Exhibit No. AS-42

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Competitive Duty Personnel

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Ameren Energy Generating Company	)	
and	)	
Union Electric Company	)	Docket No. EC03-53-000
d/b/a AmerenUE	)	

PREPARED REBUTTAL TESTIMONY OF RICHARD A. VOYTAS

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PREPARED REBUTTAL TESTIMONY OF RICHARD A. VOYTAS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Richard A. Voytas. My business address is 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom and in what capacity are you employed?

A. I am employed by Ameren Services Company as Manager of the Corporate Analysis section in the Corporate Planning Department.

Q. Are you the same Richard A. Voytas who submitted prepared direct testimony on June 10, 2003?

A. Yes.

Q. Have your position or duties with Ameren changed since that time?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the direct and answering testimony and exhibits of Dr. Craig A. Roach (Exhibit Nos. EPS-1 through EPS-14), the direct and answering testimony of Ershel C. Redd, Jr. (Exhibit Nos. NRG-1.0 through 1.2), and the direct and answering testimony of Dr. Aleksandr Rudkevich (Exhibit No. NRG-2.0 through 2.8). I will also respond to Dr. Roach's cross-answering testimony (Exhibit Nos. EPS-15). Finally, I also reference and respond to certain aspects of the direct and answering testimony of FERC Staff witness Elisabeth E. Fager.

II. TESTIMONY OF CRAIG R. ROACH, PH.D.

Q. What areas of Dr. Roach's testimony will you address?

A. I will focus on Dr. Roach's misrepresentations of AmerenUE's evaluation of the bids submitted in response to AmerenUE's August 2001 Request for Proposals ("RFP") for capacity and energy, Dr. Roach's lack of understanding of non-price issues that impact the value of different supply alternatives, Dr. Roach's inability to accept the preferred supply options of the Missouri Public Service Commission ("MPSC"), and the fundamental flaws and inconsistencies in Dr. Roach's support of the "annuity" method of comparing assets with different economic lives.

A. Misrepresentation Of AmerenUE's Evaluation Of Bids

Q. What is the purpose of discussing AmerenUE's evaluation of the power purchase agreements ("PPA") that bid in response to AmerenUE's August 2001 RFP?

A. Although for purposes of this transaction there is little practical value in discussing the process AmerenUE used to evaluate power purchase agreements since the MPSC has clearly given AmerenUE direction to buy or build capacity, there is value in exposing the blatant misrepresentations, selective use of facts, and lack of understanding of fundamental electric utility operations that Dr. Roach employs throughout his testimony in an unsuccessful attempt to show that affiliate abuse permeated the evaluation of power purchase options that were bid in response to AmerenUE's August 2001 RFP.

Q. As an initial matter, have any of the participants in this proceeding acknowledged the MPSC's and its Staff's preference that AmerenUE meet its resource needs through the construction or acquisition of hard generation assets?

A. Yes. This has been acknowledged by Staff witness Fager (Exhibit No. S-9 at 4 and 12) and Linda H. Boner (Exhibit No. S-12 at 25). While the MPSC is not a party to this proceeding, as explained by Mr. Nelson, it acknowledged this preference in a letter filed in this proceeding on June 3, 2003. See Exhibit No. AS-9.

Q. Dr. Roach makes the statement on page 6, line 21 of his direct testimony that "the Applicants pushed aside the ten lowest price power sales offers, which allowed an affiliate to be declared the winner." Dr. Roach also makes similar claims beginning page 25, line 16 of his cross-answering testimony. Is it accurate that Ameren pushed aside the ten lowest price power sales offers?

A. Absolutely not. To the contrary, Ameren had valid reasons for rejecting specific bids. As of the date of the January 15, 2002 presentation to the Missouri Public Service Commission Staff ("MPSC Staff"), Ameren listed the status of each bid as they existed at that time.

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Q. Please describe the individual bids.

A. The lowest priced bid was from AEP. At that time AEP did not have transmission to the Ameren system. Ameren had been approved for 100 MW from the AEP border to the sink, but if AEP could not get power to Ameren's border, it was not a viable bid. I would like to note that AEP was later granted transmission and Ameren reevaluated the bid and awarded a contract to AEP for 100 MW for the summer of 2002.

Reliant Energy was the second lowest priced bid and Ameren listed them as the recommended first option for 215 MW, even with a summer only operation limit.

GenPower was the third lowest priced bid, but this project was in the early stages of development with a scheduled on line date just before summer 2003. Being a small LLC development company of only 14 people and in the early stages of development, this bid was not considered a viable option for commercial operation for summer 2002 or 2003.

The next Reliant bid was ranked fourth on price. This bid was from Reliant's Aurora facility in the ComEd service area. Reliant did not have firm transmission to the Ameren border and the units had a summer only operation limit.

The fifth bid was a NRG combined cycle unit in the ComEd service area. NRG did not have firm transmission from ComEd to the Ameren border, and the operating flexibility of the combined cycle plant was not as desirable as a simple cycle unit. This bid was through 2004 with the remaining years to be negotiated.

The sixth bid was from Constellation Power for a 500 MW combined cycle facility. This facility was designed as a 2x2x1 (two CTGs, two heat recovery steam generators ("HRSG") and one steam turbine) and did not offer the operating flexibility of simple cycle units. There were also credit issue concerns.

NRG's Audrain facility was ranked seventh and ninth, based on the two different capacity prices that NRG bid from the same facility. Transmission upgrades were required and could not be completed until 2006 at the earliest.

The eighth ranked bid was from Panda Montgomery Power for a combined cycle plant in the early stages of development. The combined cycle technology concerns with the Panda plant were the same as with the Constellation plant. The Panda bid was considered even a higher construction risk than Constellation since construction had not commenced at the time of the bid.

Finally, the tenth ranked bid (the ninth ranked bid was one of the NRG bids described above) was from Aquila Energy's Raccoon Creek facility. This facility was not scheduled for commercial operation until the middle of summer 2002 and would have operating constraints until transmission upgrades could be completed in the 2006 or beyond timeframe.

Q. Please summarize AmerenUE's general view of the bids.

A. AmerenUE did not consider the issues listed above to be minor. The facts are well documented that AmerenUE did not "push aside the ten lowest price power sales offers, which allowed an affiliate to be declared the winner" as alleged by Dr. Roach. Also, if and when transmission service was approved, as with AEP being granted transmission shortly after the January 15, 2002 presentation to the MPSC, AmerenUE then included AEP as a valid bid. As a result, for the power purchase bids, AmerenUE considered the number one and two ranked bids from Reliant and AEP as the recommended bids for a total of 315 MW of the 500 MW requested in the August 2001 RFP for the summer of 2002.

Q. In their testimony, did Staff find that AmerenUE had unfairly disqualified any bidders?

A. No. In fact, Staff witness Fager concludes that there was no evidence that AmerenUE discriminated in favor of any affiliate. See Exhibit No. S-9 at 4, 31-32.

Q. Dr. Roach states Ameren dismissed the lowest price bid (from AEP) because it was said to have a 100 MW limit on transmission in the Ameren territory. Is this true?

A. Dr. Roach is wrong as to why the lowest price AEP bid was not initially considered. Point to point transmission was needed from AEP to the Ameren border, and from the Ameren border to the sink. Ameren had secured transmission from the border to the sink, but AEP did not have transmission to the Ameren border. Without the AEP transmission the bid could not be considered. AEP later received transmission to the Ameren border and Ameren executed a contract with AEP for 100 MW for the summer of 2002.

Q. On page 29 of his direct testimony, Dr. Roach states Ameren did not incorporate the recommendations from Burns & McDonnell into the January 15, 2002 presentation to the MPSC Staff Briefing, because this was before Ameren received the draft report from Burns, dated January 20, 2002. Is this true?

A. No. AmerenUE staff was in contact with Burns & McDonnell extensively during the entire RFP process. AmerenUE received recommendations from Burns & McDonnell starting in October 2001. The draft report Ameren received from Burns dated January

20, 2002 was merely a formal reporting of recommendations already discussed between AmerenUE and Burns & McDonnell.

Q. Dr. Roach further states that Ameren did not follow the recommendations in the Burns & McDonnell report, nor in a subsequent report issued on February 13, 2002. Is he correct?

A. No. The Burns reports identified AEP and Reliant as the two lowest priced bids, which is the same as AmerenUE's analysis. Burns also noted that AEP did not have a point to point transmission path between AEP and AmerenUE and should not be considered until that issue was resolved. AEP was later granted transmission to AmerenUE and they were awarded a one-year contract covering the summer of 2002. The Burns report recommended that AmerenUE begin negotiations with Reliant to finalize terms of their offer. AmerenUE did that and a contract was also awarded to Reliant for the summer of 2002. The Burns report also recommended Aquila's bid if transmission issues could be resolved. AEM was the next recommended bid by Burns.

Q. On page 38 of his direct testimony, Dr. Roach states that Ameren should have taken 250 MW of the fourth-ranked Reliant Aurora bid. His conclusion was "As with AEP, the obvious response is "well, okay, why not take 250 MW of this very low cost supply through 2006 and then boost it to a higher level." Please comment.

A. The only thing that is obvious is Dr. Roach's lack of understanding about how transmission service between control areas is necessary to complete a transaction. For AmerenUE to get firm transmission from the Reliant Aurora facility two transmission pieces are needed. Reliant needed point to point transmission from the Aurora facility to the Ameren border, and AmerenUE needed point to point transmission from the ComEd/ Ameren border to the sink. Reliant could not get the transmission from ComEd to the Ameren border. Ameren had 250 MW of transmission service from the ComEd/Ameren border but Reliant could not get it from Aurora to the Ameren border. As a result of the transmission limitation on the ComEd system, there was no firm transmission from Reliant's Aurora plant to the Ameren border. Accordingly, none of the output of that plant was available to AmerenUE.

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Q. Dr. Roach states on page 12, line 15 of his direct testimony that "Ameren finally (and artificially) narrowed the field of competition to only its affiliates by declaring abruptly that it would consider only power plant acquisitions and no longer consider power purchases of any kind."

A. The record is clear that AmerenUE presented three alternatives for meeting its capacity and energy needs for 2002-2011 to the MPSC Staff on January 15, 2002. AmerenUE was willing to work with the MPSC Staff on any one or a combination of the three alternatives. The record clearly shows that the MPSC Staff preferred the alternatives of building or buying capacity or transferring load to long-term PPAs. The MPSC Staff's perspective on long-term power purchase agreements is that a PPA is merely the deferral of the need to build capacity. That perspective was reinforced by written testimony of MPSC Staff witness Dr. Michael Proctor in Missouri Case No. EC-2002-1 which I discussed in my direct testimony. The perspective was even more strongly supported by MPSC Commissioner Steve Gaw who, in his written opinion on the unanimous

Stipulation and Agreement in Case No. EC-2002-1, states, "This is a continuation of the traditional philosophy [in Missouri] that ratepayers should have reliability of service by receiving electricity generated from the regulated company's own assets." Exhibit No. AS-6 at 32. The MPSC further reinforced this perspective in the June 3, 2003 letter included as Exhibit No. AS-9.

Recent events, including attempts by financially strapped power marketers like NRG to renege on long-term power purchase agreements and the August 14, 2003 blackout in the Northeast, further support the rationale expressed by the MPSC and its Staff that ratepayers should have reliability of service by receiving electricity generated from the regulated company's own assets.

Q. Dr. Roach states on page 12, line 3 of his direct testimony that Ameren dismissed an entire class of competitors-specifically "combined cycle plants." Dr. Roach proceeds to state that in so doing Ameren favored an affiliate from whom it proposes to buy simple cycle plants. Please comment.

A. While Dr. Roach has both a Bachelor and Ph.D. in Economics, he does not have an engineering background. Dr. Roach's lack of knowledge of combined cycle technology severely limits his ability to address that technology compared to simple cycle plants. Included at footnote 3 on page 12 of Dr. Roach's testimony is the statement, "Combined cycles have a much lower fuel cost and are run in 40% to 60% of all hours." In theory, combined cycle plants need to operate at this level of capacity factor in order to be more economic than simple cycle plants. However, power plants are generally operated in order of economic dispatch. The reality in the market is that combined cycle plants in the Midwest region have been operating at less than 20% capacity factors.

Q. Did Dr. Roach ignore evidence of other operational limits associated with combined cycle plants?

A. Yes. Dr. Roach had access to the supporting documents for each combined cycle bid. If Dr. Roach had taken the time to review the specific bids he would have noticed several factors that severely limit operational flexibility associated with combined cycle technology. The first is the exceptionally high per start charge of approximately $24,000 per start. The second is the extraordinary amount of time, typically eight hours, to go from start to full load. The third is the lack of dispatch flexibility such that day ahead or two day ahead scheduling is required. The fourth is a typical minimum run time of 16 hours. Yet, AmerenUE's needs are primarily of a peaking capacity nature for the 1 or 2% hours of the year where the highest system peaks occur. Consequently, AmerenUE needs the quick start capability with little or no notice dispatch flexibility that are characteristic of simple cycle peaking units.

Q. Are there other flaws in Dr. Roach's discussion of combined cycle and simple cycle power plants?

A. Yes. Dr. Roach makes an outrageous and totally untrue statement that, "Both of the two affiliate plants Ameren proposes to acquire are simple cycle plants (also called "peaking" plants) so this redefinition of need, which Ameren did not properly justify, served to favor the affiliate." AEG owns a combined cycle plant, the Grand Tower Plant. For reasons known only to AEG, it did not offer its Grand Tower Plant in its bid to the

Exh. No. NRG 2.0 at page 9, lines 3-12 and line 21, through page 10, line 2. EPSA and NRG consequently concluded that peaking plants could be bought at prices below net plant values. Dr. Roach attempts to support a position that it is reasonable to assume that at the end of the period covered by AmerenUE's August 2001 request for capacity and energy or in 2011, bidders would rebid their generation assets to AmerenUE at the equivalent of the depressed market prices that the same bidders bid in 2001. In other words, Dr. Roach assumes bidders would be willing to re-bid at less than the cost of building a new CTG. Dr. Roach asserts that this is a "legitimate" method of analyzing a 10-year power purchase agreement as compared to a 25-year generation asset purchase. Dr. Roach calls this method the "annuity method." Dr. Roach is absolutely correct in stating that the major assumption in the annuity method is that the initial offer is repeatable, <u>even if the initial offer is below market at the time the power purchase agreement is renegotiated.</u>

Q. What did AmerenUE do in comparing 10-year power purchase agreements to 25-year assets acquisitions?

A. AmerenUE assumed that electric supply and demand are in balance by the end of 2011 and that power purchase agreements for peaking capacity and energy would be renewed at the cost of building and operating a CTG in 2012.

Q. Does this assumption support a bias in favor of Ameren's affiliates as purported by Dr. Roach?

A. Absolutely not. AmerenUE's analysis assumes that supply and demand are in balance in 2012. Dr. Roach assumes that power marketers will be agreeable to renegotiate power

AmerenUE August 2001 RFP for capacity and energy. If AEG had chosen to offer its Grand Tower Plant to AmerenUE, it is likely that Grand Tower would have similar performance and cost characteristics as the other combined cycle bids and would have been rejected from consideration.

B. <u>Fundamental Flaws and Inconsistencies in Dr. Roach's Support of the "Annuity" Method of Comparing Assets With Different Economic Lives</u>

Q. What is the context within which Dr. Roach discusses the annuity method of comparing assets with different economic lives?

A. In the January 15, 2002 presentation to the MPSC Staff concerning AmerenUE's evaluation of bids to the August 2001 RFP for capacity and energy, AmerenUE did a high level economic analysis of the 10-year power purchase bids versus a hybrid approach of both buying and building capacity to meet AmerenUE's future incremental capacity needs. An assumption in the AmerenUE analysis was that at the end of the 10-year power purchase agreement, power marketers would renew power purchase agreements at the cost of building new simple cycle combustion turbines.

Q. Please discuss the "methodological bias" that Dr. Roach on page 33 of his direct testimony claims AmerenUE used in comparing the costs of 10-year power purchase agreements to the long-term ownership of peaking plants.

A. There is consensus between EPSA and NRG that there was a supply/demand imbalance for electric capacity and energy that supposedly depressed the market prices for generation assets at the time that AmerenUE made the decision to buy the Kinmundy and Pinckneyville peaking plants. <u>See</u> Roach, Exh. No. EPS-1 at page 14, lines 10-14 and page 57, lines 15-20; Redd, Exh. No. NRG 1.0 at page 13, lines 274-277; and Rudkevich;

purchase agreements in 2012 at below market prices or the same prices that they quoted to AmerenUE in 2001. Power marketers sell at market. If market is above cost, they sell at market. If market is below cost, it is only logical to assume that power marketers are forced to sell at market if they want to make sales. To assume that the market is in equilibrium in 2011 and that power marketers are willing to sell below market is illogical at best. The only bias that exists is the bias that Dr. Roach implicitly adopts when he claims that power marketers would be willing to sign new power purchase agreements at below market prices.

Q. Did NRG hire a consultant to independently value NRG's Audrain County peaking plant as well as AEG's Kinmundy and Pinckneyville peaking plants?

A. Yes. NRG hired Dr. Aleksandr Rudkevich, a Director with Tabors Caramanis & Associates ("TCA").

Q. At what price did Dr. Rudkevich assume new peaking plants would be added in the future?

A. Similar to AmerenUE's analysis of 10-year power purchase agreements versus the cost of building or buying CTGs, Dr. Rudkevich assumed that new CTGs would be valued at their installed capital costs.

Q. Are there any other witnesses in this case that support Dr. Roach's "annuity" method of valuing assets with unequal lives?

A. No other witnesses support the annuity method as applied by Dr. Roach. Ameren witness Frank Graves points out additional flaws in Dr. Roach's use of the annuity method.

C. Non-Price Issues That Impact The Value Of Different Supply Alternatives

Q. Dr. Roach states on page 29, line 13 of his direct testimony that AmerenUE first used the 2001 RFP results to support the purchase of the Pinckneyville and Kinmundy peaking plants at its January 15, 2002 presentation to the MPSC Staff even though the proposed acquisitions were not the most competitive deals in terms of both price and non-price factors. Is this true?

A. This statement is not true. Dr. Roach's assertion shows a lack of understanding of facts that he should have known by reviewing the January 15, 2002 presentation to the MPSC Staff that was provided to Dr. Roach. As stated previously, AmerenUE presented several alternatives for meeting AmerenUE's long-term resource needs to the MPSC Staff. Alternatives included long-term power purchase agreements, a hybrid alternative consisting of 50% power purchase agreements and 50% building or buying capacity, and the transfer of AmerenUE's Illinois service territory to AmerenCIPS. The alternative of building or buying 100% of its long-term capacity needs was not presented to the MPSC Staff.

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The high level economic analysis presented to Staff on January 15, 2002 focused on the least cost tolling power purchase agreement versus the cost of acquiring any one of the AEG assets. The least cost tolling power purchase agreement was the only agreement offered for an annual four month period of June through September 2002-2010 rather than a full 12-month period each year. This fact is clearly stated in the January 15, 2002 presentation. See Exhibit No. AS-17 at 7. The AEG assets were priced for the full 12-

month period. Non-price factors such as transmission availability, creditworthiness, and operational flexibility were not addressed in this analysis. Consequently, Dr. Roach is totally incorrect in surmising that "the proposed acquisitions were not the most competitive deals in terms of both price and non-price factors."

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Q. AmerenUE's August 2001 RFP for capacity and energy for the period 2002-2011 required in excess of 400 MW of capacity and energy for each year beginning in 2002. Did Dr. Roach address how AmerenUE would meet its immediate needs for capacity from prospective bidders who had not begun construction of their proposed facilities or who did not have firm transmission service to AmerenUE?

A. No. Dr. Roach fails to address this fundamental issue. Instead, Dr. Roach focuses solely on the indicative pricing proposals of bidders with no regard for commercial operation date, transmission availability, or operational flexibility. Dr. Roach states that even if AmerenUE has reliability or other issues with a potential power purchase, there will always be some type of interim purchase that it can make. At the same time, Dr. Roach thinks that it is reasonable for AmerenUE to make a power purchase today from a generator with transmission service limitations for delivery at a later date while speculating that the transmission issues associated with the future power purchase can be resolved within a specific period of time.

Q. Is AmerenUE willing to "speculate" on the reliability of its service to its customers?

A. As explained in greater detail by Ameren witness Craig Nelson, AmerenUE is obligated to provide reliable service to its customers and will not make speculative moves in acquiring generation capacity in the hope that the moves will work out as planned. This would be contrary to AmerenUE's service obligations and the dictates of the MPSC, which reviews and regulates the vast majority of AmerenUE's retail services. This obligation is also recognized in the testimony of Staff witness Fager, Exhibit No. AS-9 at 3.

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Q. Dr. Roach cites a bid from Aquila's Raccoon Creek peaking plant that was rejected due to transmission limitations as an example why AmerenUE's exclusion of options based on non-price factors is, in Dr. Roach's opinion, unconvincing. Please comment.

A. Dr. Roach accurately states the AmerenUE perspective of the transmission limitations at Raccoon Creek. Dr. Roach also accurately states the Aquila perspective that even though there are transmission limitations the expectation is that the limits will only occur for a small number of hours each year and are therefore insignificant. However, Dr. Roach simply appears to side with Aquila and to ignore the significant transmission service operating guides associated with Raccoon Creek that are clearly and thoroughly spelled out by AmerenUE. As Mr. Nelson explains, these operating guides make the Raccoon Creek facility unacceptable to satisfy AmerenUE's firm resource needs.

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Q. Please comment on Dr. Roach's broader concerns that are stated on page 43 of his direct testimony, namely "if Ameren can find any hint of a transmission constraint

right now, the non-affiliate offer can be pushed aside for the entire term of the proposal."

A. In the utopian world of transmission planning that Dr. Roach describes, Dr. Roach assumes that AmerenUE can build transmission reinforcements to import any and all power from any source prior to issuing a RFP for capacity and energy. Nowhere does Dr. Roach mention that there are transmission limits, over which AmerenUE has no control, on non-Ameren transmission systems from generators located outside the Ameren control area. Even if there are transmission limits, Dr. Roach states that "It is ludicrous for Ameren to say, as it has implicitly done here, that since all non-affiliates lack firm transmission for at least a couple of years, our only option is to award our affiliate with a life-of-facility deal through the Proposed Transaction." I suggest that it is more ludicrous to believe, as Dr. Roach apparently does, that transmission upgrades can be completed with reasonable certainty in "a couple of years." A case in point is the changing timetable and obstacles associated with building the Callaway-Franks 345-kV line. The MPSC's recent ruling, closely following the August 14 blackout in the Northeast, approving construction of the line does not completely resolve all issues. Intervenors may be appealing the MPSC decision and additional easements for the project still need to be acquired. As explained by Ameren witness Edward Pfeiffer, assuming these issues are resolved, the best case scenario would be completion of the project by 2006.

<u>D. Preferred Supply Options Of The Missouri Public Service Commission</u>

Q. Dr. Roach cites non-price factors such as pay-for-performance provisions in power purchase agreements that, in his opinion, make a power purchase better than the Proposed Transaction. Please comment.

A. The record is undisputed, as FERC Staff recognizes, that the MPSC does not prefer Missouri investor-owned electric utilities such as AmerenUE to rely on long-term power purchase agreements, but rather prefers that ratepayers should have reliability of service by receiving electricity generated from the regulated company's own assets. As stated earlier in my testimony, the wisdom of the MPSC's direction has been borne out by recent events including the August 14 blackout in the Northeast and attempts by power marketers like NRG to abrogate some of their long-term power supply contracts. Dr. Roach prefers to discuss the economic aspects of power purchases in a short-lived buyers market versus the long-term benefits of the proposed transaction and ignores the reliability issues that have been continuously stressed by both the MPSC and AmerenUE. However, the fact in this case is that the MPSC recognizes that while its directives on generation ownership may run against current trends, its policy favoring the surety and reliability of company-owned generation assets best protects Missouri customers of AmerenUE from the up and down ride of the unregulated market and from curtailment issues. <u>See</u> Exh. No. AS-6, page 32; Exh. No AS-9, page 2. The MPSC's preference and direction in this regard is a highly relevant non-price factor that neither AmerenUE nor the FERC can ignore.

III. CROSS-ANSWERING TESTIMONY OF CRAIG R. ROACH, PH.D.

Q. Did you review Dr. Roach's prepared cross-answering testimony?

A. Yes I did. For the most part, Dr. Roach's testimony rehashes many of the arguments he has previously raised, and they do not warrant a further response here. However, they are a number of issues I would like to address.

Q. On page 7 of his cross-answer testimony, beginning on line 15, Dr. Roach states that FERC Staff witness Fager erred by determining that there were no competitive alternatives to the purchase of the AEG units, and that Commission's order setting this proceeding for hearing requires Ameren to demonstrate that the purchase of the AEG units was achieved under terms comparable to that of "available" competitive alternatives, such as power purchase agreements. What is your response to this claim?

A. Dr. Roach's assertions here are wrong on at least two counts. In the first place, there were very little available competitive alternatives to the purchase of the AEG units. As demonstrated in my direct testimony and my testimony above, because of the MPSC directives that Ameren acquire company-owned generation assets, as well as transmission constraints both to the Ameren border and within Ameren, other operational concerns, and creditworthiness issues, the use of power purchase agreements was not an "available" alternative to the purchase of the AEG units. In addition, the MPSC Staff had made it clear that it considered the use of PPAs as the deferral of the need to build needed generating assets, as I describe above. Also, during the course of the 2001 RFP, Ameren determined that the costs of purchased power was not significantly less expensive in the long run than the acquisition of the Kinmundy and Pinckneyville units, and that the risks and concerns associated with PPAs weighed against their use.

Q. On page 9 of his cross-answering testimony, Dr. Roach states that "in the industry," the term "hard asset" means "asset back" as opposed to "financially backed." Dr. Roach goes on to equate PPAs with company-owned assets in terms of reliability and operating flexibility. Please respond.

A. While Dr. Roach can quibble about what "the industry" means by the term "hard assets," it is clear that as the term has been used in this proceeding, it means company-owned generation facilities. It is also clear that this is what the MPSC prefers, and this is not the use of PPAs of any type.

I also disagree with Dr. Roach's contention (Exhibit No. EPS-15 at 9-10) that a PPA can offer the same level of reliability, operating flexibility, and surety of service as a company-owned asset. With a PPA, there is always the possibility that the seller may declare bankruptcy and attempt to get out of its contracts, as NRG and more recently Mirant have attempted to do. The seller can also attempt to get out of the PPA for other reasons or file with the FERC to change the underlying rate, or fail to perform under a contract if it does not think that certain services are required by the PPA or thinks that the purchaser has failed to meet its obligations. These are risks that a utility would not face with assets that it owns itself.

Q. On page 27 of his rebuttal testimony, Dr. Roach indicates that new generation facilities could have been built before 2006 in time for AmerenUE to meet its obligations under the Missouri Stipulation, implying that Ameren should have accepted an offer from a facility that was not yet constructed. Please respond.

A. There are a number of problems with this approach. In the first place, entering into a PPA with any party would not address the MPSC's preference for hard assets and Ameren's obligation under the Missouri Stipulation to acquire additional capacity, or any of the other concerns associated with PPAs. This is true irrespective of whether a particular facility that will be used to supply the power under a PPA is in operation or has not yet been constructed. In addition, there are many risks associated with the construction of new facilities, including financing and credit risks, delays in siting and permitting, and the fact that, like NRG's Audrain facility, the plant may not have adequate transmission capacity once it is constructed to get the power to market. Ameren witness Mr. Jeff Greig also addresses completion risk in his rebuttal testimony.

IV. TESTIMONY OF NRG WITNESS ERSHEL C. REDD, JR.

Q. What areas of Mr. Redd's testimony will you address?

A. I will focus on Mr. Redd's misrepresentations of the net capability of NRG's Audrain peaking plant and the factors that impact the selling price of the Audrain facility.

Q. On page 2, line 31, Mr. Redd states that, through its subsidiary NRG Audrain Generating LLC, NRG owns a 640 MW plant located in Vandalia, Missouri. Is the rating of 640 MW based on the same criteria as the Kinmundy and Pinckneyville peaking plants are rated? If not, please explain and state the rating of the NRG Audrain County facility on a comparable basis to that of Kinmundy and Pinckneyville.

A. Mr. Redd's basis for the 640 MW Audrain Rating is documented in Ameren/NRG data request number 52 as a "nameplate rating." This DR further states individual units are rated at 73.63 MW at 88°F based on standards provided by the International Standards Organization ("ISO"). The nameplate rating of a CTG is a meaningless number that represents a theoretical maximum rating at ideal conditions. It should not be the rating that is used to determine the $/kW selling price of a CTG. The Audrain facility should be rated on MAIN criteria at summer peak weather conditions. Since the output of combustion turbines is a function of the density of the inlet air and since hotter air is less dense than cooler air, the net capability rating of combustion turbines is less at summer peaking weather conditions than during cooler times of the year. The true net capability of the Audrain CTGs as stated by NRG at ISO conditions at 88°F is 73.63 MW per unit. However, AmerenUE rates its units at 95°F. Rating units at 95°F rather than 88°F further reduces the net capability of the Audrain units. The Audrain units have inlet air coolers that provide a slight boost in summer net capability. Factoring in both the 95° F design temperature as well as the inlet air coolers, the comparable rating (comparable to the way the Kinmundy and Pinckneyville CTGs are rated) of the Audrain units is 75 MW per unit times 8 units which equals 600 MW – a difference of 40 MW or 6.25% less than the nameplate rating used by NRG in its calculation of a selling price of $391/kW.

Q. Given that NRG's Audrain facility has a summer net capability rating of 600 MW rather than 640 MW, how does this impact the calculation of NRG's purported selling price of the Audrain facility in terms of $/kW?

A. Mr. Redd states that NRG would sell its Audrain facility for a price not to exceed $391/kW, based on a rating of 640 MW. If the true summer net capability of 600 MW is used, the Audrain facility selling price in total dollars remains the same but the net capability of the units is decreased from 640 MW to 600 MW. Consequently, since the selling price is divided by the net capability to obtain the effective selling price in terms of $/kW, NRG is actually offering to sell the Audrain facility for $417/kW.

Q. What is the price of the Kinmundy peaking plant?

A. The price of the Kinmundy peaking plant is to be based on its net plant value at the time of the closing of the sale. As of September 2002, Kinmundy's net plant value was $415/kW. As of August 2003, Kinmundy's net plant value was $406/kW.

Q. Does that mean that NRG's Audrain facility is actually more expensive than the Kinmundy facility on a $/kW basis when rating both plants at peak summer conditions?

A. That is correct.

Q. What is the price of the Pinckneyville peaking plant?

A. The price of the Pinckneyville peaking plant is to be based on its net plant value at the time of the closing of the sale. As of September 2002, Pinckneyville's net plant value was $511/kW. As of August 2003, Pinckneyville's net plant value was $496/kW. At a price of $496/kW, the acquisition cost is approximately $79/kW higher than that of the Audrain facility based on a net capability of 600 MW. However, the value of Pinckneyville is also a function of its better operating efficiency, its quick start capability, its black start capability, its unencumbered transmission outlet, its load following capability, its ability to provide generation and voltage support that enhances the eastern import capability for AmerenUE, etc. – none of which have been factored into the Pinckneyville purchase price.

Q. What is the combined price of the Kinmundy and Pinckneyville plants as of August 2003 and how does the combined price compare to the Audrain facility?

A. Using the net plant values of $406/kW for Kinmundy and $496/kW for Pinckneyville, and net plant capabilities of 232 MW for Kinmundy and 316 MW for Pinckneyville, the weighted average combined price of both facilities is $458/kW. As calculated previously, the Audrain price is $417/kW, which is only $41/kW, or 9% lower than that of the combined Kinmundy and Pinckneyville peaking plants.

Q. Please discuss factors other than the selling price that impact the valuation of a peaking facility such as NRG's Audrain plant.

A. Without firm transmission outlet capability, the value of a peaking plant like NRG's Audrain facility is minimal – perhaps no more than salvage value. The transmission issues associated with Audrain County have been extensively discussed in Mr. Pfeiffer's testimony. Acknowledging the transmission difficulties associated with the Audrain facility, we can discuss value drivers for the Kinmundy and Pinckneyville peaking plants relative to the Audrain facility under a scenario where there are no transmission limits associated with the Audrain facility. Our knowledge of the design and operating characteristics of the Audrain facility is based on NRG's responses to our engineering due diligence data requests. These data responses are included as Exhibit No. AS-43 to my rebuttal testimony.

A significant value driver that Kinmundy has is dual fuel capability. Audrain is limited to a single fuel. Significant value drivers for Pinckneyville include: most efficient heat rates for CTGs, quick start capability, black start capability, lowest NOx emissions, high turn down ratios for maximum dispatch flexibility and the fact that the Pinckneyville facility is directly connected to the AmerenUE transmission system and can provide generation and voltage support which enhances the eastern import capability for AmerenUE. The Audrain facility has none of these features.

Q. Are there other deficiencies associated with the Audrain facility?

A. Yes. From a design perspective, the Audrain facility has several significant deficiencies relative to both Kinmundy and Pinckneyville. Deficiencies associated with the Audrain facility include:

- Generator step-up ("GSU") transformers with inferior characteristics to those at Kinmundy and Pinckneyville.
- Multiple transformer failures at Audrain.
- Use of 1 GSU per two CTGs whereas Kinmundy uses 1 GSU per CTG: A single GSU failure will cause a loss of a nominal 160 MW at Audrain versus a high of 116 MW at Kinmundy or 88 MW at Pinckneyville.
- Lower turn down ratios than either Kinmundy or Pinckneyville: Units with a lower turndown ratio will need to be cycled on and off more often to follow load. This leads to higher maintenance costs on frame CTGs with high start charges.

Operational issues that may impact the value of the Audrain facility include:

- CTGs at Audrain have never been operated at full output simultaneously. Are they capable of operating at full output?
- Significant staff reductions at Audrain: the fact that all eight units at Audrain have never been operated simultaneously coupled with significant staff reductions (from 10

to 2) and NRG's refusal to provide detailed maintenance records are significant concerns. No one can know for certain how reliable a plant is that has aforementioned unknowns.

Q. In summary, how important is the $/kW purchase price in determining the value of a CTG?

A. The $/kW purchase price is one of many factors that enter into the valuation of a CTG. If there is a relatively narrow range of purchases prices, as there is in the comparison of the combined Kinmundy and Pinckneyville purchase relative to an Audrain purchase, it is essential to consider the heat rates or efficiencies of the different CTGs, the dispatch flexibility, and the reliability enhancement aspects, such as quick start and black start capabilities, of the alternative CTGs.

Q. Is there any question that the Kinmundy and Pinckneyville CTGs have operating characteristics that are far superior to those of the Audrain facility?

A. No. It is clear based on the evidence provided by AmerenUE, as well as on the documentation of the design, construction, operation, and maintenance of the Audrain facility provided by NRG, that the Kinmundy and Pinckneyville peaking plants have superior operating characteristics compared to NRG's Audrain facility.

Q. Mr. Redd states on page 9 of his testimony that generation prices have fallen dramatically in response to lower energy prices and reduced demand growth and that the acquisition of Audrain could be accomplished for a far lower price per kW than the acquisition of the Kinmundy and Pinckneyville plants at their net book values. Do you agree?

A. No. All the evidence points to the direct opposite of what Mr. Redd states. Mr. Redd asserts that generation prices are falling yet NRG's indicative pricing proposal for the Audrain facility increased from $312/kW in August 2002 to $391/kW in August 2003 – a 20% increase in one year! I need to reiterate that both $/kW values are significantly understated due to the use of a "nameplate" rather than summer net capability rating of the Audrain CTGs. The comparable plant sales presented in the February 5, 2003 FERC application to transfer the Kinmundy and Pinckneyville CTGs provides further factual evidence that generation prices were not falling significantly at the time AmerenUE made its decision to buy the Kinmundy and Pinckneyville facilities. Finally, the leveling off of electric market prices beginning in 2002 further supports the fact that market prices were not driving down the value of peaking generation facilities.

As discussed earlier in my testimony, the Audrain facility is actually priced higher on a $/kW basis than the Kinmundy unit based on Kinmundy's net plant value as of August 2003. In addition, the combined Kinmundy and Pinckneyville purchase price is only 9% higher than that of Audrain. The initial cost differential has to be balanced with the unquestionably superior operating and reliability characteristics of the Kinmundy and Pinckneyville plants. Of course, this price comparison is based on the assumption that the Audrain facility is a viable plant, i.e., it has firm transmission outlet capability. The evidence is clear that Audrain has transmission outlet limitations that could essentially reduce its value to salvage until those limits are removed.

Finally, the testimonies of Mr. Redd and NRG's generation asset valuation "expert," Dr. Rudkevich, are in direct contradiction with each other. As I discussed in more detail later in my testimony, according to Dr. Rudkevich's detailed workpapers, the market value of Kinmundy and Pinckneyville exceed net plant values.

Q. Please summarize your response to Mr. Redd's testimony.

A. Mr. Redd's testimony is filled with inaccuracies and unsubstantiated claims. Mr. Redd makes statements about market conditions for peaking plants that are unsubstantiated by any evidence. Perhaps the most glaring error in Mr. Redd's testimony is his use of a theoretical nameplate rating of 640 MW for the Audrain facility used to calculate a proposed selling price of $391/kW. Equally serious omissions from Mr. Redd's testimony are the significant design and operational deficiencies of the Audrain facility relative to either Kinmundy or Pinckneyville. Mr. Redd makes inept comparisons to the $/kW net plant values of the Kinmundy and Pinckneyville peaking plants, whose ratings based on true net plant capability ratings for summer peak weather conditions, to the Audrain facility, whose ratings are based on a maximum theoretical nameplate rating. Mr. Redd's statements about generation prices falling dramatically in response to lower energy prices and that "it is a good time to purchase a power plant" are unsubstantiated and, in fact, are totally refuted by the evidence presented by AmerenUE. Moreover, NRG's generation asset valuation "expert" has provided workpapers stating that buying existing assets at net book value or below today provides significant value to buyers, despite his testimony to the contrary.

V. TESTIMONY OF DR. ALEKSANDR RUDKEVICH

Q. What areas of Dr. Rudkevich's testimony will you address?

A. I will focus on Dr. Rudkevich's calculation of the fair market value of the Kinmundy and Pinckneyville peaking plants. Specifically, I will point out the technical errors, the dramatic changes in modeling assumptions between Dr. Rudkevich's current analysis and the earlier analysis on the same topic that he submitted to the Illinois Commerce Commission ("ICC"), and the irrational assumptions that underlie Dr. Rudkevich's analysis. I will show that this witness's technical credibility in these areas is lacking and subject to substantial doubt.

A. Major Flaws in Dr. Rudkevich's Market Simulation Analysis

Q. What does Dr. Rudkevich state in his testimony as the purpose of his market simulation analysis?

A. Dr. Rudkevich states the purpose of his market simulation analysis on page 2, lines 15 – 19 of his direct testimony.

> *"Using this analysis, I calculate the fair market value of the AEG Facilities in order to compare that value with the price at which AmerenUE intends to acquire those generating units from its affiliate. Finally, I evaluate if there are alternative capacity options available to AmerenUE at a lower price."*

Q. And what conclusions did Dr. Rudkevich arrive at based on this analysis?

A. Based on his market simulation analysis, Dr. Rudkevich concludes the proposed price for the purchase of the Kinmundy and Pinckneyville facilities is higher than these facilities' fair market value, and that there exists capacity options available to AmerenUE at a cost below the price it is willing to pay for the AEG units. Both of these conclusions are incorrect and Dr. Rudkevich's testimony is directly contradicted by his workpapers.

Q. Do you agree with Dr. Rudkevich's market simulation analysis and the conclusions he arrives at based on its results?

A. No, I do not. As I will discuss in detail later in my testimony, there are numerous major flaws in both the methodology Dr. Rudkevich uses in his analysis and the assumptions that drive his results. First, I focus on one of the central flawed assumptions, the value of capacity used in Dr. Rudkevich's analysis.

1. Value of Capacity

Q. Please provide some background as to how Dr. Rudkevich calculates the capacity value and how that value has changed in this analysis as compared to the analysis filed at the Illinois Commerce Commission on April 17, 2003.

A. Dr. Rudkevich uses a financial model to calculate the annual carrying charge for a new simple cycle gas turbine ("SCGT"). He then uses this value as the capacity value of each generating unit in his analysis once the market for capacity hits its equilibrium point. In his April 17, 2003 filing at the ICC, his financial model produced an annual carrying charge rate of $57/kW-Yr for a SCGT. In his valuation model Dr. Rudkevich showed capacity values remaining at a depressed level due to the current oversupply situation for the years 2004 through 2007 and then reaching the full capacity value of $57/kW-Yr for the years 2008 and beyond.

The financial model that Dr. Rudkevich used to support his August 8, 2003 testimony in this proceeding produced quite different results. The financial model used to support his FERC testimony produces an annual carrying charge rate of $90/kW-Yr for a SCGT. As compared to his ICC testimony, in his updated valuation model, Dr. Rudkevich shows capacity values remaining at a depressed level due to the current oversupply situation for the years 2004 through 2013, and then reaching the full capacity value of $90/kW-Yr for the years 2014 and beyond.

Q. Does this drastic change in Dr. Rudkevich's capacity value seem reasonable to you?

A. No, it does not. The drastic change in the level and shape of the capacity curve used in Dr. Rudkevich's valuation analysis prompted Ameren to generate numerous data requests of Dr. Rudkevich on this topic.

Q. Was any significant new information brought to the forefront through this data request process?

A. Yes there was. Ameren, through discovery, obtained information on the change in capacity value in each year of Dr. Rudkevich's current analysis as compared to the analysis he performed back in April 2003 for the ICC proceeding. In Dr. Rudkevich's responses to data requests Ameren/NRG-184 and Ameren/NRG-185, which I have included as Exh. No. AS-44 to my rebuttal testimony, Dr. Rudkevich states that the capacity prices in the years 2008 and 2011 were calculated incorrectly due to a technical error. His responses reference his response to data request Ameren/NRG-171, which is also included as part of Exhibit No. AS-44. Also included in Dr. Rudkevich's responses to Ameren's data request data requests Ameren/NRG-177 were revisions to his Exhibit Nos. NRG 2.2, NRG 2.6 and NRG 2.7, which were originally submitted as part of his testimony at FERC on August 8, 2003. I have included these revised exhibits as Exhibit No. AS-45 to my rebuttal testimony.

Q. Does the correction of this technical error have any effect on the results of Dr. Rudkevich's valuation analysis?

A. Yes, it does. Dr. Rudkevich's Exhibit No. NRG 2.7 (Revised) contains the scenario 1 and scenario 2 valuation analysis summary for each of the three generating facilities evaluated (Pinckneyville, Kinmundy and Audrain). The results of Dr. Rudkevich's analysis are shown in Exhibit No. NRG 2.2 (Revised). The revised results show the market value of the Kinmundy plant ranges from $475/kW – $592/kW and the market value of the Pinckneyville plant ranges from $484/kW – $603/kW. This represents a roughly 50% increase in the fair market value of these facilities as compared to the results included in Dr. Rudkevich's direct testimony which includes the technical error.

Q. Do these results support Dr. Rudkevich's first conclusion that AmerenUE's proposed purchase price of the Pinckneyville and Kinmundy facilities from AEG is higher than the fair market value of those facilities?

A. No, they do not. The revised results of Dr. Rudkevich's analysis show that the market value of the Pinckneyville and Kinmundy facilities is actually higher than the proposed purchase price based on net book value as shown in Dr. Rudkevich's Exhibit No. NRG 2.2 (Revised). This is a direct contradiction to Dr. Rudkevich's stated conclusion.

Q. Do these results support Dr. Rudkevich's second conclusion that NRG's Audrain generating facility priced at the fair market value is superior to the proposed purchase from AEG?

A. No. The revised results of Dr. Rudkevich's analysis show that the market value of the Audrain facility ($475/kW - $592/kW) is higher than the weighted average price of the proposed purchase from AEG ($470/kW).

2. Income Tax Calculation

Q. Was there any other significant new information brought to the forefront through discovery that is pertinent in this case?

A. Yes. In data request Ameren/NRG-189, Ameren asks Dr. Rudkevich detailed questions related to the calculation of income taxes in his valuation model. Specifically, Ameren asked Dr. Rudkevich how income taxes would be calculated differently in years in which the AEG facilities generate negative taxable income if AmerenUE were to purchase such facilities. NRG's response was as follows:

> *"NRG objects to this request because Dr. Rudkevich is not informed regarding the tax situation of Ameren and its affiliates; the questions therefore call for speculation by Dr. Rudkevich as to matters not within his knowledge."*

Q. What is the significance of this response to Dr. Rudkevich's market valuation analysis in this proceeding?

A. The point of market valuation analysis is to determine the value of the Pinckneyville and Kinmundy generating assets to AmerenUE. Dr. Rudkevich's response indicates he would have to speculate as to matters not within his knowledge that are relevant to such an analysis. This also means that Dr. Rudkevich's valuation analysis of generating assets to AmerenUE must also be based on speculation as to matters not within his knowledge.

The FERC's decision in this case should not be based on Dr. Rudkevich's speculative valuation analysis.

3. Flaws in Methodology

Q. You stated earlier that there are major flaws in both the methodology used in Dr. Rudkevich's asset valuation analysis and the assumptions that drive the results. Could you please discuss these flaws now?

A. The asset valuation methodology is flawed in that it attributes too large of a percentage of an asset's value to the capacity value. The result of such analysis is the value of assets that have drastically different operating characteristics falling into a very tight range. The GE MAPS results included in Dr. Rudkevich's testimony as Exhibit No. NRG 2.7 illustrate this point.. For the year 2014 the value of the energy for the three generating facilities is in the range of $0.0002/kW-Yr to $2.26/kW-Yr (Pinckneyville - $2.26/kW-Yr, Audrain - $0.0002/kW-Yr, Kinmundy - $0.22/kW-Yr). For the same year of the analysis, the capacity value for each of the three facilities is $120.44/kW-Yr. The result is the capacity value of each facility accounting for 98.1% to 100% of the total value of the assets in that year.

Q. Does this relationship hold true in other years of Dr. Rudkevich's analysis?

A. Yes, it does. The same relationship can be seen in every year of Dr. Rudkevich's analysis.

Q. Does this relationship hold true in Dr. Rudkevich's revised analysis included in Exhibit No. AS-45 attached to your rebuttal testimony?

A. Yes, it does.

Q. How would an inefficient, oil fired asset be valued using Dr. Rudkevich's asset valuation methodology?

A. For sake of argument, let us assume an oil fired combustion turbine with a high heat rate of 14000 Btu/kWh and an equivalent availability of less than 80%. Based on the operating characteristics of this unit, let us assume the unit is never dispatched and that its 2014 energy value is $0/kW-Yr. Under Dr. Rudkevich's methodology this asset would be credited in the year 2014 with $0/kW-Yr as the energy value and $120.44/kW-Yr for the capacity value for a total value of $120.44/kW-Yr. This compares to a total value of $122.70/kW-Yr for the Pinckneyville assets or 98.2% of the value of the Pinckneyville assets. This relatively negligible difference in value, as calculated using Dr. Rudkevich's methodology for two drastically different assets does not make sense, and fails to assign any value to the superior operating characteristics of a more efficient unit such as Pinckneyville. Accordingly, Dr. Rudkevich's methodology should not be used by the Commission in assigning value to assets at issue in this proceeding.

<u>4. *Additional Flawed Assumptions*</u>

Q. Are there any flaws in the assumptions underlying Dr. Rudkevich's analysis?

A. There are at least four major flaws in the assumptions used in Dr. Rudkevich's asset valuation analysis. They are as follows:

1. Each of the three generating facilities he values has identical access to the power grid despite known transmission limitations associated with the Audrain facility.
2. In the Fixed Charge Rate Model, the cost to install a new combustion turbine in the year 2002 is an extremely low $400/kW.

3. The Valuation Model ignores the income tax benefit in years in which the taxable income is negative.

4. The capacity value is artificially low in the years 2007 through 2013 due to a technical error on the part of Dr. Rudkevich.

5. Transmission Constraints

Q. Contrary to Dr. Rudkevich's testimony, are you aware of any transmission limitations associated with any of the three generating facilities included in Dr. Rudkevich's analysis?

A. Yes, I am aware of transmission limitations related to the Audrain facility. Existing overloading on AmerenUE's 345 kV Bland-Franks line and the 345/161 kV Palmyra transformer (owned by Associated Electric Cooperative Inc.) would be aggravated by additional generation located at Audrain County, Callaway, or Labadie. By order issued August 21, 2003 in Case EO-2002-351, the MPSC approved AmerenUE's application to construct, own and operate the proposed 345 kV Callaway-Franks line. Once this line is constructed and in service, the loading issues associated with the Bland-Franks line should go away. However, given the fact that AmerenUE's application in Case EO-2002-351 was just approved, it is unlikely the Bland-Franks line will be constructed before sometime in 2006 under the best of circumstances, as explained by Mr. Pfeiffer. Moreover, this application was opposed by local property owners. It is possible that further property owner challenges may delay the construction and in-service date of this upgrade even further or that the MPSC's order may be modified or overturned on appeal. As Mr. Pfeiffer testifies, AmerenUE also will need to obtain additional easements to build this facility, which could add time to the process. As a result, existing transmission constraints would significantly limit the availability of the Audrain facility until 2006 at best.

Q. How do known transmission constraints of this type affect the value of the Audrain facility in Dr. Rudkevich's analysis?

A. Dr. Rudkevich's defines the current value of a generating asset as the net present value of the after-tax cash flow for that unit over a 26-year period from 2004 through 2029. During peak periods, the transmission constraints associated with the Audrain facility cause both the margin on energy sales and the capacity value to be equal to zero in all years in which the constraint is present. Because of the uncertainty of when or if a fix (that is, the construction of the Bland-Franks line) will be in place, there is no value for the Audrain facility at least until 2006 or maybe later.

<u>6. Cost of a new CT unit</u>

Q. What value does Dr. Rudkevich use in his FCR Model for the cost of installing a new combustion turbine in the year 2002?

A. The value Dr. Rudkevich uses is $400/kW.

Q. Do you believe this is a valid assumption?

A. No, I do not. This value is much lower than what Ameren would use in its modeling. A more realistic value would be closer to $450/kW based on CTGs that Ameren either built recently or is planning to build in the near future. It also seems unusual to me that NRG believes that the cost to build a combustion turbine in 2002 was $400/kw yet they were willing to purchase the Audrain facility just one year earlier for $508/kw. Either the cost to build dropped dramatically in that year or NRG is intentionally using a low number in its analysis to depress the value of the assets in question here.

7. Tax Benefits

Q. Why is it incorrect to ignore the tax benefit in years in which the taxable income is negative?

A. Dr. Rudkevich's assumption that there is no tax benefit is based on analysis of the generating assets as stand alone entities. Under this assumption it is valid that negative taxable income would provide no tax benefit. But in AmerenUE's case, these assets would become a part of a portfolio of assets. Negative taxable income associated with these generating assets in any given year would act to offset taxable income associated with other AmerenUE assets, the result being a decrease in the overall level of AmerenUE's income taxes. As stated earlier in my testimony, NRG's response to a data request on this topic states that Dr. Rudkevich is not informed regarding the tax situation of AmerenUE and that responding to the data request would require speculation by Dr. Rudkevich as to matters not within his knowledge. This holds true for this analysis. Assuming that there would be no tax benefit to AmerenUE in years in which these assets produced negative taxable income is pure speculation on the part of Dr. Rudkevich that is contrary to reality.

Q. What is the effect of Dr. Rudkevich's technical error which cause the capacity value in his valuation model to be artificially low in the years 2007 though 2013?

A. As stated previously, the correction of Dr. Rudkevich's technical error increased the value of the generating assets in question by approximately 50% in Dr. Rudkevich's revised analysis.

VI. RESPONSE TO TESTIMONY OF FERC STAFF WITNESS FAGER

Q. In her testimony (Exhibit No. S-9 at 21-27), Staff witness Fager states that because of a lack of liquidity in the market for sale of CTGs, the transactions reflected in your benchmark analysis (as well as the benchmark analysis contained in Ameren witness James Metcalfe's prepared direct testimony) do not satisfy the Commission's standards for benchmark evidence and do not firmly support the proposed purchase price. Please respond.

A. The benchmark analysis that Ms. Fager refers to appears at pages 22 through 23 of my direct testimony, Exhibit No. AS-10. I agree with Ms. Fager's central conclusion that unlike the market for long-term purchased power agreements, there is not a liquid market for the sale of CTGs. However, my analysis was intended to demonstrate that the price that AmerenUE would pay for the Kinmundy and Pinckneyville facilities is in line with market prices for similar facilities, which my analysis does show. See Exhibit No. AS-10 at 21-22.

Q. Do Ms. Fager's benchmark analysis and testimony support your conclusion?

A. Yes. In her analysis, Ms. Fager examined seven out of the twelve transactions that Mr. Metcalfe and I used in our testimonies. She concludes while the comparability of the benchmark transactions is too much in doubt to say they firmly support the proposed purchase price, their average value is in line with the purchase price, which is exactly what I had determined. She also states the benchmark evidence offers reassurance that the proposed purchase price may be appropriate. Exhibit No. AS-9 at 22. Finally, I note that Ms. Fager ultimately determines that there is no evidence that the purchase price is improper, and that the proposed transactions should be approved. Fager, Exhibit No. S-9 at 4-5, 32-33.

Q. Staff witness Fager offers a number of recommendations for future RFPs that she says Ameren should take for future resource acquisitions that may involve affiliates. Is there any part of these proposals that you wish to address?

A. Yes, I do. As an initial matter, Ameren's response to these proposals is set forth in Mr. Nelson's rebuttal testimony and I agree with his statement that Staff's proposals are generally acceptable. Ms. Fager (Exhibit No. S-9 at 34-35) recommends that when Ameren is considering purchasing a facility from an affiliate, it should use an independent and non-affiliated consultant to design the RFP and evaluate the bids. She states that Ameren should first define the precise type of products it is willing to consider, and should include in its RFP the acceptable points for suppliers to deliver energy to the Ameren control area border. Additionally, if the RFP requires a network resource, she would allow bidders to propose an interim PPA until they can meet the network resource requirement.

While I basically agree with Ms. Fager's proposal, I have concerns as to her recommendation that Ameren specify the precise type of product it is willing to consider. Ameren should have the flexibility to propose multiple products, and select among them based on the bids received, subject to the review and recommendations by the independent consultant. Ameren may not know until the RFP is conducted what the best product options are. Similarly, Ameren should not be obliged to enter into a PPA as an interim measure unless Ameren determines that to do so is a reasonable alternative that serves Ameren's customers. Finally, the RFP process and results must comply with the requirements of MPSC Case No. EA-2000-37 and other applicable MPSC orders. Ameren should not be forced to accept an RFP that contains terms or conditions that are contrary to any MPSC requirements or orders.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Ameren Energy Generating Company and Union Electric Company d/b/a AmerenUE	))))	Docket No. EC03-53-000

AFFIDAVIT OF RICHARD A. VOYTAS

Richard A. Voytas, being first duly sworn, deposes and says that he is the Richard A. Voytas referred to in the document entitled "Prepared Rebuttal Testimony of Richard A. Voytas;" that the exhibits accompanying that document where prepared by him or under his direction; that he has read such testimony and is familiar with the contents thereof; and that the contents of that document are true, correct, accurate and complete to the best of his knowledge, information, and belief in this proceeding.

Richard A. Voytas

Richard A. Voytas

Subscribed and sworn to me before this 2nd day of October, 2003.

My commission expires:

Valerie W. Whitehead

Notary Public

VALERIE W. WHITEHEAD
Notary Public - Notary Seal
STATE OF MISSOURI
Jefferson County
My Commission Expires: Dec. 10, 2006

Exhibit No. AS-43

Ameren/NRG - 57:
To the extent not already provided in response to Ameren/NRG-33 and Ameren/NRG-34, provide monthly staffing levels at the Audrain County Facility for every month that it has been in service.

Response:

NRG states as follows:

June 2001-August 2002	10 personnel
September 2002-present	2 personnel

Certification:

I certify that this response was prepared under my direct supervision and is true and accurate to the best of my knowledge, information and belief, formed after a reasonable inquiry.

/s/
Lawrence Schuermann
Donna Stephenson
NRG Energy, Inc.

Ameren/NRG - 59:
Have all 6 units at the Audrain County Facility ever been at 100% power simultaneously? If so, when?

Response:

NRG states that there are eight (8) units at Audrain, and no they have not all run simultaneously.

Certification:

I certify that this response was prepared under my direct supervision and is true and accurate to the best of my knowledge, information and belief, formed after a reasonable inquiry.

/s/
Lawrence Schuermann
Donna Stephenson
NRG Energy, Inc.

Ameren/NRG - 60:
Provide a detailed explanation of all equipment problems at the Audrain County Facility since it went on-line in June 2001.

Response:

NRG states that during the start-up and initial commercial operation of Audrain there were three problems that have since been resolved, (1) Unreliable Air Processing Unit (backup instrument air compressors were installed on all power blocks), (2) GSU transformer failure (ABB re-built), and (3) Load Tunnel Thermocouple (T/C) problems (repair and set point adjustment under warranty from GE).

Certification:

I certify that this response was prepared under my direct supervision and is true and accurate to the best of my knowledge, information and belief, formed after a reasonable inquiry.

/s/
Lawrence Schuermann
Donna Stephenson
NRG Energy, Inc.

Ameren/NRG - 78:
Provide the history of all generator protection scheme problems at the Audrain County Facility, including a description of any design changes to correct problems or potential problems.

Response:

NRG is unaware of any problems related to generator protection schemes.

Certification:

I certify that this response was prepared under my direct supervision and is true and accurate to the best of my knowledge, information and belief, formed after a reasonable inquiry.

/s/
Lawrence Schuermann
Donna Stephenson
NRG Energy, Inc.

Ameren/NRG - 90:
Provide the daily, weekly, monthly and annual operational and maintenance check lists concerning the Audrain County Facility.

Objection:

1. NRG objects to this request on the basis that it is not relevant to, nor will it lead to the discovery of relevant information.
2. NRG objects to this request as unreasonably burdensome.

Response:

Without waiving the foregoing objections, NRG states that it would be willing to allow Ameren access to the Audrain plant in order to obtain such information.

Ameren/NRG - 102:
Provide copies of all construction punch lists concerning the Audrain County Facility.

Response:

NRG states that it has no such "punch lists."

Certification:

I certify that this response was prepared under my direct supervision and is true and accurate to the best of my knowledge, information and belief, formed after a reasonable inquiry.

/s/
Lawrence Schuermann
Donna Stephenson
NRG Energy, Inc.

Ameren/NRG - 109:
Provide copies of all change order notices concerning the Audrain County Facility.

Objection:

1. NRG objects to this request as vague in not defining "change order notice."

2. NRG objects that this information is not relevant to the determination of the competitive impacts of the affiliate transfer of Kinmundy and Pinckneyville, and not likely to lead to relevant information.

Ameren/NRG - 110:
Provide copies of all "Requests For Information" from the installation contractor(s) concerning the Audrain County Facility.

Objections:

1. NRG objects to this request as vague in not defining "requests for information."

2. NRG objects that this information is not relevant to the determination of the competitive impacts of the affiliate transfer of Kinmundy and Pinckneyville, and not likely to lead to relevant information.

Ameren/NRG- 119:
How many GSU's are installed at the Audrain County Facility? One per unit or are there multiple units on a single GSU?

Response:

Four GSUs (one per two GT units)

Certification:

I certify that this response was prepared under my direct supervision and is true and accurate to the best of my knowledge, information and belief, formed after a reasonable inquiry.

/s/
Lawrence Schuermann
Donna Stephenson
NRG Energy, Inc.

Ameren/NRG – 129:
Provide the NO_X and CO_2 limits contained in the air permit(s) concerning the Audrain County Facility.

Response:

In accordance with the operating permit, NOx is 9.0 ppm by volume corrected to 15% O2 on a dry basis, expressed as a 12-month roll for GT loads greater than or equal to 60 MWs. Additionally, Audrain is allowed 12.0 ppm for a one hour period. The operating permit includes no limit on CO2.

Certification:

I certify that this response was prepared under my direct supervision and is true and accurate to the best of my knowledge, information and belief, formed after a reasonable inquiry.

/s/
Lawrence Schuermann
Donna Stephenson
NRG Energy, Inc.

Exhibit No. AS-44

Ameren/NRG-171:

On April 17, 2003 Dr. Rudkevich submitted direct testimony at the ICC Case No. 03-0083 which included an analysis of the Pinckneyville, Kinmundy and Audrain County generating facilities. Reference Exh. No. NRG 2.0, page 3, lines 2-5, where Dr. Rudkevich states, "For the purpose of this filing before the Federal Energy Regulatory Commission I updated my analysis based on more recent data and addressing certain criticism expressed in the rebuttal testimony of several witnesses testifying before the ICC on behalf of AmerenUE."

a. In his April 17, 2003 ICC testimony Dr. Rudkevich stated that the Fixed O&M cost for Simple Cycle Gas Turbine Power Plants to be $5-5.25/kW-Yr. In Exh. No. NRG 2.0, page 19, Dr. Rudkevich states the Fixed O&M cost for Simple Cycle Gas Turbine Power Plants to be $10-10.25/kW-Yr. Please explain the reason for this drastic change in this assumption. Provide all supporting documents upon which you rely for your response.

b. In his April 17, 2003 ICC testimony Dr. Rudkevich stated that the heat rate for all Simple Cycle Gas Turbine Power Plants to be 10,000 Btu/kWh. In his FERC testimony on page 19 (Exh. No. NRG 2.0, page 19) he states the heat rate varies by unit. Please explain the reason for the change in this assumption. Provide all supporting documents upon which you rely for your response.

c. In his April 17, 2003 ICC testimony Dr. Rudkevich stated that the heat rate for all Simple Cycle Gas Turbine Power Plants to be 10,000 Btu/kWh. In his FERC testimony, Exh. No. NRG 2.0, page 19, he states the heat rate varies by unit. Provide the unit specific heat rate for all other peaking units with which the Pinckneyville, Kinmundy and Audrain facilities will compete in the market. Provide all supporting documents upon which you rely for your response.

d. In his April 17, 2003 ICC testimony Dr. Rudkevich stated that the annual carrying charge for new SCGT and CCGT units to be $57/kW-Yr and $76/kW-Yr, respectively. As part of his FERC testimony, Exh. No. NRG 2.4, page 3, he states the annual carrying charge for new SCGT and CCGT units to be $80/kW-Yr and $99/kW-Yr, respectively. Please explain the reason for this change in this assumption. Provide all supporting documents upon which you rely for your response.

e. Provide a copy of the financial models relied upon to calculate both the April 17, 2003 annual carrying charges and the annual carrying charges in the current FERC testimony.

Objections:

1. NRG objects to the request in subsection 171.c that Dr. Rudkevich provide the "unit specific heat rate for all other peaking units with which the Pinckneyville,

Kinmundy and Audrain facilities will compete in the market" as vague and overbroad; the relevant "market" is not specified nor is the meaning of "compete" clear in the context of the request.

2. NRG objects to this request to the extent it seeks information that is proprietary to Tabors Caramanis & Associates ("TCA") and/or is confidential or commercially sensitive.

Response:

Notwithstanding NRG's stated objections, NRG responds as follows:
a, c, d. The referenced changes are among other changes to the TCA database and underlying assumptions TCA made in June of 2003. At that time, the TCA modeling group directed by Dr. Rudkevich undertook its annual revision of its database of generating units and modeling assumptions underlying TCA's regional modeling of power markets and asset valuation projects. This revision of the TCA database and assumptions has been and is being used in regional market analyses in several projects on behalf of several TCA clients, including the analysis underlying Dr. Rudkevich's testimony on behalf of NRG in this proceeding. In particular:

- TCA revised its generic assumptions with respect to the operating costs of recently developed and future gas-fired generating units based on a review of specific engineering and economic studies and discussions with various clients with direct experience in operating such plants. In particular, we came to a conclusion that the previously assumed fixed operating cost for the SCGT facility of $5/kW-year is too low and that a $10/kW-year cost estimate better reflects the actual economics of operating such plants. It is worth noting though, that this increase in fixed operating costs makes very little (if any) impact on the value of analyzed facilities, because projected capacity prices when set by CT units increase by the same amount.

- TCA Staff made additional efforts to collect publicly available information with respect to the type of turbines installed on gas-fired generating plants developed since 1999. Heat rate assumptions with respect to those plants have been revised as specified in Attachment NRG-170-b-c;

- The environment that presently exists to finance development of new merchant power plants appears inconsistent with the assumptions underlying the development of carrying charges for new CCGTs and SCGTs as used in the April 17, 2003 ICC testimony. Lending institutions presently place much higher risk premiums, resulting in substantially higher required Returns on Equity (ROE). Thus, TCA changed its generic assumptions with respect to this parameter: the ROE for SCGT was increased from 16% to 21%; the ROE for CCGT was increased from 16% to 19%, resulting in carrying charges of $80/kW-year for SCGT and $99/kW-year for CCGT.

b. Please refer to the testimony of Dr. Rudkevich on p. 19-20. The reason for the change in heat rate assumptions is stated in footnote 5 on p. 20. Supporting documents for heat rates of the Audrain, Kinmundy and Pinckneyville generating facilities are identified in the referenced portion of the testimony.

e. Requested electronic working papers are attached:

- Working Paper NRG_AR_10: "Carrying Charge Calculation 8-8-03.xls";
- Working paper NRG_AR_11: "Carrying charge calculation 4-17-03.xls".

Certification:

I certify that this response was prepared under my direct supervision and is true and accurate to the best of my knowledge, information and belief, formed after a reasonable inquiry.

/s/
Aleksandr Rudkevich, Ph.D.
Director, Modeling Group
Tabors Caramanis & Associates

Ameren/NRG-184:

Reference Exh. No. NRG 2.7, page 11. Dr. Rudkevich shows a capacity sales value of $17,284,845 for the Audrain County Facility or $27.01/kW in the year 2008. In his April 17, 2003 ICC testimony the capacity price for the Audrain County Facility in the year 2008 was stated to be $57/kW in his "Summary of GE-MAPS Results by Unit by Year". Provide a detailed description of what has changed since April 17, 2003 which decreased the capacity value of the Audrain County Facility to $27.01/kW. Provide copies of all supporting documentation.

Response:

Due to the technical error described in the response to Ameren/NRG-177, the capacity price for 2008 was calculated incorrectly. Revised capacity prices by year expressed in real 2002 dollars are provided in Exhibit NRG 2.6 (Revised). This revised capacity price differs substantially from the capacity price developed for the April 17, 2003 ICC testimony because of the revised set of assumptions underlying the computation of the carrying charge for new SCGT units, as described in the response to Ameren/NRG-171.

Certification:

I certify that this response was prepared under my direct supervision and is true and accurate to the best of my knowledge, information and belief, formed after a reasonable inquiry.

/s/
Aleksandr Rudkevich, Ph.D.
Director, Modeling Group
Tabors Caramanis & Associates

Ameren/NRG-185:

Reference Exh. No. NRG 2.7, page 12. Dr. Rudkevich shows a capacity sales value of $18,466,543 for the Audrain County Facility or $28.85/kW in the year 2011. In his April 17, 2003 ICC testimony the capacity price for the Audrain County Facility in the year 2011 was stated to be $57/kW in his "Summary of GE-MAPS Results by Unit by Year". Provide a detailed description of what has changed since April 17, 2003 which decreased the capacity value of the Audrain County Facility to $28.85/kW. Provide copies of all supporting documentation.

Response:

Due to the technical error described in the response to Ameren/NRG-177, the capacity price for 2011 was calculated incorrectly. Revised capacity prices by year expressed in real 2002 dollars are provided in Exhibit NRG 2.6 (Revised). This revised capacity price differs substantially from the capacity price developed for the April 17, 2003 ICC testimony because of the revised set of assumptions underlying the computation of the carrying charge for new SCGT units, as described in the response to Ameren/NRG-171.

Certification:

I certify that this response was prepared under my direct supervision and is true and accurate to the best of my knowledge, information and belief, formed after a reasonable inquiry.

/s/
Aleksandr Rudkevich, Ph.D.
Director, Modeling Group
Tabors Caramanis & Associates

Exhibit No. AS-45

Ameren/NRG-177:

Reference Exh. No. NRG 2.0, page 21, footnote 6. Dr. Rudkevich states that, "Beyond 2014 we assumed the market to be at equilibrium resulting in the stream of cost and revenues measured in real dollars for all generating units to remain as simulated for 2014."

a. Provide copies of all analysis and supporting documents that show that the market is at equilibrium in 2014.

b. If your analysis shows that the market is at equilibrium prior to 2014, provide the date at which the market reaches equilibrium.

Response:

a, b. A technical error has been found in the computation of capacity prices underlying the analysis on which the August 8, 2003 testimony was based. The error occurred due to a previously undetected error in the software program that resulted in incorrect capacity prices in 2008 and 2011. With this error corrected, starting in 2008 capacity prices will be driven by the cost of new entry and effectively will remain constant in real terms in all years beyond 2008. However, fuel costs are expected to change for several years after 2008. As shown in Exhibit No. NRG 2.5, fuel prices become nearly constant in real terms by year 2012. Thus, it is estimated that the market is likely to reach equilibrium in year 2012.

Certification:

I certify that this response was prepared under my direct supervision and is true and accurate to the best of my knowledge, information and belief, formed after a reasonable inquiry.

/s/
Aleksandr Rudkevich, Ph.D.
Director, Modeling Group
Tabors Caramanis & Associates

Summary of Asset Valuation by Scenario

Scenario 1 ICC Approved (Staff Ratio) WACC Structure 1)

	Rate of return	Ratio	After Tax Weighted Cost
Debt	6.57%	49%	2.00%
Equity	11.412%	51%	5.82%
WACC	9.04%		7.82%

Summary of Asset Valuation Results (as of Sep-2002)

Unit	Market Value	Offer Price	Market to Offer Ratio
Audrain	$ 592	$ 391	151%
Kinmundy	$ 592	$ 415	143%
Pinckneyville	$ 603	$ 511	118%

Scenario 2 AmerenUE Proposed WACC Structure 1)

	Rate of return	Ratio	Weighted Cost
Debt	7.96%	38%	1.88%
Equity	12.6%	62%	7.78%
WACC	10.81%		9.66%

Summary of Asset Valuation Results (as of Sep-2002)

Unit	Market Value	Offer Price	Market to Offer Ratio
Audrain	$ 475	$ 391	121%
Kinmundy	$ 475	$ 415	114%
Pinckneyville	$ 484	$ 511	95%

1) Source: Illinois Commerce Commission DOC 00-0802 dated December 11, 2001

Exhibit 1b – Thermal Unit Characteristics

Unit Type	Size (MW)	Quick Start Capability (% of Capacity)	Spinning Reserves (% of Capacity)	Forced Outage Rate (% of Year)	Planned Outage Rate (% of Year)	Total Unavailability
Combined Cycle		0%	10%	1.5%	7.0%	8.5%
Steam Coal	<100	0%	10%	3.0%	9.5%	12.5%
	<200	0%	10%	3.5%	8.5%	12%
	>200	0%	10%	4.5%	10.0%	14.5%
Steam Gas/Oil	<100	0%	10%	2.5%	7.5%	10%
	<200	0%	10%	4.0%	10.5%	14.5%
	>200	0%	10%	3.5%	12.0%	15.5%
Nuclear		0%	0%	*	*	*
Hydro		0%	100%	0%	0%	0%
Combustion Turbine		100%	90%	1.5%	7.0%	8.5%

Source: Utility engineers, NERC Generator Availability Data System

* See Nuclear units Section

3. Planned Additions and Retirements

Description: Planned entry and retirements impact the fuel mix of installed capacity and composition of plants on the margin, since most retirements are oil or coal plants, which are likely to be replaced by combined cycle gas plants. New entry before 2005 is based on existing projects already in the construction phase or in advanced stages of permitting, as indicated by environmental permit applications and internal knowledge. In addition to known projects, we add capacity based on economic criteria and market conditions. That is, we enter only as much capacity as is profitable. A list of new entry and retirement (subject to additional economic new entry and retirement) for the ECAR, MAIN and MAPP region is included in Appendix 2. Capacity balance for the MAIN region is included in Appendix 3.

New generation capacity is most likely to be either gas-fired combined-cycle (CCGT) or simple-cycle gas turbines (SCGT), based on market requirements and the relative economics of their entry. Below are the capital cost, performance and financing assumptions we use for new entry:

Exhibit 2 – New Entry Assumptions (2002$)

Assumption	CCGT	SCGT
All-In Capital Cost ($/kW)	600-700	350-450
Debt:Equity Ratio	60:40	40:60
Return on Equity	19%	21%
Cost of Debt	8%	8%
Term of Debt	30 years	25 years
Fixed O&M ($/kW-yr)	15	10
Variable O&M ($/MWh)	2	2.5
Full Load Heat Rate (Btu/kWh)	6,900	10,000
Forced Outage Rate	3%	4%
Planned Outage Rate	4%	3%

Using our financial model, we calculate the annual carrying charge for new SCGT and CCGT units to be about $80/kW-yr and $99/kW-yr respectively (in real 2002$).

Summary of GE MAPS Results by Unit by Year

Index	Pool	Name	Winter Capacity (MW)	Summer Capacity (MW)	Average FOR	Generation (GWh)	Energy and Spinning Revenue ($K)	Avg Revenue ($/MWh)	Generation Cost ($k)	Avg Generation Cost ($/MWh)	Fuel Cost ($K)	O&M ($K)
AMPINCKN-2004	MAIN	Ameren/Pinckneyv	44	44	0.04	0.79	42.59	53.77	39.99	50.49	38.01	1.98
AMPNCKN2-2004	MAIN	Ameren/Pinckneyv	44	44	0.04	0.88	47.22	53.66	44.47	50.54	42.23	2.24
AMPNCKN3-2004	MAIN	Ameren/Pinckneyv	44	44	0.04	0.79	42.50	53.77	39.91	50.49	37.94	1.98
AMPNCKN4-2004	MAIN	Ameren/Pinckneyv	44	44	0.04	0.84	44.90	53.71	42.21	50.49	40.12	2.09
AMPINCK5-2004	MAIN	Ameren/Pinckneyv	35	35	0.04	-	-	-	-	-	-	-
AMPINCK6-2004	MAIN	Ameren/Pinckneyv	35	35	0.04	-	-	-	-	-	-	-
AMPINCK7-2004	MAIN	Ameren/Pinckneyv	35	35	0.04	-	-	-	-	-	-	-
AMPINCK8-2004	MAIN	Ameren/Pinckneyv	35	35	0.04	-	-	-	-	-	-	-
AUDRAIN-2004	MAIN	Audrain Generati	80	80	0.04	-	-	-	-	-	-	-
AUDRAIN2-2004	MAIN	Audrain Generati	80	80	0.04	0.10	5.72	55.04	5.64	54.19	5.38	0.26
AUDRAIN3-2004	MAIN	Audrain Generati	80	80	0.04	0.18	9.69	55.04	9.54	54.19	9.10	0.44
AUDRAIN4-2004	MAIN	Audrain Generati	80	80	0.04	0.10	5.72	55.04	5.64	54.19	5.38	0.26
AUDRAIN5-2004	MAIN	Audrain Generati	80	80	0.04	0.10	5.72	55.04	5.64	54.19	5.38	0.26
AUDRAIN6-2004	MAIN	Audrain Generati	80	80	0.04	0.03	1.91	55.04	1.88	54.19	1.80	0.09
AUDRAIN7-2004	MAIN	Audrain Generati	80	80	0.04	0.19	10.25	55.04	10.10	54.19	9.63	0.47
AUDRAIN8-2004	MAIN	Audrain Generati	80	80	0.04	0.18	9.95	55.04	9.79	54.19	9.34	0.45
KINMUNDY-2004	MAIN	Kinmundy Plant 1	116	116	0.04	-	-	-	-	-	-	-
KINMNDY2-2004	MAIN	Kinmundy Plant 2	116	116	0.04	-	-	-	-	-	-	-
AMPINCKN-2006	MAIN	Ameren/Pinckneyv	44	44	0.04	2.18	111.01	50.81	103.07	47.18	97.61	5.46
AMPNCKN2-2006	MAIN	Ameren/Pinckneyv	44	44	0.04	2.35	118.22	50.39	110.78	47.22	104.80	5.98
AMPNCKN3-2006	MAIN	Ameren/Pinckneyv	44	44	0.04	2.36	119.39	50.65	111.20	47.18	105.31	5.89
AMPNCKN4-2006	MAIN	Ameren/Pinckneyv	44	44	0.04	2.38	120.52	50.63	112.31	47.18	106.36	5.95
AMPINCK5-2006	MAIN	Ameren/Pinckneyv	35	35	0.04	0.00	0.19	55.32	0.19	53.94	0.18	0.01
AMPINCK6-2006	MAIN	Ameren/Pinckneyv	35	35	0.04	0.00	0.19	55.32	0.19	53.94	0.18	0.01
AMPINCK7-2006	MAIN	Ameren/Pinckneyv	35	35	0.04	0.00	0.19	55.32	0.19	53.94	0.18	0.01
AMPINCK8-2006	MAIN	Ameren/Pinckneyv	35	35	0.04	0.01	0.28	55.32	0.27	53.94	0.26	0.01
AUDRAIN-2006	MAIN	Audrain Generati	80	80	0.04	0.22	11.49	52.44	11.10	50.63	10.54	0.56
AUDRAIN2-2006	MAIN	Audrain Generati	80	80	0.04	0.49	25.22	51.69	24.67	50.55	23.45	1.22
AUDRAIN3-2006	MAIN	Audrain Generati	80	80	0.04	0.27	14.19	52.18	13.76	50.58	13.08	0.68
AUDRAIN4-2006	MAIN	Audrain Generati	80	80	0.04	0.39	20.46	51.84	19.96	50.57	18.97	0.99
AUDRAIN5-2006	MAIN	Audrain Generati	80	80	0.04	0.26	13.56	51.35	13.34	50.53	12.68	0.66
AUDRAIN6-2006	MAIN	Audrain Generati	80	80	0.04	0.42	21.73	51.79	21.22	50.56	20.17	1.05
AUDRAIN7-2006	MAIN	Audrain Generati	80	80	0.04	0.50	26.00	51.67	25.44	50.56	24.18	1.26
AUDRAIN8-2006	MAIN	Audrain Generati	80	80	0.04	0.56	29.11	51.61	28.52	50.56	27.11	1.41
KINMUNDY-2006	MAIN	Kinmundy Plant 1	116	116	0.04	0.84	45.14	54.04	42.29	50.62	40.16	2.13
KINMNDY2-2006	MAIN	Kinmundy Plant 2	116	116	0.04	-	-	-	-	-	-	-
AMPINCKN-2008	MAIN	Ameren/Pinckneyv	44	44	0.04	7.04	369.83	52.50	334.20	47.44	316.59	17.61

Index	Pool	Name	Winter Capacity (MW)	Summer Capacity (MW)	Average FOR	Generation (GWh)	Energy and Spinning Revenue ($K)	Avg Revenue ($/MWh)	Generation Cost ($k)	Avg Generation Cost ($/MWh)	Fuel Cost ($K)	O&M ($K)
AMPNCKN2-2008	MAIN	Ameren/Pinckneyv	44	44	0.04	8.37	435.25	52.01	397.56	47.50	376.22	21.34
AMPNCKN3-2008	MAIN	Ameren/Pinckneyv	44	44	0.04	7.44	390.62	52.48	353.17	47.45	334.57	18.61
AMPNCKN4-2008	MAIN	Ameren/Pinckneyv	44	44	0.04	8.03	420.40	52.35	381.03	47.45	360.95	20.08
AMPINCK5-2008	MAIN	Ameren/Pinckneyv	35	35	0.04	0.98	58.46	59.56	53.24	54.25	50.79	2.45
AMPINCK6-2008	MAIN	Ameren/Pinckneyv	35	35	0.04	0.92	54.97	60.01	49.70	54.26	47.41	2.29
AMPINCK7-2008	MAIN	Ameren/Pinckneyv	35	35	0.04	0.80	48.30	60.67	43.19	54.26	41.20	1.99
AMPINCK8-2008	MAIN	Ameren/Pinckneyv	35	35	0.04	0.76	46.55	60.89	41.49	54.27	39.57	1.91
AUDRAIN-2008	MAIN	Audrain Generati	80	80	0.04	0.43	22.48	52.12	21.92	50.82	20.82	1.10
AUDRAIN2-2008	MAIN	Audrain Generati	80	80	0.04	2.04	104.88	51.51	103.46	50.82	98.37	5.09
AUDRAIN3-2008	MAIN	Audrain Generati	80	80	0.04	1.69	87.14	51.60	85.83	50.83	81.61	4.22
AUDRAIN4-2008	MAIN	Audrain Generati	80	80	0.04	2.03	104.44	51.55	102.95	50.81	97.88	5.07
AUDRAIN5-2008	MAIN	Audrain Generati	80	80	0.04	1.57	81.16	51.61	79.92	50.82	75.99	3.93
AUDRAIN6-2008	MAIN	Audrain Generati	80	80	0.04	1.96	101.08	51.58	99.62	50.84	94.72	4.90
AUDRAIN7-2008	MAIN	Audrain Generati	80	80	0.04	2.31	119.08	51.53	117.54	50.86	111.76	5.78
AUDRAIN8-2008	MAIN	Audrain Generati	80	80	0.04	2.30	118.40	51.55	116.77	50.84	111.03	5.74
KINMUNDY-2008	MAIN	Kinmundy Plant 1	116	116	0.04	5.59	317.60	56.86	283.76	50.81	269.51	14.24
KINMNDY2-2008	MAIN	Kinmundy Plant 2	116	116	0.04	0.81	58.28	71.77	41.21	50.76	39.18	2.03
AMPINCKN-2011	MAIN	Ameren/Pinckneyv	44	44	0.04	9.17	535.07	58.35	413.16	45.06	390.23	22.92
AMPNCKN2-2011	MAIN	Ameren/Pinckneyv	44	44	0.04	11.13	638.64	57.39	502.04	45.12	473.66	28.38
AMPNCKN3-2011	MAIN	Ameren/Pinckneyv	44	44	0.04	9.84	565.15	57.44	443.34	45.06	418.74	24.60
AMPNCKN4-2011	MAIN	Ameren/Pinckneyv	44	44	0.04	10.56	611.35	57.88	476.03	45.07	449.63	26.41
AMPINCK5-2011	MAIN	Ameren/Pinckneyv	35	35	0.04	3.82	262.88	68.81	196.69	51.48	187.14	9.55
AMPINCK6-2011	MAIN	Ameren/Pinckneyv	35	35	0.04	3.78	260.59	68.99	194.46	51.48	185.02	9.44
AMPINCK7-2011	MAIN	Ameren/Pinckneyv	35	35	0.04	3.87	265.81	68.69	199.20	51.48	189.53	9.67
AMPINCK8-2011	MAIN	Ameren/Pinckneyv	35	35	0.04	3.50	240.14	68.68	179.96	51.47	171.22	8.74
AUDRAIN-2011	MAIN	Audrain Generati	80	80	0.04	0.51	26.69	52.49	24.45	48.07	23.15	1.30
AUDRAIN2-2011	MAIN	Audrain Generati	80	80	0.04	1.99	99.51	50.10	95.70	48.19	90.74	4.97
AUDRAIN3-2011	MAIN	Audrain Generati	80	80	0.04	1.03	51.06	49.57	49.67	48.22	47.10	2.58
AUDRAIN4-2011	MAIN	Audrain Generati	80	80	0.04	1.58	79.82	50.48	76.21	48.20	72.26	3.95
AUDRAIN5-2011	MAIN	Audrain Generati	80	80	0.04	1.81	90.44	50.03	87.12	48.20	82.60	4.52
AUDRAIN6-2011	MAIN	Audrain Generati	80	80	0.04	1.83	91.90	50.27	88.16	48.22	83.59	4.57
AUDRAIN7-2011	MAIN	Audrain Generati	80	80	0.04	1.11	56.24	50.45	53.64	48.11	50.85	2.79
AUDRAIN8-2011	MAIN	Audrain Generati	80	80	0.04	1.58	79.19	50.21	76.00	48.19	72.06	3.94
KINMUNDY-2011	MAIN	Kinmundy Plant 1	116	116	0.04	13.96	748.56	53.62	674.19	48.29	638.59	35.60
KINMNDY2-2011	MAIN	Kinmundy Plant 2	116	116	0.04	2.37	145.61	61.33	114.38	48.18	108.44	5.94
AMPINCKN-2014	MAIN	Ameren/Pinckneyv	44	44	0.04	7.60	438.75	57.75	344.74	45.38	325.74	18.99
AMPNCKN2-2014	MAIN	Ameren/Pinckneyv	44	44	0.04	9.04	507.77	56.15	410.80	45.43	387.75	23.06

Index	Pool	Name	Winter Capacity (MW)	Summer Capacity (MW)	Average FOR	Generation (GWh)	Energy and Spinning Revenue ($K)	Avg Revenue ($/MWh)	Generation Cost ($k)	Avg Generation Cost ($/MWh)	Fuel Cost ($K)	O&M ($K)
AMPNCKN3-2014	MAIN	Ameren/Pinckneyv	44	44	0.04	7.71	439.27	56.94	350.09	45.38	330.81	19.29
AMPNCKN4-2014	MAIN	Ameren/Pinckneyv	44	44	0.04	7.81	444.01	56.82	354.63	45.38	335.09	19.54
AMPINCK5-2014	MAIN	Ameren/Pinckneyv	35	35	0.04	2.72	175.68	64.59	141.12	51.89	134.32	6.80
AMPINCK6-2014	MAIN	Ameren/Pinckneyv	35	35	0.04	3.08	202.97	65.93	159.73	51.89	152.04	7.70
AMPINCK7-2014	MAIN	Ameren/Pinckneyv	35	35	0.04	3.06	201.90	66.02	158.70	51.89	151.05	7.65
AMPINCK8-2014	MAIN	Ameren/Pinckneyv	35	35	0.04	2.84	188.34	66.42	147.15	51.90	140.06	7.09
AUDRAIN-2014	MAIN	Audrain Generati	80	80	0.04	-	-	-	-	-	-	-
AUDRAIN2-2014	MAIN	Audrain Generati	80	80	0.04	0.02	1.17	48.94	1.16	48.40	1.10	0.06
AUDRAIN3-2014	MAIN	Audrain Generati	80	80	0.04	0.02	1.17	48.94	1.16	48.40	1.10	0.06
AUDRAIN4-2014	MAIN	Audrain Generati	80	80	0.04	0.02	0.78	48.91	0.77	48.37	0.73	0.04
AUDRAIN5-2014	MAIN	Audrain Generati	80	80	0.04	0.02	0.78	48.91	0.77	48.37	0.73	0.04
AUDRAIN6-2014	MAIN	Audrain Generati	80	80	0.04	0.02	0.78	48.91	0.77	48.37	0.73	0.04
AUDRAIN7-2014	MAIN	Audrain Generati	80	80	0.04	0.01	0.39	48.80	0.39	48.26	0.37	0.02
AUDRAIN8-2014	MAIN	Audrain Generati	80	80	0.04	0.11	5.50	48.89	5.44	48.35	5.16	0.28
KINMUNDY-2014	MAIN	Kinmundy Plant 1	116	116	0.04	6.19	329.94	53.28	301.31	48.66	285.52	15.79
KINMNDY2-2014	MAIN	Kinmundy Plant 2	116	116	0.04	0.70	42.29	60.76	33.75	48.49	32.01	1.74

Index	Startup ($K)	Energy Margin (with spin) ($K)	Avg Energy Margin ($/MWh)	Energy Margin per kw-year($/kw-year)	Total Margin per kw-year ($/kw-year)	Capacity Factor	Hours Up (hrs)	Capacity Factor While Up	Starts	Average Hours Up	Max Spot Price ($/MWh)	Min Spot Price ($/MWh)
AMPINCKN-2004	-	2.60	3.28	0.06	0.01	0%	18	100%	10	1.80	$ 54.94	$ 3.87
AMPNCKN2-2004	-	2.74	3.12	0.06	0.00	0%	20	100%	11	1.82	$ 54.94	$ 3.87
AMPNCKN3-2004	-	2.59	3.28	0.06	0.00	0%	18	100%	10	1.80	$ 54.94	$ 3.87
AMPNCKN4-2004	-	2.69	3.22	0.06	0.01	0%	19	100%	11	1.73	$ 54.94	$ 3.87
AMPINCK5-2004	-	-	-	-	0.00	0%	0	0%	0	-	$ 54.94	$ 3.87
AMPINCK6-2004	-	-	-	-	-	0%	0	0%	0	-	$ 54.94	$ 3.87
AMPINCK7-2004	-	-	-	-	0.02	0%	0	0%	0	-	$ 54.94	$ 3.87
AMPINCK8-2004	-	-	-	-	0.02	0%	0	0%	0	-	$ 54.94	$ 3.87
AUDRAIN-2004	-	-	-	-	0.01	0%	0	0%	0	-	$ 55.04	$ (2.69)
AUDRAIN2-2004	-	0.09	0.85	0.00	0.00	0%	4	33%	2	2.00	$ 55.04	$ (2.69)
AUDRAIN3-2004	-	0.15	0.85	0.00	0.15	1%	4	55%	2	2.00	$ 55.04	$ (2.69)
AUDRAIN4-2004	-	0.09	0.85	0.00	0.12	1%	4	33%	2	2.00	$ 55.04	$ (2.69)
AUDRAIN5-2004	-	0.09	0.85	0.00	0.15	1%	4	33%	2	2.00	$ 55.04	$ (2.69)
AUDRAIN6-2004	-	0.03	0.85	0.00	0.10	0%	4	11%	2	2.00	$ 55.04	$ (2.69)
AUDRAIN7-2004	-	0.16	0.85	0.00	0.11	1%	4	58%	2	2.00	$ 55.04	$ (2.69)
AUDRAIN8-2004	-	0.15	0.85	0.00	0.11	1%	4	56%	2	2.00	$ 55.04	$ (2.69)
KINMUNDY-2004	-	-	-	-	0.04	0%	0	0%	0	-	$ 54.50	$ 10.49
KINMNDY2-2004	-	-	-	-	0.04	0%	0	0%	0	-	$ 54.50	$ 10.49
AMPINCKN-2006	-	7.94	3.64	0.18	0.03	0%	50	99%	30	1.67	$ 55.32	$ 5.40
AMPNCKN2-2006	-	7.43	3.17	0.17	0.02	0%	57	94%	33	1.73	$ 55.32	$ 5.40
AMPNCKN3-2006	-	8.18	3.47	0.19	0.02	0%	54	99%	32	1.69	$ 55.32	$ 5.40
AMPNCKN4-2006	-	8.21	3.45	0.19	0.03	0%	55	98%	33	1.67	$ 55.32	$ 5.40
AMPINCK5-2006	-	0.00	1.38	0.00	0.01	0%	1	10%	1	1.00	$ 55.32	$ 5.40
AMPINCK6-2006	-	0.00	1.38	0.00	0.00	0%	1	10%	1	1.00	$ 55.32	$ 5.40
AMPINCK7-2006	-	0.00	1.38	0.00	0.03	0%	1	10%	1	1.00	$ 55.32	$ 5.40
AMPINCK8-2006	-	0.01	1.38	0.00	0.04	0%	1	14%	1	1.00	$ 55.32	$ 5.40
AUDRAIN-2006	-	0.40	1.80	0.00	0.18	2%	3	91%	3	1.00	$ 53.76	$ 0.07
AUDRAIN2-2006	-	0.55	1.13	0.01	0.11	1%	7	87%	5	1.40	$ 53.76	$ 0.07
AUDRAIN3-2006	-	0.44	1.60	0.01	0.33	3%	7	49%	5	1.40	$ 53.76	$ 0.07
AUDRAIN4-2006	-	0.50	1.27	0.01	0.20	2%	8	62%	6	1.33	$ 53.76	$ 0.07
AUDRAIN5-2006	-	0.22	0.82	0.00	0.32	3%	6	55%	4	1.50	$ 53.76	$ 0.07
AUDRAIN6-2006	-	0.52	1.23	0.01	0.11	1%	8	66%	6	1.33	$ 53.76	$ 0.07
AUDRAIN7-2006	-	0.56	1.11	0.01	0.22	2%	9	70%	7	1.29	$ 53.76	$ 0.07
AUDRAIN8-2006	-	0.59	1.05	0.01	0.21	2%	8	88%	6	1.33	$ 53.76	$ 0.07
KINMUNDY-2006	-	2.86	3.42	0.02	0.02	0%	8	90%	7	1.14	$ 56.32	$ 10.68
KINMNDY2-2006	-	-	-	-	0.02	0%	0	0%	0	-	$ 56.32	$ 10.68
AMPINCKN-2008	-	35.63	5.06	0.81	0.62	1%	164	98%	78	2.10	$ 70.07	$ 3.28

Index	Startup ($K)	Energy Margin (with spin) ($K)	Avg Energy Margin ($/MWh)	Energy Margin per kw-year($/kw-year)	Total Margin per kw-year ($/kw-year)	Capacity Factor	Hours Up (hrs)	Capacity Factor While Up	Starts	Average Hours Up	Max Spot Price ($/MWh)	Min Spot Price ($/MWh)
AMPNCKN2-2008	-	37.69	4.50	0.86	0.43	1%	193	99%	83	2.33	$ 70.07	$ 3.28
AMPNCKN3-2008	-	37.44	5.03	0.85	0.70	1%	175	97%	75	2.33	$ 70.07	$ 3.28
AMPNCKN4-2008	-	39.37	4.90	0.89	0.73	1%	189	97%	85	2.22	$ 70.07	$ 3.28
AMPINCK5-2008	-	5.22	5.32	0.15	0.67	1%	30	93%	11	2.73	$ 70.07	$ 3.28
AMPINCK6-2008	-	5.27	5.75	0.15	0.66	1%	32	82%	12	2.67	$ 70.07	$ 3.28
AMPINCK7-2008	-	5.11	6.41	0.15	0.75	1%	32	71%	12	2.67	$ 70.07	$ 3.28
AMPINCK8-2008	-	5.06	6.62	0.14	0.76	1%	32	68%	12	2.67	$ 70.07	$ 3.28
AUDRAIN-2008	-	0.56	1.29	0.01	0.55	3%	6	90%	4	1.50	$ 52.52	$ (2.95)
AUDRAIN2-2008	-	1.42	0.70	0.02	0.45	2%	44	58%	32	1.38	$ 52.52	$ (2.95)
AUDRAIN3-2008	-	1.31	0.77	0.02	0.75	6%	47	45%	34	1.38	$ 52.52	$ (2.95)
AUDRAIN4-2008	-	1.49	0.73	0.02	0.62	4%	46	55%	33	1.39	$ 52.52	$ (2.95)
AUDRAIN5-2008	-	1.24	0.79	0.02	0.71	6%	47	42%	35	1.34	$ 52.52	$ (2.95)
AUDRAIN6-2008	-	1.45	0.74	0.02	0.38	2%	50	49%	36	1.39	$ 52.52	$ (2.95)
AUDRAIN7-2008	-	1.55	0.67	0.02	0.58	4%	49	59%	35	1.40	$ 52.52	$ (2.95)
AUDRAIN8-2008	-	1.63	0.71	0.02	0.52	3%	44	65%	32	1.38	$ 52.52	$ (2.95)
KINMUNDY-2008	-	33.85	6.06	0.29	0.21	1%	49	98%	30	1.63	$ 82.63	$ 9.53
KINMNDY2-2008	-	17.06	21.01	0.15	0.19	1%	7	100%	5	1.40	$ 82.63	$ 9.53
AMPINCKN-2011	-	121.91	13.29	2.77	2.76	2%	211	99%	64	3.30	$ 116.45	$ 6.44
AMPNCKN2-2011	-	136.60	12.28	3.10	2.72	2%	259	98%	69	3.75	$ 116.45	$ 6.44
AMPNCKN3-2011	-	121.81	12.38	2.77	2.73	2%	229	98%	62	3.69	$ 116.45	$ 6.44
AMPNCKN4-2011	-	135.31	12.81	3.08	2.74	2%	247	97%	67	3.69	$ 116.45	$ 6.44
AMPINCK5-2011	-	66.19	17.32	1.89	2.68	2%	115	95%	24	4.79	$ 116.45	$ 6.44
AMPINCK6-2011	-	66.13	17.51	1.89	2.65	2%	115	94%	24	4.79	$ 116.45	$ 6.44
AMPINCK7-2011	-	66.60	17.21	1.90	2.80	3%	117	94%	27	4.33	$ 116.45	$ 6.44
AMPINCK8-2011	-	60.18	17.21	1.72	2.46	3%	106	94%	24	4.42	$ 116.45	$ 6.44
AUDRAIN-2011	-	2.25	4.42	0.03	1.57	5%	7	91%	5	1.40	$ 53.88	$ (8.31)
AUDRAIN2-2011	-	3.81	1.92	0.05	1.37	3%	37	67%	18	2.06	$ 53.88	$ (8.31)
AUDRAIN3-2011	-	1.39	1.35	0.02	1.66	6%	26	50%	15	1.73	$ 53.88	$ (8.31)
AUDRAIN4-2011	-	3.61	2.28	0.05	1.57	5%	36	55%	17	2.12	$ 53.88	$ (8.31)
AUDRAIN5-2011	-	3.32	1.84	0.04	1.14	6%	32	71%	15	2.13	$ 53.88	$ (8.31)
AUDRAIN6-2011	-	3.74	2.05	0.05	1.42	3%	33	69%	15	2.20	$ 53.88	$ (8.31)
AUDRAIN7-2011	-	2.60	2.34	0.03	1.54	5%	27	52%	17	1.59	$ 53.88	$ (8.31)
AUDRAIN8-2011	-	3.19	2.02	0.04	1.42	4%	31	64%	16	1.94	$ 53.88	$ (8.31)
KINMUNDY-2011	-	74.37	5.33	0.64	1.52	2%	123	98%	47	2.62	$ 81.84	$ 10.79
KINMNDY2-2011	-	31.23	13.16	0.27	1.58	2%	22	93%	16	1.38	$ 81.84	$ 10.79
AMPINCKN-2014	-	94.01	12.37	2.14	1.55	2%	176	98%	44	4.00	$ 88.11	$ 6.52
AMPNCKN2-2014	-	96.97	10.72	2.20	1.50	1%	211	97%	55	3.84	$ 88.11	$ 6.52

Summary of GE MAPS Results by Unit by Year

Index	Startup ($K)	Energy Margin (with spin) ($K)	Avg Energy Margin ($/MWh)	Energy Margin per kw-year($/kw-year)	Total Margin per kw-year ($/kw-year)	Capacity Factor	Hours Up (hrs)	Capacity Factor While Up	Starts	Average Hours Up	Max Spot Price ($/MWh)	Min Spot Price ($/MWh)
AMPNCKN3-2014	-	89.17	11.56	2.03	1.50	1%	185	95%	47	3.94	$ 88.11	$ 6.52
AMPNCKN4-2014	-	89.38	11.44	2.03	1.54	2%	189	94%	49	3.88	$ 88.11	$ 6.52
AMPINCK5-2014	-	34.56	12.71	0.99	1.47	1%	86	90%	22	3.91	$ 88.11	$ 6.52
AMPINCK6-2014	-	43.23	14.04	1.24	1.46	1%	96	92%	22	4.36	$ 88.11	$ 6.52
AMPINCK7-2014	-	43.20	14.13	1.23	1.14	1%	94	93%	21	4.48	$ 88.11	$ 6.52
AMPINCK8-2014	-	41.19	14.53	1.18	1.59	2%	89	91%	20	4.45	$ 88.11	$ 6.52
AUDRAIN-2014	-	-	-	-	2.16	4%	0	0%	0	-	$ 49.01	$ (24.29)
AUDRAIN2-2014	-	0.01	0.54	0.00	1.99	2%	3	10%	3	1.00	$ 49.01	$ (24.29)
AUDRAIN3-2014	-	0.01	0.54	0.00	2.22	7%	3	10%	3	1.00	$ 49.01	$ (24.29)
AUDRAIN4-2014	-	0.01	0.54	0.00	0.84	3%	2	10%	2	1.00	$ 49.01	$ (24.29)
AUDRAIN5-2014	-	0.01	0.54	0.00	1.99	6%	2	10%	2	1.00	$ 49.01	$ (24.29)
AUDRAIN6-2014	-	0.01	0.54	0.00	2.00	3%	2	10%	2	1.00	$ 49.01	$ (24.29)
AUDRAIN7-2014	-	0.00	0.54	0.00	2.16	4%	1	10%	1	1.00	$ 49.01	$ (24.29)
AUDRAIN8-2014	-	0.06	0.54	0.00	2.15	4%	3	47%	3	1.00	$ 49.01	$ (24.29)
KINMUNDY-2014	-	28.63	4.62	0.25	0.59	1%	55	97%	24	2.29	$ 63.80	$ 11.73
KINMNDY2-2014	-	8.53	12.26	0.07	0.60	1%	6	100%	4	1.50	$ 63.80	$ 11.73

Summary of GE MAPS Results by Unit by Year

Index	All-hours Avg Spot Price ($/MWh)	Standard Deviation	FOM	O3 Season Gen (GWh)	O3 Season NOx (ton)	Total NOx(ton)	Total SOx(ton)	Count capacity	Capacity Price ($/kW-yr)	Profitability ($/kW-yr)
AMPINCKN-2004	$ 23.83	$ 10.33	10	0.79	0.36	0.36	-	TRUE	17.97456	8.03
AMPNCKN2-2004	$ 23.83	$ 10.33	10.25	0.88	0.37	0.37	-	TRUE	17.97456	7.79
AMPNCKN3-2004	$ 23.83	$ 10.33	10	0.79	0.36	0.36	-	TRUE	17.97456	8.03
AMPNCKN4-2004	$ 23.83	$ 10.33	10	0.84	0.38	0.38	-	TRUE	17.97456	8.04
AMPINCK5-2004	$ 23.83	$ 10.33	10	-	-	-	-	TRUE	17.97456	7.97
AMPINCK6-2004	$ 23.83	$ 10.33	10	-	-	-	-	TRUE	17.97456	7.97
AMPINCK7-2004	$ 23.83	$ 10.33	10	-	-	-	-	TRUE	17.97456	7.97
AMPINCK8-2004	$ 23.83	$ 10.33	10	-	-	-	-	TRUE	17.97456	7.97
AUDRAIN-2004	$ 22.99	$ 11.39	10.25	-	-	-	-	TRUE	17.97456	7.72
AUDRAIN2-2004	$ 22.99	$ 11.39	10	0.10	0.02	0.02	-	TRUE	17.97456	7.98
AUDRAIN3-2004	$ 22.99	$ 11.39	10	0.18	0.03	0.03	-	TRUE	17.97456	7.98
AUDRAIN4-2004	$ 22.99	$ 11.39	10	0.10	0.02	0.02	-	TRUE	17.97456	7.98
AUDRAIN5-2004	$ 22.99	$ 11.39	10	0.10	0.02	0.02	-	TRUE	17.97456	7.98
AUDRAIN6-2004	$ 22.99	$ 11.39	10	0.03	0.01	0.01	-	TRUE	17.97456	7.97
AUDRAIN7-2004	$ 22.99	$ 11.39	10	0.19	0.03	0.03	-	TRUE	17.97456	7.98
AUDRAIN8-2004	$ 22.99	$ 11.39	10	0.18	0.03	0.03	-	TRUE	17.97456	7.98
KINMUNDY-2004	$ 25.21	$ 9.41	10.25	-	-	-	-	TRUE	17.97456	7.72
KINMNDY2-2004	$ 25.21	$ 9.41	10	-	-	-	-	TRUE	17.97456	7.97
AMPINCKN-2006	$ 23.92	$ 10.01	10	2.18	1.04	1.04	-	TRUE	21.481704	11.66
AMPNCKN2-2006	$ 23.92	$ 10.01	10.25	2.35	1.00	1.00	-	TRUE	21.481704	11.40
AMPNCKN3-2006	$ 23.92	$ 10.01	10	2.36	1.08	1.08	-	TRUE	21.481704	11.67
AMPNCKN4-2006	$ 23.92	$ 10.01	10	2.38	1.10	1.10	-	TRUE	21.481704	11.67
AMPINCK5-2006	$ 23.92	$ 10.01	10	0.00	0.00	0.00	-	TRUE	21.481704	11.48
AMPINCK6-2006	$ 23.92	$ 10.01	10	0.00	0.00	0.00	-	TRUE	21.481704	11.48
AMPINCK7-2006	$ 23.92	$ 10.01	10	0.00	0.00	0.00	-	TRUE	21.481704	11.48
AMPINCK8-2006	$ 23.92	$ 10.01	10	0.01	0.00	0.00	-	TRUE	21.481704	11.48
AUDRAIN-2006	$ 23.08	$ 11.01	10.25	0.22	0.04	0.04	-	TRUE	21.481704	11.24
AUDRAIN2-2006	$ 23.08	$ 11.01	10	0.49	0.09	0.09	-	TRUE	21.481704	11.49
AUDRAIN3-2006	$ 23.08	$ 11.01	10	0.27	0.05	0.05	-	TRUE	21.481704	11.49
AUDRAIN4-2006	$ 23.08	$ 11.01	10	0.39	0.07	0.07	-	TRUE	21.481704	11.49
AUDRAIN5-2006	$ 23.08	$ 11.01	10	0.26	0.05	0.05	-	TRUE	21.481704	11.48
AUDRAIN6-2006	$ 23.08	$ 11.01	10	0.42	0.08	0.08	-	TRUE	21.481704	11.49
AUDRAIN7-2006	$ 23.08	$ 11.01	10	0.50	0.09	0.09	-	TRUE	21.481704	11.49
AUDRAIN8-2006	$ 23.08	$ 11.01	10	0.56	0.10	0.10	-	TRUE	21.481704	11.49
KINMUNDY-2006	$ 25.36	$ 9.16	10.25	0.84	0.33	0.33	-	TRUE	21.481704	11.26
KINMNDY2-2006	$ 25.36	$ 9.16	10	-	-	-	-	TRUE	21.481704	11.48
AMPINCKN-2008	$ 25.46	$ 10.60	10	7.04	3.35	3.35	-	TRUE	89.7956016	80.61

Summary of GE MAPS Results by Unit by Year

Index	All-hours Avg Spot Price ($/MWh)	Standard Deviation	FOM	O3 Season Gen (GWh)	O3 Season NOx (ton)	Total NOx(ton)	Total SOx(ton)	Count capacity	Capacity Price ($/kW-yr)	Profitability ($/kW-yr)
AMPNCKN2-2008	$ 25.46	$ 10.60	10.25	8.37	3.56	3.56	-	TRUE	89.7956016	80.40
AMPNCKN3-2008	$ 25.46	$ 10.60	10	7.44	3.42	3.42	-	TRUE	89.7956016	80.65
AMPNCKN4-2008	$ 25.46	$ 10.60	10	8.03	3.69	3.69	-	TRUE	89.7956016	80.69
AMPINCK5-2008	$ 25.46	$ 10.60	10	0.98	0.45	0.45	-	TRUE	89.7956016	79.94
AMPINCK6-2008	$ 25.46	$ 10.60	10	0.92	0.42	0.42	-	TRUE	89.7956016	79.95
AMPINCK7-2008	$ 25.46	$ 10.60	10	0.80	0.37	0.37	-	TRUE	89.7956016	79.94
AMPINCK8-2008	$ 25.46	$ 10.60	10	0.76	0.35	0.35	-	TRUE	89.7956016	79.94
AUDRAIN-2008	$ 24.77	$ 11.32	10.25	0.43	0.08	0.08	-	TRUE	89.7956016	79.55
AUDRAIN2-2008	$ 24.77	$ 11.32	10	2.04	0.37	0.37	-	TRUE	89.7956016	79.81
AUDRAIN3-2008	$ 24.77	$ 11.32	10	1.69	0.30	0.30	-	TRUE	89.7956016	79.81
AUDRAIN4-2008	$ 24.77	$ 11.32	10	2.03	0.36	0.36	-	TRUE	89.7956016	79.81
AUDRAIN5-2008	$ 24.77	$ 11.32	10	1.57	0.28	0.28	-	TRUE	89.7956016	79.81
AUDRAIN6-2008	$ 24.77	$ 11.32	10	1.96	0.35	0.35	-	TRUE	89.7956016	79.81
AUDRAIN7-2008	$ 24.77	$ 11.32	10	2.31	0.42	0.42	-	TRUE	89.7956016	79.81
AUDRAIN8-2008	$ 24.77	$ 11.32	10	2.30	0.41	0.41	-	TRUE	89.7956016	79.82
KINMUNDY-2008	$ 26.59	$ 9.81	10.25	5.59	2.23	2.23	-	TRUE	89.7956016	79.84
KINMNDY2-2008	$ 26.59	$ 9.81	10	0.81	1.84	1.84	7.55	TRUE	89.7956016	79.94
AMPINCKN-2011	$ 27.41	$ 10.84	10	9.17	4.36	4.36	-	TRUE	89.4184815	82.19
AMPNCKN2-2011	$ 27.41	$ 10.84	10.25	11.13	4.73	4.73	-	TRUE	89.4184815	82.27
AMPNCKN3-2011	$ 27.41	$ 10.84	10	9.84	4.53	4.53	-	TRUE	89.4184815	82.19
AMPNCKN4-2011	$ 27.41	$ 10.84	10	10.56	4.86	4.86	-	TRUE	89.4184815	82.49
AMPINCK5-2011	$ 27.41	$ 10.84	10	3.82	1.76	1.76	-	TRUE	89.4184815	81.31
AMPINCK6-2011	$ 27.41	$ 10.84	10	3.78	1.74	1.74	-	TRUE	89.4184815	81.31
AMPINCK7-2011	$ 27.41	$ 10.84	10	3.87	1.78	1.78	-	TRUE	89.4184815	81.32
AMPINCK8-2011	$ 27.41	$ 10.84	10	3.50	1.61	1.61	-	TRUE	89.4184815	81.14
AUDRAIN-2011	$ 26.12	$ 10.41	10.25	0.51	0.09	0.09	-	TRUE	89.4184815	79.20
AUDRAIN2-2011	$ 26.12	$ 10.41	10	1.99	0.36	0.36	-	TRUE	89.4184815	79.47
AUDRAIN3-2011	$ 26.12	$ 10.41	10	1.03	0.19	0.19	-	TRUE	89.4184815	79.44
AUDRAIN4-2011	$ 26.12	$ 10.41	10	1.58	0.28	0.28	-	TRUE	89.4184815	79.46
AUDRAIN5-2011	$ 26.12	$ 10.41	10	1.81	0.33	0.33	-	TRUE	89.4184815	79.46
AUDRAIN6-2011	$ 26.12	$ 10.41	10	1.83	0.33	0.33	-	TRUE	89.4184815	79.47
AUDRAIN7-2011	$ 26.12	$ 10.41	10	1.11	0.20	0.20	-	TRUE	89.4184815	79.45
AUDRAIN8-2011	$ 26.12	$ 10.41	10	1.58	0.28	0.28	-	TRUE	89.4184815	79.46
KINMUNDY-2011	$ 28.27	$ 9.55	10.25	13.96	5.58	5.58	-	TRUE	89.4184815	79.81
KINMNDY2-2011	$ 28.27	$ 9.55	10	2.37	5.37	5.37	22.07	TRUE	89.4184815	79.69
AMPINCKN-2014	$ 28.67	$ 9.91	10	7.60	3.61	3.61	-	TRUE	89.6197448	81.76
AMPNCKN2-2014	$ 28.67	$ 9.91	10.25	9.04	3.84	3.84	-	TRUE	89.6197448	81.57

Summary of GE MAPS Results by Unit by Year

Index	All-hours Avg Spot Price ($/MWh)	Standard Deviation	FOM	O3 Season Gen (GWh)	O3 Season NOx (ton)	Total NOx(ton)	Total SOx(ton)	Count capacity	Capacity Price ($/kW-yr)	Profitability ($/kW-yr)
AMPNCKN3-2014	$ 28.67	$ 9.91	10	7.71	3.55	3.56	-	TRUE	89.6197448	81.65
AMPNCKN4-2014	$ 28.67	$ 9.91	10	7.81	3.59	3.59	-	TRUE	89.6197448	81.66
AMPINCK5-2014	$ 28.67	$ 9.91	10	2.72	1.25	1.25	-	TRUE	89.6197448	80.61
AMPINCK6-2014	$ 28.67	$ 9.91	10	3.08	1.42	1.42	-	TRUE	89.6197448	80.85
AMPINCK7-2014	$ 28.67	$ 9.91	10	3.06	1.41	1.41	-	TRUE	89.6197448	80.85
AMPINCK8-2014	$ 28.67	$ 9.91	10	2.84	1.30	1.30	-	TRUE	89.6197448	80.80
AUDRAIN-2014	$ 27.35	$ 10.03	10.25	-	-	-	-	TRUE	89.6197448	79.37
AUDRAIN2-2014	$ 27.35	$ 10.03	10	0.02	0.00	0.00	-	TRUE	89.6197448	79.62
AUDRAIN3-2014	$ 27.35	$ 10.03	10	0.02	0.00	0.00	-	TRUE	89.6197448	79.62
AUDRAIN4-2014	$ 27.35	$ 10.03	10	0.02	0.00	0.00	-	TRUE	89.6197448	79.62
AUDRAIN5-2014	$ 27.35	$ 10.03	10	0.02	0.00	0.00	-	TRUE	89.6197448	79.62
AUDRAIN6-2014	$ 27.35	$ 10.03	10	0.02	0.00	0.00	-	TRUE	89.6197448	79.62
AUDRAIN7-2014	$ 27.35	$ 10.03	10	0.01	0.00	0.00	-	TRUE	89.6197448	79.62
AUDRAIN8-2014	$ 27.35	$ 10.03	10	0.11	0.02	0.02	-	TRUE	89.6197448	79.62
KINMUNDY-2014	$ 29.34	$ 8.75	10.25	6.19	2.48	2.48	-	TRUE	89.6197448	79.62
KINMNDY2-2014	$ 29.34	$ 8.75	10	0.70	1.57	1.57	6.47	TRUE	89.6197448	79.69

Summary of DCF Based Valuation
KINMUNDY

NPV of after-tax cash flow (Sep 2002$):		$137,449,271
Value per kW (2002$/kW):		$ 592
Operating Life (Yrs):	25	
WACC(%):	7.8%	
Inflation Rate (%):	2.3%	

Year:	1	2	3	4	5	6
	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Dec-09
Annual generation (GWh)	-	0.418	0.835	3.616	6.397	9.710
Summer Capacity (MW)	232	232	232	232	232	232
Revenues						
Energy sales	-	24,165	49,441	235,858	430,825	643,306
Capacity sales	4,364,128	4,900,054	5,458,323	14,462,480	23,877,940	24,392,936
Ancillary services						
Total Revenues	**4,364,128**	**4,924,218**	**5,507,764**	**14,698,338**	**24,308,765**	**25,036,243**
Operating costs						
Fuel purchases	-	21,495	43,980	195,430	353,824	533,284
Fixed O&M costs	2,212,467	2,263,354	2,315,411	2,368,665	2,423,145	2,478,877
Variable O&M costs	-	1,140	2,333	10,309	18,651	28,954
Total Operating Costs	**2,212,467**	**2,285,989**	**2,361,723**	**2,574,405**	**2,795,620**	**3,041,115**
Property Taxes & Insurance	2,686,832	2,418,149	2,176,334	1,958,559	1,762,562	1,586,362
Net Pre-Tax Revenues	(535,171)	220,080	969,706	10,165,374	19,750,583	20,408,766
Tax Depreciation	7,070,612	13,434,162	12,090,746	10,888,742	9,799,868	8,809,982
Taxable Income	(7,605,783)	(13,214,082)	(11,121,040)	(723,368)	9,950,715	11,598,783
Capital Expenditures	245,829.66	251,483.74	257,267.87	263,185.03	269,238.29	275,430.77
Income Taxes						
Federal income tax	-	-	-	-	3,482,750	4,059,574
State income tax	-	-	-	-	298,521	347,964
Total Income Taxes	-	-	-	-	3,781,272	4,407,538
Net After-tax Cash Flow	**(781,001)**	**(31,404)**	**712,438**	**9,902,189**	**15,700,073**	**15,725,797**

Summary of DCF Based Valuation
KINMUNDY

Year:	7	8	9	10	11	12
	Dec-10	Dec-11	Dec-12	Dec-13	Dec-14	Dec-15
Annual generation (GWh)	13.022	16.335	13.186	10.037	6.889	-
Summer Capacity (MW)	232	232	232	232	232	232
Revenues						
Energy sales	865,334	1,097,235	904,071	701,441	489,012	500,259
Capacity sales	24,918,991	25,456,341	26,061,375	26,680,774	27,314,880	27,943,122
Ancillary services						
Total Revenues	**25,784,325**	**26,553,576**	**26,965,446**	**27,382,215**	**27,803,892**	**28,443,381**
Operating costs						
Fuel purchases	720,812	916,683	758,047	591,628	417,153	426,747
Fixed O&M costs	2,535,891	2,594,217	2,653,884	2,714,923	2,777,366	2,841,246
Variable O&M costs	39,721	50,967	42,096	32,789	23,032	23,562
Total Operating Costs	**3,296,423**	**3,561,867**	**3,454,026**	**3,339,340**	**3,217,550**	**3,291,554**
Property Taxes & Insurance	1,419,496	1,252,630	1,085,480	918,614	751,465	584,598
Net Pre-Tax Revenues	21,068,406	21,739,078	22,425,940	23,124,262	23,834,877	24,567,229
Tax Depreciation	8,343,322	8,343,322	8,357,463	8,343,322	8,357,463	8,343,322
Taxable Income	12,725,084	13,395,757	14,068,477	14,780,940	15,477,414	16,223,907
Capital Expenditures	281,765.68	288,246.29	294,875.95	301,658.10	308,596.23	315,693.95
Income Taxes						
Federal income tax	4,453,779	4,688,515	4,923,967	5,173,329	5,417,095	5,678,368
State income tax	381,753	401,873	422,054	443,428	464,322	486,717
Total Income Taxes	4,835,532	5,090,388	5,346,021	5,616,757	5,881,417	6,165,085
Net After-tax Cash Flow	**15,951,108**	**16,360,445**	**16,785,043**	**17,205,847**	**17,644,863**	**18,086,450**

Kinmundy Scenario 1

Exhibit No. NRG 2.7(Revised)
Docket No. EC03-53-000

Summary of DCF Based Valuation
KINMUNDY

Year:	13	14	15	16	17	18
	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21
Annual generation (GWh)	-	-	-	-	-	-
Summer Capacity (MW)	232	232	232	232	232	232
Revenues						
Energy sales	511,765	523,536	535,577	547,895	560,497	573,389
Capacity sales	28,585,814	29,243,287	29,915,883	30,603,948	31,307,839	32,027,920
Ancillary services						
Total Revenues	**29,097,579**	**29,766,823**	**30,451,460**	**31,151,844**	**31,868,336**	**32,601,308**
Operating costs						
Fuel purchases	436,562	446,603	456,875	467,383	478,133	489,130
Fixed O&M costs	2,906,594	2,973,446	3,041,835	3,111,797	3,183,369	3,256,586
Variable O&M costs	24,103	24,658	25,225	25,805	26,399	27,006
Total Operating Costs	**3,367,260**	**3,444,707**	**3,523,935**	**3,604,986**	**3,687,900**	**3,772,722**
Property Taxes & Insurance	417,449	250,582	83,433	(0)	(0)	(0)
Net Pre-Tax Revenues	25,312,870	26,071,534	26,844,092	27,546,858	28,180,436	28,828,586
Tax Depreciation	8,357,463	8,343,322	8,357,463	4,171,661	-	-
Taxable Income	16,955,407	17,728,212	18,486,629	23,375,197	28,180,436	28,828,586
Capital Expenditures	322,954.91	330,382.87	337,981.68	345,755.26	353,707.63	361,842.90
Income Taxes						
Federal income tax	5,934,393	6,204,874	6,470,320	8,181,319	9,863,153	10,090,005
State income tax	508,662	531,846	554,599	701,256	845,413	864,858
Total Income Taxes	6,443,055	6,736,721	7,024,919	8,882,575	10,708,566	10,954,863
Net After-tax Cash Flow	**18,546,861**	**19,004,430**	**19,481,191**	**18,318,528**	**17,118,163**	**17,511,880**

Exhibit No. AS-45
Docket No. EC03-53-000

Summary of DCF Based Valuation
KINMUNDY

Year:	19	20	21	22	23	24
	Dec-22	Dec-23	Dec-24	Dec-25	Dec-26	Dec-27
Annual generation (GWh)	-	-	-	-	-	-
Summer Capacity (MW)	232	232	232	232	232	232
Revenues						
Energy sales	586,576	600,068	613,869	627,988	642,432	657,208
Capacity sales	32,764,562	33,518,147	34,289,064	35,077,712	35,884,500	36,709,843
Ancillary services						
Total Revenues	**33,351,138**	**34,118,214**	**34,902,933**	**35,705,701**	**36,526,932**	**37,367,051**
Operating costs						
Fuel purchases	500,380	511,889	523,662	535,706	548,028	560,632
Fixed O&M costs	3,331,488	3,408,112	3,486,498	3,566,688	3,648,722	3,732,642
Variable O&M costs	27,627	28,262	28,912	29,577	30,258	30,954
Total Operating Costs	**3,859,495**	**3,948,263**	**4,039,073**	**4,131,972**	**4,227,007**	**4,324,228**
Property Taxes & Insurance	(0)	(0)	(0)	(0)	(0)	(0)
Net Pre-Tax Revenues	29,491,643	30,169,951	30,863,860	31,573,729	32,299,925	33,042,823
Tax Depreciation	-	-	-	-	-	-
Taxable Income	29,491,643	30,169,951	30,863,860	31,573,729	32,299,925	33,042,823
Capital Expenditures	370,165.29	378,679.09	387,388.71	396,298.65	405,413.52	414,738.03
Income Taxes						
Federal income tax	10,322,075	10,559,483	10,802,351	11,050,805	11,304,974	11,564,988
State income tax	884,749	905,099	925,916	947,212	968,998	991,285
Total Income Taxes	11,206,825	11,464,581	11,728,267	11,998,017	12,273,971	12,556,273
Net After-tax Cash Flow	**17,914,654**	**18,326,691**	**18,748,205**	**19,179,413**	**19,620,540**	**20,071,812**

Summary of DCF Based Valuation
KINMUNDY

Year:	25	26
	[illegible]	[illegible]
Annual generation (GWh)	-	-
Summer Capacity (MW)	232	232
Revenues		
Energy sales	672,324	687,787
Capacity sales	37,554,170	38,417,916
Ancillary services		
Total Revenues	**38,226,493**	**39,105,703**
Operating costs		
Fuel purchases	573,527	586,718
Fixed O&M costs	3,818,493	3,906,318
Variable O&M costs	31,666	32,394
Total Operating Costs	**4,423,685**	**4,525,430**
Property Taxes & Insurance	(0)	(0)
Net Pre-Tax Revenues	33,802,808	34,580,272
Tax Depreciation	-	-
Taxable Income	33,802,808	34,580,272
Capital Expenditures	424,277.00	434,035.37
Income Taxes		
Federal income tax	11,830,983	12,103,095
State income tax	1,014,084	1,037,408
Total Income Taxes	12,845,067	13,140,504
Net After-tax Cash Flow	**20,533,464**	**21,005,734**

Summary of DCF Based Valuation
PINCKNEY

NPV of after-tax cash flow (Sep 2002$):		$190,661,253
Value per kW (2002$/kW):		$ 603
Operating Life (Yrs):	25	
WACC(%):	7.8%	
Inflation Rate (%):	2.3%	

Year:	1	2	3	4	5
	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08
Annual generation (GWh)	3.298	6.291	9.284	21.815	34.346
Summer Capacity (MW)	316	316	316	316	316
Revenues					
Energy sales	185,457	346,449	514,750	1,285,323	2,091,070
Capacity sales	5,944,244	6,674,211	7,434,613	19,698,895	32,523,401
Ancillary services					
Total Revenues	**6,129,701**	**7,020,661**	**7,949,362**	**20,984,217**	**34,614,470**
Operating costs					
Fuel purchases	165,659	306,817	454,380	1,110,428	1,796,413
Fixed O&M costs	2,986,689	3,055,383	3,125,657	3,197,547	3,271,090
Variable O&M costs	8,676	16,925	25,549	61,404	98,895
Total Operating Costs	**3,161,024**	**3,379,125**	**3,605,586**	**4,369,379**	**5,166,399**
Property Taxes & Insurance	3,727,010	3,354,309	3,018,878	2,716,794	2,444,919
Net Pre-Tax Revenues	(758,334)	287,227	1,324,899	13,898,044	27,003,152
Tax Depreciation	9,807,922	18,635,051	16,771,546	15,104,199	13,593,779
Taxable Income	(10,566,255)	(18,347,824)	(15,446,647)	(1,206,155)	13,409,373
Capital Expenditures	331,854	339,487	347,295	355,283	363,454
Income Taxes					
Federal income tax	-	-	-	-	4,693,281
State income tax	-	-	-	-	402,281
Total Income Taxes	-	-	-	-	5,095,562
Net After-tax Cash Flow	**(1,090,188)**	**(52,260)**	**977,603**	**13,542,761**	**21,544,136**

Summary of DCF Based Valuation
PINCKNEY

Year:	6	7	8	9	10	11
	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Annual generation (GWh)	41.451	48.557	55.663	51.729	47.795	43.861
Summer Capacity (MW)	316	316	316	316	316	316
Revenues						
Energy sales	2,747,025	3,432,049	4,147,131	3,915,737	3,671,506	3,413,969
Capacity sales	33,224,862	33,941,385	34,673,292	35,497,390	36,341,055	37,204,750
Ancillary services						
Total Revenues	**35,971,887**	**37,373,434**	**38,820,423**	**39,413,128**	**40,012,561**	**40,618,719**
Operating costs						
Fuel purchases	2,188,659	2,597,997	3,025,008	2,881,887	2,730,581	2,570,792
Fixed O&M costs	3,346,326	3,423,291	3,502,027	3,582,573	3,664,973	3,749,267
Variable O&M costs	122,054	146,225	171,443	162,996	154,070	144,647
Total Operating Costs	**5,657,038**	**6,167,513**	**6,698,478**	**6,627,456**	**6,549,624**	**6,464,706**
Property Taxes & Insurance	2,200,505	1,969,038	1,737,571	1,505,712	1,274,245	1,042,386
Net Pre-Tax Revenues	28,114,344	29,236,882	30,384,373	31,279,959	32,188,692	33,111,627
Tax Depreciation	12,220,670	11,573,348	11,573,348	11,592,963	11,573,348	11,592,963
Taxable Income	15,893,673	17,663,534	18,811,026	19,686,996	20,615,344	21,518,664
Capital Expenditures	371,814	380,366	389,114	398,064	407,219	416,585
Income Taxes						
Federal income tax	5,562,786	6,182,237	6,583,859	6,890,449	7,215,370	7,531,532
State income tax	476,810	529,906	564,331	590,610	618,460	645,560
Total Income Taxes	6,039,596	6,712,143	7,148,190	7,481,058	7,833,831	8,177,092
Net After-tax Cash Flow	**21,702,934**	**22,144,373**	**22,847,069**	**23,400,837**	**23,947,642**	**24,517,950**

Pinckney Scenario 1

Summary of DCF Based Valuation
PINCKNEY

Year:	12	13	14	15	16	17
	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20
Annual generation (GWh)	-	-	-	-	-	-
Summer Capacity (MW)	316	316	316	316	316	316
Revenues						
Energy sales	3,492,491	3,572,818	3,654,993	3,739,058	3,825,056	3,913,032
Capacity sales	38,060,459	38,935,850	39,831,374	40,747,496	41,684,688	42,643,436
Ancillary services						
Total Revenues	**41,552,950**	**42,508,668**	**43,486,367**	**44,486,553**	**45,509,744**	**46,556,468**
Operating costs						
Fuel purchases	2,629,920	2,690,408	2,752,288	2,815,590	2,880,349	2,946,597
Fixed O&M costs	3,835,500	3,923,717	4,013,962	4,106,283	4,200,728	4,297,344
Variable O&M costs	147,974	151,378	154,859	158,421	162,065	165,792
Total Operating Costs	**6,613,394**	**6,765,502**	**6,921,109**	**7,080,294**	**7,243,141**	**7,409,733**
Property Taxes & Insurance	*810,919*	579,060	347,593	115,733	(0)	(0)
Net Pre-Tax Revenues	34,128,637	35,164,106	36,217,665	37,290,526	38,266,603	39,146,735
Tax Depreciation	11,573,348	11,592,963	11,573,348	11,592,963	5,786,674	-
Taxable Income	22,555,289	23,571,142	24,644,318	25,697,562	32,479,929	39,146,735
Capital Expenditures	426,167	435,969	445,996	456,254	466,748	477,483
Income Taxes						
Federal income tax	7,894,351	8,249,900	8,625,511	8,994,147	11,367,975	13,701,357
State income tax	676,659	707,134	739,330	770,927	974,398	1,174,402
Total Income Taxes	8,571,010	8,957,034	9,364,841	9,765,074	12,342,373	14,875,759
Net After-tax Cash Flow	**25,131,460**	**25,771,103**	**26,406,829**	**27,069,198**	**25,457,482**	**23,793,493**

Pinckney Scenario 1

Summary of DCF Based Valuation
PINCKNEY

Year:	18	19	20	21	22
	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25
Annual generation (GWh)	-	-	-	-	-
Summer Capacity (MW)	316	316	316	316	316
Revenues					
Energy sales	4,003,032	4,095,102	4,189,289	4,285,643	4,384,212
Capacity sales	43,624,235	44,627,593	45,654,027	46,704,070	47,778,263
Ancillary services					
Total Revenues	**47,627,267**	**48,722,694**	**49,843,316**	**50,989,712**	**52,162,476**
Operating costs					
Fuel purchases	3,014,368	3,083,699	3,154,624	3,227,180	3,301,406
Fixed O&M costs	4,396,183	4,497,296	4,600,733	4,706,550	4,814,801
Variable O&M costs	169,605	173,506	177,497	181,579	185,756
Total Operating Costs	**7,580,157**	**7,754,501**	**7,932,854**	**8,115,310**	**8,301,962**
Property Taxes & Insurance	(0)	(0)	(0)	(0)	(0)
Net Pre-Tax Revenues	40,047,110	40,968,193	41,910,462	42,874,402	43,860,514
Tax Depreciation	-	-	-	-	-
Taxable Income	40,047,110	40,968,193	41,910,462	42,874,402	43,860,514
Capital Expenditures	488,465	499,700	511,193	522,950	534,978
Income Taxes					
Federal income tax	14,016,488	14,338,868	14,668,662	15,006,041	15,351,180
State income tax	1,201,413	1,229,046	1,257,314	1,286,232	1,315,815
Total Income Taxes	15,217,902	15,567,914	15,925,976	16,292,273	16,666,995
Net After-tax Cash Flow	**24,340,743**	**24,900,580**	**25,473,294**	**26,059,180**	**26,658,541**

Summary of DCF Based Valuation
PINCKNEY

Year:	23	24	25	26
	Dec-26	Dec-27	Dec-28	Dec-29
Annual generation (GWh)	-	-	-	-
Summer Capacity (MW)	316	316	316	316
Revenues				
Energy sales	4,485,049	4,588,205	4,693,734	4,801,690
Capacity sales	48,877,164	50,001,338	51,151,369	52,327,851
Ancillary services				
Total Revenues	**53,362,213**	**54,589,544**	**55,845,103**	**57,129,541**
Operating costs				
Fuel purchases	3,377,338	3,455,017	3,534,482	3,615,775
Fixed O&M costs	4,925,541	5,038,829	5,154,722	5,273,280
Variable O&M costs	190,028	194,399	198,870	203,444
Total Operating Costs	**8,492,907**	**8,688,244**	**8,888,074**	**9,092,499**
Property Taxes & Insurance	(0)	(0)	(0)	(0)
Net Pre-Tax Revenues	44,869,306	45,901,300	46,957,029	48,037,041
Tax Depreciation	-	-	-	-
Taxable Income	44,869,306	45,901,300	46,957,029	48,037,041
Capital Expenditures	547,282	559,870	572,747	585,920
Income Taxes				
Federal income tax	15,704,257	16,065,455	16,434,960	16,812,964
State income tax	1,346,079	1,377,039	1,408,711	1,441,111
Total Income Taxes	17,050,336	17,442,494	17,843,671	18,254,076
Net After-tax Cash Flow	**27,271,687**	**27,898,936**	**28,540,611**	**29,197,045**

Summary of DCF Based Valuation
AUDRAIN

NPV of after-tax cash flow (Sep 2002$):		**$378,834,122**
Value per kW (2002$/kW):		**$ 592**
Operating Life (Yrs):	25	
WACC(%):	7.8%	
Inflation Rate (%):	2.3%	

Year:	1	2	3	4	5
	Dec-04	[illegible]	[illegible]	[illegible]	[illegible]
Annual generation (GWh)	0.890	2.007	3.125	8.723	14.322
Summer Capacity (MW)	640	640	640	640	640
Revenues					
Energy sales	51,250	112,807	177,168	504,420	846,632
Capacity sales	12,038,975	13,517,390	15,057,443	39,896,495	65,870,179
Ancillary services					
Total Revenues	**12,090,225**	**13,630,197**	**15,234,612**	**40,400,916**	**66,716,811**
Operating costs					
Fuel purchases	48,134	105,006	164,469	471,891	793,368
Fixed O&M costs	6,046,845	6,185,922	6,328,198	6,473,747	6,622,643
Variable O&M costs	2,327.913	5,378.049	8,567.261	24,451.928	41,062.758
Total Operating Costs	**6,097,307**	**6,296,306**	**6,501,235**	**6,970,090**	**7,457,073**
Property Taxes & Insurance	7,405,378	6,664,840	5,998,356	5,398,131	4,857,928
Net Pre-Tax Revenues	(1,412,460)	669,050	2,735,021	28,032,695	54,401,810
Tax Depreciation	19,487,837	37,026,890	33,324,201	30,011,269	27,010,142
Taxable Income	(20,900,296)	(36,357,840)	(30,589,180)	(1,978,574)	27,391,668
Capital Expenditures	671,872	687,325	703,133	719,305	735,849
Income Taxes					
Federal income tax	-	-	-	-	9,587,084
State income tax	-	-	-	-	821,750
Total Income Taxes	-	-	-	-	10,408,834
Net After-tax Cash Flow	**(2,084,331)**	**(18,274)**	**2,031,888**	**27,313,390**	**43,257,127**

Summary of DCF Based Valuation
AUDRAIN

Year:	6	7	8	9	10	11
	Dec-09	Dec-10	Dec-11	Dec-12	Dec-13	Dec-14
Annual generation (GWh)	13.359	12.396	11.434	7.695	3.956	0.216
Summer Capacity (MW)	640	640	640	640	640	640
Revenues						
Energy sales	802,086	755,043	705,412	485,521	255,142	13,909
Capacity sales	67,290,859	68,742,045	70,224,389	71,893,449	73,602,136	75,351,392
Ancillary services						
Total Revenues	**68,092,945**	**69,497,088**	**70,929,800**	**72,378,970**	**73,857,279**	**75,365,301**
Operating costs						
Fuel purchases	745,231	694,460	640,960	441,289	232,095	13,044
Fixed O&M costs	6,774,964	6,930,788	7,090,196	7,253,271	7,420,096	7,590,758
Variable O&M costs	39,186.873	37,202.976	35,107.090	24,169.505	12,710.221	711.023
Total Operating Costs	**7,559,382**	**7,662,451**	**7,766,263**	**7,718,729**	**7,664,901**	**7,604,513**
Property Taxes & Insurance	4,372,291	3,912,378	3,452,465	2,991,773	2,531,860	2,071,167
Net Pre-Tax Revenues	56,161,272	57,922,259	59,711,072	61,668,467	63,660,518	65,689,621
Tax Depreciation	24,281,845	22,995,648	22,995,648	23,034,623	22,995,648	23,034,623
Taxable Income	31,879,428	34,926,611	36,715,425	38,633,844	40,664,870	42,654,998
Capital Expenditures	752,774	770,088	787,800	805,919	824,455	843,418
Income Taxes						
Federal income tax	11,157,800	12,224,314	12,850,399	13,521,845	14,232,705	14,929,249
State income tax	956,383	1,047,798	1,101,463	1,159,015	1,219,946	1,279,650
Total Income Taxes	12,114,182	13,272,112	13,951,861	14,680,861	15,452,651	16,208,899
Net After-tax Cash Flow	**43,294,316**	**43,880,069**	**44,971,411**	**46,181,688**	**47,383,412**	**48,637,304**

Summary of DCF Based Valuation
AUDRAIN

Year:	12	13	14	15	16	17
	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20
Annual generation (GWh)	-	-	-	-	-	-
Summer Capacity (MW)	640	640	640	640	640	640
Revenues						
Energy sales	14,229	14,556	14,891	15,233	15,584	15,942
Capacity sales	77,084,474	78,857,417	80,671,138	82,526,574	84,424,685	86,366,453
Ancillary services						
Total Revenues	**77,098,703**	**78,871,973**	**80,686,029**	**82,541,807**	**84,440,269**	**86,382,395**
Operating costs						
Fuel purchases	13,344	13,651	13,965	14,286	14,615	14,951
Fixed O&M costs	7,765,345	7,943,948	8,126,659	8,313,572	8,504,784	8,700,394
Variable O&M costs	727.377	744.107	761.221	778.729	796.640	814.963
Total Operating Costs	**7,779,417**	**7,958,343**	**8,141,385**	**8,328,637**	**8,520,196**	**8,716,160**
Property Taxes & Insurance	1,611,254	1,150,562	690,649	229,956	(0)	(0)
Net Pre-Tax Revenues	67,708,032	69,763,068	71,853,994	73,983,214	75,920,073	77,666,235
Tax Depreciation	22,995,648	23,034,623	22,995,648	23,034,623	11,497,824	-
Taxable Income	44,712,384	46,728,445	48,858,347	50,948,590	64,422,249	77,666,235
Capital Expenditures	862,816	882,661	902,962	923,730	944,976	966,710
Income Taxes						
Federal income tax	15,649,335	16,354,956	17,100,421	17,832,007	22,547,787	27,183,182
State income tax	1,341,372	1,401,853	1,465,750	1,528,458	1,932,667	2,329,987
Total Income Taxes	16,990,706	17,756,809	18,566,172	19,360,464	24,480,455	29,513,169
Net After-tax Cash Flow	**49,854,510**	**51,123,598**	**52,384,860**	**53,699,019**	**50,494,642**	**47,186,355**

Summary of DCF Based Valuation
AUDRAIN

Year:	18	19	20	21	22
	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25
Annual generation (GWh)	-	-	-	-	-
Summer Capacity (MW)	640	640	640	640	640
Revenues					
Energy sales	16,309	16,684	17,068	17,460	17,862
Capacity sales	88,352,881	90,384,998	92,463,853	94,590,521	96,766,103
Ancillary services					
Total Revenues	**88,369,190**	**90,401,682**	**92,480,920**	**94,607,981**	**96,783,965**
Operating costs					
Fuel purchases	15,295	15,647	16,006	16,375	16,751
Fixed O&M costs	8,900,504	9,105,215	9,314,635	9,528,872	9,748,036
Variable O&M costs	833.707	852.882	872.498	892.566	913.095
Total Operating Costs	**8,916,632**	**9,121,716**	**9,331,514**	**9,546,139**	**9,765,700**
Property Taxes & Insurance	(0)	(0)	(0)	(0)	(0)
Net Pre-Tax Revenues	79,452,558	81,279,967	83,149,406	85,061,843	87,018,265
Tax Depreciation	-	-	-	-	-
Taxable Income	79,452,558	81,279,967	83,149,406	85,061,843	87,018,265
Capital Expenditures	988,945	1,011,691	1,034,959	1,058,764	1,083,115
Income Taxes					
Federal income tax	27,808,395	28,447,988	29,102,292	29,771,645	30,456,393
State income tax	2,383,577	2,438,399	2,494,482	2,551,855	2,610,548
Total Income Taxes	30,191,972	30,886,387	31,596,774	32,323,500	33,066,941
Net After-tax Cash Flow	**48,271,641**	**49,381,889**	**50,517,672**	**51,679,579**	**52,868,209**

Summary of DCF Based Valuation
AUDRAIN

Year:	23	24	25	26
	Dec-26	Dec-27	Dec-28	Dec-29
Annual generation (GWh)	-	-	-	-
Summer Capacity (MW)	640	640	640	640
Revenues				
Energy sales	18,273	18,693	19,123	19,563
Capacity sales	98,991,724	101,268,533	103,597,709	105,980,457
Ancillary services				
Total Revenues	**99,009,996**	**101,287,226**	**103,616,832**	**106,000,019**
Operating costs				
Fuel purchases	17,137	17,531	17,934	18,346
Fixed O&M costs	9,972,241	10,201,602	10,436,239	10,676,272
Variable O&M costs	934.096	955.580	977.558	1,000,042
Total Operating Costs	**9,990,311**	**10,220,088**	**10,455,150**	**10,695,619**
Property Taxes & Insurance	(0)	(0)	(0)	(0)
Net Pre-Tax Revenues	89,019,685	91,067,138	93,161,682	95,304,401
Tax Depreciation	-	-	-	-
Taxable Income	89,019,685	91,067,138	93,161,682	95,304,401
Capital Expenditures	1,108,027	1,133,511	1,159,582	1,186,252
Income Taxes				
Federal income tax	31,156,890	31,873,498	32,606,589	33,356,540
State income tax	2,670,591	2,732,014	2,794,850	2,859,132
Total Income Taxes	33,827,480	34,605,512	35,401,439	36,215,672
Net After-tax Cash Flow	**54,084,178**	**55,328,114**	**56,600,661**	**57,902,476**

Summary of DCF Based Valuation
KINMUNDY

NPV of after-tax cash flow (Sep 2002$):		**$110,257,451**
Value per kW (2002$/kW):		**$ 475**
Operating Life (Yrs):	25	
WACC(%):	9.7%	
Inflation Rate (%):	2.3%	

Year:	1	2	3	4	5	6
	Dec-04	Dec-05	Dec-06	Dec-07	Dec-08	Dec-09
Annual generation (GWh)	-	0.418	0.835	3.616	6.397	9.710
Summer Capacity (MW)	232	232	232	232	232	232
Revenues						
Energy sales	-	24,165	49,441	235,858	430,825	643,306
Capacity sales	4,364,128	4,900,054	5,458,323	14,462,480	23,877,940	24,392,936
Ancillary services						
Total Revenues	**4,364,128**	**4,924,218**	**5,507,764**	**14,698,338**	**24,308,765**	**25,036,243**
Operating costs						
Fuel purchases	-	21,495	43,980	195,430	353,824	533,284
Fixed O&M costs	2,212,467	2,263,354	2,315,411	2,368,665	2,423,145	2,478,877
Variable O&M costs	-	1,140	2,333	10,309	18,651	28,954
Total Operating Costs	**2,212,467**	**2,285,989**	**2,361,723**	**2,574,405**	**2,795,620**	**3,041,115**
Property Taxes & Insurance	2,155,292	1,939,763	1,745,786	1,571,094	1,413,871	1,272,530
Net Pre-Tax Revenues	(3,630)	698,466	1,400,254	10,552,839	20,099,273	20,722,598
Tax Depreciation	5,671,821	10,776,459	9,698,813	8,734,604	7,861,144	7,067,089
Taxable Income	(5,675,451)	(10,077,993)	(8,298,559)	1,818,235	12,238,130	13,655,510
Capital Expenditures	245,829.66	251,483.74	257,267.87	263,185.03	269,238.29	275,430.77
Income Taxes						
Federal income tax	-	-	-	636,382	4,283,345	4,779,428
State income tax	-	-	-	54,547	367,144	409,665
Total Income Taxes	-	-	-	690,929	4,650,489	5,189,094
Net After-tax Cash Flow	**(249,460)**	**446,983**	**1,142,986**	**9,598,725**	**15,179,546**	**15,258,074**

Summary of DCF Based Valuation
KINMUNDY

Year:	7	8	9	10	11	12
	Dec-10	Dec-11	Dec-12	Dec-13	Dec-14	Dec-15
Annual generation (GWh)	13.022	16.335	13.186	10.037	6.889	-
Summer Capacity (MW)	232	232	232	232	232	232
Revenues						
Energy sales	865,334	1,097,235	904,071	701,441	489,012	500,259
Capacity sales	24,918,991	25,456,341	26,061,375	26,680,774	27,314,880	27,943,122
Ancillary services						
Total Revenues	**25,784,325**	**26,553,576**	**26,965,446**	**27,382,215**	**27,803,892**	**28,443,381**
Operating costs						
Fuel purchases	720,812	916,683	758,047	591,628	417,153	426,747
Fixed O&M costs	2,535,891	2,594,217	2,653,884	2,714,923	2,777,366	2,841,246
Variable O&M costs	39,721	50,967	42,096	32,789	23,032	23,562
Total Operating Costs	**3,296,423**	**3,561,867**	**3,454,026**	**3,339,340**	**3,217,550**	**3,291,554**
Property Taxes & Insurance	1,138,675	1,004,820	870,738	736,883	602,801	468,946
Net Pre-Tax Revenues	21,349,227	21,986,888	22,640,682	23,305,993	23,983,540	24,682,881
Tax Depreciation	6,692,748	6,692,748	6,704,092	6,692,748	6,704,092	6,692,748
Taxable Income	14,656,479	15,294,140	15,936,590	16,613,244	17,279,448	17,990,133
Capital Expenditures	281,765.68	288,246.29	294,875.95	301,658.10	308,596.23	315,693.95
Income Taxes						
Federal income tax	5,129,768	5,352,949	5,577,806	5,814,636	6,047,807	6,296,546
State income tax	439,694	458,824	478,098	498,397	518,383	539,704
Total Income Taxes	5,569,462	5,811,773	6,055,904	6,313,033	6,566,190	6,836,250
Net After-tax Cash Flow	**15,498,000**	**15,886,869**	**16,289,902**	**16,691,302**	**17,108,754**	**17,530,937**

Summary of DCF Based Valuation
KINMUNDY

Year:	13	14	15	16	17	18
	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20	Dec-21
Annual generation (GWh)	-	-	-	-	-	-
Summer Capacity (MW)	232	232	232	232	232	232
Revenues						
Energy sales	511,765	523,536	535,577	547,895	560,497	573,389
Capacity sales	28,585,814	29,243,287	29,915,883	30,603,948	31,307,839	32,027,920
Ancillary services						
Total Revenues	**29,097,579**	**29,766,823**	**30,451,460**	**31,151,844**	**31,868,336**	**32,601,308**
Operating costs						
Fuel purchases	436,562	446,603	456,875	467,383	478,133	489,130
Fixed O&M costs	2,906,594	2,973,446	3,041,835	3,111,797	3,183,369	3,256,586
Variable O&M costs	24,103	24,658	25,225	25,805	26,399	27,006
Total Operating Costs	**3,367,260**	**3,444,707**	**3,523,935**	**3,604,986**	**3,687,900**	**3,772,722**
Property Taxes & Insurance	334,864	201,009	66,927	(0)	(0)	(0)
Net Pre-Tax Revenues	25,395,455	26,121,107	26,860,598	27,546,858	28,180,436	28,828,586
Tax Depreciation	6,704,092	6,692,748	6,704,092	3,346,374	-	-
Taxable Income	18,691,363	19,428,359	20,156,506	24,200,484	28,180,436	28,828,586
Capital Expenditures	322,954.91	330,382.87	337,981.68	345,755.26	353,707.63	361,842.90
Income Taxes						
Federal income tax	6,541,977	6,799,926	7,054,777	8,470,169	9,863,153	10,090,005
State income tax	560,741	582,851	604,695	726,015	845,413	864,858
Total Income Taxes	7,102,718	7,382,776	7,659,472	9,196,184	10,708,566	10,954,863
Net After-tax Cash Flow	**17,969,782**	**18,407,948**	**18,863,144**	**18,004,919**	**17,118,163**	**17,511,880**

Summary of DCF Based Valuation
KINMUNDY

Year:	19	20	21	22	23	24
Annual generation (GWh)	-	-	-	-	-	-
Summer Capacity (MW)	232	232	232	232	232	232
Revenues						
Energy sales	586,576	600,068	613,869	627,988	642,432	657,208
Capacity sales	32,764,562	33,518,147	34,289,064	35,077,712	35,884,500	36,709,843
Ancillary services						
Total Revenues	**33,351,138**	**34,118,214**	**34,902,933**	**35,705,701**	**36,526,932**	**37,367,051**
Operating costs						
Fuel purchases	500,380	511,889	523,662	535,706	548,028	560,632
Fixed O&M costs	3,331,488	3,408,112	3,486,498	3,566,688	3,648,722	3,732,642
Variable O&M costs	27,627	28,262	28,912	29,577	30,258	30,954
Total Operating Costs	**3,859,495**	**3,948,263**	**4,039,073**	**4,131,972**	**4,227,007**	**4,324,228**
Property Taxes & Insurance	(0)	(0)	(0)	(0)	(0)	(0)
Net Pre-Tax Revenues	29,491,643	30,169,951	30,863,860	31,573,729	32,299,925	33,042,823
Tax Depreciation	-	-	-	-	-	-
Taxable Income	29,491,643	30,169,951	30,863,860	31,573,729	32,299,925	33,042,823
Capital Expenditures	370,165.29	378,679.09	387,388.71	396,298.65	405,413.52	414,738.03
Income Taxes						
Federal income tax	10,322,075	10,559,483	10,802,351	11,050,805	11,304,974	11,564,988
State income tax	884,749	905,099	925,916	947,212	968,998	991,285
Total Income Taxes	11,206,825	11,464,581	11,728,267	11,998,017	12,273,971	12,556,273
Net After-tax Cash Flow	**17,914,654**	**18,326,691**	**18,748,205**	**19,179,413**	**19,620,540**	**20,071,812**

Summary of DCF Based Valuation
KINMUNDY

Year:	25	26
	Dec-28	Dec-29
Annual generation (GWh)	-	-
Summer Capacity (MW)	232	232
Revenues		
Energy sales	672,324	687,787
Capacity sales	37,554,170	38,417,916
Ancillary services		
Total Revenues	**38,226,493**	**39,105,703**
Operating costs		
Fuel purchases	573,527	586,718
Fixed O&M costs	3,818,493	3,906,318
Variable O&M costs	31,666	32,394
Total Operating Costs	**4,423,685**	**4,525,430**
Property Taxes & Insurance	(0)	(0)
Net Pre-Tax Revenues	33,802,808	34,580,272
Tax Depreciation	-	-
Taxable Income	33,802,808	34,580,272
Capital Expenditures	424,277.00	434,035.37
Income Taxes		
Federal income tax	11,830,983	12,103,095
State income tax	1,014,084	1,037,408
Total Income Taxes	12,845,067	13,140,504
Net After-tax Cash Flow	**20,533,464**	**21,005,734**

Summary of DCF Based Valuation
PINCKNEY

NPV of after-tax cash flow (Sep 2002$):		$152,947,977
Value per kW (2002$/kW):		$ 484
Operating Life (Yrs):	25	
WACC(%):	9.7%	
Inflation Rate (%):	2.3%	

Year:	1	2	3	4	5
	Dec-04	[illegible]	Dec-06	[illegible]	Dec-08
Annual generation (GWh)	3.298	6.291	9.284	21.815	34.346
Summer Capacity (MW)	316	316	316	316	316
Revenues					
Energy sales	185,457	346,449	514,750	1,285,323	2,091,070
Capacity sales	5,944,244	6,674,211	7,434,613	19,698,895	32,523,401
Ancillary services					
Total Revenues	**6,129,701**	**7,020,661**	**7,949,362**	**20,984,217**	**34,614,470**
Operating costs					
Fuel purchases	165,659	306,817	454,380	1,110,428	1,796,413
Fixed O&M costs	2,986,689	3,055,383	3,125,657	3,197,547	3,271,090
Variable O&M costs	8,676	16,925	25,549	61,404	98,895
Total Operating Costs	**3,161,024**	**3,379,125**	**3,605,586**	**4,369,379**	**5,166,399**
Property Taxes & Insurance	2,989,798	2,690,818	2,421,737	2,179,406	1,961,308
Net Pre-Tax Revenues	(21,122)	950,718	1,922,040	14,435,433	27,486,764
Tax Depreciation	7,867,890	14,948,991	13,454,092	12,116,551	10,904,896
Taxable Income	(7,889,012)	(13,998,273)	(11,532,052)	2,318,882	16,581,868
Capital Expenditures	331,854	339,487	347,295	355,283	363,454
Income Taxes					
Federal income tax	-	-	-	811,609	5,803,654
State income tax	-	-	-	69,566	497,456
Total Income Taxes	-	-	-	881,175	6,301,110
Net After-tax Cash Flow	**(352,976)**	**611,231**	**1,574,745**	**13,198,975**	**20,822,199**

Pinckney Scenario 2

Summary of DCF Based Valuation
PINCKNEY

Year:	6	7	8	9	10	11
	Dec-09	Dec-10	Dec-11	Dec-12	Dec-13	Dec-14
Annual generation (GWh)	41.451	48.557	55.663	51.729	47.795	43.861
Summer Capacity (MW)	316	316	316	316	316	316
Revenues						
Energy sales	2,747,025	3,432,049	4,147,131	3,915,737	3,671,506	3,413,969
Capacity sales	33,224,862	33,941,385	34,673,292	35,497,390	36,341,055	37,204,750
Ancillary services						
Total Revenues	**35,971,887**	**37,373,434**	**38,820,423**	**39,413,128**	**40,012,561**	**40,618,719**
Operating costs						
Fuel purchases	2,188,659	2,597,997	3,025,008	2,881,887	2,730,581	2,570,792
Fixed O&M costs	3,346,326	3,423,291	3,502,027	3,582,573	3,664,973	3,749,267
Variable O&M costs	122,054	146,225	171,443	162,996	154,070	144,647
Total Operating Costs	**5,657,038**	**6,167,513**	**6,698,478**	**6,627,456**	**6,549,624**	**6,464,706**
Property Taxes & Insurance	1,765,240	1,579,558	1,393,875	1,207,878	1,022,196	836,199
Net Pre-Tax Revenues	28,549,609	29,626,363	30,728,069	31,577,793	32,440,741	33,317,814
Tax Depreciation	9,803,391	9,284,110	9,284,110	9,299,846	9,284,110	9,299,846
Taxable Income	18,746,218	20,342,252	21,443,959	22,277,947	23,156,630	24,017,968
Capital Expenditures	371,814	380,366	389,114	398,064	407,219	416,585
Income Taxes						
Federal income tax	6,561,176	7,119,788	7,505,386	7,797,281	8,104,821	8,406,289
State income tax	562,387	610,268	643,319	668,338	694,699	720,539
Total Income Taxes	7,123,563	7,730,056	8,148,704	8,465,620	8,799,520	9,126,828
Net After-tax Cash Flow	**21,054,232**	**21,515,941**	**22,190,251**	**22,714,109**	**23,234,002**	**23,774,401**

Summary of DCF Based Valuation
PINCKNEY

Year:	12	13	14	15	16	17
	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20
Annual generation (GWh)	-	-	-	-	-	-
Summer Capacity (MW)	316	316	316	316	316	316
Revenues						
Energy sales	3,492,491	3,572,818	3,654,993	3,739,058	3,825,056	3,913,032
Capacity sales	38,060,459	38,935,850	39,831,374	40,747,496	41,684,688	42,643,436
Ancillary services						
Total Revenues	**41,552,950**	**42,508,668**	**43,486,367**	**44,486,553**	**45,509,744**	**46,556,468**
Operating costs						
Fuel purchases	2,629,920	2,690,408	2,752,288	2,815,590	2,880,349	2,946,597
Fixed O&M costs	3,835,500	3,923,717	4,013,962	4,106,283	4,200,728	4,297,344
Variable O&M costs	147,974	151,378	154,859	158,421	162,065	165,792
Total Operating Costs	**6,613,394**	**6,765,502**	**6,921,109**	**7,080,294**	**7,243,141**	**7,409,733**
Property Taxes & Insurance	650,517	464,520	278,838	92,841	(0)	(0)
Net Pre-Tax Revenues	34,289,038	35,278,645	36,286,420	37,313,418	38,266,603	39,146,735
Tax Depreciation	9,284,110	9,299,846	9,284,110	9,299,846	4,642,055	-
Taxable Income	25,004,928	25,978,799	27,002,310	28,013,572	33,624,548	39,146,735
Capital Expenditures	426,167	435,969	445,996	456,254	466,748	477,483
Income Taxes						
Federal income tax	8,751,725	9,092,580	9,450,808	9,804,750	11,768,592	13,701,357
State income tax	750,148	779,364	810,069	840,407	1,008,736	1,174,402
Total Income Taxes	9,501,873	9,871,944	10,260,878	10,645,157	12,777,328	14,875,759
Net After-tax Cash Flow	**24,360,999**	**24,970,733**	**25,579,547**	**26,212,007**	**25,022,527**	**23,793,493**

Pinckney Scenario 2

Summary of DCF Based Valuation
PINCKNEY

Year:	18	19	20	21	22
	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25
Annual generation (GWh)	-	-	-	-	-
Summer Capacity (MW)	316	316	316	316	316
Revenues					
Energy sales	4,003,032	4,095,102	4,189,289	4,285,643	4,384,212
Capacity sales	43,624,235	44,627,593	45,654,027	46,704,070	47,778,263
Ancillary services					
Total Revenues	**47,627,267**	**48,722,694**	**49,843,316**	**50,989,712**	**52,162,476**
Operating costs					
Fuel purchases	3,014,368	3,083,699	3,154,624	3,227,180	3,301,406
Fixed O&M costs	4,396,183	4,497,296	4,600,733	4,706,550	4,814,801
Variable O&M costs	169,605	173,506	177,497	181,579	185,756
Total Operating Costs	**7,580,157**	**7,754,501**	**7,932,854**	**8,115,310**	**8,301,962**
Property Taxes & Insurance	(0)	(0)	(0)	(0)	(0)
Net Pre-Tax Revenues	40,047,110	40,968,193	41,910,462	42,874,402	43,860,514
Tax Depreciation	-	-	-	-	-
Taxable Income	40,047,110	40,968,193	41,910,462	42,874,402	43,860,514
Capital Expenditures	488,465	499,700	511,193	522,950	534,978
Income Taxes					
Federal income tax	14,016,488	14,338,868	14,668,662	15,006,041	15,351,180
State income tax	1,201,413	1,229,046	1,257,314	1,286,232	1,315,815
Total Income Taxes	15,217,902	15,567,914	15,925,976	16,292,273	16,666,995
Net After-tax Cash Flow	**24,340,743**	**24,900,580**	**25,473,294**	**26,059,180**	**26,658,541**

Pinckney Scenario 2

Summary of DCF Based Valuation
PINCKNEY

Year:	23	24	25	26
	Dec-26	Dec-27	Dec-28	Dec-29
Annual generation (GWh)	-	-	-	-
Summer Capacity (MW)	316	316	316	316
Revenues				
Energy sales	4,485,049	4,588,205	4,693,734	4,801,690
Capacity sales	48,877,164	50,001,338	51,151,369	52,327,851
Ancillary services				
Total Revenues	**53,362,213**	**54,589,544**	**55,845,103**	**57,129,541**
Operating costs				
Fuel purchases	3,377,338	3,455,017	3,534,482	3,615,775
Fixed O&M costs	4,925,541	5,038,829	5,154,722	5,273,280
Variable O&M costs	190,028	194,399	198,870	203,444
Total Operating Costs	**8,492,907**	**8,688,244**	**8,888,074**	**9,092,499**
Property Taxes & Insurance	(0)	(0)	(0)	(0)
Net Pre-Tax Revenues	44,869,306	45,901,300	46,957,029	48,037,041
Tax Depreciation	-	-	-	-
Taxable Income	44,869,306	45,901,300	46,957,029	48,037,041
Capital Expenditures	547,282	559,870	572,747	585,920
Income Taxes				
Federal income tax	15,704,257	16,065,455	16,434,960	16,812,964
State income tax	1,346,079	1,377,039	1,408,711	1,441,111
Total Income Taxes	17,050,336	17,442,494	17,843,671	18,254,076
Net After-tax Cash Flow	**27,271,687**	**27,898,936**	**28,540,611**	**29,197,046**

Summary of DCF Based Valuation
AUDRAIN

NPV of after-tax cash flow (Sep 2002$):		**$303,898,607**
Value per kW (2002$/kW):		**$ 475**
Operating Life (Yrs):	25	
WACC(%):	9.7%	
Inflation Rate (%):	2.3%	

Year:	1	2	3	4	5
	Dec-04	[illegible]	[illegible]	[illegible]	Dec-08
Annual generation (GWh)	0.890	2.007	3.125	8.723	14.322
Summer Capacity (MW)	640	640	640	640	640
Revenues					
Energy sales	51,250	112,807	177,168	504,420	846,632
Capacity sales	12,038,975	13,517,390	15,057,443	39,896,495	65,870,179
Ancillary services					
Total Revenues	**12,090,225**	**13,630,197**	**15,234,612**	**40,400,916**	**66,716,811**
Operating costs					
Fuel purchases	48,134	105,006	164,469	471,891	793,368
Fixed O&M costs	6,046,845	6,185,922	6,328,198	6,473,747	6,622,643
Variable O&M costs	2,327.913	5,378.049	8,567.261	24,451.928	41,062.758
Total Operating Costs	**6,097,307**	**6,296,306**	**6,501,235**	**6,970,090**	**7,457,073**
Property Taxes & Insurance	5,940,553	5,346,497	4,811,848	4,330,350	3,897,003
Net Pre-Tax Revenues	52,366	1,987,393	3,921,529	29,100,476	55,362,735
Tax Depreciation	15,633,033	29,702,763	26,732,487	24,074,871	21,667,384
Taxable Income	(15,580,668)	(27,715,370)	(22,810,958)	5,025,604	33,695,351
Capital Expenditures	671,872	687,325	703,133	719,305	735,849
Income Taxes					
Federal income tax	-	-	-	1,758,962	11,793,373
State income tax	-	-	-	150,768	1,010,861
Total Income Taxes	-	-	-	1,909,730	12,804,233
Net After-tax Cash Flow	**(619,506)**	**1,300,068**	**3,218,396**	**26,471,441**	**41,822,653**

Summary of DCF Based Valuation
AUDRAIN

Year:	6	7	8	9	10	11
	Dec-09	Dec-10	Dec-11	Dec-12	Dec-13	Dec-14
Annual generation (GWh)	13.359	12.396	11.434	7.695	3.956	0.216
Summer Capacity (MW)	640	640	640	640	640	640
Revenues						
Energy sales	802,086	755,043	705,412	485,521	255,142	13,909
Capacity sales	67,290,859	68,742,045	70,224,389	71,893,449	73,602,136	75,351,392
Ancillary services						
Total Revenues	**68,092,945**	**69,497,088**	**70,929,800**	**72,378,970**	**73,857,279**	**75,365,301**
Operating costs						
Fuel purchases	745,231	694,460	640,960	441,289	232,095	13,044
Fixed O&M costs	6,774,964	6,930,788	7,090,196	7,253,271	7,420,096	7,590,758
Variable O&M costs	39,186.873	37,202.976	35,107.090	24,169.505	12,710.221	711.023
Total Operating Costs	**7,559,382**	**7,662,451**	**7,766,263**	**7,718,729**	**7,664,901**	**7,604,513**
Property Taxes & Insurance	3,507,427	3,138,488	2,769,548	2,399,983	2,031,044	1,661,479
Net Pre-Tax Revenues	57,026,136	58,696,149	60,393,989	62,260,257	64,161,334	66,099,309
Tax Depreciation	19,478,760	18,446,979	18,446,979	18,478,245	18,446,979	18,478,245
Taxable Income	37,547,376	40,249,170	41,947,010	43,782,011	45,714,354	47,621,064
Capital Expenditures	752,774	770,088	787,800	805,919	824,455	843,418
Income Taxes						
Federal income tax	13,141,582	14,087,209	14,681,453	15,323,704	16,000,024	16,667,372
State income tax	1,126,421	1,207,475	1,258,410	1,313,460	1,371,431	1,428,632
Total Income Taxes	14,268,003	15,294,684	15,939,864	16,637,164	17,371,455	18,096,004
Net After-tax Cash Flow	**42,005,359**	**42,631,377**	**43,666,326**	**44,817,174**	**45,965,424**	**47,159,888**

Summary of DCF Based Valuation
AUDRAIN

Year:	12	13	14	15	16	17
	Dec-15	Dec-16	Dec-17	Dec-18	Dec-19	Dec-20
Annual generation (GWh)	-	-	-	-	-	-
Summer Capacity (MW)	640	640	640	640	640	640
Revenues						
Energy sales	14,229	14,556	14,891	15,233	15,584	15,942
Capacity sales	77,084,474	78,857,417	80,671,138	82,526,574	84,424,685	86,366,453
Ancillary services						
Total Revenues	**77,098,703**	**78,871,973**	**80,686,029**	**82,541,807**	**84,440,269**	**86,382,395**
Operating costs						
Fuel purchases	13,344	13,651	13,965	14,286	14,615	14,951
Fixed O&M costs	7,765,345	7,943,948	8,126,659	8,313,572	8,504,784	8,700,394
Variable O&M costs	727.377	744.107	761.221	778.729	796.640	814.963
Total Operating Costs	**7,779,417**	**7,958,343**	**8,141,385**	**8,328,637**	**8,520,196**	**8,716,160**
Property Taxes & Insurance	1,292,539	922,974	554,035	184,470	(0)	(0)
Net Pre-Tax Revenues	68,026,747	69,990,656	71,990,609	74,028,700	75,920,073	77,666,235
Tax Depreciation	18,446,979	18,478,245	18,446,979	18,478,245	9,223,490	-
Taxable Income	49,579,768	51,512,410	53,543,629	55,550,455	66,696,583	77,666,235
Capital Expenditures	862,816	882,661	902,962	923,730	944,976	966,710
Income Taxes						
Federal income tax	17,352,919	18,029,344	18,740,270	19,442,659	23,343,804	27,183,182
State income tax	1,487,393	1,545,372	1,606,309	1,666,514	2,000,898	2,329,987
Total Income Taxes	18,840,312	19,574,716	20,346,579	21,109,173	25,344,702	29,513,169
Net After-tax Cash Flow	**48,323,619**	**49,533,279**	**50,741,067**	**51,995,797**	**49,630,395**	**47,186,355**

Summary of DCF Based Valuation
AUDRAIN

Year:	18	19	20	21	22
	Dec-21	Dec-22	Dec-23	Dec-24	Dec-25
Annual generation (GWh)	-	-	-	-	-
Summer Capacity (MW)	640	640	640	640	640
Revenues					
Energy sales	16,309	16,684	17,068	17,460	17,862
Capacity sales	88,352,881	90,384,998	92,463,853	94,590,521	96,766,103
Ancillary services					
Total Revenues	**88,369,190**	**90,401,682**	**92,480,920**	**94,607,981**	**96,783,965**
Operating costs					
Fuel purchases	15,295	15,647	16,006	16,375	16,751
Fixed O&M costs	8,900,504	9,105,215	9,314,635	9,528,872	9,748,036
Variable O&M costs	833.707	852.882	872.498	892.566	913.095
Total Operating Costs	**8,916,632**	**9,121,715**	**9,331,514**	**9,546,139**	**9,765,700**
Property Taxes & Insurance	(0)	(0)	(0)	(0)	(0)
Net Pre-Tax Revenues	79,452,558	81,279,967	83,149,406	85,061,843	87,018,265
Tax Depreciation	-	-	-	-	-
Taxable Income	79,452,558	81,279,967	83,149,406	85,061,843	87,018,265
Capital Expenditures	988,945	1,011,691	1,034,959	1,058,764	1,083,115
Income Taxes					
Federal income tax	27,808,395	28,447,988	29,102,292	29,771,645	30,456,393
State income tax	2,383,577	2,438,399	2,494,482	2,551,855	2,610,548
Total Income Taxes	30,191,972	30,886,387	31,596,774	32,323,500	33,066,941
Net After-tax Cash Flow	**48,271,641**	**49,381,889**	**50,517,672**	**51,679,579**	**52,868,209**

Summary of DCF Based Valuation
AUDRAIN

Year:	23	24	25	26
	Dec-46	Dec-47	Dec-48	Dec-49
Annual generation (GWh)	-	-	-	-
Summer Capacity (MW)	640	640	640	640
Revenues				
Energy sales	18,273	18,693	19,123	19,563
Capacity sales	98,991,724	101,268,533	103,597,709	105,980,457
Ancillary services				
Total Revenues	**99,009,996**	**101,287,226**	**103,616,832**	**106,000,019**
Operating costs				
Fuel purchases	17,137	17,531	17,934	18,346
Fixed O&M costs	9,972,241	10,201,602	10,436,239	10,676,272
Variable O&M costs	934,096	955,580	977,558	1,000,042
Total Operating Costs	**9,990,311**	**10,220,088**	**10,455,150**	**10,695,619**
Property Taxes & Insurance	(0)	(0)	(0)	(0)
Net Pre-Tax Revenues	89,019,685	91,067,138	93,161,682	95,304,401
Tax Depreciation	-	-	-	-
Taxable Income	89,019,685	91,067,138	93,161,682	95,304,401
Capital Expenditures	1,108,027	1,133,511	1,159,582	1,186,252
Income Taxes				
Federal income tax	31,156,890	31,873,498	32,606,589	33,356,540
State income tax	2,670,591	2,732,014	2,794,850	2,859,132
Total Income Taxes	33,827,480	34,605,512	35,401,439	36,215,672
Net After-tax Cash Flow	**54,084,178**	**55,328,114**	**56,600,661**	**57,902,476**