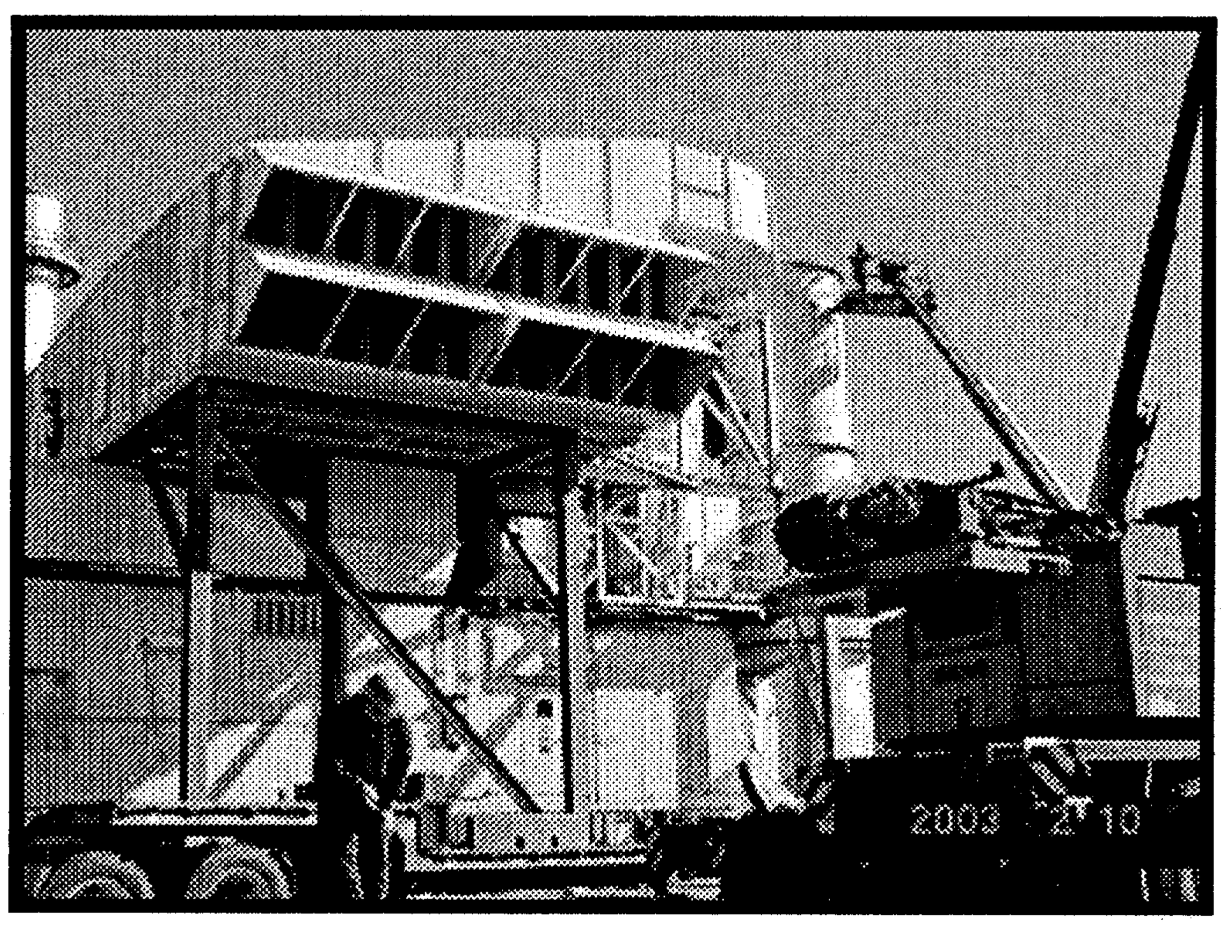


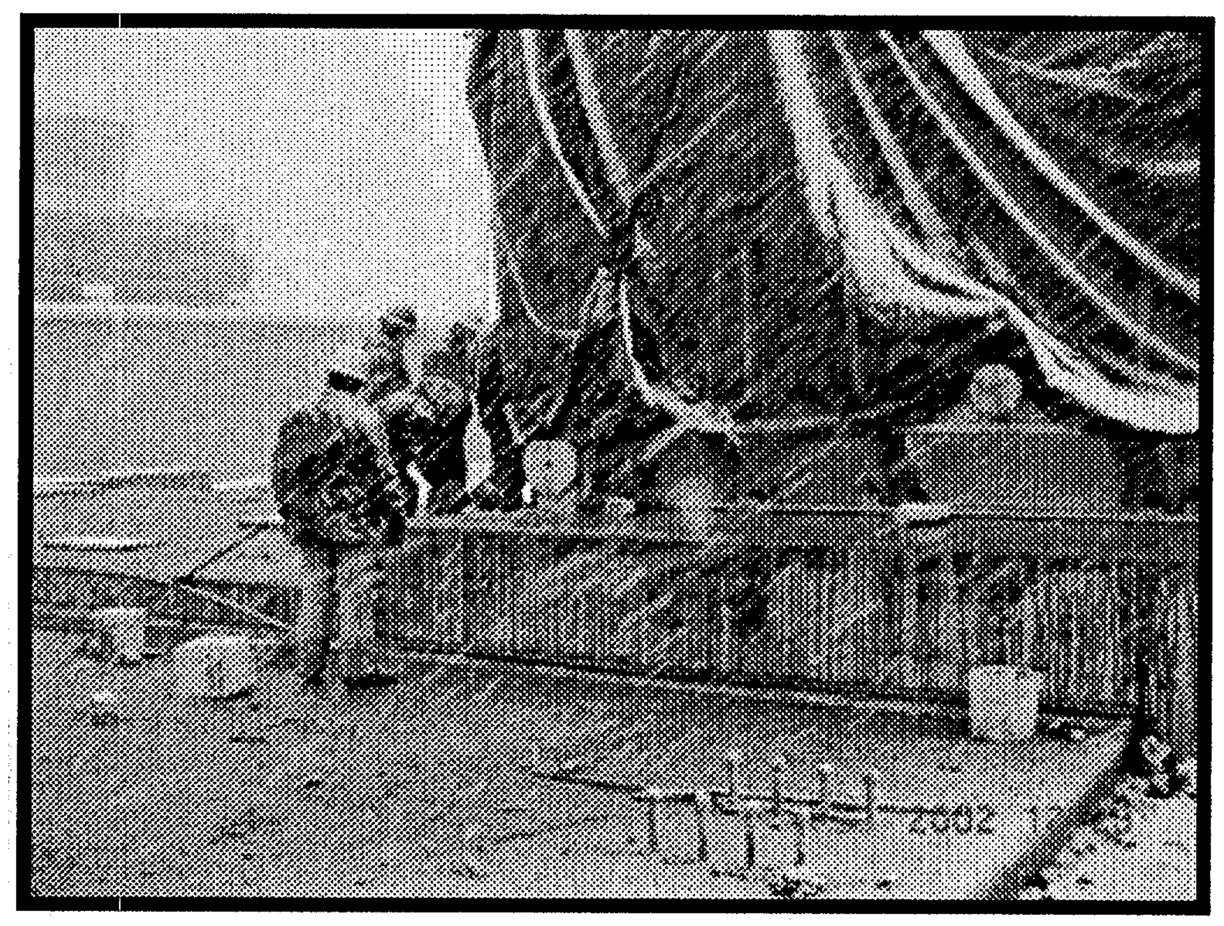


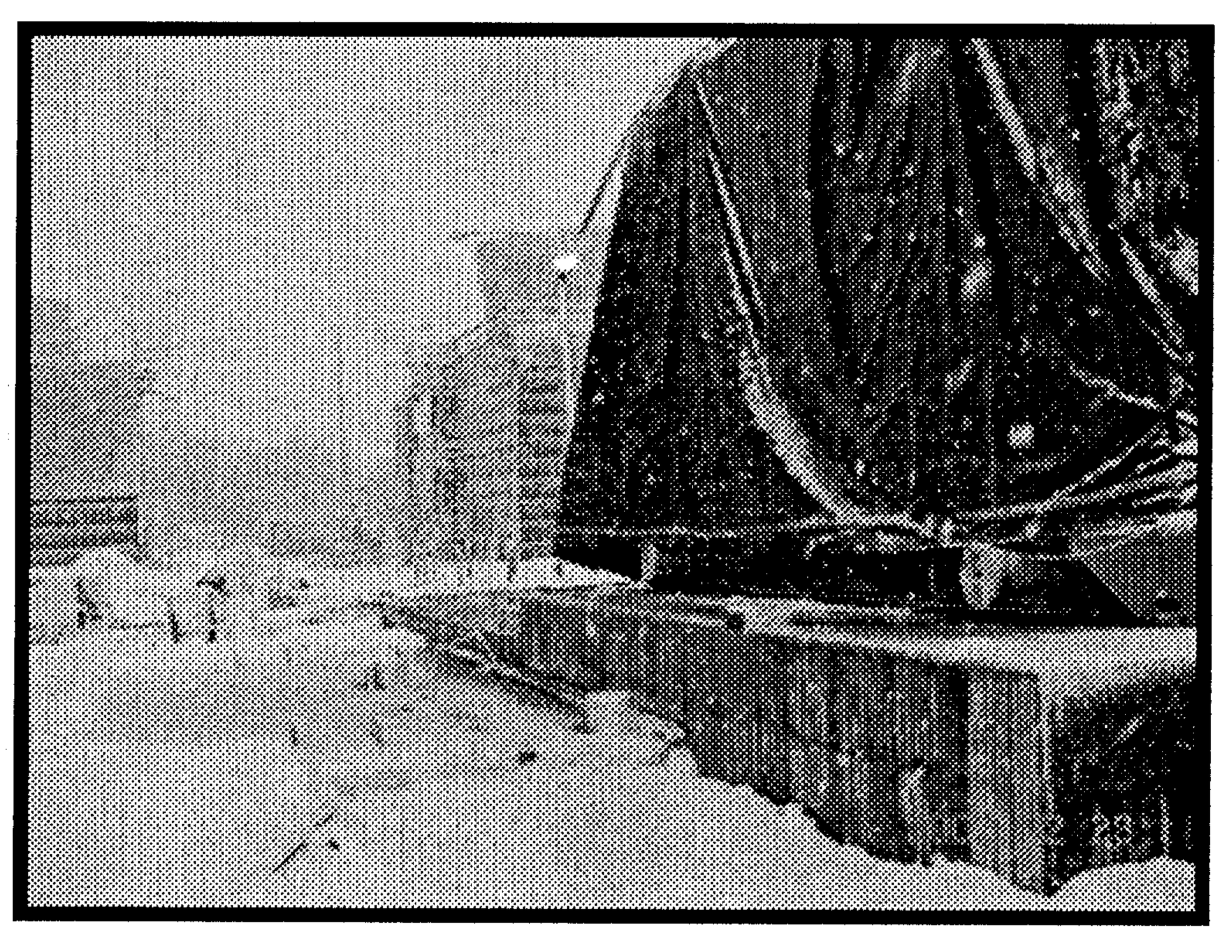


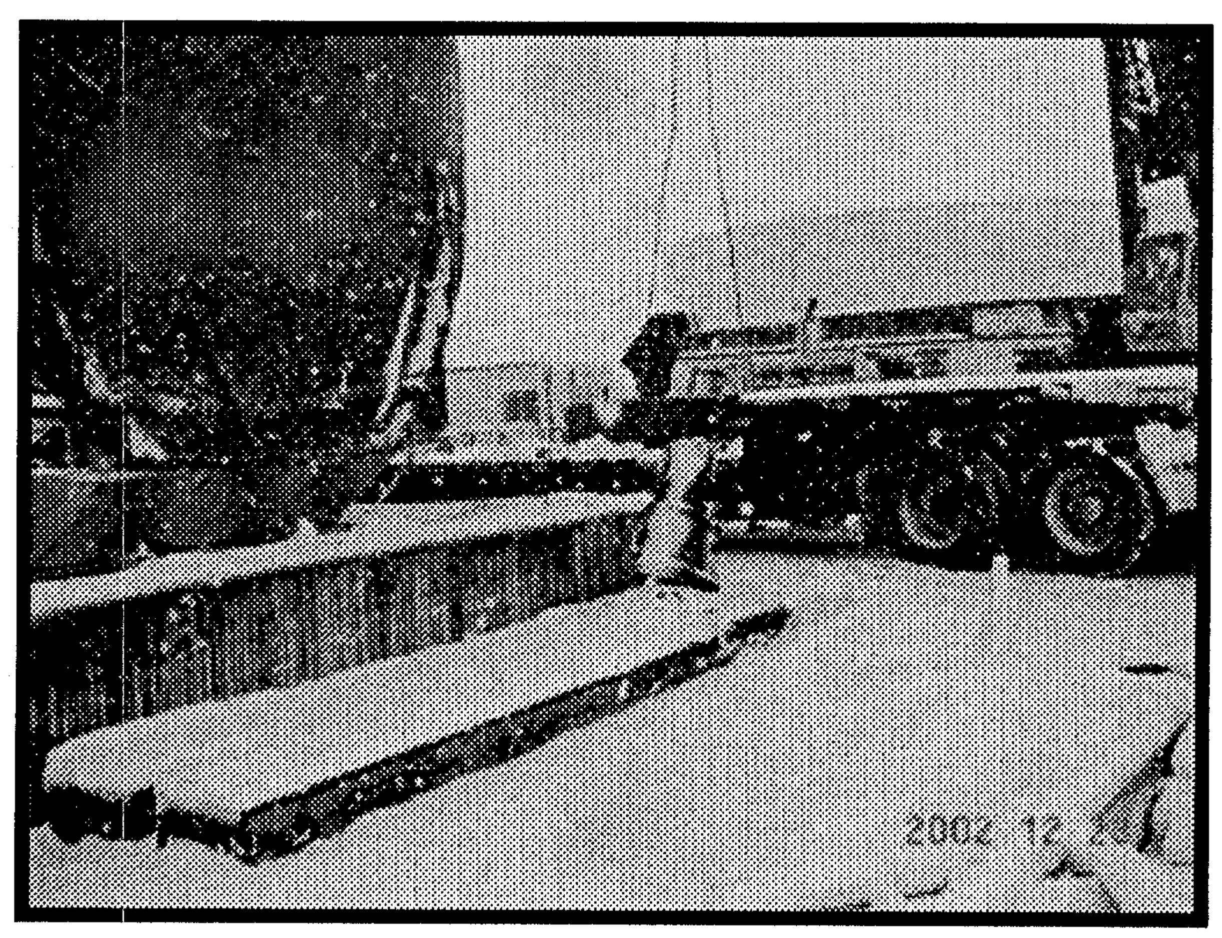
OMPA – Ponca City Unit #4

Wood Group Power Solutions, Inc. signed an EPC turnkey contract in September 2002 to provide a 42 MW power plant in Ponca City, Oklahoma. The contract with Oklahoma Municipal Power Authority (OMPA), valued at $17 million dollars, was to provide and install one Norway Packaged LM6000 PC E-Sprint gas turbine and Balance of Plant equipment to be interconnected with their existing LM6000 unit #2. WGPS also provided engineering, construction, and start-up services with commercial operation scheduled for May 15, 2003. The engineering began immediately following contract signing, with site mobilization and construction beginning in late October 2002. The Norway LM6000 equipment arrived at site in mid December during one of the worst winters experienced in Oklahoma in 50 years. "Although the weather elements were not in our favor during December, January and February, our construction team and subcontractors strived to maintain the schedule. Because of the extra effort put forth by everyone, we overcame the 22 days lost to weather and we will make the commercial operation date" said Craig DeWees, V.P. Operations for WGPS. As of April 25, 2003 the project is completing the start-up and commissioning phase on schedule and will make the May 15, 2003 commercial operation date. The project is expected to be complete by June 1, 2003.



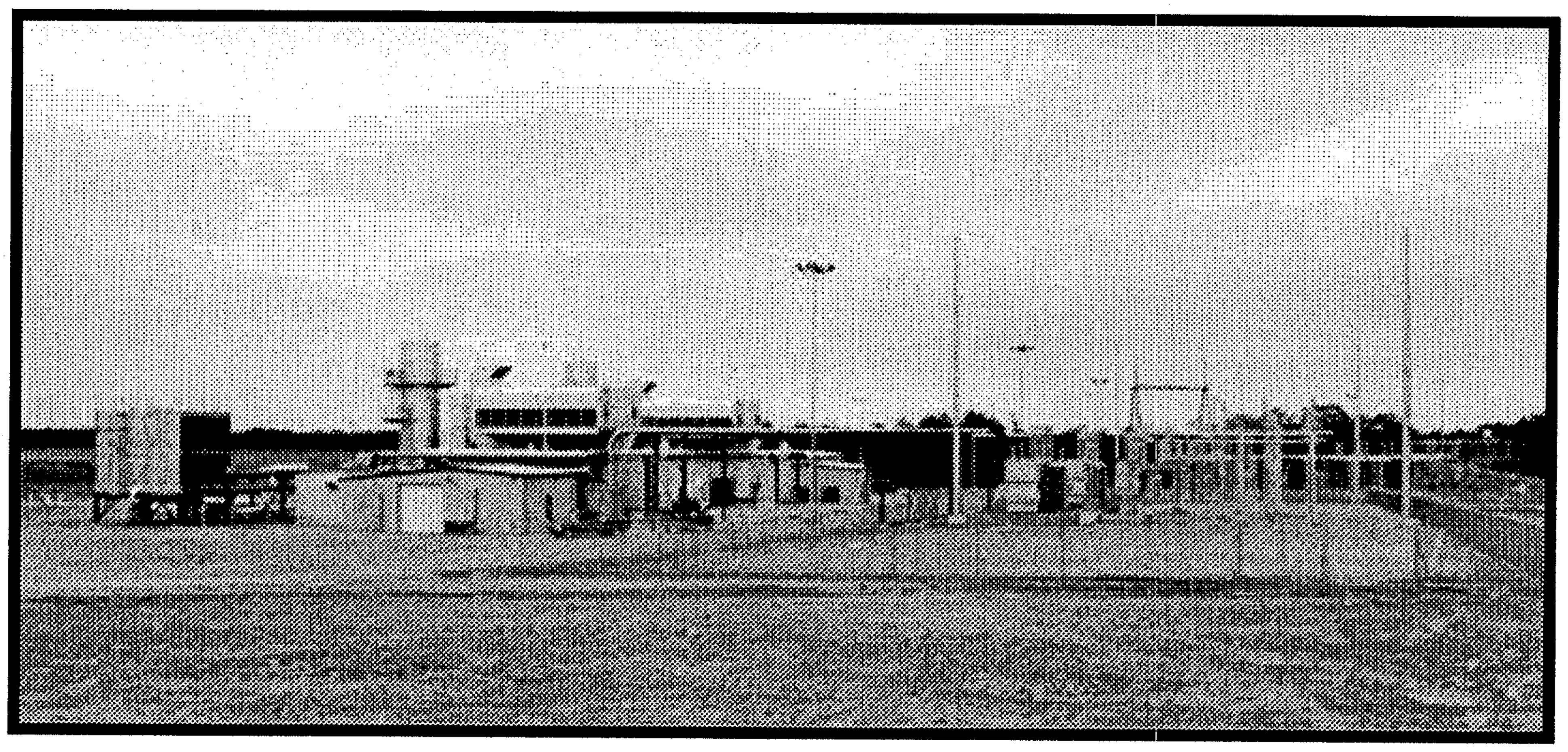






SOWEGA Power Project

During the winter of 1999 and spring of 2000 we contracted for the SOWEGA Project, located in Baconton, Georgia, shown below that was the 1st phase of a 6 unit project. The project included Balance of Plant infrastructure (pipe header, liquid fuel unloading and storage, firewater system with storage, raw water wells and storage, buildings), chiller systems, duel fuel to each turbine, inlet air heating, plant DCS system, demineralized water storage and provision for two trailer mounted demineralized water treatment. This project was developed by Cornerstone Power Services and their partners, two Rural Electric Cooperatives. SOWEGA was a $12.5 million contract. The project budget and schedule were successfully met.



SOWEGA Power Project
2 GE LM6000 GTG's installed in Baconton, Georgia.

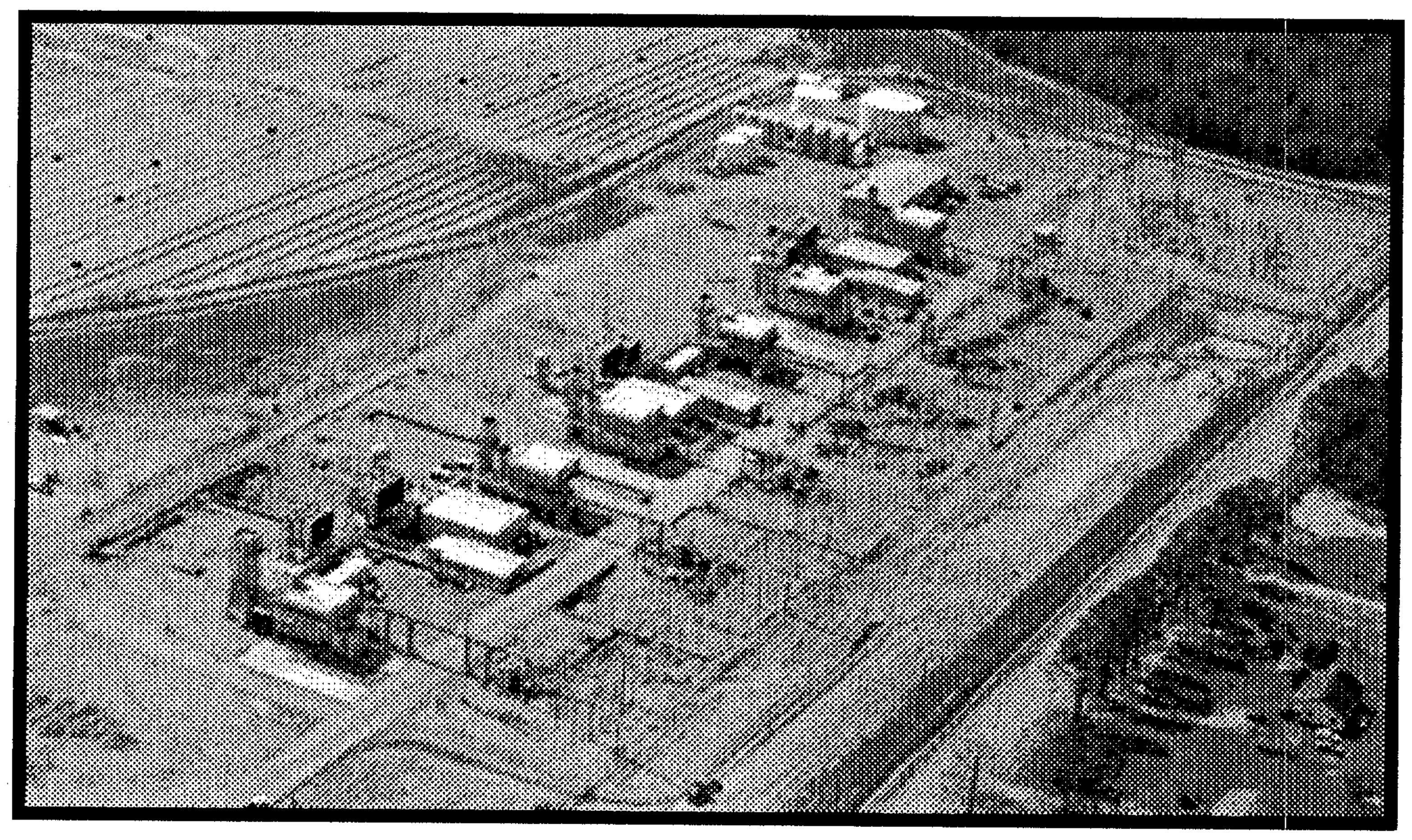
SOWEGA Project Timeline:

12/1998	4/1999	5/1999	6/1999	6/22/1999
Notice to Proceed	Unit #1 Delivery	Unit #2 Delivery	Commercial Operation Unit #1	Commercial Operation Unit #2

Wood Group Power Solutions, Inc.
Qualifications, Experience and References

Baconton Power Project

During the next year 2000 and 2001, under two contracts with Baconton Power, we agreed to expand the plant by adding four units for a total cost of $22 million. CornerStone Power Services and Coral Energy, a division of Shell Oil, were the developers and Owners of this expansion project. Our first activity involved dismantling and packing for shipment during October and November of 2000 three (3) GE LM6000 PA GTG's installed in Argentina and relocated them to the U.S. for Stewart & Stevenson. The units were converted from 50Hz to 60Hz, and installed in Baconton where we assisted GE in upgrading the turbines to PC Sprint. The installation included adding chiller systems, connecting piping from the header system to each unit and expanding the BOP electrical system as well as 230KV switchyard. The final fourth unit was added with an April 12, 2001 Notice to Proceed.



Baconton Power Project
4 GE LM6000 GTG's installed in Baconton, Georgia.

Baconton Project Timeline:

12/10/1999	2/10/2000	3/1/2000	4/1/2000	4/12/2000	5/1/2000	6/1/2000	8/1/2000
Notice to Proceed	Deliver Unit #1	Deliver Unit #2	Deliver Unit #3 & Unit #1 Commercial Operation	Notice to Proceed on Unit #4	Commercial Operation Unit #2	Commercial Operation Unit #3	Commercial Operation Unit #4

SOWEGA & Baconton Projects Owner's Reference Letter:

CornerStone Power LLC

5500 Oakbrook Parkway
Suite 130
Norcross, Georgia 30093

Telephone 770-242-5720
Fax 770-242-1545

April 16, 2003

To Whom It May Concern

Dear Sirs,

We are pleased to provide the following reference for the Wood Group staff. Cornerstone has developed over 290 MW of Simple Cycle Peaking Power Projects over the last four years. Our developments have been based around the General Electric LM 6000 Gas Turbine Generator sets, of which we have installed six during this time period. We contracted with EDG of Tulsa, OK to perform EPC work on all of these projects.

Many of the individuals who now are part of the Wood Group staff were heavily involved in completion of all of these LM 6000's, with EDG. The individuals involved in the projects were as follows:

W.T. Stewart
Kent McAllister
Craig DeWees
Bob Middaugh
Ron Carr
Les Pry

We were pleased with the ability of the group to perform on a fast track. Our first project was a Greenfield development of two LM 6000's which broke ground in mid February 1999 and was commercial in June of that same year. The second project added three LM 6000's to the same site and went commercial in July of 2000, and a third project added one LM 6000 to the same site in August of 2000. Each project had its own challenges and each was completed on a very short schedule.

These individuals showed a willingness to cooperate with the owners particularly during the construction and commissioning phase of the project. They were also very cooperative in a performance dispute with a cooling tower, and worked well with us and other vendors to resolve the issue.

They showed the ability to properly coordinate various trades during the construction phase to effectively utilize the work force in a safe manner.

All in all we were pleased with the product that we received, and would certainly consider the Wood Group as strong candidate to provide EPC work on our next project.

Sincerely,

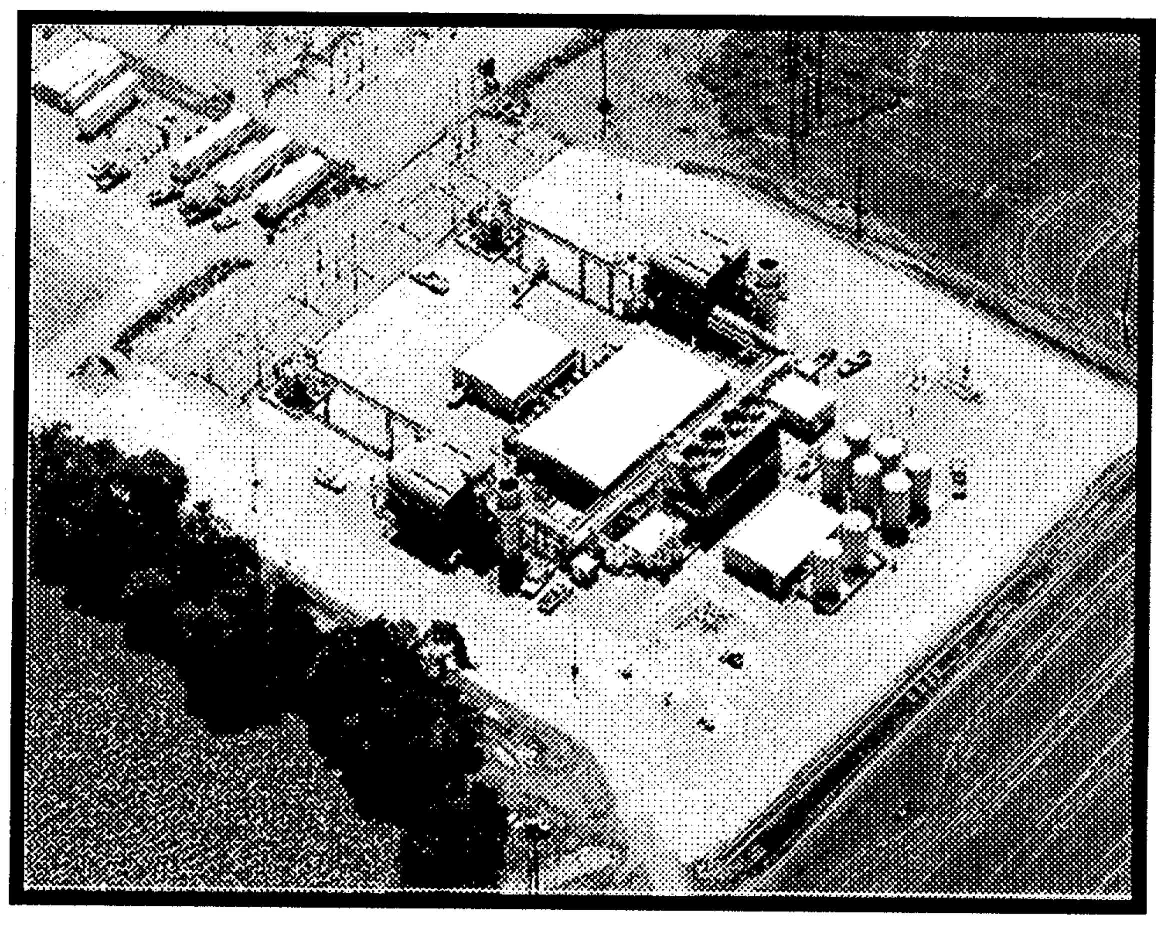
Stephen D. Howard, P.E.
Senior Vice President

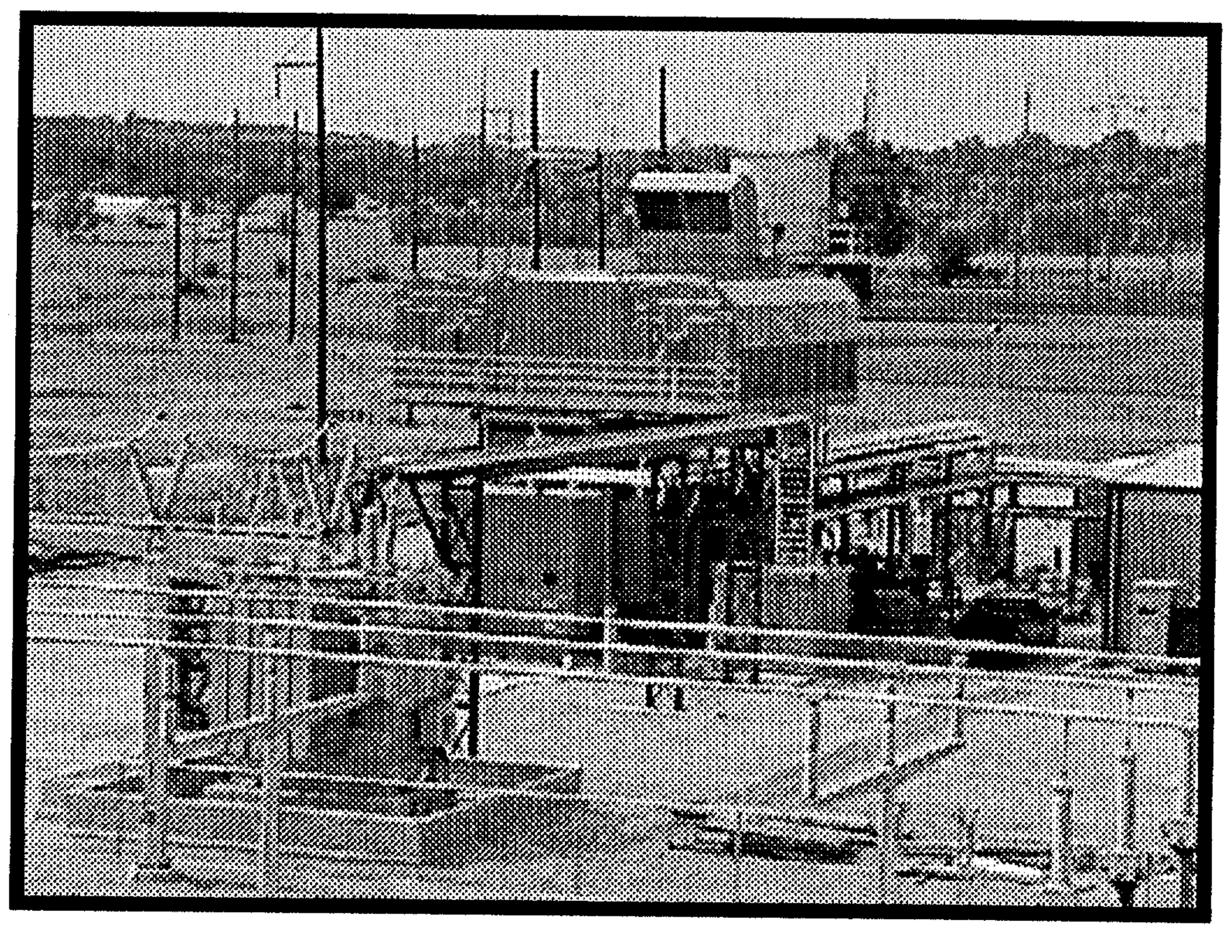
SDH:sh

Wood Group Power Solutions, Inc.
Qualifications, Experience and References

OG+E – Horseshoe Lake Power Project

During the winter of 2000 and spring of 2001, we contracted with Oklahoma Gas & Electric to provide turnkey EPC services for the installation and balance of plant services for two GE LM6000 PC GTG's for their Horseshoe Lake Power Project located in Harrah, Oklahoma site. Due to poor soil conditions, we had to remove 4 ft. of soil and reinstall it with compaction and limestone treatment. Our portion of this project included Balance of Plant, installation of the owner provided GSU's, and a ½ mile demineralized water pipeline installation underwater to the existing power plant supply. Balance of Plant equipment included a chiller system, inlet air boiler, complete plant winterization (piping heat tracing, water pumps inside buildings, etc.), demineralized water storage and fuel gas regulator/filter skids.





The project was started after the contract was signed November 10, 2000. Foundations were poured shortly after a December 2000 snow. The $12 million project was completed on time and on budget.

Horseshoe Lake Project Timeline:

11/20/2000	2/15/2001	4/15/2001	5/1/2001	6/15/2001
Notice to Proceed	Deliver Unit #1	Deliver Unit #2	Commercial Operation Unit #1	Commercial Operation Unit #2

Horseshoe Lake Project Owner's Reference Letter:

May 16, 2005

Kent McAllister
VP Turnkey Sales
Wood Group Power Solutions, Inc.
10820 East 45th Street, Suite 100
Tulsa, Oklahoma 74146-3803

Ref: Letter of Recommendation

Dear Kent,

I am writing this letter of recommendation for the former employees of EDG International, Inc. (EDG) which has since formed Wood Group Power Solutions, Inc. This letter briefly describes the project and the working relationship between OGE and EDG Inc.

The site developed was for two LM6000 PC units, complete with balance of plant equipment to be remotely operated from the main station. The schedule for construction of the units was a short duration. Construction dirt-work began mid-November 1999 with first firing of the jets expected May 1 and June 1, 2000. The May 1 target was met and the second unit was ahead of deadline by 5 days.

EDG was selected for several reasons: cost competitiveness, innovative approaches to equipment placement, and their willingness to work with us to meet deadlines. Bob Middaugh's knowledge of the Stewart and Stevens (S&S) machinery and his willingness to share information of potential problems and suggested solutions with the machinery and services from S&S also factored into the decision..

Cooperation and coordination between EDG and others involved in the project was excellent. Each day during construction a tailboard conference was called with all workers to discuss activities for the day, projected schedule and safety concerns. The crews had opportunities to voice safety concerns and planned activities in the daily meeting. There were no medical attention accidents to any contractor during the construction of these units. Once a week there was a coordination meeting when all parties active in the project (OGE, S&S etc.), discussed completed activities, planned activities, areas of concern and possible solutions to those concerns.

Both EDG QC and OGE's inspection group conducted construction quality control.. Workmanship was as expected for this type of plant. EDG took extra steps to make certain quality was in the product being delivered. No workmanship issue or workmanship warrantee claim has arisen since demobilization of the crews. Balance of plant equipment was quality, name brand equipment.

I have been informed by the Stewart & Stevens Project Manager that this was one of his best projects at that time. I believe this was largely due to EDG's ability, cooperation, and willingness to get the job done.

Should future opportunities present, OGE would seek services from the Wood Group.

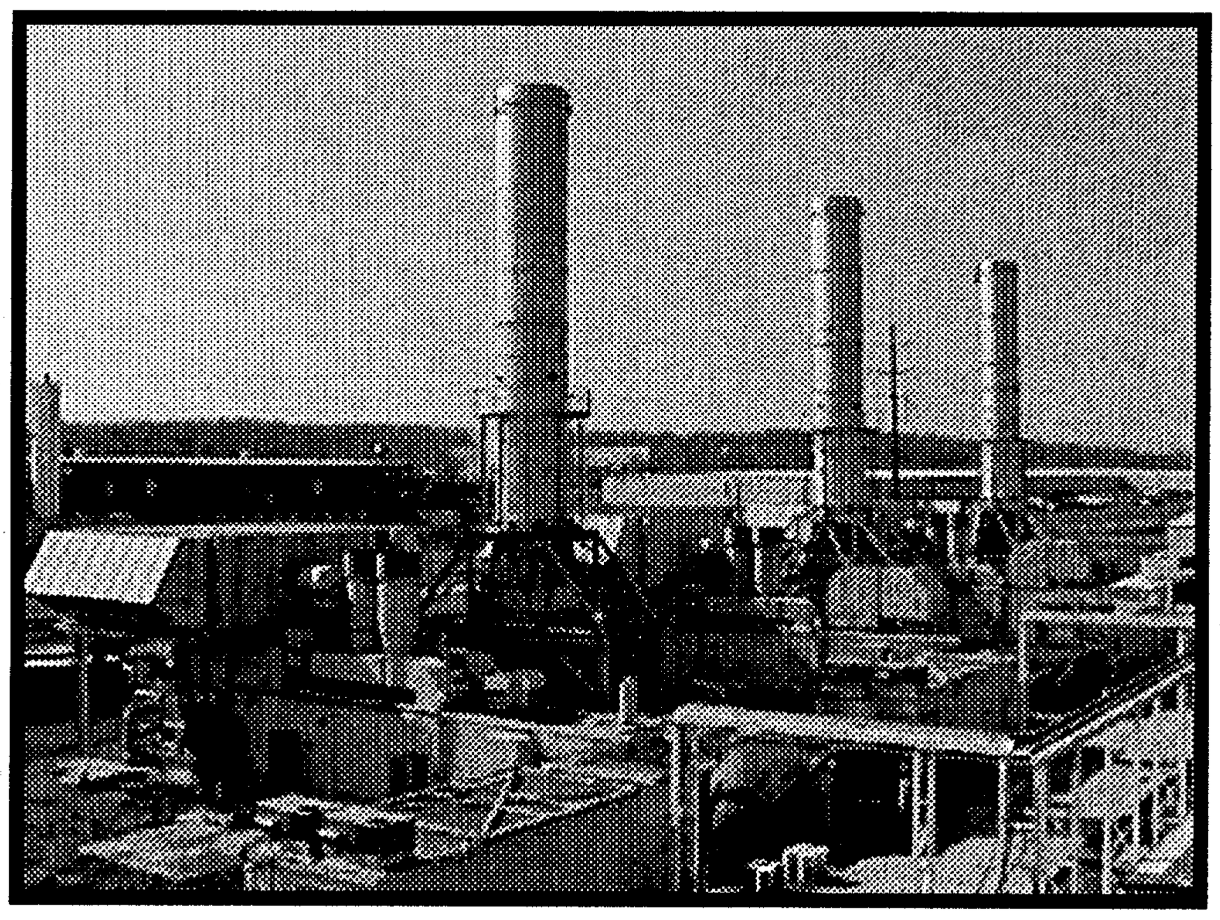
If you should have any questions, please feel free to contact me.

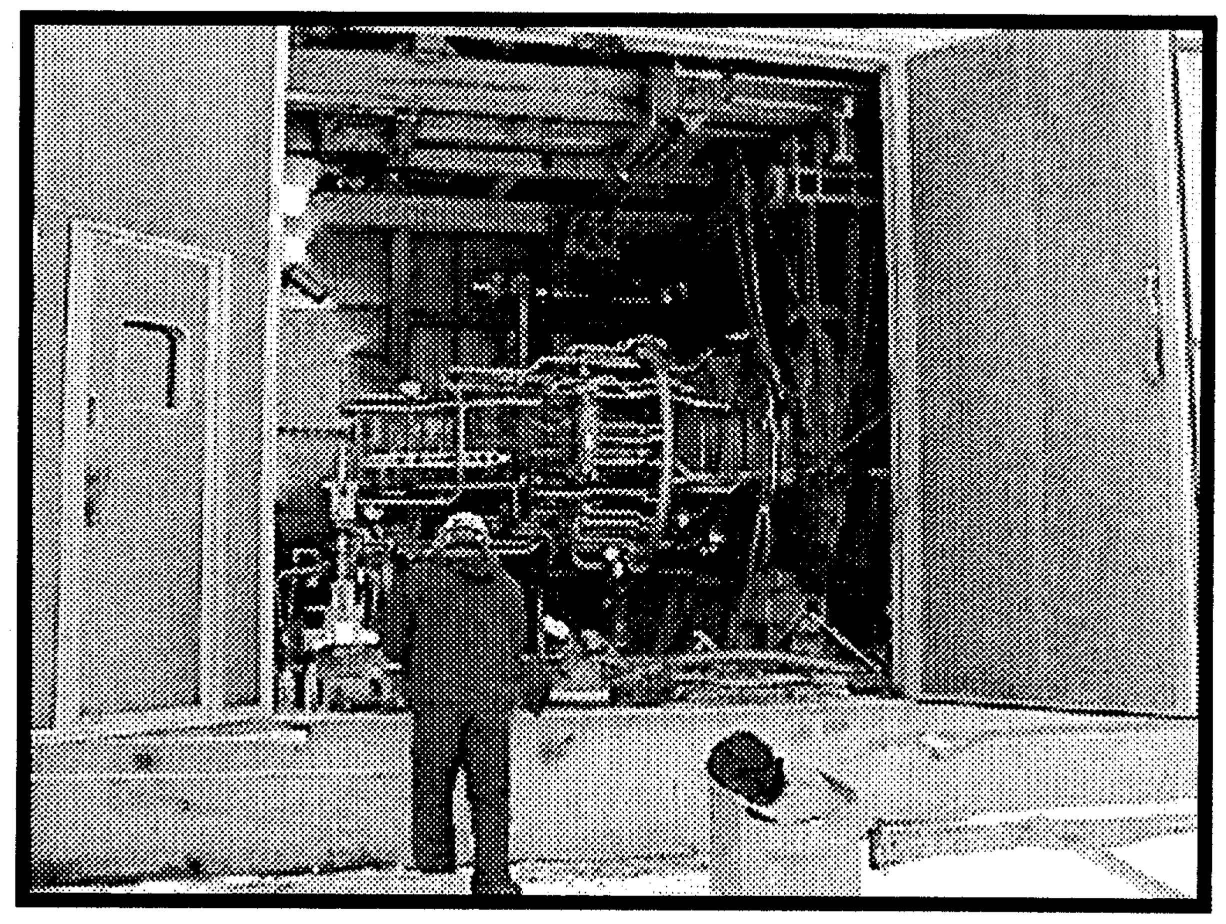
David J. Nunez
Supt. Engineering
Power Supply Service
OGE Electric

Wood Group Power Solutions, Inc.
Qualifications, Experience and References

Williams-Hazleton Power Project

After several months of studying several options for the owner, in June 2001 we executed a $10 million turnkey EPC contract with Williams Energy Services to add three (3) GE LM 5000 gas turbine generator peaking units to their Williams-Hazleton Power Project. The owner relocated the units from China. Our Scope of Work included working inside their existing facility to clear space, provide utility interconnects, expand plant DCS system, provide BOP facilities and electrical switch yard, transformers and switchgear to connect into the 69KV grid. The project was built and mechanically complete on schedule and on budget. The plant commercial operation was delayed due to the Owner's air permit but is presently operational.





Hazleton Project Timeline:

6/2001	11/10/2001	12/20/2001	1/10/2002	1/20/2002	2/20/2002	5/30/2002
Notice to Proceed	Unit #1 Delivery	Unit #2 Delivery	Unit #1 Mechanical Complete*	Unit #3 Delivery	Unit #2 Mechanical Complete*	Unit #3 Mechanical Complete*

***Owner did not have air permit to operate.**

Letter from Owner's Project Manager for the Hazleton Project:

April 17, 2003

To Whom It May Concern:

Subject: Hazelton Power Project
EPC Contractor Performance

As Project Manager for Williams Company for the installation of the power generation facility addition at Hazleton, I was very satisfied with the performance of the present Wood Power Solutions, Inc. personnel assigned to the project.

Key individuals included the following:

W.T. Stewart
Craig DeWees
Lee Fields
John Lopez
Jessica Baker

These individuals are now with the Wood Group Power Solutions and were responsible for the success of the Hazleton Project. The project EPC Contract was administered in a very professional manner. Exceptional communications existed between Williams and Lee Fields, the EPC Contractors Project Manager. Key to the success was the upfront planning, scheduling of manpower, administration of QA/QC and Safety and focus on quality workmanship. The project was completed on schedule. There were no QA/QC or Safety issues associated with the project. Commercial operations, however, was delayed because of Air Permits which were Williams responsibility. The facility now has its Air Permit and is commercial.

I personally enjoyed the opportunity to work with this group of people.

Greg Grooms
Project Manager – Hazleton Project
Williams Energy Services, Inc.

REFERENCES:

The representative plants, Ponca City Unit #4, SOWEGA, Baconton, Horseshoe Lake, and Williams-Hazleton involved at least three of our Key Personnel as we performed turnkey EPC services. Below you will find reference information regarding said projects:

Project	Contact Name	Telephone#
Drummond	Alan Perks	(205) 384-2331
TCT Test Cell	Pete Watson	(403) 219-8641
Vineland	Rich Albosta	(973) 753-0104
SOWEGA	Bud Stacy	(770) 242-5720
Baconton	Bud Stacy	(770) 242-5720
OG+E	David Nunez	(405) 553-3099
Hazleton	Greg Grooms	(918) 706-2992

Addendum No. 3

Strategic Energy Services, Inc. Qualifications and Experience

Proven Results

Numerous clients have been successfully supported by Strategic. A partial listing of clients includes the following companies:

ABB Energy Ventures, Inc.
Advanced Energy Systems, Inc.
Air Products and Chemical, Inc.
Atlantic Thermal Systems, Inc.
Aquila Corporation
ArcLight Capital Partners, LLC.
Bioenergy Development Corporation
Catalyst Energy Corporation
Comision De Regulacion De Energia Y Gas ("CREG")
Republica De Colombia
Commonwealth Electric Company
Delta Power Company, LLC.
DG Energy Solutions, LLC.
El Paso Electric Company
Exelon Capital Partners, LLC.
General Electric Capital Corporation
Gregory Power Partners, LLC.
Hill International, Inc.
Liberty Power Latin America LP
Mobil Power, Inc.
Novion, Inc.
Ontario Hydro International, Inc.
PEPCO Energy Services, Inc.
PJM Interconnection, LLC
Sun Oil Company
Toronto District Heating Corporation
Trigen Energy Corporation
Unicom Enterprises, Inc.
University of Pennsylvania

Professional Services

Strategic located midway between Philadelphia and New York City operates as a unique energy firm providing services in the following areas:

- Utilities Asset Management & Optimization
- Project Economic and Financial Evaluation
- Energy System Planning and Management
- Energy Technology Investment Due Diligence
- Combined Heat and Power ("CHP") Development
- CHP, District Heating and Cooling Cycle Studies
- GE GateCycle Heat & Material Balances
- Gas Turbine Inlet Air Cooling Evaluation
- Low Temperature Thermal Energy Storage
- Energy Conservation Audits
- Distributed Generation Project Development
- District Heating and Cooling Project Development

Strategic provides domestic and international services to independent power, financial institutions, regulators, governments, district heat & cooling companies, CHP, thermal energy producers, consumers. Services are provided at any phase of a project.

- Operations and Asset Management
- Energy Project Appraisal and Feasibility Analysis
- Energy Project Condition Assessment
- Operative Contract Development and Negotiation
- Environmental Permitting Overview
- EPC Contract Assistance and Selection
- Energy Project Identification
- Services to Independent System Operators (ISO)

Client service is **Strategic's** key objective. **Strategic** acts as an extension of an organization enhancing the effectiveness of their staff for the short or long term. **Strategic's** broad experience provides valuable creative input immediately upon request mitigating risk and maximizing the bottom line.

Contact:
Raymond Pasteris
Strategic Energy Services, Inc.
430 Trend Road
Yardley, Pennsylvania 19067
Phone: 215-736-8170 Fax: 215-736-8171
email: rpasteris@strategicenergy.com

strategic

strategic

Strategic Energy Services, Inc.

Strategic located between Philadelphia and New York City operates as a unique professional services firm to independent power, district energy and energy consumers.

Exhibit IMM-00011
Docket No. EL21-91-000, -003

Raymond M. Pasteris

Raymond M. Pasteris is President of Strategic Energy Services, Inc., a professional services firm, which he founded in 1993 to provide project development services to energy producers and consumers worldwide. Mr. Pasteris has over thirty years of domestic and international experience with all phases of engineering, operations and development of energy projects. He has lead energy project development in Argentina, Canada, China, Colombia, the Czech Republic, Peru, Viet Nam, the United Kingdom, as well as the United States.

Previously, from 1990 to 1993, he served as Vice President of Development for United Thermal Corporation, the largest publicly held, independent district heating company in North America. Mr. Pasteris was responsible for project development, contract negotiations, equipment selection and economic evaluations of energy projects. Concurrently he also served as Vice President of Engineering and was responsible for managing corporate engineering, capital budgets and risk management.

From 1986 to 1990 Mr. Pasteris served as General Manager of Cogeneration for Catalyst Energy Corporation a publicly held independent power company, headquartered in New York City. Mr. Pasteris was responsible for all operational, commercial and financial activities of three operating cogeneration projects and one hydroelectric project totaling 51 MW electric capacity, 150 Million BTU per hour of thermal energy and $17 million in annual revenue. Mr. Pasteris also was responsible for facility modifications to improve performance and the management of 42 on site employees.

From 1974 to 1986 Mr. Pasteris served as a senior engineer for Mobil Corporation and developed cogeneration projects for Mobil's operating affiliates worldwide. Activities included field survey of processing facilities to identify cogeneration opportunities, developing power plant configurations to match facility energy requirements for steam and power, performing capital cost estimates, and presenting economic feasibility for executive approval. His efforts resulted in the construction of four cogeneration projects totaling 200 MW at four Mobil refineries.

Mr. Pasteris developed and taught courses in Industrial Water Treatment, for engineers and operators from industries and water utilities in the Chicago area, at Joliet Junior College, Joliet, Illinois.

He is a Licensed Professional Engineer in the State of Illinois and a member of IEEE, USCHPA, ASHRAE and a founding member and Vice-Chairman of the Turbine Inlet Cooling Association.

Mr. Pasteris received a Bachelor of Science in Chemical Engineering in 1975 from the University of Illinois.

Past Services Provided

Independent Power and Cogeneration Industry

IPP Optimization and Strategic Energy Plan
- Build GateCycle model of a 400 MW two on one GE Frame 7FA Combined Cycle Plant.
- Evaluated economics of overnight part load operation of the GTG's and STG.
- Evaluated economics of the shutdown of the STG overnight.
- Provided CycleLink offline GateCycle interface for real-time plant optimization by operators.

Cogeneration Project Request for Proposal Response
- Selected technical power cycle configuration to meet industrial steam and power demands.
- Performed cogeneration project heat and material balances.
- Performed project capital cost estimate and soft cost estimates.
- Performed project proforma analysis and determined steam and power price and structure.
- Generated final technical and commercial proposal on behalf of the client.
- Client currently exclusively developing 11 MW power project with host industry start-up in 2002.

Cogeneration Project Feasibility Study
- Selected the technical power cycle configurations to meet district steam demands.
- Performed cogeneration project heat and material balances.
- Performed project EPC cost estimates and soft cost estimates.
- Performed project proforma analysis and determined steam and power price and structure.
- Generated a final technical and commercial report.

Acquisition of Existing Industrial Cogeneration Project
- Performed financial evaluation to establish project value for the acquiring company.
- Performed technical evaluation to determine future project up side potential for client.
- Generated final technical and commercial proposal on behalf of the client.
- Client was selected to the short list of bidders.

Cost of New Entry CT Plant Evaluation for PJM
- Performed technical evaluation to establish project performance, capital and O&M fixed costs.
- Performed financial evaluation to determine fixed revenue requirements of new entry CT plant.
- Conducted numerous presentations to PJM member generators.

Past Services Provided

District Heating and Cooling Industry

EPC Bid Evaluation
- Performed a life cycle economic evaluation of six (6) competitive EPC bids for a 22,000 Ton and 250MMBTU/Hr district heating and cooling plant.
- Evaluation included determining all electric, fuel, water, chemical and O&M expenses.
- Provided a final report ranking the bidders on a project life cycle cost NPV basis.

Convention Center Heating and Cooling Plant RFP Response (50 MMBTU/Hr Heating-10,500 Tons Cooling 4 MW Electric Peak Shave)
- Selected the technical heating and cooling cycle configurations to meet convention center demands.
- Performed heating and cooling project heat and material balances.
- Performed project EPC cost estimates and soft cost estimates.
- Performed project proforma analysis and determined heating and cooing price and structure.
- Assisted in final RFP response preparation and follow up question by Convention Center Authority.
- Client was awarded contract of 20-year energy supply services. Scheduled for 2003 startup.

Services Provided to Governments

Country Regulatory Review Regarding Cogeneration
- Conducted a comprehensive review of current and proposed regulations regarding cogeneration and self-generation for the country of Colombia's Commission for the Regulation of Energy and Gas.
- Submitted a final report of recommendations for implementation into new or modified regulations.

US Trade and Development Agency Funding Proposal
- Developed and submitted proposal to obtain TDA funding for a feasibility study for a cogeneration project in Europe on behalf of our client.
- Approval was obtained for $350,000 of TDA funding to perform the feasibility study.

Oil Refining Industry

Cogeneration Project Proposal Bid Evaluation
- Performed life cycle economic and financial evaluation of seven (7) competitive third party developer bids for a nominal 100 MW cogeneration project.
- Evaluation included a detailed analysis of the electric and steam price and structure expenses for each proposal over the project life.
- Provided a final report ranking the bidders on a project life cycle basis.

TAB J

Federal Register Notice

Notice of Filing

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket Nos. ER05-____ and EL05-___

NOTICE OF FILING

(September __, 2005)

Take notice that on August 31, 2005, PJM Interconnection, L.L.C. ("PJM") submitted under section 205 of the Federal Power Act, 16 U.S.C. § 824d, revisions to the Reliability Assurance Agreement among Load-Serving Entities in the MAAC Control Zone, the Reliability Assurance Agreement among Load-Serving Entities in the PJM West Region, and the Reliability Assurance Agreement among Load-Serving Entities in the PJM South Region, to amend such agreements to incorporate a new Reliability Pricing Model and consolidate such agreements into a single Reliability Assurance Agreement among Load-Serving Entities in the PJM Region. PJM also submitted under FPA section 205 related revisions to the PJM Open Access Transmission Tariff and, under FPA section 206, 16 U.S.C. § 824e, associated conforming revisions to the PJM Operating Agreement.

PJM requests that the enclosed changes generally become effective on June 1, 2006, the start of PJM's next annual planning period, except for those changes concerning the RPM auctions needed before that planning period, for which PJM requests an effective date of February 1, 2006.

PJM states that copies of this filing were served upon all PJM members, and each state electric utility regulatory commission in the PJM regions, and requests waiver as necessary to permit such service.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Document Content(s)

Exhibit IMM-00012

2009 FEB 17
2009 FEB 19 P 12:53

PJM Interconnection
Valley Forge Corporate Center
955 Jefferson Avenue
Norristown, PA 19403-2497

Robert V. Eckenrod
Counsel
610.666.3184| fax 610.666.8211
eckenr@pjm.com

February 19, 2009

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426-0001

ORIGINAL

Re: *PJM Interconnection, L.L.C.*, Docket No. ER09-730-000

Dear Ms. Bose:

Pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d and the Federal Energy Regulatory Commission's ("FERC" or "Commission") Regulations, 18 C.F.R. Part 35, PJM Interconnection, L.L.C. ("PJM") hereby submits for filing revised tariff sheets of the PJM Open Access Transmission Tariff ("PJM Tariff").[1] The purpose of these revisions is to make clarifying and other changes to PJM's Black Start Service practices and rules by amending Schedule 6A of the PJM Tariff to allow Black Start Service providers the opportunity to recover incremental costs associated with complying with North American Electric Reliability Corporation ("NERC") Reliability Standards. Additionally, the proposed revisions address the ability of Black Start Service provider to seek independent, Commission-approved capital investment recovery, in lieu of the PJM Schedule 6A formulaic revenue recovery. PJM respectfully requests that the Commission accept the proposed revisions to the Tariff for filing, allowing them to become effective April 21, 2009.

I. Background

Currently, Schedule 6A of the PJM Tariff sets forth the details necessary for identifying generators to provide Black Start Service[2] that are included in each Transmission Owner's system restoration plans and are critical for restoration of the Transmission System in the event of de-energizing event. In this regard, the owners of Black Start Units identified for inclusion in a system restoration plan commit to providing Black Start Service for a rolling two-year commitment, until terminated either by the Transmission Provider, Transmission Owner and/or Black Start Service provider.

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[1] Capitalized terms not otherwise defined herein have the meaning specified in the PJM Operating Agreement or the PJM Open Access Transmission Tariff, as appropriate.

[2] Black Start Service represents the capability of generating units to start without an external (system) electrical supply or the demonstrated ability automatically to remain operating at reduced levels when disconnected from the grid. *See PJM Tariff Schedule 6A ¶ 2.*

Importantly, the provisions of Schedule 6A also set forth the annual Black Start Service revenue requirement for the PJM Region, which is the sum of the annual Black Start Service revenue requirements for each generator that is designated as providing Black Start Service and has provided PJM with a calculation of its annual revenue requirements; calculated based upon the formula as set forth in paragraph 18 of Schedule 6A. In turn, Transmission Customers are charged for Black Start Service according to the formulas set forth in Schedule 6A.

Schedule 6A and its associated revenue requirements were grounded in the idea that they would provide an incentive for generators to produce Black Start Services by allowing them to include in their Black Start Service revenue requirements the costs associated with Black Start Service, plus an incentive factor.[3] Subsequently, more flexibility in the recovery of fixed costs associated with providing Black Start Service was adopted so as to encourage existing and new generation to provide the service.[4]

With the establishment and development of mandatory Reliability Standards in recent years, there exists a general concern that Black Start Service providers may be subjected to incremental costs associated with providing Black Start Service that they otherwise would not have incurred, particularly as those requirements related to the designation of their facilities as "critical assets" in a system restoration plan[5] and, therefore, subject to further Critical Infrastructure Protection ("CIP")[6] Reliability Standards. Thus, late in 2007, PJM's Market Implementation Committee chartered the Black Start Services Working Group ("BSSWG"). The BSSWG was directed to discuss and recommend courses of action to address additional Black Start issues. Specifically, at that time, the BSSWG was charged with: (i) investigation of the inclusion of NERC CIP Reliability Standards costs in the current Black Start cost recovery; (ii) investigation of a provision for Black Start Service providers to seek capital investment recovery related to Black Start Service independently of the formulaic rate set forth in the current Schedule 6A; (iii) investigation of a requirement for PJM to handle billing associated with any newly proposed cost recovery mechanisms, and; (iv) investigation of the need to update a cross reference in the Schedule 6A formulaic rate to Capacity Deficiency Rate ("CDR") to account for implementation of the Reliability Pricing Model ("RPM").

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3 Currently, the incentive factor is set at ten percent.

4 In 2004, a change to the "Black Start Allocation Factor" used to determine the "Fixed Black Start Service Costs" was made to allow Black Start Service providers the opportunity to recover capital investment incurred to replace retired Black Start Service resources, to install Black Start capability on new units with better control capabilities to improve existing restoration plans and to address any significant major equipment failures on existing resources. *See PJM Interconnection, L.L.C.*, Docket No. ER04-598-000 (2004).

5 NERC Reliability Standard CIP-002-1, R1 requires the Responsible Entity to identify and document a risk-based assessment methodology to use to identify its Critical Cyber Assets. Such risk-based assessment methodology shall consider, among other things, systems and facilities critical to system restoration, including black start generators. Once identified as a Critical Cyber Asset, the Responsible Entity must undertake a variety of further steps to ensure the protection of that Critical Cyber Asset, including placement of security management controls (CIP-003-1), training of personnel having authorized cyber or physical access to the Critical Cyber Asset (CIP-004-1), identification and protection of electronic security perimeters (CIP-004-1), physical security program (CIP-005-1), and so forth. As set forth in detail in those requirements, they chiefly apply to those cyber assets associated with identified critical assets.

6 Early on in the process, it was recognized that Black Start Unit owners may be subject to a variety of NERC Reliability Standards that may not relate to their provision of Black Start Service, for example, NERC CIP 003 – 009.

Over the course of the ensuing months, the BSSWG met and discussed various alternatives designed to address the assigned goals. The following proposed revisions to Schedule 6A represent the collective work of the BSSWG members and, in turn, PJM stakeholder consultation and consideration, and are designed to address the following purposes:

(1) establish a tiered level of commitment for a Black Start Unit to provide service dependent upon whether they are seeking to recover additional fixed cost capital costs or not;

(2) allow Black Start Service Providers the opportunity to recoup reasonable costs that would not otherwise be incurred but for maintaining their Black Start units in compliance with NERC standards, and;

(3) establish an alternative capital cost recovery mechanism by allowing a Black Start Service Provider to seek Commission approved cost of service recovery in lieu of the proposed Schedule 6A formulaic rate.

II. The Proposed Revisions

As indicated above, the proposed changes tendered in this filing are primarily grounded in the recognition that Black Start Services are a key element in reliably and promptly restoring power to the PJM Region in the event of a power system restoration event (e.g., blackout). The need for adequate Black Start Service and the obligation of an ISO/RTO to compensate those entities that provide Black Start Service in order to ensure reliable operation of the transmission system has been recognized by the Commission [7] and the proposed revisions here attempt to encourage the provision of new and existing Black Start Service by ensuring that Black Start Service providers are afforded the opportunity to recover their true costs of service, plus a reasonable incentive factor. In this regard, while the concepts originally established under Schedule 6A remain intact, some revisions in the calculation of reasonable cost of service recovery have been changed.

A. Election of Applicable Commitment Period

Initially, the proposed revisions set forth two levels of commitment for a generator to provide Black Start Service dependent upon the election of the unit owner to either forego or recover any new or additional "Black Start Capital Costs"[8]. The election to forego recovery of Black Start Capital Costs requires a commitment to provide Black Start Service on a rolling, two year basis. However, those Black Start Service providers who elect to recover new or additional Black Start Capital Costs will commit to provide Black Start Service for a term based upon the

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[7] *See e.g. PJM Interconnection, L.L.C.*, 109 FERC ¶ 61,368 at P1 (2004).

[8] Newly defined further in Schedule 6A, as a sub-set of the definition of Fixed Black Start Service Costs, Black Start Capital Costs are the capital costs approved by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other products or services such unit may provide. These costs are proposed to include those costs incurred by the Black Start Owner to meet applicable NERC Reliability Standards.

reasonable estimate of the expected life of the Black Start Unit, as set forth in a newly proposed Cost Recovery Factor ("CRF") Table in paragraph 18 of Schedule 6A.

The allowance of this newly proposed option is grounded in the recognition that some, but not all, Black Start Service Providers may be required to invest in additional capital improvements to ensure compliance with relevant Reliability Standards that are solely related to the provision of Black Start Service, and may decide to recover those costs through Schedule 6A in return for an applicable commitment period. It was recognized by the BSSWG that while Black Start Unit owners may be subject to a variety of NERC Reliability Standards unrelated to the provision of Black Start Service, certain Reliability Standards may uniquely impact the provision of Black Start Service and require further capital investment to remain compliant. This option now permits the Black Start Service provider to recover those improvements. However, to be clear, the proposed inclusion of Fixed Black Start Capital Costs contemplates only the inclusion of further capital improvements that would otherwise not be required but for the Black Start Unit owner's prevision of Black Start Service.[9]

Accordingly, proposed paragraph 6 sets forth the applicable commitment period for those owners who elect to recover new or additional Black Start Capital Costs and provides that they shall commit to provide Black Start Service for a term based upon a reasonable estimate of the expected life of the Black Start Unit, as set forth in the CRF Table in paragraph 18. Application of the proposed CRF to any newly incurred fixed Black Start Service Costs is designed to ensure that recovery of the new improvements are depreciated in a manner commensurate with the age of the Black Start Unit at the time of the improvement. Likewise, the commitment to provide Black Start Service on a forward basis is also tied to the age of the Black Start Unit to ensure that the Black Start Unit owner may reasonably recover the additional capital investment with a corresponding commitment term based upon the expected life of the Black Start Unit. Thus, the opportunity to recover fixed capital improvements through the application of Schedule 6A will require a commitment on the part of the Black Start Unit owner to provide Black Start Service for the term as set forth in the CRF table and represents a reasonable recovery of its capital investment.[10]

Further proposed language in paragraph 6 has been offered to ensure that the Black Start Unit owner, who has elected to make capital improvements and commit to providing Black Start Service for the applicable term, has the opportunity to recoup those costs in the event that its commitment period is terminated through no fault of its own. As such, where the Transmission Provider, with the consent of the Transmission Owner, or the Transmission Owner, with the consent of the Transmission Provider, decides to terminate the commitment with one-year advance notice, then the Transmission Owner shall reimburse the Black Start Unit owner for any unrecovered amount Fixed Black Start Service Costs over a period not to exceed

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[9] Perhaps the most elementary example of this would be an otherwise compliant generator who is required to install a fence around its facility as a result of the facility's designation as a "critical," and therefore subject to NERC CIP standards. In this case, the owner would elect to recover the additional fixed costs and commit to providing Black Start service based upon the reasonable estimate of the expected life of the Black Start Unit itself, as set forth in the CRF Table found in paragraph 18.

[10] As set forth further herein, the election of a Black Start Unit owner to recover its investment is not limited to Schedule 6A. Indeed, as part of these suggested changes to Schedule 6A, the Black Start Unit owner has the option to seek recovery of its Black Start costs of service through the application of a Commission approved rate in lieu of the recovery provided under Schedule 6A.

five years.[11] However, in those cases where the Black Start Unit owner decides to terminate its applicable commitment period, or is the subject of involuntary termination for failure to meet the testing requirements set forth in paragraph 15, then it shall forego any otherwise existing entitlements to revenues collected pursuant to Schedule 6A and must fully refund any amount of Black Start Capital Costs recovered under a FERC-approved rate in excess of the amount that would heve been recovered pursuant to the Schedule 6A revenue requirement formula.

For those Black Start Service providers who forego recovery of new or additional Black Start Capital Costs, Paragraph 5 of Schedule 6A still sets forth a rolling, two-year term of commitment. However, the tendered revisions to paragraph 5 further clarify that the term commitment shall continue to extend until the Black Start Unit owner, or the Transmission Owner, with the consent of the Transmission Provider (or the Transmission Provider with the consent of the Transmission Owner) provides written, one-year advance notice of its intention to terminate the commitment. Aside from clarifying changes made to the calculation of the revenue requirement as discussed further herein, the requirements of Black Start Unit owners providing service under Schedule 6A pursuant to this commitment remain largely intact.

Newly proposed paragraph 6A has been carved out of the existing paragraph 5, and like existing paragraph 5, it details the consequences in the event that a Black Start Unit owner fails to meet its applicable commitment period. Except, the provisions of this paragraph have been expanded to account for the different consequences attendant to the Black Start Unit owner's election of revenue recovery under proposed paragraph 5 or 6, with similar consequences of revenue forfeiture as applicable to its election of recovery. Similarly, revisions to paragraph 15 have been proposed to clarify that if the Black Start Unit owner fails to meet its annual testing requirements and does not make the necessary corrections to pass subsequent testing, then the Black Start Unit owner will be deemed to have failed to meet its applicable commitment period and will be subject to the forfeiture of revenues as set forth in proposed paragraph 6A.

B. Revenue Requirements

Currently, paragraph 17 of Schedule 6A limits the recovery of an owner's Black Start Service expenses to the formula rate contained in paragraph 18. However, proposed revisions to paragraph 17 now contemplate that the Black Start Service provider may elect to base its applicable revenue requirements on either a FERC-approved rate for the recovery of the cost of providing such service for the entire duration of the commitment term selected in either paragraph 5 or 6, or the formula set forth in paragraph 18. By allowing the Black Start Service provider the option to elect either avenue to recover rates, PJM also will clarify further in proposed paragraph 17 that PJM will presume that any FERC-approved cost recovery plan would be the exclusive basis for the recovery of a Black Start Unit's recovery or costs during the applicable term.

Spelling out the authorization for a Black Start Unit owner to seek FERC-approved cost recovery merely reinforces that owner's unilateral right under Section 205 to file with FERC to establish or to revise its annual cost based revenue requirement for Schedule 6A. Importantly,

[11] The choice to establish a five-year reimbursement period was largely made as a result of a compromise between two competing stakeholder views; namely reimbursing the investment over the one year period prior to the termination or allowing reimbursement over the remaining expected life of the unit as set forth in the proposed CRF table.

however, proposed paragraph 17 clarifies that an owner seeking FERC-approved recovery will be limited to that recovery method to ensure that the Black Start Unit owner will only be compensated for those costs associated with that service that are not being recovered through other rates or charges.

As noted above, the primary impetus for the proposed Tariff revisions center on allowing a Black Start Unit owner to recover its reasonable costs associated with compliance to NERC-mandated Reliability Standards that it otherwise would not have incurred but for the application of those standards. This is primarily a result of the generation owner's classification of certain units, likely black start units, as critical assets. The critical asset designation is the differentiating issue which separates black start units from other generation resources. It makes the "critical" units potentially subject to the NERC CIP standards where other generation assets are not. Thus, sweeping changes to the formula for calculating a generator's annual Black Start Service revenue requirement are set forth in paragraph 18.

Currently, Schedule 6A provisions calculate a Black Start Unit owner's revenue requirement by application of a formula which is comprised of five distinct factors: (i) Fixed Black Start Service Costs (" Fixed BSSC"); (ii) Variable Black Start Service Costs ("Variable BSSC"); (iii) Training Costs; (iv) Fuel Storage Costs and Carrying Costs; and (v) 1 + an Incentive Factor.[12] The application of these five distinct factors is not proposed to change in any substantial way, but, rather, it is the pieces that make up those factors that are slated for renovation. In this regard, the first formulaic factor – Fixed BSSC – has been substantially revised to capture two broad purposes; namely, (i) allow Black Start Service providers to recover the fixed costs of any capital improvements made solely to meet the requirements of NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by that unit; and (ii) replace a reference in the formula to the retired PJM Capacity Deficiency Rate concept with the net CONE concept currently used in PJM's Reliability Pricing Model ("Cost Of New Entry").

With respect to the first purpose, the Fixed BSSC formulaic factor had to be broken down further to be applicable to, both, a generator that elects to forego any new or additional Black Start Capital Costs and those that seek to recover additional Black Start Capital Costs. Thus, the applicable Fixed BSSC formulaic factor for Black Start Units with a commitment established under proposed paragraph 5 (i.e., electing to forego capital costs recovery) is **CONE *365 * Black Start Unit Capacity * X**, where CONE is the newly defined Cost of New entry, Black Start Unit Capacity is the capacity of the unit expressed in MW, and X is the Black Start Service Allocation Factor.[13]

12 For units that operate at reduced levels when automatically disconnected from the grid, the formula is revised to remove Fixed Black Start Service Costs, Variable Black Start Service Costs and Fuel Storage and Carrying Costs since these components are not necessary as these units do not have qualifying incremental expense associated with providing Black Start Service and do not keep an inventory of fuel specifically for Black Start Service. This revised formula exists in the current Schedule 6A and will be applicable in the proposed Schedule 6A, with proposed clarifications to the formulaic component definitions, where applicable.

13 The Black Start Service Allocation Factors is a defined term which was incorporated into Schedule 6A in February 2004 to provide an incentive to encourage existing and new generators to provide black start service. The inclusion of the allocation factor created more flexibility in the recovery of the fixed costs incurred to provide the black start service since the then current formula did not permit black start service providers the opportunity to recover capital expenditures to replace existing resources or make major improvements in the resources to continue or

Where a generator has elected to recover new or additional fixed Black Start Capital Costs pursuant to a commitment established under proposed paragraph 6, the proposed Fixed BSSC formulaic factor shall be **Black Start Capital Cost * CRF**. Black Start Capital Costs are defined as the capital costs approved by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service and those fixed costs incurred by the generator in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by that unit. Importantly, in this calculation, Black Start Capital Costs are defined and limited to only those incremental costs incurred by the generator to provide the Black Start Service. All other costs, including those relating to compliance with NERC Reliability Standards which would have been incurred by the Black Start Unit Owner notwithstanding its provision of Black Start Service, may not be recovered pursuant to this Schedule 6A.

The proposed CRF table is a vital component of this proposed formula as it provides the calculation of the levelized CRF which is then multiplied by the Black Start Unit owner's Black Start Capital Costs to derive the appropriate Fixed Black Start Service Costs. Also, the CRF table provides the appropriate level of commitment for those Black Start Unit owners electing to provide service pursuant to proposed paragraph 6, which is a term based upon a reasonable estimate of the expected life of the Black Start Unit.

Conversely, the opportunity to recover variable costs attributable to supporting Black Start Service is not tied to the election of one commitment period over another. But, instead, all Back Start Service providers are given the opportunity to include those operating and maintenance expenses attributable to supporting Black Start Service, including costs incurred to meet NERC Reliability Standards that apply to the Black Start Unit solely on the basis of the provision of Black Start Service. The universal inclusion of variable operating and maintenance costs in the formulaic calculation of revenue requirements recognizes the inherent differences associated with making actual capital improvements to a Black Start Unit to provide Black Start Service as opposed to recovery of ongoing operation and maintenance expense.

In this regard, the Variable BSSC component of the formula has been slightly revised to clarify that all Black Start Units, regardless of commitment level, shall calculate Variable BSSC using this formula and to include a definition of "Black Start Unit O&M." Similar to the definition of Black Start Capital Costs used in the calculation of Fixed BSSC above, Black Start Unit O&M are the operations and maintenance costs attributable to supporting Black Start Service and shall include those costs incurred by the owner in order to meet NERC Reliability Standards that apply to the Black Start Unit. Importantly, like the definition of Black Start Capital Costs, Black Start Unit O&M is explicit in limiting the recovery of those costs incurred to comply with NERC Reliability Standards that apply to the Black Start Unit solely on the basis of the provision of Black Start Service by the unit.

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increase a generator's ability to provide black start service. The allocation factors permitted generators to recover capital investment incurred which might have been above the then current caps used as allocation factors under the PJM Tariff. *See PJM Interconnection, L.L.C.* Letter Order, Docket No. ER04-596-000 (April 27, 2004). The Allocation Factors set forth in this filing are not proposed to change, other than to clarify that units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, the Allocation Factor shall be zero. PJM stakeholders have agreed that the listed amounts are the minimum percentages of a generator's fixed costs that appropriately should be attributed to Black Start Service.

Additional revisions are proposed to the remaining components of the paragraph 18 revenue requirements formula which do not change the disposition of the formulaic calculation, but provide further clarification as to the structure of those components. For example, the definition of Fuel Storage Costs has been changed to clarify that Black Start Units that cannot use oil for fuel shall calculate Fuel Storage Costs as zero. Moreover, the definition has been arranged to provide clarity by separating out key components of the Fuel Storage Costs and ordering them into line-item definitions. Also, words and appropriate punctuation have been added where applicable.

The existing incentive factor has been re-termed "Z," and further clarified thet it will be an incentive factor for Black Start Units that have elected to forego recovery of new or additional fixed Black Start Capital Costs in accordance with the commitment pursuant to proposed paragraph 5, and shall be ten percent. The incentive factor, as it exists currently, was contemplated to provide compensation for Black Start Service providers which includes reimbursement for the actual out of pocket costs of providing Black Start Service plus and adequate, but not excessive, incentive payment to encourage generators to provide such service. Its application in the proposed revisions is limited those owners electing to forego recovery of new or additional fixed Black Start Service Costs because those owners who seek to recover new or additional fixed costs will fully recover all costs of service under the proposed formula without the application of Z. Conversely, those unit owners electing to provide Black Start Service pursuant to a commitment period established under proposed Paragraph 5 may actually incur costs that otherwise would not be recovered through application of the revenue requirements formula, and application of the Z factor is designed to compensate them for those difficult to quantify costs. Thus, the PJM stakeholders determined that it was appropriate to limit application of Z to those specific Black Start Unit owners.

Finally, to ensure that Black Start Unit owners are adequately compensated for providing Black Start Service, and that proper incentives exist to ensure continued provision of Black Start Services, PJM has proposed to require that it review the revenue requirement formula and its cots components every two years and report on the results of that review to the PJM stakeholders.

III. Stakeholder Support

On January 15, 2009, the PJM Members Committee met and endorsed by acclamation these proposed revisions, with no member opposed or abstaining.

IV. Effective Date

Consistent with the Commission's notice requirements, PJM requests an effective date of April 21, 2009, which is at least 60 days after the date of this filing.

V. Documents Enclosed

This submittal includes an original and six copies of the following:

- This letter of transmittal;
- The proposed PJM Tariff revisions in non-redlined format (Attachment A);

- The proposed PJM Tariff revisions red-lined against the currently effective tariff sheets (Attachment B)

VI. Correspondence and Communication

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

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VII. Service

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. Electronic service is permitted as of November 3, 2008, under the Commission's regulations[14] pursuant to Order No. 714[15] and the Commission's Notice of Effectiveness of Regulations, issued on October 28, 2008, in Docket No. RM01-5-000. In compliance with these regulations, PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: *http://www.pjm.com/documents.ferc.html* with a specific link to the newly filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region alerting them that this filing has been made by PJM today and is available by following such link.[16]

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[14] See 18 C.F.R. §§ 35.2, 154.2, 154.208 and 341.2.

[15] *Electronic Tariff Filings*, 124 FERC ¶ 61,270 (2008) (Order No. 714).

[16] PJM already maintains updates and regularly used e-mail lists for all PJM Members and affected Commissions.

Respectfully submitted,

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Attachment A

Tariff Changes

Clean Version

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SCHEDULE 6A

Black Start Service

To ensure the reliable restoration following a shut down of the PJM transmission system, Black Start Service is necessary to facilitate the goal of complete system restoration. Black Start Service enables Transmission Provider and Transmission Owners to designate specific generators called Black Start Units whose location and capabilities are required to re-energize the transmission system following a system-wide blackout.

TRANSMISSION CUSTOMERS

1. All Transmission Customers and Network Customers must obtain Black Start Service from the Transmission Provider pursuant to this Schedule 6A.

PROVISION OF BLACK START SERVICE

2. A Black Start Unit is a generating unit that has equipment enabling it to start without an outside electrical supply or a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid. A Black Start Unit shall be considered capable of providing Black Start Service only when it meets the criteria set forth in the PJM manuals. For the purposes of this Schedule 6A, the expected life of the Black Start Unit shall take into consideration expectations regarding both the enabling equipment and the generation unit itself.

3. A Black Start Plant is a generating plant that includes one or more Black Start Units. A generating plant with Black Start Units electrically separated at different voltage levels will be considered multiple Black Start Plants.

4. The Transmission Provider, in conjunction with the Transmission Owners, are responsible for developing a coordinated and efficient system restoration plan that identifies all of the locations where Black Start Units are needed. The PJM Manuals shall set forth the criteria and process for selecting or identifying the Black Start Units necessary to commit to providing Black Start Service at the identified locations.. No more than three Black Start Units at a Black Start Plant will be eligible for compensation under this Schedule 6A, unless specifically approved by the Transmission Provider as an exception. No Black Start Unit shall be eligible to recover the costs of providing Black Start Service in PJM unless it agrees to provide such service for a term of commitment established under Paragraph 5 or 6 below.

5. Black Start Units selected to provide Black Start Service in accordance with paragraph 4 and electing to forego any recovery of new or additional Black Start Capital Costs shall commit to provide Black Start Service for an initial term of no less than two years. The term commitment shall continue to extend until the Black Start Unit owner, or the Transmission Owner, with the consent of the Transmission Provider, or the Transmission Provider, with the consent of the Transmission Owner, provides written, one-year advance notice of its intention to terminate the commitment.

6. Black Start Units selected to provide Black Start Service in accordance with paragraph 4 and electing to recover new or additional Black Start Capital Costs shall commit to provide Black Start Service for a term based upon a reasonable estimate of the expected life of the Black Start Unit, as set forth in the CRF Factor Table in paragraph 18. Either the Transmission Provider, with the consent of the Transmission Owner, or the Transmission Owner, with the consent of the Transmission Provider, may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Transmission Owner shall reimburse the Black Start Unit owner for any amount of unrecovered Fixed Black Start Service Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice (or its commitment period may be involuntarily terminated pursuant to the paragraph 15 below), provided that it foregoes any otherwise existing entitlement to revenues collected pursuant to this Schedule 6A and fully refunds any amount of the Black Start Capital Costs recovered under a FERC-approved rate in excess of the amount that would have been recovered pursuant to paragraph 18 during the same period. At the conclusion of the term of commitment established under this paragraph 6, a Black Start Unit shall commence a new term of commitment under either paragraph 5 or 6, as applicable.

6A. In the event that a Black Start Unit fails to fulfill its commitment established under Paragraph 5 to provide Black Start Service, receipt of any Black Start Service revenues associated with the non-performing Black Start Unit shall cease and, for the period of the unit's non-performance, the Black Start Unit owner shall forfeit the Black Start Service revenues associated with the non-performing Black Start Unit that it received or would have received had the Black Start Unit performed, not to exceed revenues for a maximum of one year.

In the event that a Black Start Unit fails to fulfill its commitment established under Paragraph 6 above, such unit shall forego any otherwise existing entitlement to revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate in excess of the amount that would have been recovered pursuant to paragraph 18 during the same period, but such unit remains eligible to establish a new commitment under paragraph 5 or 6.

<u>Performance Standards and Outage Restrictions</u>

7. Black Start Units must have the capabilities listed below. These capabilities must be demonstrated in accordance with the criteria set forth in the PJM manuals and will remain in effect for the duration of the commitment to provide Black Start Service.

   a. A Black Start Unit must be able to close its output circuit breaker to a dead (de-energized) bus within 90 minutes of a request from the Transmission Owner or the Transmission Provider.

   b. A Black Start Unit must be capable of maintaining frequency and voltage under varying load.

   c. A Black Start Unit must be able to maintain rated output for a period of time identified by each Transmission Owner's system restoration requirements, in conjunction with the Transmission Provider.

8. Each owner of Black Start Units or Black Start Plants must maintain procedures for the start-up of the Black Start Units.

9. If a Black Start Unit is a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, this ability must be demonstrated in accordance with the criteria set forth in the PJM manuals.

10. No more than one Black Start Unit at a Black Start Plant may be subject to planned maintenance at any one time. This restriction excludes outages on common plant equipment that may make all units unavailable. A Black Start Unit not currently designated as critical and on the same voltage level may be

substituted for a Black Start Unit that is subject to a planned outage to permit a concurrent planned outage of another critical Black Start Unit at the Black Start Plant to begin. The Black Start Unit used as a substitute must have had a valid annual test within the previous 12 months.

11. Concurrent planned outages at multiple Black Start Plants within a zone may be restricted based on Transmission Owner requirements for Black Start Service availability. Such restrictions must be predefined and approved by Transmission Provider in accordance with the PJM manuals.

Testing

12. To verify that they can be started and operated without being connected to the Transmission System, Black Start Units designated as critical shall be tested annually in accordance with the PJM manuals. The Black Start Unit owner shall determine the time of the annual test.

13. Compensation for energy output delivered to the Transmission System during the annual test shall be provided for the Black Start Unit's minimum run time at the higher of the unit's cost-capped offer or real-time Locational Marginal Price plus start-up and no-load costs for up to two start attempts, if necessary. For Black Start Units that are generating units with a high operating factor (subject to Transmission Provider's concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, an opportunity cost will be provided to compensate the unit for lost revenues during testing.

14. To receive Black Start Service revenues, a Black Start Unit must have a successful annual test on record with the Transmission Provider within the preceding 13 months.

15. If a Black Start Unit fails the annual test, the unit may be re-tested within a ten-day period without financial penalty. If the Black Start Unit does not successfully re-test within that ten-day period, monthly Black Start Service revenues will be forfeited by that unit from the time of the first unsuccessful test until such time as the unit passes an annual test. If the Black Start Unit owner determines not to make the necessary repairs to enable the Black Start Unit to pass the annual test, the Black Start Unit owner will have failed to fulfill its commitment pursuant to paragraph 5 of this Schedule 6A and will be subject to the additional forfeiture of revenues set forth in paragraph 6A

Revenue Requirements

16. The annual Black Start Service revenue requirement shall be the sum of the annual Black Start Service revenue requirements for each generator that is designated as providing Black Start Service and has provided the Transmission Provider with a calculation of its annual Black Start Service revenue requirements. A separate line item shall appear on the participants' Transmission Provider bill for Black Start Service charges and credits.

17. Black Start Service revenue requirements for each Black Start Unit shall be based , at the election of the owner, on either (i) a FERC-approved rate for the recovery of the cost of providing such service for the entire duration of the commitment term set forth in either paragraph 5 or 6, as applicable, or (ii) the formulas set forth in paragraph 18 of this Schedule 6A for the commitment term set forth in paragraph 5 or 6 as applicable. Each generator's Black Start Service revenue requirements shall be an annual calculation. No change to a Black Start Service revenue requirement shall become effective until the existing revenue requirement has been effective for at least twelve months. PJM will presume that any FERC-approved cost recovery plan would be the exclusive basis for the recovery of a Black Start Unit's recovery of its costs during the applicable term.

18. The formula for calculating a generator's annual Black Start Service revenue requirement is:

{(Fixed BSSC) + (Variable BSSC) + (Training Costs) + (Fuel Storage Costs)} * (1 + Z)

For units that have the demonstrated ability to operate at reduced levels when automatically disconnected from the grid, the formula is revised to:

(Training Costs) * (1+ Z)

where:

Fixed BSSC

Black Start Units with commitment established under paragraph 5 shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance the following formula:

CONE * 365 * Black Start Unit capacity * X

Where:

"CONE" is the then current net Cost of New Entry for the CONE Area where the Black Start Unit is located as set forth in Section 5.10 of Attachment DD.

"Black Start Unit Capacity is the Black Start Unit's installed capacity, expressed in MW.

X is the Black Start Service allocation factor unless a higher or lower value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For Black Start Units with a commitment established under paragraph 5, X shall be .01 for Hydro units, 02 for Diesel or CT units. For Black Start Units having recovered new or additional Fixed Black Start Service Costs on an accelerated basis prior to April 21, 2009, X shall instead be .005 for Hydro units and .01 Diesel or CT units.

Black Start Units with commitments established under paragraph 6 above shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with the following formula:

Black Start Capital Cost * CRF

Where:

"Black Start Capital Costs" is the capital cost approved by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit.

"CRF" or "Capital Recovery Factor " is equal to the levelized CRF based on the age of the Black Start Unit, which is modified to provide Black Start Service, as present in the CRF Table:

Age of Black Start Unit	Years of Remaining Life of Black Start Unit	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

Variable BSSC

All Black Start Units shall calculate Variable BSSC or "Variable Black Start Service Costs" in accordance with the following formula:

Black Start Unit O&M * Y

Where:

"Black Start Unit O&M" are the operations and maintenance costs attributable to supporting Black Start Service and must equal the annual variable O&M outlined in the PJM Cost Development Task Force Manual. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to the Black Start Unit solely on the basis of the provision of Black Start Service by unit.

"Y" is 0.01, unless a higher or lower value is supported by the documentation of costs. If a value of Y is submitted for this cost, a (1-Y) factor must be applied to the Black Start Unit's O&M costs on the unit's cost-based energy schedule, calculated based on the Cost of Element Guidelines in the PJM Manauls.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no variable costs associated with providing Black Start Service and the value for Variable BSSC shall be zero.

Training Costs:

All Black Start Units shall calculate Training Costs in accordance with the following formula:

50 staff hours/year/plant*75/hour

Fuel Storage Costs:

Black Start Units that cannot use oil for fuel shall cacluate Fuel Storage Costs or "FSC" as zero. Black Start Units that can use oil for fuel shall calculate Fuel Storage Costs in accordance with the following formula:

{MTSL + [(# Run Hours) * (Fuel Burn Rate)]} *
(12 Month Forward Strip + Basis) * (Bond Rate)Where:

Run Hours are the actual number of hours a Transmission Provider requires a Black Start Unit to run. Run Hours shall be at least 16 hours or as defined by the Transmission Owner restoration plan, whichever is less.

"Fuel Burn Rate" is actual fuel burn rate for the Black Start Unit.

"12-Month Forward Strip" is the average of forward prices for the fuel burned in the Black Start Unit.
"Basis" is the transportation costs from the location referenced in the forward price data to the Black Start Unit plus any variable taxes.
"Bond rate" is the value determined with reference to the Moody's Utility Index for bonds rated Baa1.
"MTSL" is the "minimum tank suction level" and shall apply where no direct current pumps are available for the Black Start Unit.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no associated fuel storage costs and the value for FSC shall be zero.

Z

Z shall be an incentive factor for Black Start Units with a commitment established under paragraph 5 above and shall be ten percent.

At least every two years, PJM shall review the formula and its costs components set forth in this paragraph, and report on the results of that review to stakeholders.

19. Transmission Provider or its agent shall have the right to independently audit the accounts and records of each Black Start Unit that is receiving payments for providing Black Start Service.

Credits

20. Monthly credits are provided to generators that submit to the Transmission Provider their annual revenue requirements established pursuant to paragraph 17 of this Schedule 6A. The generator's monthly credit is equal to 1/12 of its annual Black Start Service revenue requirement for eligible critical Black Start Units.

21. Revenue requirements for jointly owned Black Start Units will be allocated to the owners based on ownership percentage.

Attachment B

Tariff Changes

Redline Version

K:\pjm\TARREVS\Schedule 6a tariff changes 2-13-09 (redline).DOC

SCHEDULE 6A

Black Start Service

To ensure the reliable restoration following a shut down of the PJM transmission system, Black Start Service is necessary to facilitate the goal of complete system restoration. Black Start Service enables Transmission Provider and —Transmission Owners to designate specific generators called Black Start Units whose location and capabilities are required to re-energize the transmission system following a system-wide blackout.

TRANSMISSION CUSTOMERS

1. All Transmission Customers and Network Customers must obtain Black Start Service from the Transmission Provider pursuant to this Schedule 6A.

PROVISION OF BLACK START SERVICE

2. A Black Start Unit is a generating unit that ~~is able~~ has equipment enabling it to start without an outside electrical supply or a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the demonstrated ability to automatically remain operating, at reduced levels, when disconnected from the grid. A Black Start Unit shall be considered capable of providing Black Start Service only when it meets the criteria set forth in the PJM manuals. For the purposes of this Schedule 6A, the expected life of the Black Start Unit shall take into consideration expectations regarding both the enabling equipment and the generation unit itself.

3. A Black Start Plant is a generating plant that includes one or more Black Start Units. A generating plant with Black Start Units electrically separated at different voltage levels will be considered multiple Black Start Plants.

4. The Transmission ~~Owners~~Provider, in conjunction with the Transmission ~~Provider~~Owners, are responsible for developing a coordinated and efficient system restoration plan that identifies all of the locations where Black Start Units are needed. The PJM Manuals shall set forth the criteria and process for selecting or identifying the Black Start Units ~~that are included in each Transmission Owner's system restoration plans and are critical for restoration of the Transmission System. Black Start Units will be identified as critical pursuant to criteria set forth in the PJM manuals~~ necessary to commit to providing Black Start Service at the identified locations.. No more than three Black Start Units at a Black Start Plant will be ~~considered critical and~~ eligible for compensation under this Schedule 6A, unless specifically approved by the Transmission Provider as an exception. ~~The Transmission Provider shall consider such exceptions on a case-by-case basis~~No Black Start Unit shall be eligible to recover the costs of providing Black Start Service in PJM unless it agrees to provide such service for a term of commitment established under Paragraph 5 or 6 below.

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5. ~~Owners of Black Start Units initially shall commit to providing Black Start Service for a two year period. Black Start Unit owners and Transmission Owners that identify the Black Start Unit as critical may terminate this two year commitment upon notice given one year before the date the commitment period ends~~ Black Start Units selected to provide Black Start Service in accordance with paragraph 4 and electing to forego any recovery of new or additional Black Start Capital Costs shall commit to provide Black Start Service for an initial term of no less than two years. The term commitment shall continue to extend until the Black Start Unit owner, or the Transmission Owner, with the consent of the Transmission Provider, or the Transmission Provider, with the consent of the Transmission Owner, provides written, one-year advance notice of its intention to terminate the commitment.

6. Black Start Units selected to provide Black Start Service in accordance with paragraph 4 and electing to recover new or additional Black Start Capital Costs shall commit to provide Black Start Service for a term based upon a reasonable estimate of the expected life of the Black Start Unit, as set forth in the CRF Factor Table in paragraph 18. Either the Transmission Provider, with the consent of the Transmission Owner, or the Transmission Owner, with the consent of the Transmission Provider, may terminate the commitment with one year advance notice of its intention to the Black Start Unit owner, but the Transmission Owner shall reimburse the Black Start Unit owner for any amount of unrecovered Fixed Black Start Service Costs over a period not to exceed five years. A Black Start Unit owner may terminate the provision of Black Start Service with one year advance notice (or its commitment period may be involuntarily terminated pursuant to the paragraph 15 below), provided that it foregoes any otherwise existing entitlement to revenues collected pursuant to this Schedule 6A and fully refunds any amount of the Black Start Capital Costs recovered under a FERC-approved rate in excess of the amount that would have been recovered pursuant to paragraph 18 during the same period. At the conclusion of the term of commitment established under this paragraph 6, a Black Start Unit shall commence a new term of commitment under either paragraph 5 or 6, as applicable.

Issued By: Craig Glazer Effective: April 21, 2009
Vice President, Governmental Policy
Issued On: February 19, 2009

6A. ~~In the event that neither the Black Start Unit owner nor the Transmission Owner exercises its right to terminate by providing a one-year notice of termination, the commitment to provide Black Start Service automatically will be extended for an additional year to maintain a rolling two year commitment.~~ In the event that a Black Start Unit fails to fulfill its ~~two-year rolling~~ commitment established under Paragraph 5 to provide Black Start Service, receipt of any Black Start Service revenues associated with the non-performing Black Start Unit shall cease and, for the period of the unit's non-performance, the Black Start Unit owner shall forfeit the Black Start Service revenues associated with the non-performing Black Start Unit that it received or would have received had the Black Start Unit performed, not to exceed revenues for a maximum of one year.

In the event that a Black Start Unit fails to fulfill its commitment established under Paragraph 6 above, such unit shall forego any otherwise existing entitlement to revenues collected pursuant to this Schedule 6A and fully refund any amount of the Black Start Capital Costs recovered under a FERC-approved rate in excess of the amount that would have been recovered pursuant to paragraph 18 during the same period, but such unit remains eligible to establish a new commitment under paragraph 5 or 6.

~~6. Transmission Provider may terminate a Black Start Unit's designation as critical by providing two years prior notice of such termination.~~

Performance Standards and Outage Restrictions

7. Black Start Units must have the capabilities listed below. These capabilities must be demonstrated in accordance with the criteria set forth in the PJM manuals and will remain in effect for the duration of the commitment to provide Black Start Service.

   a. A Black Start Unit must be able to close its output circuit breaker to a dead (de-energized) bus within 90 minutes of a request from the Transmission Owner or the Transmission Provider.

   b. A Black Start Unit must be capable of maintaining frequency and voltage under varying load.

   c. A Black Start Unit must be able to maintain rated output for a period of time identified by each Transmission Owner's system restoration requirements, in conjunction with the Transmission Provider.

8. Each owner of Black Start Units or Black Start Plants must maintain procedures for the start-up of the Black Start Units.

9. If a Black Start Unit is a generating unit with a high operating factor (subject to Transmission Provider concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, this ability must be demonstrated in accordance with the criteria set forth in the PJM manuals.

10. No more than one Black Start Unit at a Black Start Plant may be subject to planned maintenance at any one time. This restriction excludes outages on common plant equipment that may make all units unavailable. A Black Start Unit not currently designated as critical and on the same voltage level may be

substituted for a Black Start Unit that is subject to a planned outage to permit a concurrent planned outage of another critical Black Start Unit at the Black Start Plant to begin. The Black Start Unit used as a substitute must have had a valid annual test within the previous 12 months.

11. Concurrent planned outages at multiple Black Start Plants within a zone may be restricted based on Transmission Owner requirements for Black Start Service availability. Such restrictions must be predefined and approved by Transmission Provider in accordance with the PJM manuals.

Testing

12. To verify that they can be started and operated without being connected to the Transmission System, Black Start Units designated as critical shall be tested annually in accordance with the PJM manuals. The Black Start Unit owner shall determine the time of the annual test.

13. Compensation for energy output delivered to the Transmission System during the annual test shall be provided for the Black Start Unit's minimum run time at the higher of the unit's cost-capped offer or real-time Locational Marginal Price plus start-up and no-load costs for up to two start attempts, if necessary. For Black Start Units that are generating units with a high operating factor (subject to Transmission Provider's concurrence) with the ability to automatically remain operating at reduced levels when disconnected from the grid, an opportunity cost will be provided to compensate the unit for lost revenues during testing.

14. To receive Black Start Service revenues, a Black Start Unit must have a successful annual test on record with the Transmission Provider within the preceding 13 months. ~~To receive initial Black Start Service revenues, within six months after the effective date of this Schedule 6A, each critical Black Start Unit must have had a successful annual test within the previous 13 months. In the event a Black Start Unit does not have a successful test at the end of the six-month period, the initial six months of revenues from Black Start Service will be forfeited and the unit will be ineligible to receive such revenue until the successful completion of an annual test.~~

15. If a Black Start Unit fails the annual test, the unit may be re-tested within a ten-day period without financial penalty. If the Black Start Unit does not successfully re-test within that ten-day period, monthly Black Start Service revenues will be forfeited by that unit from the time of the first unsuccessful test until such time as the unit passes an annual test. If the Black Start Unit owner determines not to make the necessary repairs to enable the Black Start Unit to pass the annual test, the Black Start Unit owner will have failed to fulfill its ~~two-year~~ commitment pursuant to paragraph 5 of this Schedule 6A and will be subject to the ~~penalties~~ additional forfeiture of revenues set forth in ~~that~~ paragraph ~~5~~6A~~.~~

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Second Revised Sheet No. 241
Superseding First Revised Sheet No. 241

Revenue Requirements

16. The annual Black Start Service revenue requirement shall be the sum of the annual Black Start Service revenue requirements for each generator that is designated as providing Black Start Service and has provided the Transmission Provider with a calculation of its annual Black Start Service revenue requirements. A separate line item shall appear on the participants' Transmission Provider bill for Black Start Service charges and credits.

17. Black Start Service revenue requirements for each Black Start Unit shall be based ~~on the formula~~, at the election of the owner, on either (i) a FERC-approved rate for the recovery of the cost of providing such service for the entire duration of the commitment term set forth in either paragraph 5 or 6, as applicable, or (ii) the formulas set forth in paragraph 18 of this Schedule 6A for the commitment term set forth in paragraph 5 or 6 as applicable. Each generator's Black Start Service revenue requirements shall be an annual calculation. No ~~C~~changes to ~~a~~the Black Start Service revenue requirements ~~may be made annually, but will become effective in the second year of the generator's commitment to provide Black Start Service~~ shall become effective until the existing revenue requirement has been effective for at least twelve months. PJM will presume that any FERC-approved cost recovery plan would be the exclusive basis for the recovery of a Black Start Unit's recovery of its costs during the applicable term.

18. The formula for calculating a generator's annual Black Start Service revenue requirement is:

{(Fixed BSSC~~lack Start Service Costs~~) + (Variable BSSC~~lack Start Service Costs~~) + (Training Costs) + (Fuel Storage Costs ~~& Carrying Costs~~)} * (1 + ~~Incentive Factor~~Z)

For units that have the demonstrated ability to operate at reduced levels when automatically disconnected from the grid, the formula is revised to:

(Training Costs) * (1+ ~~Incentive Factor~~Z)

where:

Fixed ~~Black Start Service Costs~~BSSC

Black Start Units with commitment established under paragraph 5 shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance the following formula:

CONE ~~= CDR~~ * 365 * Black Start Unit capacity * X

Where:

"CONE" is the then current net Cost of New Entry for the CONE Area where the Black Start Unit is located as set forth in Section 5.10 of Attachment DD.

~~CDR = PJM Capacity Deficiency Rate on an installed capacity basis~~

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"Black Start Unit Capacity ~~=~~is the Black Start Unit's installed capacity, expressed in MW.

X ~~=~~is the Black Start Service allocation factor ~~(Hydro = 0.01, Diesel = 0.02, CT = 0.02)~~ unless a higher or lower ~~another~~ value is supported by the documentation of the actual costs of providing Black Start Service. For such units qualifying as Black Start Units on the basis of demonstrated ability to operate at reduced levels when automatically disconnected from the grid, X shall be zero. For Black Start Units with a commitment established under paragraph 5, X shall be .01 for Hydro units, .02 for Diesel or CT units. For Black Start Units having recovered new or additional Fixed Black Start Service Costs on an accelerated basis prior to April 21, 2009, X shall instead be .005 for Hydro units and .01 Diesel or CT units.

Black Start Units with commitments established under paragraph 6 above shall calculate Fixed BSSC or "Fixed Black Start Service Costs" in accordance with the following formula:

Black Start Capital Cost * CRF

Where:

"Black Start Capital Costs" is the capital cost approved by the Commission for the incremental equipment solely necessary to enable a unit to provide Black Start Service in addition to whatever other product or services such unit may provide. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to Black Start Units solely on the basis of the provision of Black Start Service by such unit.

"CRF" or "Capital Recovery Factor " is equal to the levelized CRF based on the age of the Black Start Unit, which is modified to provide Black Start Service, as present in the CRF Table:

Age of Black Start Unit	Years of Remaining Life of Black Start Unit	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

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Variable BSSC ~~lack Start Service Costs = Black Start Unit O&M * Y~~

All Black Start Units shall calculate Variable BSSC or "Variable Black Start Service Costs" in accordance with the following formula:

Black Start Unit O&M * Y

Where:

"Black Start Unit O&M" are the operations and maintenance costs attributable to supporting Black Start Service and must equal the annual variable O&M outlined in the PJM Cost Development Task Force Manual. Such costs shall include those incurred by a Black Start Owner in order to meet NERC Reliability Standards that apply to the Black Start Unit solely on the basis of the provision of Black Start Service by unit.

"Y" is 0.01, unless a higher or lower value is supported by the documentation of costs. If a value of Y is submitted for this cost, a (1-Y) factor must be applied to the Black Start Unit's O&M costs on the unit's cost-based energy schedule, calculated based on the Cost of Element Guidelines in the PJM Manauls.

~~Variable Black Start Service Costs are the variable O & M costs that can be attributed to supporting Black Start Service, to be calculated as follows:~~

~~where: Y = 0.01 unless another value is supported by the documentation of costs~~

~~Note: If a value of Y is submitted for this cost, (1-Y) factor must be applied to the Black Start Unit's O&M costs on the unit's cost-based energy schedule.~~
~~Variable O&M~~ For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no variable costs associated with providing Black Start Service ~~are equal to annual variable O&M as outlined in the Cost Development Task Force PJM manual~~and the value for Variable BSSC shall be zero.

Training Costs: ~~**= 50 staff hours/year/plant * $75/hour**~~

All Black Start Units shall calculate Training Costs in accordance with the following formula:

50 staff hours/year/plant*75/hour

Fuel Storage Costs:

Black Start Units that cannot use oil for fuel shall cacluate Fuel Storage Costs or "FSC" as zero. Black Start Units that can use oil for fuel shall calculate Fuel Storage Costs in accordance with the following formula: ~~**Fuel Storage & Carrying Costs (applicable only to oil-fired units) = (# Run Hours) * (Fuel Burn Rate) * (12 Month Forward Strip + Basis) * (Bond Rate)**~~

{MTSL + [(# Run Hours) * (Fuel Burn Rate)]} *
(12 Month Forward Strip + Basis) * (Bond Rate)Where:

Run Hours are the actual number of hours a Transmission Provider requires a Black Start Unit to run. Run Hours shall be at least 16 hours or as defined by the Transmission Owner restoration plan, whichever is less.

~~**Note: If no direct current pumps are available for the Black Start Unit, the fuel storage and carrying costs may include a tank minimum suction level.**~~
"Fuel ~~b~~Burn ~~r~~Rate" is actual fuel burn rate for the Black Start Unit.

"12-Month Forward Strip" is the average of forward prices for the fuel burned in the Black Start Unit.
~~Black Start Unit.~~
"Basis" is the transportation costs from the location referenced in the forward price data to the Black Start Unit plus any variable taxes
~~data to the Black Start Unit plus any variable taxes~~.
"Bond rate" is the value determined with reference to ~~will be~~ the Moody's Utility Index for bonds rated Baa1.

"MTSL" is the "minimum tank suction level" and shall apply where no direct current pumps are available for the Black Start Unit.

For units qualifying as Black Start Units on the basis of a demonstrated ability to operate at reduced levels when automatically disconnected from the grid, there are no associated fuel storage costs and the value for FSC shall be zero.

~~**Incentive Factor = Z = 10%**~~

~~Where Z~~ shall be ~~is~~ an incentive factor for Black Start Units with a commitment established under paragraph 5 above and shall be ten percent.

At least every two years, PJM shall review the formula and its costs components set forth in this paragraph, and report on the results of that review to stakeholders. ~~initially set to the above level and will be periodically reviewed by Transmission Provider.~~

19. Transmission Provider or its agent shall have the right to independently audit the accounts and records of each Black Start Unit that is receiving payments for providing Black Start Service.

Credits

20. Monthly credits are provided to generators that submit to the Transmission Provider their annual revenue requirements ~~based on the formula in~~ established pursuant to paragraph 1~~8~~7 of this Schedule 6A. The generator's monthly credit is equal to 1/12 of ~~their~~ its annual Black Start Service revenue requirement for eligible critical Black Start Units.

21. Revenue requirements for jointly owned Black Start Units will be allocated to the owners based on ownership percentage.

Document Content(s)

Exhibit IMM-00013

Black Start Education

Black Start Unit Testing, Substitution, Termination Rules, and Capital Recovery Factor (CRF)

Becky Davis

PJM Performance Compliance

PJM Operating Committee Meeting
May 14, 2020

Black Start Definitions

Black Start Unit

A single generator that is able to start without an outside electrical supply, or the demonstrated ability of a base load unit to remain operating, at reduced levels, when automatically disconnected from the grid.

Black Start Plant

A plant that includes a unit that can black start. A Black Start Plant with Black Start Units at different voltage levels (electrically separated) will be considered multiple Black Start Plants.

Black Start Units

PJM, in collaboration with the Transmission Owners, identify the generating units that are critical for system restoration.

- Transmission Owners develop and review the restoration plan annually.

Black Start Units Listed in TO Restoration Plans

Black Start Units								
Unit Name	Unit Type	ICAP	Emergency Minimum (Unit Min Stable Load)	Prim.Fuel	Sec. Fuel	Hot Start Time (Hours)	Cold Start Time (Hours)	Ramp Rate (MWs/Minute)

- Black Start Units receiving compensation under Schedule 6A have agreed that the unit should be designated as black start.

Black Start Testing Requirements

Every generating unit that is providing black start capability shall be tested to verify that it can be started and operated without being connected to the PJM power system.

- Scheduled at the discretion of the generator owner; however, prescheduled with PJM prior to testing.
- Completed and submitted black start test report for all testing performed (pass or fail, and requested 14 days following test).
- A successful test is required, on a 13-month rolling basis, for the Black Start Unit to continue receiving black start compensation under Schedule 6A.

Identify all Black Start Units for annual testing.

Black Start Testing Requirements

- Start when requested from "blackout" state
- Close to a dead bus within 3 hours
- Operate at reduced levels when disconnected from the grid
- Maintain frequency and voltage under varying load

SECTION 2 : TEST PERFORMANCE

TEST PERFORMED ON DATE

BLACK START TEST BEGINS TIME

Please notify PJM Dispatch on the day of the actual test, prior to test start.

TIME OF OUTPUT BREAKER CLOSE TIME

The generating unit must have the ability to close the output breaker to a dead bus within 180 minutes.

THE BLACK START TEST DISPLAYED THE ABILITY TO ...	ACTUAL EQUIPMENT TEST SUCCESS	SIMULATED EQUIPMENT TEST SUCCESS	ITEM NOT TESTED	TESTING FAILED
... START WITHOUT POWER				
... CLOSE INTO A DE-ENERGIZED BUS				
... OPERATE AT REDUCED LEVELS WHEN DISCONNECTED FROM THE GRID				
... MAINTAIN FREQUENCY UNDER VARYING LOAD (FOR A PERIOD OF AT LEAST THIRTY MINUTES)				
... MAINTAIN VOLTAGE UNDER VARYING LOAD (FOR A PERIOD OF AT LEAST THIRTY MINUTES)				
... MAINTAIN BLACKSTART RATED OUTPUT FOR DURATION MATCHING LCC RESTORATION REQ				

Please check the appropriate box above for each testing item.

BLACK START TEST ENDED TIME

TEST SUPERVISED BY NAME

Black Start Unit Substitutions

Schedule 6A Black Start Service – Section 10

10. No more than one Black Start Unit at a Black Start Plant may be subject to planned maintenance at any one time. This restriction excludes outages on common plant equipment that may make all units unavailable. A Black Start Unit not currently designated as critical and on the same voltage level may be substituted for a Black Start Unit that is subject to a planned outage to permit a concurrent planned outage of another critical Black Start Unit at the Black Start Plant to begin. The Black Start Unit used as a substitute must have had a valid annual test within the previous 12 months.

Provide additional clarification and guidance for Black Start Unit substitution.

Schedule 6A Black Start Service – Unit Terminations

Initial commitment of at least two years from black start service implementation date.

May terminate with one year's advanced notice if:

- **Black Start Unit owner initiated termination**

  Forego any existing entitlement to revenues collected under Schedule 6A (refund FERC-approved rates)

- **PJM initiated termination**

  Black Start Unit owner eligible to recover any amount of unrecovered fixed black start service costs over a period < 5 years

Additional termination rules to address potential delays for units without a black start test on file for an extended period.

Schedule 6A Black Start Service – Capital Recovery Factor

Black Start Units may recover new or additional black start capital costs for a term based on the age of the Black Start Unit.

Capital Recovery Factor (CRF) Table

Age of Black Start Unit	Term of Black Start Commitment	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16+	5	0.363

Capital recovery factor (CRF) based on a levelized pro forma for a 100 MW combustion turbine for $1 M.

Capital Recovery Factor Components

9%
State tax rate

50%
Equity

and

50%
Debt

12%
Internal rate of return on equity

Federal tax rate

36% Current

~21% Proposed — Current federal corporate tax rate 21%

Income tax rate

41% Current

~28% Proposed — Based on current federal corporate and state tax rates

Interest Rate

7% Current

~3.5% Proposed — Based on current bond rate

New/Revised Tax Laws

Bonus depreciation

Appendix

Appendix

References:

- PJM OATT Schedule 6A Black Start Service
- PJM M-12 Balancing Operation; Section 4
- PJM M-10 Pre-Scheduling Operations; Section 2
- PJM M-14D Generation Operational Requirements; Section 10
- PJM M-27 Open Access Transmission Tariff Accounting; S-7
- PJM M-36 System Restoration; Sections 6 & 8

Appendix

Black Start Testing Form:

https://www.pjm.com/-/media/markets-ops/ancillary/black-start-test-report-forms.ashx?la=en

Exhibit IMM-00014

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PJM Interconnection, L.L.C.	)	Docket No. EL21-91-003
	)	

RESPONSE OF THE INDEPENDENT MARKET MONITOR FOR PJM TO FERC TRIAL STAFF'S FIRST SET OF DATA REQUESTS

S-IMM-1.1. Please provide all available workpapers and/or formulas used to derive the Levelized Capital Recovery Factor (CRF) for Black Start facilities selected to provide service prior to June 6, 2021 (pre-June 6, 2021 CRFs). Define all terms and where applicable provide as live excel spreadsheets.

RESPONSE

Documents responsive to this request are attached. The attached spreadsheet contains a simulation model that was used to calculate the pre-June 6, 2021, CRF values.[1] There is a separate tab for calculating the CRFs corresponding to the four capital recovery periods (5 years, 10 years, 15 years and 20 years). The annual revenue payment is equal to the product of the CRF and capital investment amount. The after tax cash flow to the equity investor is equal to the revenue net of income tax payments and debt payments.[2] The model uses the solver function to iterate through possible values for the CRF, stopping when the internal rate of return (IRR) corresponding to the after tax cash flow is equal to the required return on equity (12.0 percent).

There is an assumption in the simulation model that has an effect on the calculated CRF value, increasing the CRF value slightly. In the simulation model, the debt payments are treated as occurring at mid year. The mid year convention can be used to better align the

[1] 2023-09-15 S-IMM DR 1-1 Response-Attachment.

[2] Generally the fixed O&M expense would also be subtracted from the revenue but the fixed O&M is set to $0 for the capital recovery calculation.

timing of the revenue, income tax and debt payments which would likely be made on a monthly or quarterly basis.[3]

Three presentations from 2006 on the CRF approach are attached to the response to Data Request S-IMM-1.2.

Sponsor: Prepared under the supervision of Dr. Joseph E. Bowring.

Dated: September 15, 2023

[3] The Market Monitor noted this issue in a previous filing but described it as a rounding error. See pages 8-9 and footnote 20 in *Errata Filing of the Independent Market Monitor for PJM,* Attachment B, EL21-91 (November 18, 2021).

S-IMM-1.2. Please provide any Market Monitor records of the stakeholder process in which these CRF factors were developed.

RESPONSE

Please see the following attached documents:

- Attachment A: Black Start Tariff Section 6.4 Proposed Changes, MIC (September 18, 2006).
- Attachment B: Black Start Tariff Section 6.4 Issues, MRC (October 25, 2006).
- Attachment C: Black Start Tariff Section 6.4 Proposed Changes, MIC (October 31, 2006).

Sponsor: Prepared under the supervision of Dr. Joseph E. Bowring.

Dated: September 15, 2023

S-IMM-1.3. Was the formula used to derive the pre-June 6, 2021 CRFs equivalent to the formula for the CRF for facilities selected to provide service after June 6, 2021 (post-June 6, 2021 CRFs)? If not, please explain your understanding of the differences between the two formulas.

RESPONSE

No. The pre-June 6, 2021, CRFs were calculated using a flow to equity (FTE) financial model that incorporates a mortgage payment approach for the loan repayment. Under this approach, the debt to equity ratio is not constant during the cost recovery period. The formula for the post-June 6, 2021, CRF was derived from a weighted average cost of capital (WACC) financial model. When the revenue is equal to the level required to meet all the payment obligations, without excess payments, the results of the two models are quite close.

But when there are payments in excess of the level required to meet all the payment obligations, as has occurred in this case, the difference between the models is significant. In the WACC model, the revenue in excess of income taxes, required interest payments and return on equity is split between accelerated loan repayment and payment to equity according to the debt to equity ratio, and the debt to equity ratio is maintained at a constant level during the cost recovery period. In the FTE model, revenue in excess of income taxes, required debt payments and return on equity flows to the equity investor.

In this case, payments to black start resources used CRF calculations based on taxes higher than actual required tax payments. As a result, there were payments in excess of the level required to meet all the payment obligations. In cases where there are excess payments, the FTE model accurately captures the excess returns to equity while the WACC model does not.

The attached spreadsheet includes a side by side comparison of the approaches.[4] Model A is an FTE model and Model B is a WACC model. Both models use the mid year convention where revenue, tax and debt payments are assumed to occur at the midpoint of the year rather than at the end of the year. Model A uses a mortgage type loan repayment and model B splits the return of the investment between repayments of loan principal and payments to equity according to the debt to equity ratio. Model A results in a debt to equity ratio based on repaying the debt principal following the mortgage payment structure and all excess revenues flowing to equity. Model B maintains a constant debt to equity ratio throughout the cost recovery period. Model A is the model

[4] 2023-09-15 S-IMM DR 1-3 Response-Attachment.

used to determine the pre-June 6, 2021 CRFs. Model B is the model used to determine the post-June 6, 2021 CRFs.

The spreadsheet illustrates how each model reflects the impacts of using the incorrect federal income tax law to calculate the CRF.[5] Table 1 shows the revenue and payment streams associated with the FTE model that uses a mortgage style loan repayment (Model A in the attached spreadsheet). The revenue payment reflects the five year CRF value, 0.363, used to determine the revenue payments to pre-June 6, 2021, black start units based on tax laws in place prior to the Tax Cuts and Jobs Act of 2017 (TCJA).[6] The income tax payment in the model reflects the 100 percent bonus depreciation and 21 percent federal income tax rate included in the current tax laws. The interest on the debt and the repayment of the debt principal are not affected by the excess revenue which results from the incorrect income tax assumptions. All of the excess is paid to equity investors. In year 1, revenue in excess of income taxes, interest payments and return on equity is $500,542 of which $100,685 goes toward repayment of the debt principal and the remaining $399,857 goes to the equity investors. In year 2, the remaining equity investment is paid off and there is an additional $38,769 paid to the equity investors. Over the five year recovery period the repayment of the debt principal totals $500,000 as does the repayment of the equity investment. The excess revenue to equity investors in the table is the money left over in each year after meeting all other obligations. The after tax cash flow to equity investors is the sum of the ROE, repayment of the equity investment and the excess revenue to equity investors. The internal rate of return corresponding to the after tax cash flow is 61.7 percent. This 61.7 percent rate of return is more than five times higher than the target return. The intent of the CRF payment is to provide the equity investors with a 12 percent return on investment.

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5 On the Parameters Assumptions tab of the spreadsheet, set the federal income tax rate to 21 percent, the depreciation type to 100 percent bonus deprecation (by inputting 'B100') and set the CRF override flag to 1 (this forces the model to use a CRF value of 0.363 which is the original five year CRF).

6 Public Law 115-97.

Table 1 FTE model with five year cost recovery period and $1 million investment

Flow to Equity Approach - Non Constant D/E with Mid Year Payments					
Capital Recovery Year	1	2	3	4	5
Revenue	$363,000	$363,000	$363,000	$363,000	$363,000
Depreciation	$1,000,000	$0	$0	$0	$0
Interest on debt	$17,204	$27,952	$21,656	$14,920	$7,712
Income Tax	($183,897)	$94,182	$95,952	$97,845	$99,871
Return on equity (ROE)	$29,150	$12,017	$0	$0	$0
Revenue in excess of taxes, interest and ROE	$500,542	$228,849	$245,392	$250,235	$255,416
Repayment of debt principal	$100,685	$89,937	$96,233	$102,969	$110,177
Repayment of equity investment	$399,857	$100,143	$0	$0	$0
Debt Remaining	$399,315	$309,378	$213,145	$110,177	$0
Equity Remaining	$100,143	$0	$0	$0	$0
Excess Revenue to equity investors	$0	$38,769	$149,159	$147,266	$145,240
After tax cash flow to equity investors	$429,008	$150,929	$149,159	$147,266	$145,240
Internal Rate of Return (IRR) to equity investors	61.7%				

Table 2 shows the revenue and payment streams for the WACC model with a constant debt to equity ratio (Model B in the attached spreadsheet). Revenue in excess of income taxes, interest payments and return on equity is split between repayments of loan principal and repayments of equity investment according to the debt to equity ratio which is 50/50 in this case. In year 1, revenue in excess of income taxes, interest payments and return on equity is $500,350 with $250,175 going to accelerated debt repayment and $250,175 going to the equity investors.[7] Under this approach, the debt and equity are repaid in year 4. The excess revenue to equity investors in years 4 and 5 is the money left over in each year after meeting all other obligations. The after tax cash flow to equity investors is the sum of the ROE, repayment of the equity investment and the excess revenue to equity investors. The internal rate of return corresponding to the after tax

[7] The year 1 revenue net income taxes, interest and ROE is slightly lower (by $192) under the WACC approach. This results from the return on investment calculation when using the mid year convention. In the WACC model (Model B), the year 1 investment return net the income tax shield is equal to $\left(\sqrt{1+E\cdot r_e+D\cdot(1-s)\cdot r_d}-1\right)\cdot K$ where E is the equity funding percent, D is the debt funding percent, r_e is the return on equity, r_d is the interest rate on debt, s is the effective income tax rate and K is the capital investment. Under the FTE approach with the mid year convention (Model A), the year 1 return on equity is $\left(\sqrt{1+r_e}-1\right)\cdot E\cdot K$, the year 1 interest on the debt is $\left(\sqrt{1+r_d}-1\right)\cdot D\cdot K$ and the tax shield can be explicitly stated as $s\cdot\left(\sqrt{1+r_d}-1\right)\cdot D\cdot K$. Since $\left(\sqrt{1+E\cdot r_e+D\cdot(1-s)\cdot r_d}-1\right)\neq\left(\sqrt{1+r_e}-1\right)\cdot E+(1-s)\cdot\left(\sqrt{1+r_d}-1\right)\cdot D$, models A and B give different values for revenue net of income taxes, interest and ROE.[8] For a few resources, a portion of the payments received during the 15 month refund period will have to be returned in order to achieve a 12 percent return on investment.

cash flow is 41.5 percent. This 41.5 percent rate of return is more than three times higher than the target return. The intent of the CRF payment is to provide the equity investors with a 12 percent return on investment. The internal rate of return to equity investors in the WACC model is lower than in the FTE Model A because Model B is based on the incorrect assumption that equity holders would repay debt holders early despite the fact that it reduces the return to equity holders.

Table 2 WACC model with a five year cost recovery period and $1 million investment

WACC Approach - Constant D/E with Mid Year Payments					
Capital Recovery Year	1	2	3	4	5
Revenue	$363,000	$363,000	$363,000	$363,000	$363,000
Depreciation	$1,000,000	$0	$0	$0	$0
Gross Income Tax	($179,061)	$102,039	$102,039	$102,039	$102,039
Income Tax Shield[1 2]	$4,643	$4,916	$2,767	$435	$0
Interest on debt[1 2]	$17,204	$17,488	$9,843	$1,548	$0
Return on Equity (ROE)[1 2]	$29,150	$29,979.01	$16,874.42	$2,653.83	$0.00
Revenue in excess of taxes, interest and ROE	$500,350	$218,410	$237,010	$257,194	$260,961
Repayment of debt principal	$250,175	$109,205	$118,505	$22,115	$0
Repayment of equity investment	$250,175	$109,205	$118,505	$22,115	$0
Debt Remaining	$249,825	$140,620	$22,115	$0	$0
Equity Remaining	$249,825	$140,620	$22,115	$0	$0
Excess Revenue to equity investors	$0	$0	$0	$212,963	$260,961
After tax cash flow to equity investors	$279,325	$139,184	$135,379	$237,733	$260,961
Internal Rate of Return (IRR) to equity investors	41.5%				

The reduction in the income tax liability introduced with the TCJA significantly reduced the income tax payments and the windfall savings that resulted from continuing to pay black start resources under the outdated tax laws went to the equity investors. The FTE model correctly reflects the accelerated repayment of the equity investment and the flow of excess revenues to the equity investor. The WACC model with a constant debt to equity ratio understates the cash flow to the equity investor. The Market Monitor's proposal to calculate a revised CRF is based on the FTE model that reflects the windfall income tax savings accruing to the equity investors. Under the Market Monitor's proposal, a date is selected, for example January 1, 2024, and a revised CRF that accounts for the repayment of the investment as of January 1, 2024, is calculated. Under this approach, the revised revenue will be set at a level for which the return on investment for equity investors, over the entire black start service period, is 12 percent, as originally intended.[8] The revised CRF will result in a lower payment for black start units for the remainder of the capital recovery period but at the end of the recovery period the owner of the black start units will have received revenue sufficient to provide for the repayment of debt at 7 percent interest, federal and state income tax liabilities, a 12 percent return on equity and the return of the equity portion of the capital investment, all as intended in the CRF calculations.[9]

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Dated: September 15, 2023

8 For a few resources, a portion of the payments received during the 15 month refund period will have to be returned in order to achieve a 12 percent return on investment.

9 The Market Monitor described the proposed resolution in a previous filing. See Section H in *Errata Filing of the Independent Market Monitor for PJM*, Attachment B, EL21-91 (November 18, 2021).

S-IMM-1.4. Does the CRF increase with the age of the Black Start Unit under the pre-June 6, 2021 CRFs, as well as the post-June 6, 2021 CRFs? If there is a difference in how age affects CRF between the two, please explain that difference and why that difference exists.

RESPONSE

The CRF value, holding the other parameters constant, is a function of the recovery period. The longer the recovery period, the lower the CRF. The logic is that the recovery of the investment is over a longer period and that the longer the recovery period, the smaller the required annual recovery. In Attachment DD, the recovery period is an inverse function of the life of the underlying capacity resource. The older the underlying capacity resource, the shorter the recovery period. In Attachment DD, the CRF is applied to incremental capital investment in existing capacity resources, termed APIR. The logic was that older units had a shorter remaining life and therefore needed a shorter recovery period for incremental investment.

In the case of black start resources, the same logic applied only if an existing resource added black start capability. If an older resource with a shorter remaining life added black start capability, the recovery period for the black start investment would be shorter. For a new resource with black start capability, the recovery period should be 20 years and include a commitment to provide black start for the entire life of the resource.

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Dated: September 15, 2023

S-IMM-1.5. Please provide any materials in your control relating to engagement between the Market Monitor and PJM relating to the use of tax rates in the development of existing or past CRFs, to include presentations, emails and other communications between PJM and the Market Monitor.

RESPONSE

The Market Monitor continues to review its files, and it expects that it can provide the requested materials on or before Friday, September 22, 2023.

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Dated: September 15, 2023

S-IMM-1.6. Please provide any materials in your control relating to engagement between the Market Monitor and stakeholders, to include customers, Black Start Service providers and any other participants, relating to the use of tax rates in the development of existing or past CRFs, to include presentations, emails and other communications. Please note which if any of these are or were available to Black Start Service providers and/or to the public.

RESPONSE

The Market Monitor continues to review its files, and it expects that it can provide the requested materials on or before Friday, September 22, 2023.

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Dated: September 15, 2023

S-IMM-1.7. Did the Market Monitor prepare the initial workpapers used to develop pre-June 6, 2021 CRF rates, including the use of a 36% corporate federal income tax rate in those calculations? If yes:

a. Please explain in detail any changes made to these calculations between the preparation of any initial workpapers and the final setting of the CRF rates at issue.
b. Please identify who at the Market Monitor would have the most knowledge of such calculations and any subsequent changes.

RESPONSE

Yes, the Market Monitor prepared the initial workpapers.

a. NA

b. Any questions about the calculations and any subsequent changes should be directed to Dr. Joseph E. Bowring.

Sponsor: Prepared under the supervision of Dr. Joseph E. Bowring.

Dated: September 15, 2023