MONTANA-DAKOTA
UTILITIES CO.
A Division of MDU Resources Group, Inc.

400 North Fourth Street
Bismarck, ND 58501
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ORIGINAL

November 16, 2005

RECEIVED
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SOUTH DAKOTA PUBLIC
UTILITIES COMMISSION

Ms. Heather Forney
Acting Executive Director
South Dakota Public Utilities
Commission
State Capitol Building
500 East Capitol
Pierre, SD 57501

Re: Docket No. EL04-016

Dear Ms. Forney:

Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc. herewith submits the original and eleven (11) copies of the supplemental testimonies of Ms. Andrea L. Stomberg and Mr. Edward D. Kee. Ms. Stomberg's attached supplemental testimony replaces the prefiled direct testimony filed by Ms. Stomberg on January 31, 2005 in its entirety. Mr. Kee's attached supplemental testimony supplements the testimonies filed by Mr. Kee on January 31, 2005 and February 14, 2005.

Please acknowledge receipt by stamping or initiating the duplicate copy of this letter attached hereto and returning the same in the enclosed self-addressed, stamped envelope.

Sincerely,

Donald R. Ball/JB

Donald R. Ball
Assistant Vice President –
Regulatory Affairs

Attachment
cc: Service List

Montana-Dakota Utilities Co.
Docket No. EL04-016
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A.L.
Stomberg

MONTANA-DAKOTA UTILITIES CO.
A Division of MDU Resources Group, Inc.

Before the Public Utilities Commission of South Dakota

Docket No. EL04-016

Supplemental Direct Testimony
of
Andrea L. Stomberg

Q. Would you please state your name and business address?

A. Yes. My name is Andrea L. Stomberg, and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501.

Q. What is your position with Montana-Dakota Utilities Co.?

A. I am the Vice President of Electric Supply for Montana-Dakota Utilities Co. (Montana-Dakota), a Division of MDU Resources Group, Inc.

Q. What are your responsibilities as the Vice President of Electric Supply?

A. My responsibilities include power production and planning, transmission and system operations and dispatch.

Q. Would you please outline your educational and professional background?

A. I graduated from the University of Washington with a bachelor's degree in Geology, from Oregon State University with a Master of Science degree in Soils, and from the University of Mary, Bismarck, with a masters in business management. I worked for the North American Coal Corporation for 10 years in surface mine permitting, reclamation planning and oversite. I have worked for Montana-Dakota for about 15 years in the environmental field prior to my current position.

Q. Have you testified in other proceedings before regulatory bodies?

A. I have provided testimony during legislative sessions in North

Dakota.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide information regarding power supply planning and related activities at Montana-Dakota, and to discuss the nature of our contact with Superior Wind Energy.

Q. Please describe Montana-Dakota's current power supply?

A. Montana-Dakota operates an integrated electric system in portions of Montana, North Dakota and South Dakota. We currently support the electric energy requirements of the customers served by the integrated electric system with approximately 365 MW of baseload coal generation from five plants, and approximately 105 MW of gas or gas and oil fired combustion turbines used for peaking. Montana-Dakota also purchases 66.4 MW of energy and capacity from Basin Electric Power Cooperative's (Basin's) Antelope Valley Station II under a contract which will expire October 31, 2006.

Q. How does Montana-Dakota plan for future power needs?

A. We produce long-range (20-year) forecasts of electric demand annually in December. The projected annual energy requirements are modeled for each customer class, and growth forecasts are applied. Montana-Dakota utilizes an integrated resource planning process involving load modeling and forecasting based on various load growth assumptions, followed by analysis of various demand and supply side alternatives in determining what should be considered the best options for supplying its customers. This integrated resource plan, or IRP, is updated every two years and is filed with the Montana Public Service Commission and the North Dakota Public Service Commission pursuant to regulatory requirements in those states with a copy filed with the South Dakota Public Utilities Commission on an informational basis. The IRP is a snapshot based on conditions that exist at the time the plan is prepared and is therefore subject to change as assumptions and business conditions change.

Q. When was Montana-Dakota's most recent IRP published?

A. The last IRP was published in July, 2003, and a revision was published in July, 2005.

Q. What were the conclusions of the 2003 IRP?

A. The period studied for the 2003 IRP was 2003-2022. This document presented an "optimal integrated resource plan" that included 78 MW from two new combustion turbines to be added in 2007 to replace the 66.4 MW capacity and energy purchase from Basin; modifications to existing combustion turbines at Glendive and Miles City, Montana for an additional 7.72 MW in 2010 and 2011; and another new 39 MW combustion turbine to be added in 2012. The plan also discussed the possibility of a new coal baseload plant designated as "Lignite Vision 21". Subsequent to filing the 2003 IRP Montana-Dakota determined that the plan's reliance on gas fired generation exposes our customers to considerable price and reliability risk associated with fuel cost and availability and does not necessarily reflect our current philosophy of power supply.

Q. If the 2003 IRP doesn't reflect Montana-Dakota's current power supply plans, what are those plans?

A. Our aim is to provide our customers with a competitively priced, reliable power supply. The 2003 IRP indicated a future power supply heavily dependant on gas. This contrasts with our current reliance on coal-fired generation, which has lower and less volatile fuel prices, and a more stable fuel supply than natural gas. Several years ago, we began considering construction of another baseload coal plant for several reasons- the expiration of the Basin contract, the ageing of our current plant fleet, new environmental regulations that may be difficult to meet with our older plants, the increased volatility of gas prices coupled with low, but steady, growth in the electric requirements of our customers. A new baseload coal plant will provide stable prices for a long term period (30 to 40 years) which is not likely with natural gas. The development of this new baseload resource is addressed in the 2005 IRP filing.

Q. What new coal baseload resources are you considering?

A. Montana-Dakota spent considerable time developing a new plant concept for southwestern North Dakota, the Lignite Vision 21 plant. While we developed the planning for this plant to the point we were able to submit an air permit application, we did not commit to this project, and are assessing two other coal-fired baseload projects in the region, which I will discuss later.

Q. How does the possibility of a new coal plant impact Montana-Dakota's near-term power supply needs and plans?

A. Building a new coal fired plant can take ten or more years from initiation to completion. Because of the expiration of the Basin contract, we face an interim period of deficit capacity, from October 2006 to about 2010, the earliest we feel we could have a new plant on-line. To address this problem, we signed contracts with the Omaha Public Power District (OPPD) for summer capacity and energy for the period 2004-2006, and baseload capacity and energy for the period 2007-2010. The summer capacity purchases were relatively small- 5 to 15 MW during the period 2004-2006 with the purchases of 70 to 100 MW in the later period to replace the Basin contract and provide for load growth before a new plant would be available. The OPPD contracts were contingent upon obtaining firm transmission and were set to expire December 31, 2004 unless the required transmission was obtained.

Q. What was the result of Montana-Dakota's efforts to obtain transmission?

A. In February of 2004 we began efforts to obtain transmission. Constraints within the Midwest Independent System Operator (MISO) system blocked our efforts, despite concerted and creative efforts of our transmission engineers to mitigate the constraints. We formally withdrew transmission requests in early October, 2004, however, we did not cancel the contracts with OPPD. Our experience with transmission constraints is that they can evolve daily i.e., changes in equipment or flows almost anywhere in MISO or MAPP can affect transmission availability. We considered it a possibility, albeit remote, that transmission might become available before the end of 2004 due to the efforts of others, or through unforeseen changes elsewhere on the system. This is why we considered that we had no unmet capacity needs through 2010, up until the contracts actually expired on December 31, 2004.

Q. What did Montana-Dakota do when you learned that transmission might not be available for the OPPD contract?

A. In June of last year, we began informal discussions with NorthPoint Energy Solutions, Inc. (NorthPoint), for summer capacity and energy for the years of 2005 and 2006. As I mentioned, our load forecasts indicate that our current generation capacity is sufficient for anticipated peaks for these years, however, MAPP penalties for being short of capacity are significant, and it was deemed prudent to arrange for additional firm summer peaking capacity. Shortly after signing a contract for this product in mid-July, we obtained firm transmission for the capacity.

Q. What did you do regarding the capacity shortfall for 2007 to 2010?

A. It was determined that the only alternative was to issue a Request for Proposal (RFP) to identify what capacity and energy might be available and at what price that capacity and energy could be delivered for that time period. The RFP was widely distributed to suppliers in MAPP and to the Mid-Continent Energy Marketers Association. We received only three bids. None of the bids, nor a combination of the proposals, provided the requested amounts of capacity and associated energy. The RFP specified firm, dispatchable resources. This was the quality of resource we felt we need to provide reliable electric service for our customers.

Q. What other resources are available to meet this capacity shortfall identified for the period 2007-2010?

A. One other resource that was under consideration, in conjunction with the bids we received in response to the RFP, was rented or leased combustion turbines to be available during Montana-Dakota's summer peaking season. During the course of our continuing efforts to locate capacity for this period, in September, 2005, Montana-Dakota and Northern States Power Company signed an agreement for an escalating amount of firm summer capacity from 85 MW to 100 MW for the years 2007 through 2010, with an option for contract extension for the years 2011 and 2012. This contract will provide the projected shortfall in our system capacity needs until our next baseload unit is on-line. Any energy required will be purchased from the MISO market.

Q. Why didn't Montana-Dakota consider capacity and energy from the Superior project and reduce the requirements stated in your RFP or the agreement with NSP?

A. Montana-Dakota sought supply resources in a range of 70 to 100 MW in the RFP. In the event Superior's proposed Java wind project comes to fruition, the energy ultimately purchased from other sources will be adjusted to reflect any energy that can be provided by Superior's proposed Java wind project. However, at this time Superior's proposed Java wind project is not operational, and we do not know that it will be operational by 2007, if ever. At the time that we had the opportunity to purchase the capacity from NSP, Superior had not, and still has not, made a firm commitment to complete its project. Moreover, the price for capacity offered by NSP was significantly lower than the price demanded by Superior.

Q. Why hasn't Montana-Dakota firmly committed to a specific new coal fired baseload plant?

A. As I stated earlier, we are determined to provide the best priced, most reliable power to our customers. Many factors affect the price of power from any plant, but economies of scale profoundly impact capital costs. Due to the location of the proposed Lignite Vision 21 plant and identified transmission constraints, Montana-Dakota has not been successful in securing other partners or buyers for the capacity above the Company's identified requirements for the next 15 or so years. This has resulted in a maximum practical size for that plant of 175 MW. Other options include the Resource Coalition, which is a group of generation and transmission cooperatives, municipal corporations and investor owned utilities which is evaluating a possible 600 MW plant in the upper Midwest. Another option, and currently the most focused option, under review is the 600 MW Big Stone II plant in eastern South Dakota. We have been involved with the Resource Coalition since late 2003, and with early proposals for the Big Stone II plant since 2001. These larger plants offer economies of scale and hence lower capital costs than the Lignite Vision 21 plant. Although we haven't committed to any particular plant, and don't expect to until 2007, Big Stone II has progressed the farthest and currently appears the most likely of the options we will ultimately pursue.

Q. Why did Montana-Dakota initially use the Lignite Vision 21 plant as the next baseload resource in the estimate of avoided costs provided to Superior?

A. Montana-Dakota had been very focused on the potential development of this plant for several years. More recently we began work with the Resource Coalition in evaluating its proposed new plant. And still later we seriously considered involvement with the Big Stone II project. Neither of these projects was as fully developed as the Lignite Vision 21 plant at the time we initially submitted avoided cost data to Superior. However, given the significant economies of scale, commitment to these initiatives gained more serious consideration. That being the case, the avoided costs in this proceeding should reflect the more economic capital costs of Big Stone II, given that Big Stone II is currently the most feasible, economic, and viable alternative available to meet Montana-Dakota's power supply needs.

Q. Why has the decision of what resources to use in the future changed so significantly since the 2003 IRP?

A. As noted by Mr. Ed Kee, the electric utility industry is rapidly changing. The price of natural gas has skyrocketed. The transmission grid is adequate for the Company's existing resources, but the addition of even a few megawatts of supply can have impacts for many miles, and states, away from the new source. The emergence of MISO has profoundly altered the way transmission is reviewed and ultimately approved. In addition to this new paradigm, many utilities in the upper Midwest are capacity deficient, and alliances are forming to explore construction of large jointly owned facilities. While cognizant of the need to commit to new resources in a timely manner, the Company is also compelled to evaluate all reasonable options.

Q. What has been the nature of Montana-Dakota's contacts with Superior Wind Energy and other wind developers?

A. As noted in Mr. John Calaway's testimony filed in this case, the Company has had contact with Superior's representatives since early 2002. Superior brought us numerous projects to consider. Additionally, we had contact with many other wind developers- in 2004 alone, Montana-Dakota's staff met with nine different wind developers, including Superior, on at least 41 occasions.

Q. What was the nature of Superior's proposals?

A. Superior presented several different proposals for wind farms in the Dakota's that were consistently more expensive than other wind resources. As stated, Montana-Dakota's primary goal is reasonably priced, reliable power. During the time Superior contacted us about their proposed projects, the Company had a contract with Dakota I Power Partners (Dakota I) to purchase the output of a 20 MW wind farm in Dickey County, North Dakota, for a price much less than any price offered by Superior.

Q. What is the status of the Dakota I project?

A. Dakota I defaulted on their project in May 2004. Prior to that time, when it was apparent that Dakota I was likely unable to finance its project, we began negotiations with Dakota I and FPL Energy, LLC (FPL), which would have resulted in FPL taking over the project. It was during this period of negotiations in April of 2004 that Superior made a number of contacts pressing us to enter into power purchase negotiations, and clearly suggested that they would exercise their Qualified Facility status under PURPA.

Q. Why didn't Montana-Dakota negotiate with Superior for renewable power?

A. Early contacts with Superior indicated that Superior's projects were relatively high priced. As I have said, prior to the time Superior claimed QF status, we were still working with Dakota I and FPL to try to resurrect the Dakota I project. And, as acknowledged by Superior in John Callaway's direct testimony, Montana-Dakota's system is relatively small, and its ability to absorb a large amount of supply for a variable energy source like wind is limited. The Company's intent with Dakota I was to purchase a relatively small amount of wind energy, and learn to integrate it efficiently into our system. Additionally, other wind developers had approached us with projects with a lower cost than that offered by Superior.

Q. Do you feel that Montana-Dakota has acted in good faith with Superior?

A. Yes, I do. It is evident that Superior feels that we have made a concerted attempt to thwart their efforts to build the Java wind project. However, given the serious obligation to provide power to our customers, the larger issues discussed earlier have made us cautiously approach this and any other supply project. During the period that we have considered Superior's QF position and attempted to define avoided costs, not only have certain of Montana-Dakota's power supply contracts expired, but additional future supply possibilities have appeared. Our attempt to define the most likely future power supply has been difficult, but the changes reflect this attempt, not a deliberate effort to frustrate Superior.

Q. Does this conclude your direct testimony?

A. Yes, it does.

E. D.
Kee

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF SOUTH DAKOTA

IN THE MATTER OF THE FILING BY SUPERIOR RENEWABLE ENERGY LLC ET AL. AGAINST MONTANA-DAKOTA UTILITIES CO. REGARDING THE JAVA WIND PROJECT	))))))	EL04-016

SUPPLEMENTAL TESTIMONY OF EDWARD D. KEE

16 NOVEMBER 2005

Q. Please state your name.

A. My name is Edward D. Kee. I am a member of the management group of PA Consulting Group, Inc. (PA).

Q. Are you the same Edward D. Kee who submitted pre-filed testimony on January 31, 2005?

A. Yes.

Q. What is the purpose of this supplemental testimony?

A. I am filing this supplemental testimony to update my earlier testimony and exhibits to reflect changes that have occurred since that earlier testimony was filed.

Q. Please outline the changes that are covered in this testimony.

A. This supplemental testimony covers updates in two areas:

- Montana-Dakota's avoidable energy and capacity costs, and
- The status of MISO markets.

<u>AVOIDABLE COSTS</u>

Q. Why are you updating your earlier avoidable energy and capacity cost testimony?

A. I am updating these costs to reflect Montana-Dakota's avoided costs as of the date of this testimony because some of the inputs and assumptions upon which my earlier testimony was based have changed. The changed inputs and assumptions include:

- Period 2 resource plans,

- Period 3 capital costs and cost of capital assumptions, and
- Fuel and energy cost assumptions.

As a result of these changes Montana-Dakota has updated the PROMOD QF-IN/QF-OUT analysis and I have updated the estimates of avoided energy and capacity costs.

Q. How have the Period 2 resource plans changed?

A. In my original testimony leased combustion turbines were used as the proxy for capacity costs in Period 2. Montana-Dakota reached an agreement with Northern States Power (NSP) in September 2005 for the purchase of generation capacity. The capacity contract provides a market value of summer monthly cost of capacity between the years 2007 – 2010, with options to extend the contract for additional years. The summer period is defined as the 6 months from May through October. With the addition of this capacity Montana-Dakota is no longer capacity deficit in Period 2, and there should be no avoidable capacity cost during this period (See Kee Testimony of 31 January 2005, page 18, line 19 to page 19, line 5). Nonetheless, I have updated Exhibit 3 (avoidable capacity cost) to reflect Period 2 costs of capacity based upon the NSP contract for the information of the Commission. Were the avoidable capacity costs in Period 2 equal to zero, Montana-Dakota's levelized avoidable capacity cost, as shown in Exhibit 4, would be lower.

Q. How have the Period 3 capital costs changed?

A. The initial book value (ie, the capital cost estimate) for the Big-Stone II power plant has become more detailed and is slightly different from the capital costs in my earlier analysis. The initial book value is now $1,706 per kW, as compared to $1,666 per kW in my earlier testimony.

Q. What is the basis for this revised capital cost estimate?

A. My earlier analysis was based upon a publicly available construction cost estimate. Subsequently, more detailed analyses of Big Stone II construction costs were developed. The first update provided to me was Schedule 3.05(a) from the June 30, 2005 Participation Agreement. Montana-Dakota then provided the results of an adjusted cost estimate based upon an independent engineering review commissioned by the Big Stone II owners. The updated initial book value reflects a more detailed and more recent review of the construction costs for the Big Stone II plant.

Q. What has changed with respect to the cost of transmission upgrades related to the Big Stone II power plant?

A. My earlier analysis included the estimated costs of transmission upgrades necessary to ensure that the Big Stone II plant had firm access to the MISO market ($150 per kW; Cost to obtain firm transmission access) in the capital cost of the plant and in Period 3 avoidable capacity cost. In my updated analysis, I have excluded the cost to obtain firm transmission access.

Q. Why have you excluded the Big Stone II firm transmission access cost from your avoidable capacity cost calculation?

A. My earlier analysis assumed that the proposed Java Wind Project would pay for any transmission upgrades necessary to ensure firm access. Therefore, the avoidable capacity cost was based upon the total cost of firm capacity delivered to Montana-Dakota's load centers. I have been informed that, based upon the interconnection agreement between Montana-Dakota and the proposed Java Wind Project as prescribed by the FERC, Montana-Dakota will reimburse the proposed Java Wind Project for any necessary transmission upgrades associated with the proposed Java Wind Project. In setting the avoided costs it is important to be consistent in comparing options. If the Big Stone II transmission upgrades were included in the avoidable capacity cost, then Montana-Dakota's customers would be paying twice for transmission upgrades for the proposed Java Wind Project – once in the contract capacity payments based upon Montana-Dakota's avoidable capacity costs (calculated with the Big Stone II firm transmission access upgrades included) and once in reimbursement of the actual transmission upgrades for the proposed Java Wind Project.

Q. Have you changed the cost of capital assumptions for the avoided cost calculation?

A. Yes. I have updated the cost of capital assumptions based upon Montana-Dakota's average capital structure for 2005.

Q. How have the Montana-Dakota PROSYM runs changed?

A. The PROSYM runs are used to calculate the avoided energy costs. I have retained Superior's recommended methodology of basing avoided energy cost on the difference of Montana-Dakota energy costs based upon assuming wind and no wind generation. Since the avoided capacity costs were updated to reflect more recent data, it is also appropriate to update the PROSYM runs to reflect new information related to:

- Changes to the resource plan

- Coal prices
- Natural gas prices
- Purchased and sold power prices

Q. Have you prepared updated exhibits?

A. Yes. Attached are updated versions of Exhibits EDK-3, EDK-4 and EDK-5. Exhibit No. EDK-3 covers the Avoidable Capacity Cost, Exhibit No. EDK-4 provides levelized avoidable capacity costs, and Exhibit No. EDK-5 covers stipulated avoided energy costs.

Q. Do your exhibits provide a purchase price for levelized capacity and energy from the proposed Java Wind Project based upon the updated inputs and assumptions for a range of contract terms?

A. The levelized avoidable capacity costs for contract terms of 5, 10, 15, and 20 years are covered in Exhibit No. EDK-4, and Exhibit No. EDK-5 provides the stipulated avoided energy cost.

Q. To the extent that the power purchase contract uses levelized avoidable capacity prices, capacity payments to the proposed Java Wind Project will be front-loaded. What is your opinion about the level of security deposit necessary as a result of this front-loading?

A. The amount of a security deposit is a function of the term of the contract and the pattern of payments over time. I have estimated a security deposit amount based on the maximum cumulative overpayment in the early years of a contract of various terms. This amount is for each MW of accredited MAPP capacity included in the contract and used as the basis for capacity payments.

- $646,751 per MW for a 20-year contract
- $582,469 per MW for a 15-year contract
- $451,334 per MW for a 10-year contract
- $88,798 per MW for a 5-year contract

MISO MARKETS

Q. How have the MISO markets changed since your earlier testimony?

A. The MISO Day 2 spot market became operational on April 1, 2005.

Q. Does this conclude your supplemental testimony?

A. Yes.

Exhibit No. EDK-3 (Updated on 16 Nov 05)
Avoidable capacity cost
Summary

Period	Year	Annual Avoidable Capacity Cost ($/kW/year)
2	2007	$17.70
2	2008	$17.70
2	2009	$17.70
2	2010	$17.70
3[1]	2011	$140.93
3	2012	$260.19
3	2013	$260.19
3	2014	$260.19
3	2015	$260.19
3	2016	$260.19
3	2017	$260.19
3	2018	$260.19
3	2019	$260.19
3	2020	$260.19
3	2021	$260.19
3	2022	$260.19
3	2023	$260.19
3	2024	$260.19
3	2025	$260.19
3	2026	$260.19

[1] Period 3 starts on 15 June 2011

Exhibit No. EDK-3 (Updated on 16 Nov 05)

Avoidable capacity cost

Period 2 calculations

Unit type:	NSP Capacity contract signed in 2005
Contract price ($ per kW per month)	$2.95
Contract size (MW)	85 up to 100
Term of contract (Months per year)	6 (May through October)
Term of contract	2007 to 2010 (with option to extend)

Year	NSP Contract ($/kW)	Other cost ($/kW)	Total avoidable cost ($/kW/year)
2007	$17.70	$0.00	$17.70
2008	$17.70	$0.00	$17.70
2009	$17.70	$0.00	$17.70
2010	$17.70	$0.00	$17.70

Exhibit No. EDK-3 (Updated on 16 Nov 05)
Avoidable capacity cost
Period 3 calculations

NPV of total revenue requirements ($/kW) 2011	$2,668
Annual cost ($/kW/year)	$260.19
Fixed charge rate	13.72

Capital type[2]	Percent	Average Return	Weighted return
Debt	41.13%	8.29%	3.410%
Preferred Stock	4.63%	4.61%	0.213%
Common Stock	54.24%	10.50%	5.696%
	Weighted Average Cost of Capital		9.32%

Other inputs and assumptions

Months in first year (June 15 to end)	6.5
Initial book value ($/kW)[3]	$1,706
Cost to obtain firm transmission ($/kW)	$0
AFUDC ($/kW)	$190
Salvage (% of investment)	0.00%
ITC	$0
Tax basis ($/kW)	$1,706
Depreciation base ($/kW)	$1,896
Book life (years)	35
Base year	2011
Discount rate	9.320%
Property tax rate	0.50%
Tax rate	35.00%
Inflation rate	2.15%
O&M rate	1.87%

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[2] Projected 2005 average capital structure filed in Montana gas case – Docket No. D2005.9.148

[3] Verified updated construction costs

Exhibit No. EDK-3 (Updated on 16 Nov 05)
Avoidable capacity cost
Period 3 calculations

Plant Cost $/kW (2011)		**$1,706**		**AFUDC**
Cost of Debt (pre-tax)		**8.292%**		**$189.61**
Cost of Debt (after-tax)		**5.390%**		
Month	**S-Curve %**	**CapEx**	**Cum CapEx**	**Interest Exp**
Sep-07	1.333	22.75	23	0.10
Oct-07	1.333	22.75	45	0.20
Nov-07	1.333	22.75	68	0.31
Dec-07	2.000	34.13	102	0.46
Jan-08	2.000	34.13	136	0.61
Feb-08	2.000	34.13	171	0.77
Mar-08	2.000	34.13	205	0.92
Apr-08	2.000	34.13	239	1.07
May-08	2.000	34.13	273	1.23
Jun-08	2.333	39.81	313	1.41
Jul-08	2.333	39.81	353	1.58
Aug-08	2.333	39.81	392	1.76
Sep-08	2.667	45.51	438	1.97
Oct-08	2.667	45.51	483	2.17
Nov-08	2.667	45.51	529	2.38
Dec-08	3.333	56.88	586	2.63
Jan-09	3.333	56.88	643	2.89
Feb-09	3.333	56.88	700	3.14
Mar-09	4.000	68.26	768	3.45
Apr-09	4.000	68.26	836	3.76
May-09	4.000	68.26	904	4.06
Jun-09	3.333	56.88	961	4.32
Jul-09	3.333	56.88	1,018	4.57
Aug-09	3.333	56.88	1,075	4.83
Sep-09	3.000	51.19	1,126	5.06
Oct-09	3.000	51.19	1,177	5.29
Nov-09	3.000	51.19	1,229	5.52
Dec-09	2.333	39.81	1,268	5.70
Jan-10	2.333	39.81	1,308	5.88
Feb-10	2.333	39.81	1,348	6.05
Mar-10	2.000	34.13	1,382	6.21
Apr-10	2.000	34.13	1,416	6.36
May-10	2.000	34.13	1,450	6.51
Jun-10	1.667	28.45	1,479	6.64
Jul-10	1.667	28.45	1,507	6.77
Aug-10	1.667	28.45	1,536	6.90
Sep-10	1.333	22.75	1,558	7.00
Oct-10	1.333	22.75	1,581	7.10
Nov-10	1.333	22.75	1,604	7.20
Dec-10	1.000	17.06	1,621	7.28
Jan-11	1.000	17.06	1,638	7.36
Feb-11	1.001	17.08	1,655	7.43
Mar-11	1.001	17.08	1,672	7.51
Apr-11	1.001	17.08	1,689	7.59
May-11	1.001	17.08	1,706	7.66

Exhibit No. EDK-3 (Updated on 16 Nov 05)

Avoidable capacity cost

Period 3 annual calculations

Year	Net Book Value	20yr MACRS	Net Invested	Tax Deprec	Deferred Taxes	Debt Return	Equity Return	Book Deprec	Income Taxes	Property Taxes	O&M adder	Revenue Reqm't
2011	$1,896	0.038	$1,896	$65	$13	$35	$61	$29	$21	$9	$36	$204
2012	$1,867	0.072	$1,853	$123	$26	$63	$110	$54	$36	$9	$36	$334
2013	$1,813	0.067	$1,773	$114	$23	$60	$105	$54	$36	$9	$37	$325
2014	$1,758	0.062	$1,696	$106	$20	$58	$100	$54	$37	$9	$38	$316
2015	$1,704	0.057	$1,622	$97	$17	$55	$96	$54	$38	$9	$39	$307
2016	$1,650	0.053	$1,551	$90	$15	$53	$92	$54	$38	$8	$39	$299
2017	$1,596	0.049	$1,482	$84	$12	$51	$88	$54	$38	$8	$40	$291
2018	$1,542	0.045	$1,416	$77	$10	$48	$84	$54	$38	$8	$41	$283
2019	$1,488	0.045	$1,352	$77	$10	$46	$80	$54	$36	$7	$42	$276
2020	$1,433	0.045	$1,288	$77	$10	$44	$76	$54	$34	$7	$43	$268
2021	$1,379	0.045	$1,224	$77	$10	$42	$72	$54	$32	$7	$44	$261
2022	$1,325	0.045	$1,160	$77	$10	$40	$69	$54	$30	$7	$45	$254
2023	$1,271	0.045	$1,096	$77	$10	$37	$65	$54	$28	$6	$46	$246
2024	$1,217	0.045	$1,032	$77	$10	$35	$61	$54	$26	$6	$47	$239
2025	$1,162	0.045	$968	$77	$10	$33	$57	$54	$24	$6	$48	$232
2026	$1,108	0.045	$904	$77	$10	$31	$53	$54	$22	$6	$49	$224
2027	$1,054	0.045	$840	$77	$10	$29	$50	$54	$20	$5	$50	$217
2028	$1,000	0.045	$776	$77	$10	$26	$46	$54	$18	$5	$51	$210
2029	$946	0.045	$712	$77	$10	$24	$42	$54	$16	$5	$52	$203

Exhibit No. EDK-3 (Updated on 16 Nov 05)
Avoidable capacity cost
Period 3 annual calculations

Year	Net Book Value	20yr MACRS	Net Invested	Tax Deprec	Deferred Taxes	Debt Return	Equity Return	Book Deprec	Income Taxes	Property Taxes	O&M adder	Revenue Reqm't
2030	$892	0.045	$648	$77	$10	$22	$38	$54	$14	$4	$53	$196
2031	$837	0.017	$584	$29	($7)	$20	$34	$54	$28	$4	$54	$189
2032	$783	0	$537	$0	($17)	$18	$32	$54	$37	$4	$55	$184
2033	$729	0	$499	$0	($17)	$17	$30	$54	$36	$4	$57	$180
2034	$675	0	$462	$0	($17)	$16	$27	$54	$35	$3	$58	$176
2035	$621	0	$425	$0	($17)	$15	$25	$54	$34	$3	$59	$172
2036	$567	0	$388	$0	($17)	$13	$23	$54	$32	$3	$60	$169
2037	$512	0	$351	$0	($17)	$12	$21	$54	$31	$3	$62	$165
2038	$458	0	$314	$0	($17)	$11	$19	$54	$30	$2	$63	$162
2039	$404	0	$277	$0	($17)	$9	$16	$54	$29	$2	$64	$158
2040	$350	0	$240	$0	($17)	$8	$14	$54	$28	$2	$66	$155
2041	$296	0	$203	$0	($17)	$7	$12	$54	$26	$2	$67	$152
2042	$242	0	$165	$0	($17)	$6	$10	$54	$25	$2	$69	$148
2043	$187	0	$128	$0	($17)	$4	$8	$54	$24	$2	$70	$145
2044	$133	0	$91	$0	($17)	$3	$5	$54	$23	$2	$72	$142
2045	$79	0	$54	$0	($17)	$2	$3	$54	$22	$2	$73	$139
2046	$25	0	$17	$0	($8)	$1	$1	$25	$10	$1	$34	$63
Net Present Value at 2011												$2,668

Exhibit No. EDK-4 (Updated on 16 Nov 05)
Levelized avoidable capacity costs

Discount Rate: 9.32%

	20	15	10	5
Term of PPA	**20**	**15**	**10**	**5**
Levelized payment ($/kW/year)	**$171.70**	**$158.84**	**$130.53**	**$39.90**
Levelized payment ($/kW/month)	**$14.31**	**$13.24**	**$10.88**	**$3.32**

Period	Year	Annual capacity cost	Discount factor	Present value	NPV	NPV	NPV	NPV
2	2007	$17.70	0.9564	$16.93				
2	2008	$17.70	0.8749	$15.49				
2	2009	$17.70	0.8003	$14.17				
2	2010	$17.70	0.7321	$12.96				
3[4]	2011	$140.93	0.6697	$94.38				**$153.92**
3	2012	$260.19	0.6126	$159.39				
3	2013	$260.19	0.5604	$145.80				
3	2014	$260.19	0.5126	$133.37				
3	2015	$260.19	0.4689	$122.00				
3	2016	$260.19	0.4289	$111.60			**$826.07**	
3	2017	$260.19	0.3924	$102.08				
3	2018	$260.19	0.3589	$93.38				
3	2019	$260.19	0.3283	$85.42				
3	2020	$260.19	0.3003	$78.14				
3	2021	$260.19	0.2747	$71.48		**$1,256.57**		
3	2022	$260.19	0.2513	$65.38				
3	2023	$260.19	0.2299	$59.81				
3	2024	$260.19	0.2103	$54.71				
3	2025	$260.19	0.1924	$50.05				
3	2026	$260.19	0.1760	$45.78	**$1,532.30**			

[4] Period 3 starts on 15 June 2011

Exhibit No. EDK-5 (Updated on 16 Nov 05)
Stipulated avoided energy costs

Year	Annual average ($/MWh)	Winter off-peak ($/MWh)	Winter on-peak ($/MWh)	Summer off-peak ($/MWh)	Summer on-peak ($/MWh)
2006	24.88	22.69	31.76	19.32	29.48
2007	28.31	25.97	34.12	24.23	32.51
2008	27.38	25.13	33.95	22.89	29.72
2009	30.70	29.79	37.34	24.32	32.42
2010	27.90	27.24	33.92	22.06	28.89
2011	23.69	21.87	29.56	19.26	26.55
2012	22.33	20.01	26.51	19.62	27.78
2013	20.85	19.51	25.12	17.50	23.18
2014	19.30	17.54	21.83	17.73	24.08
2015	16.60	15.19	19.12	14.97	19.95
2016	13.77	12.41	16.52	12.04	16.38
2017	19.99	17.16	23.44	18.64	26.21
2018	21.06	18.51	24.50	18.99	28.18
2019	26.58	23.53	31.46	23.42	34.53
2020	20.33	17.78	24.39	18.05	25.88
2021	19.45	16.73	23.49	17.31	25.49
2022	24.11	20.66	29.61	21.51	30.32
2023	27.04	24.12	33.09	23.23	32.56
2024	23.12	20.79	26.35	21.11	29.65
2025	27.33	23.80	32.62	24.61	34.78
2026[5]	27.33	23.80	32.62	24.61	34.78

[5] 2026 is the same as 2025 as this year was not modeled.