

**FibroShore Power Market Assessment
PJM / Delmarva Peninsula**

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Annapolis, Maryland**

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I. Introduction

In a project funded by the U.S. Department of Energy in a sub-grant to the Maryland Environmental Service, Electrotek Concepts has been contracted to perform a power market assessment of a poultry litter fired generator. This assessment will evaluate the economic feasibility of a 40-MW generator fueled by poultry litter located on the Lower Delmarva Peninsula.

First, a review of PJM markets and market rules and operations was conducted. This was to ensure that the proposed generator could operate in accordance with the current market rules and qualifications. This effort does not, however, consider or address any legal, environmental, permitting or licensing requirements required for participation in the PJM markets. Additionally, the PJM markets are continuing to evolve. Compounded with changes in system conditions (e.g. loads, generation availability, transmission congestion, market prices), these markets continue to experience price volatility. A description of the pertinent PJM markets is presented in Section II.

Next, PJM day-ahead energy prices and wheeling costs were compiled. Hourly day-ahead prices for the specific PJM bus serving the location of the proposed generator were developed for the period 1 April 1998 to 31 Dec 2000. Additionally, hourly transmission wheeling costs were compiled using PJM historical data for the period 1 Jan 1999 to 31 Dec 2000. Finally, transmission costs were also obtained from the PJM Open Access Transmission Tariff (OATT). These cost data were then used in the market evaluation. Section III describes the PJM data development.

In Section IV a series of customer energy cost analyses are detailed. Customer-specific interval load data were compiled and evaluated to determine their electricity cost in the PJM day-ahead energy and capacity markets. Four customers were evaluated, representing a range of customer types. Using these customer evaluations, an average cost of energy is developed and then used to evaluate the economics of the proposed generator.

Finally, a market assessment was conducted to estimate the costs and revenues of specific transactions for the proposed generator. Using this approach, three separate markets were considered. These are: a firm power point-to-point sale; the sale of energy in the PJM day-ahead market; and the selling of capacity in the PJM capacity credit market. The costs and revenues of a series of transactions from the proposed generator were then calculated. For each set of transactions, a 15-year monthly cost analysis was produced. The results are presented in Section V.

There are two appendices attached. Appendix A provides a summary of the day-ahead electricity price data used in the assessment. Two price sets were used, based on 1999 and 2000 hourly prices at the DPL South bus. Appendix B provides the detailed summary outputs of the market assessment analysis results, with the annual cash flows for each of the markets and scenarios evaluated.

II. Markets

In this analysis, three specific markets were evaluated. These are:

- 1 – Firm Power Point-to-Point Sale;
- 2 – PJM Capacity Credit Market;
- 3 – PJM Day-Ahead Energy Market.

Each of these is described below.

Firm Power Point-to-Point Sale

The first market considered for the proposed generation is the firm power market. This transaction is a private purchase/sale agreement between two parties, the proposed generator and a customer. In this market, additional costs are incurred for purposes of wheeling the power from the generator to the buyer. These costs are the transmission system payments to PJM for moving the power over the bulk power system.

The wheeling costs used are based on the PJM Open Access Transmission Tariff¹ (plus escalation) for the Delmarva Peninsula location of the proposed generator. In this assessment, the firm power transactions consider energy revenues, generating costs and wheeling costs.

PJM Day-Ahead Energy Market

The second market evaluated is the PJM Day-Ahead (DA) Electricity Market. The DA Energy Market is an hourly electricity market that is bid the day before the transaction occurs. The PJM DA electricity prices are both time and location dependent. For a seller of DA electricity the specific bus that would be served by this energy determines the location component of the price. For the proposed generator this would be the DPL South bus. The DPL South locational price reflects the transmission constraints in this area, which tends to be one of the more congested and higher priced locations in the PJM system.

In the market assessment, the proposed generation would be bid at a price that is equal to its variable costs of production. As such, this generation is only dispatched when the locational-based marginal price (LBMP) is greater than or equal to the variable generating costs. In Appendix A, Figures A-1 and A-2 show the hourly chronological DA energy prices for 1999 and 2000, respectively. Figures A-3 and A-4 show these same data sorted in descending order – a price duration curve – for the 500 highest price hours in 1999 and 2000.

PJM Capacity Credit Market

The last market considered in this assessment is the PJM Capacity Credit Market. The PJM Capacity Credit Market (CCM) consists of two markets, monthly and daily, for capacity in the PJM system. This market is time, though not location, variant. In this assessment, the daily CCM was used, in that it is more favorable. For the year 1999, the annual PJM CCM revenue for the daily market per MW was \$1,740; in 2000 it was \$22,341. Clearly, capacity is a growing issue.

¹ PJM Open Access Transmission Tariff, PJM Interconnection LLC, Revised 10 March 2000 (Includes FERC-Approved Revisions As Of October 23, 2000), Fifth Revised Sheet No. 84

III. Data Development

Data used in this study are primarily from PJM. These data include day-ahead energy prices, capacity credits, and transmission wheeling charges. Customer load data are also used to develop an average energy cost, which are detailed in Section IV. Additionally, data on the proposed generator are also used to evaluate its costs and dispatch routines. The PJM and customer data are detailed below.

Day-Ahead Energy Prices

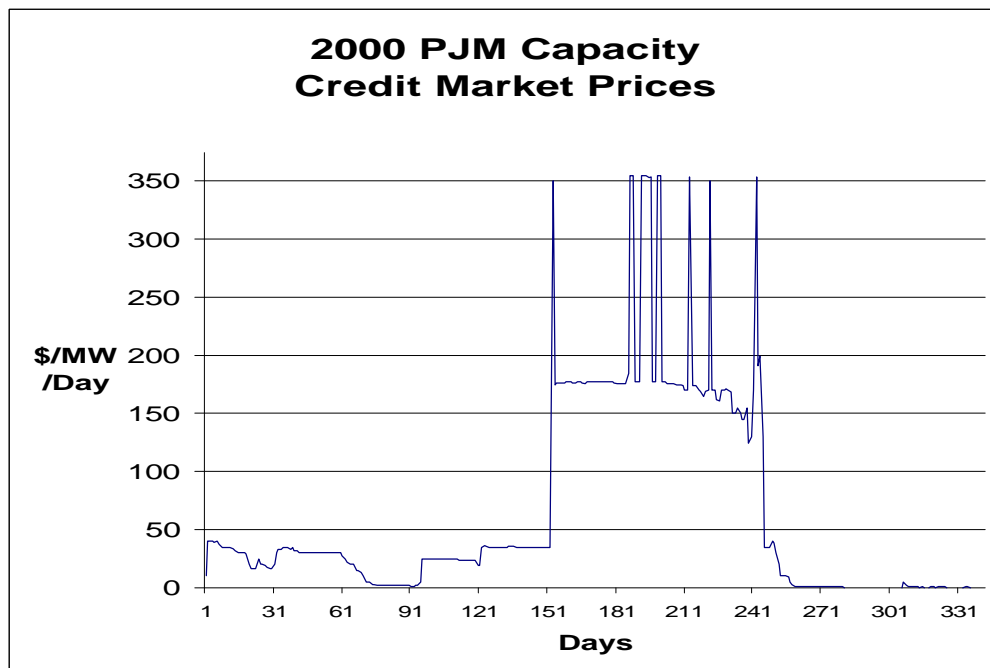
The PJM day-ahead energy prices were obtained for the calendar years 1999 and 2000. These data are both temporally and spatially variant. The PJM system accounts for energy prices at more than 70 different locations on the system. This locational diversity shows the varied conditions of the transmission system, with constraints and losses reflected in the locational prices.

The DA energy prices available from PJM include all buses (locations). Hence, the DPL South prices were extracted and compiled into annual hourly price files. The DPL South bus is the location of the proposed generator, and is characterized by heavy loading and high levels of congestion during the summer months. In general, the DPL South prices tend to be among the highest in the PJM system. Summaries of the 1999 and 2000 DPL South electricity prices are provided in Appendix A.

Capacity Credit Market

In the PJM capacity credit market, the capacity is sold (reserved) and the energy from this capacity can then be sold in other PJM markets (e.g. day-ahead electricity, ancillary services). The daily capacity credit market prices used are based on PJM historical prices for the year 2000 that are then escalated at 2% per year. These prices, which are shown in Figure 1 below, average \$65.325 per MW per day. The maximum value was \$654.60 per MW per day, occurring on 5 July 2000.

Figure 1



Wheeling Costs

For point-to-point sales, there are additional costs that need to be considered. These are the transmission costs associated with wheeling the power from the generator to the customer. There are two methods for securing transmission service in a point-to-point sale. The first is to procure fixed transmission rights (FTR), which are bought and sold in a PJM monthly market. The second way is to pay wheeling charges according to the PJM Open Access Transmission Tariff (OATT). Under this tariff, transmission service is available to all at location-based postage stamp rates. Under Schedule 7 of the PJM OATT (effective 1 June 2000) cited in Section II, the annual wheeling fee for the Delmarva Zone is \$19.378 per kW. Given the uncertainties associated with the FTR market, the OATT Schedule 7 charge is used with escalation in this assessment.

Customer Load Data

All four of the customer electricity cost analyses used customer specific interval load data. The customers were selected from a set of customers whose interval load data were provided in a State of Maryland Department of General Services solicitation². Four customers were selected based on the customer type and size. While the selected customers were not located on the Delmarva Peninsula, they represent the kinds of facilities found there (large commercial, small commercial, university, corrections facility). Profile load data provided in the solicitation were 15-minute interval, and were aggregated into hourly data sets.

² Maryland Department of General Services RFP # 001IT81194 – Generation and Transmission of Electricity, 26 September 2000. This solicitation provided “consumption data” through the DGS website (<http://www.dgs.state.md.us/procure/rfp/index.htm>) Attachment 1 a i.

IV. Customer Electricity Cost Analysis

To determine the feasibility of serving customers directly with the proposed generation, an analysis of the cost of serving four different customers was conducted. The purpose of the customer cost analysis is to determine an average energy cost for these customers for direct service from the PJM Day-Ahead Energy and Capacity Credit Markets. This cost is then used in Section V, along with federal tax credits, as a hurdle price to estimate the economic viability of the DG resource for providing firm power service to these kinds of customers.

While the specific customers selected are not located on the Delmarva Peninsula, they represent the types of customers that can be found there. Their load profiles are evaluated in the PJM DPL South market. Four customers were selected: 1) a university; 2) a large office/commercial complex; 3) a correctional facility; and 4) a small office/commercial complex. Each of these customers is profiled below.

Customer 1 - University -- The first customer evaluated is a university, in this case the University of Maryland at Baltimore³. Profile load data for this customer covered the period from 1 May 1999 to 1 June 1999, and 30 June 1999 through May 2000. Essentially, it is the period May 1999 through June 2000 excluding June 1999. Table 1 provides a summary of customer energy consumption, load and the cost for serving that load in the PJM Day-Ahead and Capacity Credit Markets for the years 1999 and 2000.

The customer is fairly large, with a maximum hourly peak demand of 8.3 MW in 1999 and 7.7 MW in 2000. The monthly peaks reflect the seasonal nature of the load, with air conditioning driving up both peak demands and electricity consumption during the summer months. Winter, spring and fall seasons show demand values of 5 to 6 MW, more indicative of the other types of end use loads found at a university, such as lighting and computers.

The energy consumption figures reflect the demand values. They are seasonal in nature, with the highest energy consumption occurring in the summer months. During the summer season, maximum monthly electricity consumption was nearly 4,900 MWh in 1999 (July), and over 4,000 MWh in 2000 (May), although data for the year 2000 ended in May. The more typical monthly electricity consumption was 3000-3500 MWh.

The energy cost for this university is calculated using the actual PJM day-ahead hourly prices and the PJM daily capacity prices for the corresponding hours at the DPL South bus for the years 1999 and 2000 for all hours the data could provide. Excluding the summer months, the total monthly electricity cost is generally about \$100,000 per month. The two highest cost months in this analysis, July 1999 and May 2000 were over \$500,000 and \$200,000, respectively. The average total energy cost was \$39.40/MWh in 1999 and \$34.48/MWh in 2000. Again, however, there is significant volatility in July 1999 and May 2000, with average total monthly costs of \$101.50/MWh and \$51.73/MWh respectively.

³ Maryland Department of General Services RFP # 001IT81194 – Generation and Transmission of Electricity, 26 September 2000. <http://www.dgs.state.md.us/procure/rfp/index.htm> Attachment 1 a I, MD-DGS GROUP1-BGE INTERVAL DATA, Account Number 1851680013

Table 1 – University Cost Analysis

1999	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Total Energy (MWh)	0	0	0	0	3,786	155	5,039	4,703	4,207	3,392	3,276	3,176	27,735
Hourly Peak (MW)	0.00	0.0	0.0	0.0	6.8	7.1	8.3	8.2	8.2	7.1	6.3	5.5	8.3
Peak Hourly Price (\$/MWh)	61.52	47.47	64.04	56.66	69.68	850.00	999.00	955.58	85.92	70.68	80.10	88.10	999.00
Capacity Cost (\$)					38	4,506	306	706	437	902	913	416	8,225
Energy Cost (\$)	0	0	0	0	87,190	2,808	511,148	183,856	99,290	72,001	61,204	66,979	1,084,477
Avg. Cost (\$/MWh)					23.04	47.04	101.50	39.24	23.71	21.49	18.96	21.22	39.40

2000	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Total Energy (MWh)	3,196	2,899	3,254	3,279	4,039	0	0	0	0	0	0	0	16,668
Hourly Peak (MW)	5.55	5.6	6.2	6.0	7.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.7
Peak Hourly Price (\$/MWh)	159.30	149.27	95.28	104.70	483.30	999.00	149.49	140.00	79.95	80.00	0.00	0.00	999.00
Capacity Cost (\$)	4,752	5,065	1,464	3,823	8,420								23,524
Energy Cost (\$)	108,538	76,230	76,083	89,879	200,522	0	0	0	0	0	0	0	551,253
Avg. Cost (\$/MWh)	35.45	28.04	23.83	28.58	51.73								34.48

Customer 2 – Large Commercial -- The second customer evaluated is the State of Maryland Stadium Authority.⁴ Interval load data were available for the period 1 September 1999 through 31 August 2000. Table 2 provides a monthly summary of the energy, peak demand, and energy cost.

This customer is fairly large, with hourly peaks of over 9 MW in 1999 and over 8 MW in 2000. There were 3 months during which hourly peaks exceeded 8 MW (September and October 1999, and May 2000). Excluding the peak months, monthly peaks were more typically 5-6 MW.

The monthly energy consumption tended to track peak demand with the exception of May 2000, reflecting a short-term peak typically weather-associated and driven by air conditioning loads. Very high temperatures characterized May 2000 early in the month, which would explain the variance in the monthly capacity factor seen. Average monthly electricity consumption was 3,000 MWh in 1999 and 3,350 MWh in 2000.

Electricity costs for the evaluation period exceeded \$250,000 for the last 4 months in 1999 and \$1 million for the first eight months of 2000. There were four months when the monthly electricity cost exceeded \$150,000. The average total monthly electricity cost in 1999 was \$20.85 per MWh, while in 2000 it was \$38.67 per MWh. The highest average monthly energy costs was over \$50 per MWh in May and June 2000.

⁴op cit, MD-DGS GROUP7-BGE INTERVAL DATA, Account Number 9108109547

Table 2 – Large Commercial Cost Analysis

1999	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Total Energy (MWh)	0	0	0	0	0	0	0	0	3,950	3,207	2,419	2,556	12,132
Hourly Peak (MW)	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	9.4	8.6	5.3	5.9	9.4
Peak Hourly Price (\$/MWh)	61.52	47.47	64.04	56.66	69.68	850.00	999.00	955.58	85.92	70.68	80.10	88.10	999.00
Capacity Cost (\$)									503	1,095	765	447	2,810
Energy Cost (\$)	0	0	0	0	0	0	0	0	90,123	67,879	41,534	50,539	250,075
Avg. Cost (\$/MWh)									22.94	21.51	17.49	19.95	20.85

2000	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Total Energy (MWh)	3,620	3,115	3,182	3,041	3,177	3,289	3,515	3,859	0	0	0	0	26,796
Hourly Peak (MW)	5.88	5.6	5.4	6.0	8.2	6.0	6.2	7.1	0.0	0.0	0.0	0.0	8.2
Peak Hourly Price (\$/MWh)	159.30	149.27	95.28	104.70	483.30	999.00	149.49	140.00	79.95	80.00	0.00	0.00	999.00
Capacity Cost (\$)	5,035	5,020	1,276	3,777	8,917	32,955	44,952	38,794					140,726
Energy Cost (\$)	126,715	83,706	74,238	84,550	152,385	133,848	108,067	131,962	0	0	0	0	895,470
Avg. Cost (\$/MWh)	36.40	28.48	23.73	29.05	50.78	50.72	43.54	44.25					38.67

Customer 3 – Small Commercial -- The third customer is listed as the State of Maryland General Services.⁵ For this account, interval load data were available for the periods 1-19 May 1999; 21 June through 19 November 1999; 21-31 December 1999; and 1 January through 19 May 2001. Table 3 summarizes the energy and cost characteristics of this customer.

While the specific facility is unknown, its load profile is characteristic of an office or commercial complex, characterized by a typical commercial load shape with activity during business hours and seasonal behavior. This customer had a maximum monthly peak demand of 2.1 MW in 1999, which increased to 2.4 MW in 2000.

Electricity consumption again reflected seasonal variation with heating and cooling loads. In 1999 average monthly electricity consumption was about 700 MWh. Maximum monthly electricity consumption in July and August were each over 900 MWh. For 2000 period, average monthly electricity consumption was about 660 MWh, with a maximum of 868 MWh in January.

Calculated monthly electricity costs were typically under \$30,000. The exceptions were July and August 1999, and January 2000. The January 2000 total electricity cost was \$36,000; August 1999 was \$39,000; and July 1999 was over \$116,000. The average electricity cost was \$50.23 per MWh in 1999 and \$37.62 per MWh in 2000 for the evaluation periods.

⁵ *op cit*, MD-DGS GROUP6-BGE INTERVAL DATA, Account Number 8637447313

Table 3 – Small Commercial Cost Analysis

1999	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Total Energy (MWh)	0	0	0	0	353	275	939	906	729	513	350	251	4,315
Hourly Peak (MW)	0.00	0.0	0.0	0.0	1.8	2.1	2.1	2.0	2.1	1.8	1.8	2.0	2.1
Peak Hourly Price (\$/MWh)	61.52	47.47	64.04	56.66	69.68	850.00	999.00	955.58	85.92	70.68	80.10	88.10	999.00
Capacity Cost (\$)					10	1,318	77	175	110	225	254	153	2,323
Energy Cost (\$)	0	0	0	0	9,154	7,432	116,204	39,064	18,617	11,541	7,757	4,684	214,453
Avg. Cost (\$/MWh)					25.97	31.87	123.80	43.31	25.70	22.95	22.86	19.28	50.23

2000	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Total Energy (MWh)	868	632	570	507	454	0	0	0	0	0	0	0	3,031
Hourly Peak (MW)	2.41	2.0	1.6	1.5	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4
Peak Hourly Price (\$/MWh)	159.30	149.27	95.28	104.70	483.30	999.00	149.49	140.00	79.95	80.00	0.00	0.00	999.00
Capacity Cost (\$)	2,066	1,809	390	939	1,753								6,958
Energy Cost (\$)	33,964	18,343	14,492	15,284	24,981	0	0	0	0	0	0	0	107,064
Avg. Cost (\$/MWh)	41.50	31.87	26.13	32.01	58.89								37.62

Customer 4 – Corrections Facility

The final customer evaluated was listed in the DGS solicitation as the State of Maryland Corrections Department.⁶ The interval data set provided covered the periods May 1999 through May 2000. Table 4 shows a summary of the electricity consumption, peak loads, and energy cost by month.

The monthly peak demand (hourly) for this customer was typically at 6 MW or below, with the exception of the summer months, where demand exceeded 8 MW. The 1999 peak was 9.4 MW in September; the 2000 peak was 8.2 MW in May. Electricity consumption was typically around 3,000 MWh per month, although in September 1999 and August 2000 energy consumption approached 4,000 MWh per month.

The electricity cost of this facility was generally below \$35,000 per month with the exception of July 1999, which was nearly \$74,000. The average monthly electricity cost in 1999 was slightly above \$25,000, while in 2000 it was about \$22,800. The average price of energy for this customer in 1999 was \$37.27 per MWh; in 2000 it was \$33.51 per MWh.

⁶ *op cit*, MD-DGS GROUP1-BGE INTERVAL DATA, Account Number 0371329065

Table 4 – Correctional Facility Cost Analysis

1999	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Total Energy (MWh)	0	0	0	0	615	654	726	718	640	650	670	731	5,403
Hourly Peak (MW)	0.00	0.0	0.0	0.0	1.1	1.2	1.3	1.2	1.2	1.1	1.2	1.2	1.3
Peak Hourly Price (\$/MWh)	61.52	47.47	64.04	56.66	69.68	850.00	999.00	955.58	85.92	70.68	80.10	88.10	999.00
Capacity Cost (\$)					6	777	46	107	63	141	169	90	1,399
Energy Cost (\$)	0	0	0	0	14,172	26,980	73,834	27,892	15,025	13,803	12,745	15,513	199,964
Avg. Cost (\$/MWh)					23.07	42.47	101.76	39.00	23.57	21.45	19.28	21.34	37.27

2000	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Total Energy (MWh)	752	691	687	629	642	0	0	0	0	0	0	0	3,401
Hourly Peak (MW)	1.27	1.3	1.2	1.1	1.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
Peak Hourly Price (\$/MWh)	159.30	149.27	95.28	104.70	483.30	999.00	149.49	140.00	79.95	80.00	0.00	0.00	999.00
Capacity Cost (\$)	1,089	1,140	277	705	1,263								4,473
Energy Cost (\$)	26,067	18,569	16,229	17,346	31,293	0	0	0	0	0	0	0	109,504
Avg. Cost (\$/MWh)	36.12	28.51	24.02	28.72	50.68								33.51

Customer Analysis Summary

Using the customer energy cost data above, an average cost of energy is developed for the DPL South location. This average cost is then used as a market price for the energy produced by the proposed generator. For the four customers considered above, the average cost of energy is about \$36.50 per MWh. This is the target price the proposed generator would accept in order to secure the firm power sale, and is used in evaluating the economics of the poultry litter-fired generation. From the generator’s perspective, with the availability of a federal tax credit in Year 1 of \$17.00 per MWh, the transaction would net the generator \$53.50/MWh (\$36.50 per MWh for the energy sale plus the tax credit of \$17.00 per MWh). In Years 2-15, when only the Maryland tax credit of \$8.50 is available, the generator would yield \$45.00 per MWh.

V. Assessment Methodology

The market assessment evaluated the costs and revenues associated with the operation of the proposed generator under two operating schedules and two day-ahead price schedules. The first operating schedule is to commit the plant fully to a firm fixed price point-to-point sale. The second operating schedule has half of the capacity committed to a point-to-point sale, and the other 20 MW committed to the PJM Capacity Credit Market and Day-Ahead Electricity Market. In all operating scenarios, the revenue realized in the firm power contracts is equal to \$36.50 per MWh, the market price. Additionally, there is a federal tax credit of \$17.00 per MWh that is accounted for separately.

The operating schedule for the day-ahead market uses two hourly day-ahead price profiles. The first price profile uses the PJM year 2000 day-ahead prices with annual escalation of 2%; the second uses the PJM 1999 day-ahead prices again with 2% per year escalation. The 1999 prices are considered to be higher than usual, while 2000 prices were generally not as extreme. The year 2000 prices, however, averaged \$32.82/MWh while in 1999 the average price was \$29.24/MWh. The CCM is calculated based on the PJM Year 2000 values, escalated at an annual rate of 2%.

In evaluating the proposed 40 MW generator, a series of 15-year cash flow analyses were developed with the generator output sold in the markets described above. The firm power sale is a set amount of capacity and energy provided at a fixed price. The firm power contract revenue is \$36.50/MWh. This energy price is escalated at 2% per year. Also to be calculated in this firm power point-to-point sale is the wheeling cost, the cost of delivering this power over the high voltage system. The yearly wheeling cost is \$19.378 per kW, based on the PJM tariff prices, and was escalated at 2% per annum. The wheeling cost is to be paid by the customer, and is not included in the total cost figure.

The proposed generator is a 40 MW unit designed to operate as a baseload plant. A general characterization of the plant is one that has a high capital (\$2600/kW) and fixed O&M (\$13.68 per kW-Month) costs. It has a low variable operating cost (\$20.65/MWh) due to its low fuel cost. In the analysis, fixed O&M costs are escalated at 2% per annum, while fuel and variable O&M escalate at 1% per year. The plant has assumed capacity factor of 82% in its first year of operation, and 91% thereafter. These capacity factors are accounted for by a 2-month outage in Year 1, and 1-month outages in Years 2 through 15. Maintenance outages are scheduled in March and April of Year 1, and in April thereafter.

A final note regarding the availability of renewable energy tax credits for this generation. The proposed generator qualifies for a federal tax credit of 1.7¢ per kWh or a Maryland tax credit of 0.85¢ per kWh as a renewable resource. The federal tax credit is scheduled to expire at the end of 2001. These tax credits are significant. In Year 1, federal tax credits can total over \$4.9 million with full dispatch of the generator in the firm power market. In Years 2-15, upon expiration of the federal tax credit, the Maryland tax credit yields over \$2.7 million per year.

V. Results

In evaluating the economic viability of the proposed generator, two factors define each scenario. The first factor is the operating schedule, of which there are two. The first operating schedule is a fixed price firm power contract for all 40 MW of the generation. The second operating schedule is a split of 20 MW in firm power sales, and 20 MW in the PJM Capacity Credit Market and Day-Ahead Energy Markets. The second factor is the day-ahead price profile used, the 1999 or 2000 day-ahead prices, and applies only to those cases when there are sales to the PJM markets.

This market assessment has been confined to the operating costs and revenues for the proposed generator. No consideration is given to the plant capital costs or to capital cost recovery. As can be seen in the detailed annual cash flows (Appendix B), the project does not have positive cash flows. In fact, it is only through federal and state tax credits that the project is able to make money. Total tax credits were over \$43 million over the 15 year planning horizon in the 40 MW firm power operating schedule; and over \$32 million in the 20 MW firm power operating schedule.

Table 5 presents the total net present value for the costs and revenues of each operating schedule using the 1999 and 2000 day-ahead price profiles. These are based on a 15-year analysis using a discount rate of 12%. In the FP 40 operating schedule, all of the proposed generator's production is committed to a point-to-point sale at \$36.50 per MWh. All revenue in the FP 40 operating schedule is exclusively from a firm price contract, while the FP 20 operating schedule has 20 MW in a firm price contract and 20 MW available in the PJM day ahead and capacity credit markets.

Table 5
Project Summary
Net Present Values

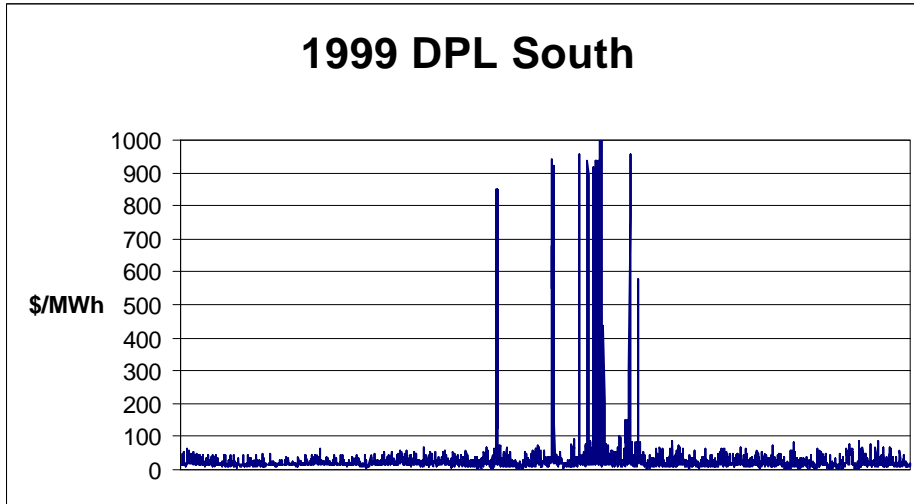
		Total Revenues	Total Costs	Tax Credits
Operating Schedule - FP 40 MW		98,057	108,122	20,607
Operating Schedule - FP 20 MW	1999 DA Prices	80,113	120,642	16,939
Operating Schedule - FP 20 MW	2000 DA Prices	87,075	125,172	19,056

The project results show that from a cash flow perspective, absent capital cost, the proposed generator is not economically viable, with costs exceeding revenues in all scenarios. However, when state and federal tax credits are considered, the balance becomes favorable only for the firm power sales. With the generating plant's substantial fixed costs, operating in the day-ahead market is not practical. Even at the low operating cost, the unit does not operate a sufficient number of hours to be profitable. Even with tax credits, the generator is not profitable when dispatched in day-ahead markets.

Appendix A

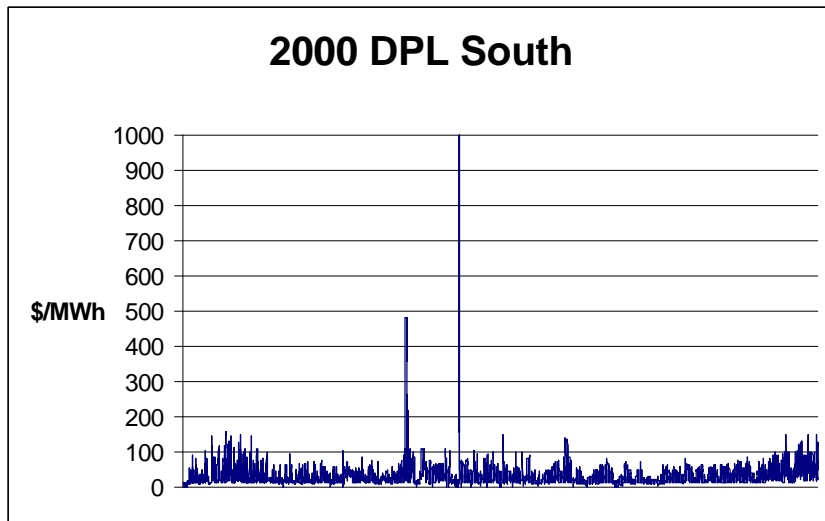
PJM Price Data

Figure A-1
1999 DPL South Chronological Prices



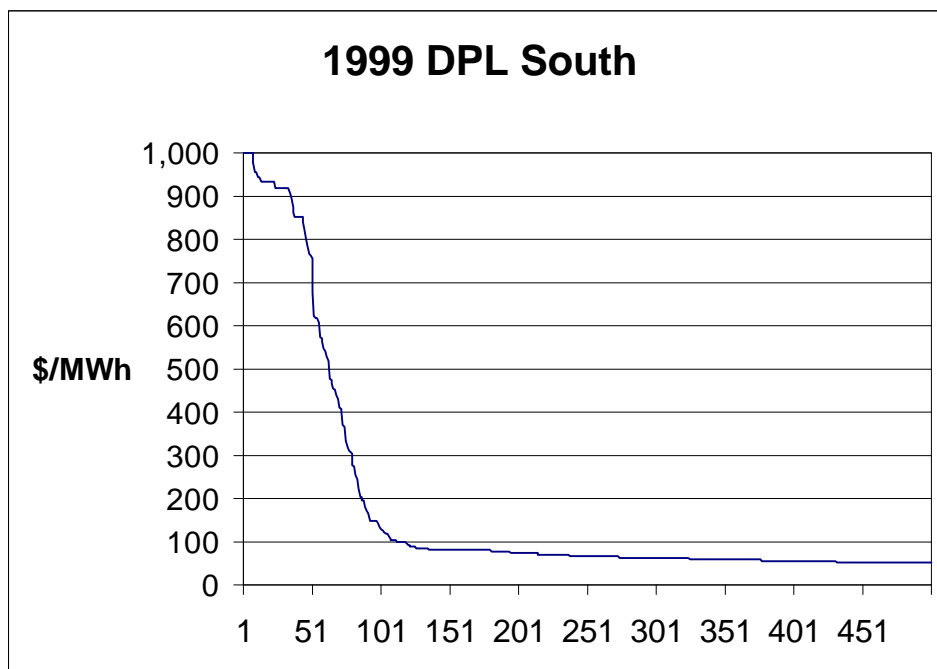
In Figure 1, a graph of the day-ahead hourly energy prices for the DPL South bus in the PJM system is presented for the calendar year 1999. These prices were obtained from the PJM web site and used in the market assessment.

Figure A-2
2000 DPL South Chronological Prices



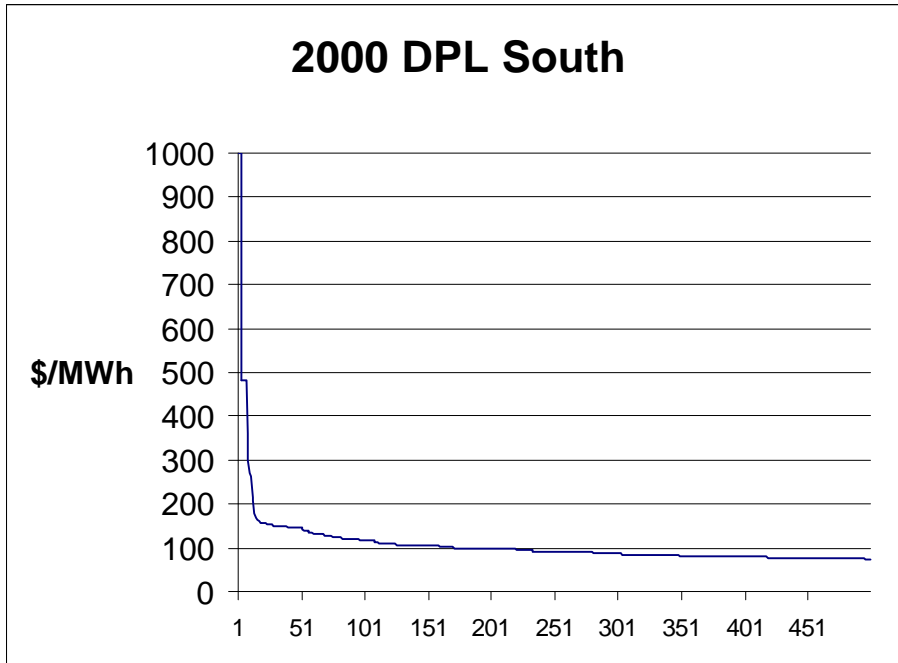
In Figure 2, a graph of the day-ahead hourly energy prices for the DPL South bus in the PJM system is presented for the calendar year 2000. These prices were obtained from the PJM web site and used in the market assessment.

Figure A-3
1999 DPL South Price Duration Curve



In Figure 3 above, a price duration curve of the day-ahead hourly energy prices for the DPL South bus in the PJM system is presented for the calendar year 1999. This curve shows the 1999 prices sorted in descending order for the 500 highest price hours.

Figure A-4
2000 DPL South Price Duration Curve



In this figure, a price duration curve of the day-ahead hourly energy prices for the DPL South bus in the PJM system is presented for the calendar year 2000. This curve shows the 2000 prices sorted in descending order for the 500 highest price hours.

Appendix B

Annual Cash Flows

Appendix B presents the annual cash flow analyses of each of the operating scenarios (40 MW Firm Power and 20 MW Firm Power / 20 Day-Ahead and Capacity Credit). In these tables, the annual results are presented for all 15 years. All dollar values are undiscounted. The tables offer a breakdown of revenue by transaction, variable generating costs, fixed O&M costs, total cost and revenue, total generation, total state/federal tax credits, and total day-ahead operating hours (the number of hours the day-ahead hourly price was greater than the generating cost). These values were used to develop the summary data found in Section IV.

The table names designate the specific scenario. The title consists of three separate fields: the amount of capacity committed to the firm power market; the firm power price; and the base year for the day ahead electricity prices. Under this convention, the table designated FP20-85-00 is for a firm power contract of 20 MW at a price of \$85/MWh with the day-ahead prices based upon the year 2000. There are a total of tables for each of the following scenarios:

- Table B-1 - Firm Power Contract for 40 MW at a price of \$36.50/MWh
- Table B-2 - Firm Power Contract for 20 MW at a price of \$36.50/MWh with 20 MW sold in the PJM Day-Ahead Electricity and Capacity Credit Markets using 1999 day-ahead energy prices for the base year
- Table B-3 - Firm Power Contract for 20 MW at a price of \$36.50/MWh with 20 MW sold in the PJM Day-Ahead Electricity and Capacity Credit Markets using 2000 day-ahead prices for the base year.

Table B-1
FP40 - 36

Year	Firm Power Rev	Day-Ahead Rev	CCM Rev	Generation Cost	Wheeling	Fixed O&M	Total Cost	Total Rev	DA_Hrs	Tax Credit	Tot Gen (MWh)
1	9,158,880	0	0	6,026,496	775,120	6,566,400	12,592,896	9,158,880	3,379	4,961,280	291,840
2	11,224,080	0	0	6,707,450	790,622	6,697,728	13,405,178	11,224,080	3,436	2,733,600	321,600
3	11,448,562	0	0	6,774,525	806,435	6,831,683	13,606,207	11,448,562	3,487	2,733,600	321,600
4	11,677,533	0	0	6,842,270	822,564	6,968,316	13,810,586	11,677,533	3,561	2,733,600	321,600
5	11,911,083	0	0	6,910,693	839,015	7,107,683	14,018,375	11,911,083	3,631	2,733,600	321,600
6	12,149,305	0	0	6,979,800	855,795	7,249,836	14,229,636	12,149,305	3,714	2,733,600	321,600
7	12,392,291	0	0	7,049,598	872,911	7,394,833	14,444,431	12,392,291	3,775	2,733,600	321,600
8	12,640,137	0	0	7,120,094	890,369	7,542,730	14,662,823	12,640,137	3,848	2,733,600	321,600
9	12,892,940	0	0	7,191,295	908,177	7,693,584	14,884,879	12,892,940	3,923	2,733,600	321,600
10	13,150,799	0	0	7,263,208	926,340	7,847,456	15,110,663	13,150,799	4,033	2,733,600	321,600
11	13,413,815	0	0	7,335,840	944,867	8,004,405	15,340,245	13,413,815	4,099	2,733,600	321,600
12	13,682,091	0	0	7,409,198	963,764	8,164,493	15,573,691	13,682,091	4,187	2,733,600	321,600
13	13,955,733	0	0	7,483,290	983,040	8,327,783	15,811,073	13,955,733	4,254	2,733,600	321,600
14	14,234,847	0	0	7,558,123	1,002,700	8,494,339	16,052,462	14,234,847	4,339	2,733,600	321,600
15	14,519,544	0	0	7,633,704	1,022,754	8,664,225	16,297,930	14,519,544	4,419	2,733,600	321,600
Firm Power MW:	40	DA_MW: 0		Cap_MW: 0							
Firm Power Price (\$/MWh):	36.50	2000									

Table B-2
FP20 – 36 - 99

Year	Firm Power Rev	Day-Ahead Rev	CCM Rev	Gen Cost	Wheeling	Fixed O&M	Total Cost	Total Rev	DA_Hrs	Tax Credit	Tot Gen (MWh)
1	5,028,447	3,226,040	429,443	4,193,602	387,560	9,849,600	14,043,202	8,683,930	3,379	3,629,500	213,500
2	5,797,573	3,428,671	442,860	4,652,668	395,311	10,046,592	14,699,260	9,669,104	3,436	1,950,920	229,520
3	5,910,985	3,516,299	451,717	4,718,153	403,217	10,247,524	14,965,677	9,879,001	3,487	1,959,590	230,540
4	6,024,931	3,613,998	460,752	4,792,568	411,282	10,452,474	15,245,042	10,099,680	3,561	1,972,170	232,020
5	6,140,681	3,711,756	469,967	4,865,850	419,507	10,661,524	15,527,374	10,322,404	3,631	1,984,070	233,420
6	6,262,190	3,820,867	479,366	4,949,234	427,898	10,874,754	15,823,988	10,562,423	3,714	1,998,180	235,080
7	6,384,787	3,921,517	488,953	5,022,838	436,456	11,092,249	16,115,088	10,795,258	3,775	2,008,550	236,300
8	6,508,468	4,028,423	498,732	5,101,405	445,185	11,314,094	16,415,500	11,035,623	3,848	2,020,960	237,760
9	6,636,385	4,140,455	508,707	5,183,725	454,088	11,540,376	16,724,101	11,285,547	3,923	2,033,710	239,260
10	6,767,302	4,271,410	518,881	5,283,442	463,170	11,771,184	17,054,625	11,557,593	4,033	2,052,410	241,460
11	6,901,728	4,386,176	529,259	5,365,473	472,433	12,006,607	17,372,081	11,817,164	4,099	2,063,630	242,780
12	7,037,911	4,512,784	539,844	5,457,833	481,882	12,246,740	17,704,572	12,090,539	4,187	2,078,590	244,540
13	7,174,462	4,630,163	550,641	5,539,403	491,520	12,491,674	18,031,077	12,355,266	4,254	2,089,980	245,880
14	7,314,178	4,759,136	561,654	5,630,990	501,350	12,741,508	18,372,498	12,634,967	4,339	2,104,430	247,580
15	7,456,644	4,888,635	572,887	5,721,480	511,377	12,996,338	18,717,818	12,918,166	4,419	2,118,030	249,180
Firm Power MW:	20	DA_MW:20		Cap_MW:20							
Firm Power Price (\$/MWh):	36.5		1999								

Table B-3
FP20 – 36 - 00

Year	Firm Power Rev	DA Rev	CCM Rev	Gen Cost	Wheeling	Fixed O&M	Total Cost	Total Rev	DA_Hrs	Tax Credit	Tot Gen (MWh)
1	4,841,697	4,087,565	429,443	4,739,588	387,560	9,849,600	14,589,188	9,358,705	4,851	4,129,980	242,940
2	5,696,504	4,398,013	442,860	5,237,901	395,311	10,046,592	15,284,493	10,537,376	4,910	2,201,500	259,000
3	5,809,164	4,504,184	451,717	5,308,396	403,217	10,247,524	15,555,920	10,765,066	4,956	2,209,320	259,920
4	5,924,490	4,614,364	460,752	5,381,480	411,282	10,452,474	15,833,954	10,999,605	5,005	2,217,650	260,900
5	6,041,683	4,759,835	469,967	5,488,156	419,507	10,661,524	16,149,680	11,271,485	5,131	2,239,070	263,420
6	6,160,340	4,872,057	479,366	5,559,966	427,898	10,874,754	16,434,720	11,511,764	5,175	2,246,550	264,300
7	6,279,580	4,986,678	488,953	5,632,664	436,456	11,092,249	16,724,913	11,755,212	5,223	2,254,710	265,260
8	6,404,282	5,104,206	498,732	5,706,702	445,185	11,314,094	17,020,796	12,007,220	5,265	2,261,850	266,100
9	6,531,469	5,221,565	508,707	5,778,975	454,088	11,540,376	17,319,351	12,261,741	5,301	2,267,970	266,820
10	6,658,016	5,375,916	518,881	5,886,450	463,170	11,771,184	17,657,634	12,552,813	5,420	2,288,200	269,200
11	6,787,510	5,504,992	529,259	5,966,757	472,433	12,006,607	17,973,364	12,821,760	5,475	2,297,550	270,300
12	6,919,561	5,649,341	539,844	6,060,521	481,882	12,246,740	18,307,261	13,108,746	5,557	2,311,490	271,940
13	7,054,212	5,792,714	550,641	6,151,376	491,520	12,491,674	18,643,051	13,397,567	5,630	2,323,900	273,400
14	7,192,460	5,932,662	561,654	6,236,862	501,350	12,741,508	18,978,369	13,686,776	5,687	2,333,590	274,540
15	7,332,967	6,088,448	572,887	6,336,259	511,377	12,996,338	19,332,597	13,994,301	5,772	2,348,040	276,240
Firm Power MW:	20	DA_MW:	20	Cap_MW:	20						
Firm Power Price (\$/MWh):	36.5		2000								