MEMORANDUM

April 3, 2012

TO: Bob Erwin
Maryland Public Service Commission

FROM: Craig R. Roach, Ph.D.
Frank Mossburg
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SUBJECT: Boston Pacific's Final Shortlist Evaluation

BACKGROUND

The purpose of this memo is to provide a summary of Boston Pacific's Final Shortlist evaluation of proposals submitted in response to the Maryland Commission's RFP for Generation Capacity Resources under Long-Term Contract (the RFP). We recommend that, should the Commission wish to go forward with a final contract, only the CPV proposal be selected. We make this recommendation for the following reasons; a) the CPV bid is the cheapest bid for customers, with a net payment to ratepayers forecast over several scenarios, b) while the CPV bid is acceptable and priced in line with market conditions, if we were to take multiple units we would prefer to have a larger pool of bids, with more time for bidders to sharpen their offers, c) accepting only one offer limits the risk for ratepayers should payments under these contracts be higher than expected, d) continued slow growth means that there is less of an urgent reliability need for the 2015/2016 time frame, and e) we have yet to see what legal challenges will result from this contract.

OVERVIEW OF PROPOSALS EVALUATED

As detailed in our memo on February 24, 2012, we received proposals from three bidders, which met the minimum threshold requirements laid out in the RFP. Two of the proposals contained multiple pricing options. After conducting our Initial Shortlist evaluation as laid out in the RFP, we selected the following bids and bid options to be evaluated for the final shortlist.

- Invenergy's 549-MW combined-cycle facility located in Aquasco in Prince George's County, Maryland. Invenergy submitted only one pricing option, a 20-year contract for differences with a COD of June 1, 2017.
- Mattawoman's 731-MW combined-cycle facility located in Brandywine, Prince George's County, Maryland with a commercial operation date of June 1, 2016.

Mattawoman offered several pricing options; we selected its 10-year contract using the Dominion South gas pricing point for further evaluation.

- CPV's 661-MW combined-cycle facility in Waldorf in Charles County, Maryland. CPV submitted two pricing proposals, each with a 20-year term and differing by online date, either June 1, 2015 or June 1, 2016. We selected both proposals for further evaluation.

FINAL SHORTLIST EVALUATION METHODOLOGY

The RFP described the final shortlist evaluation as follows:

> "The bids on the Initial Shortlist will move on to the Final Shortlist Analysis. Each bid will be modeled in a production cost model to determine their cost to ratepayers throughout the term of the contract. The cost of each bid will be assessed based on changes in key risk factors such as natural gas prices, environmental or other compliance costs, and load. The bid(s) that produces the lowest-cost solution for ratepayers when accounting for risk will be the [sic] selected to the Final Shortlist. The Commission may the direct the Maryland EDCs to finalize contracts with one or more entities from the Final Shortlist."

Consistent with this language, we evaluated each of the four pricing proposals using production cost modeling. The purpose of this effort was to generate better information regarding two important risk factors; (a) how often each bid would run in the PJM energy market and, (b) how much revenue each bid would earn from that market. The latter factor is most important, since under the CfD, any shortfall in revenue must be paid for by RPM capacity market revenues or ratepayers.

The modeling was conducted under Boston Pacific's direction by Siemens Power Technologies International (Siemens), using the PROMOD IV market simulation model. Siemens simulated operation for the entire Eastern Interconnect through the year 2024 to determine a series of locational marginal prices (LMPs) in the Southwestern MAAC energy market. For each hour, Siemens then compared the LMP to a bid's operating cost. If the LMP was higher than the operating cost, the bid was deemed to operate and to be paid the LMP. If the LMP was lower than the bid's operating cost, it did not operate. This exercise generated an annual estimate of revenues earned by the bids as well as hours operated.

Siemens used the latest "base case" inputs supplied by Ventyx (the makers of PROMOD). The only major change to these inputs in our base case was that the operating lives of several older units (primarily combined-cycle units) were manually extended through the end of the simulation period. Without this extension PROMOD had been automatically retiring the units once they reached a certain age, an action which caused capacity shortages and unrealistic prices.

Boston Pacific took the expected annual energy market revenues and dispatch quantities provided by Siemens and entered them back into our annuitized cost models used for the Initial Shortlist evaluation. This gave us, for each year, a forecast of total costs and revenues recovered from the energy market[1]. Subtracting these revenues from costs gave us a forecast of the total costs

[1] From 2025 through the end of each CfD we assumed the same MWh output as in 2024 and that revenue would continue to grow at CPI (around 2%).

over the life of the contract that would have to be recovered from the RPM capacity market or ratepayers.

We also looked at four sensitivities. The first two were a high and low gas price case, each representing a $1/MMBtu addition or subtraction from the base case. The third was a "PJM Net Revenue" case in which we assumed the bids would earn the same net revenues (i.e. market revenues less variable costs) that PJM estimates in calculating its Minimum Offer Price Rule (MOPR) screen. We did this because we noticed that PJM's estimates of net revenue were much lower than our models were predicting and we wanted to test the effect of receiving lower than-predicted revenues on the costs of the bids.

The fourth sensitivity was a "coal retirement" case. For this latter case, we increased forecast retirements to include units which were not already forecasted to retire and had either (a) announced plans to retire or (b) been identified as retirement candidates in a December 2011 AP survey of generation owners[2]. For this final scenario, retired coal units were replaced in the model with new natural gas-fired units. This was done because otherwise the model would face potential capacity deficits, again, producing unrealistic results.

Finally, an additional base case run was created in which each bid option was inserted into the dispatch stack and dispatched along with other units. This was done in order to get a more accurate picture of the revenues earned by the unit. This dispatch was more accurate because it (a) accounted for the fact that these new units would lower the energy market price and (b) accounted for the operating constraints of each unit.

RESULTS OF FINAL SHORTLIST ASSESSMENT

We looked at the cost of bids in three ways. First, we calculated the annuitized cost per MW-day over the life of the contract. This gives a sense of the cost to bring on each MW of capacity. Second, we looked at the net present value of the forecast payments under the CfD. This latter metric gives a better picture of the total amount of money that would have to be recovered from ratepayers and the RPM capacity market. The results of our base case are featured in Table One below.

TABLE ONE
BASE CASE RESULTS

	CPV 15	**CPV 16**	**Invenergy**	**MattaWoman**
Annuitized Payment ($/MW-day)	$93	$108	$135	$326
NPV of Total Cost ($000)	$227,484	$250,015	$247,107	$566,914
NPV of Total Cost ($000/MW)	$344	$378	$450	$776

As we can see from Table One, CPV had the least expensive bid, with Invenergy next and Mattawoman third. This is true both for the annuitized cost and the NPV metric. We initially had some intuition that Mattawoman's bid might be cheaper on an NPV basis, because it has a 10-year term instead of a 20-year term, but the overall cost of the bid was much higher than

[2] We included the coal fired units at the Crane and Wagner stations in this sensitivity.

the others. On an NPV basis, Invenergy's bid is cheaper than CPV's 2016 option. This occurs because Invenergy's proposed facility is much smaller than CPV's (549.5 MW vs. 661 MW). This is why we added a third view of the bids, NPV on a per-MW basis; as seen in line three of Table One, the disparity between the two bids becomes apparent again with this third view.

We note that these results are in line with our Initial Shortlist evaluation in the sense that CPV was the cheapest bid in both stages. Mattawoman's offer was more comparable to Invenergy's in the Initial Shortlist evaluation. In this evaluation we accounted for the fact that Mattawoman's project uses less efficient turbines, which results in a lower dispatch and lower revenues earned in the energy market, increasing costs to ratepayers.

The results of the four sensitivity cases are shown in the table below. For simplicity's sake, we only show the annuitized $/MW-day costs.

TABLE TWO
SENSITIVITY CASE RESULTS
($/MW-day)

	CPV 15	**CPV 16**	**Invenergy**	**Mattawoman**
Base Case	$93	$108	$135	$326
Low Gas	$81	$101	$129	$303
High Gas	$89	$101	$129	$334
PJM Net Revenue	$208	$239	$248	$352
Coal Retirements	($312)	($321)	($298)	$12

The rank order of bids does not change based on the scenario. In the PJM Net Revenue case, we see the effect that revenue estimates can have on the total cost of the bid. We also note here a somewhat unsuspected result, both the low and the high gas price cases actually lower the annuitized payment to the CPV and Invenergy bids.

This result may seem confusing at first, as we typically expect one case to be better than the base case and one to be worse. However, upon closer inspection of the results we found that this result was not an error. To see why, first consider that changing the gas price has both positive and negative effects. Take, for example, an increase in the price of natural gas. This increase has some bad effects; it raises the cost of generation and, in doing so, also assures that the unit will not run as often. However, the gas price increase also will raise the market price of electricity (in hours in which natural gas sets the market price) and, therefore increase revenues.

Whether the net effect is positive or negative depends on the rest of the market. The table below shows the annual net revenues (revenues less variable costs) of the CPV bid from 2015 through 2024.

TABLE THREE
CPV NET REVENUES UNDER BASE, LOW, AND HIGH GAS CASES
($000)

Year	Base	Low	High
2015	$41,726	$48,606	$38,457
2016	$46,332	$56,198	$42,416
2017	$48,591	$57,810	$45,874
2018	$58,060	$66,045	$56,185
2019	$67,753	$74,625	$65,949
2020	$78,993	$84,902	$79,295
2021	$97,271	$102,010	$97,028
2022	$112,584	$116,640	$112,632
2023	$121,139	$124,056	$121,992
2024	$138,866	$139,043	$140,056

Looking at the table we can see that in 2015 the gap between the low and high cases is about $10 million, with the low case being preferable, and the base case in-between. However, this gap narrows by 2020, by which time both cases are preferable to the base case, and by 2024 the high case is the best case.

Based on conversations with Siemens, this "narrowing" of the gap between cases occurs because of the retirement of coal units. In 2015, many coal units are still operating, so an increase in gas prices does not dramatically move market prices. By 2024 many coal units have retired, natural gas is on the margin much more often and a price increase is echoed in the market revenues received by the unit.

Our final analysis inserted each bid option into PROMOD and had the model dispatch each bid along with other units. This was done in order to get a more accurate picture of the revenues earned by the unit. This dispatch was more accurate because it (a) accounted for the fact that these new units would lower the energy market price and (b) accounted for the operating constraints of each unit. We would expect this run to not change any bid rankings and to increase the net cost of each unit. The results are in Table Four below.

TABLE FOUR
RESULTS OF BASE CASE SERVING LOAD

	CPV 15	CPV 16	Invenergy	Mattawoman
Serving Load ($/MW-day)	$114	$127	$178	$380
Serving Load NPV ($000)	$280,728	$292,193	$326,653	$659,992
Serving Load NPV ($000/MW)	$425	$442	$595	$903
Base Case ($/MW-day)	$93	$108	$135	$326
Base Case NPV ($000)	$227,484	$250,015	$247,107	$566,914
Base Case NPV ($000/MW)	$344	$378	$450	$776

As we can see, this analysis does what we would expect it to, that is, it raises the costs of each bid, but does not change the bid ranking order.

The ultimate conclusion of this analysis is that the CPV bid, with the 2015 in-service date, is the best choice, in the sense that it produces the lowest cost solution for ratepayers. The Invenergy bid is the next-cheapest option, with the Mattawoman bid third.

Rate Impact

The above analysis ranks the bids based on net costs, but it does not measure the ultimate cost to ratepayers. This is because, as mentioned, the costs above will actually be recovered through a combination of ratepayer funds and revenues from the RPM capacity market. To get a better sense of the ultimate rate impact we conducted a further analysis.

We began with the results from our “serving load” dispatch as shown in Table Four above. This gives us an annual cost for the bids that must be paid for via RPM and ratepayer contributions. We assume an RPM contribution of $150/MW-day. Note that the historical average of prices in Southwestern MAAC is about $175/MW-day, so this might be a bit conservative. Subtracting this contribution out gives us a net payment from (or to) the ratepayers. To convert this into a rate impact on a per kilowatt-hour basis we divided this total annual payment by Statewide 2011 loss-adjusted SOS sales for Residential and Type I customers in BGE, PEPCO, and DPL service territories. To convert this into a final monthly bill impact we multiplied this rate by the typical monthly Residential usage of 1,000 kWh.

Using this method we estimate that the CPV bid would actually provide an average net bill decrease of about $0.49/month for the 2015 in-service year bid and $0.32/month for the 2016 in-service year bid. In contrast, the Invenergy bid results in an average net bill increase of $0.32/month and the Mattawoman bid is also a net increase of $3.49/month.

This method does depend on our assumptions regarding revenues received from RPM. Table Five below shows the average bill impact in the “Serving Load” case depending on the expected RPM price. As expected, the more revenue received from RPM, the less ratepayers must pay.

TABLE FIVE
AVERAGE BILL IMPACT ACROSS RPM REVENUES
($/Month)

Rate Impact Across RPM Price Sensitivities ($/month)				
RPM Price ($/MW-day)	**CPV 15**	**CPV 16**	**Invenergy**	**Mattawoman**
50	$0.88	$1.05	$1.47	$5.01
100	$0.20	$0.37	$0.90	$4.25
150	-$0.49	-$0.32	$0.32	$3.49
200	-$1.18	-$1.01	-$0.25	$2.73
250	-$1.86	-$1.69	-$0.82	$1.97

The numbers in the above table are average monthly impacts over the life of the projects. The year-by-year bill impact can, and does, vary. Table Six, below, shows the annual average bill impact for both CPV cases with an assumed $150/MW-day RPM price. As can be seen, the initial years of the contract result in payments from ratepayers to the supplier. These payments decrease each year and become payments from the supplier to the ratepayers for the remainder of the contract. For the CPV project with the 2015 in-service date, the ratepayers pay under the CfD for the first five years and get paid in the remaining fifteen years.

TABLE SIX
BILL IMPACT BY YEAR -$150//MW-Day RPM PRICE
($/Month)

Year	CPV 15	CPV 16
2015	$2.03	
2016	$1.67	$2.40
2017	$1.51	$1.91
2018	$1.31	$1.71
2019	$1.05	$1.45
2020	-$0.32	$0.08
2021	-$0.49	-$0.09
2022	-$1.79	-$1.39
2023	-$2.18	-$1.78
2024	-$2.98	-$2.58
2025	-$2.84	-$2.44
2026	-$2.70	-$2.30
2027	-$2.56	-$2.16
2028	-$2.40	-$2.00
2029	-$2.24	-$1.84
2030	-$2.06	-$1.66
2031	-$1.87	-$1.47
2032	-$1.66	-$1.26
2033	-$1.43	-$1.03
2034	-$1.19	-$0.79
2035		-$0.52
2036		

Table Seven shows the estimated bill impact across all sensitivity cases with an average RPM price of $150/MW-day. As we can see, the only case in which the average CPV payment is positive is that of the PJM Net Revenue case.

TABLE SEVEN
AVERAGE BILL IMPACT ACROSS CASES
($/Month)

Scenario	CPV 15	CPV 16	Invenergy	Mattawoman
Base	-$0.79	-$0.57	-$0.17	$2.68
Low Gas	-$0.94	-$0.67	-$0.24	$2.32
High Gas	-$0.83	-$0.67	-$0.24	$2.80
Serving Load	-$0.49	-$0.32	$0.32	$3.49
PJM Net Revenue	$0.80	$1.22	$1.11	$3.07
Coal Retirements	-$6.34	-$6.48	-$5.12	-$2.10

As a final sensitivity, we looked at the average bill impact for the CPV bid assuming that 30% of SOS supply moved to a third-party supplier. At present, in 2011, 22.5% of Residential and Type I load was provided by third-party suppliers. For the 2015 bid, with $150/MW-day in capacity revenue, this results in an average bill impact of negative $0.54/month. For the 2016 in-service case, the average impact is a $0.35/month reduction. Table Eight below shows the year-by-year annual bill impact.

TABLE EIGHT
CPV ANNUAL BILL IMPACT 30% MIGRATION
($/Month)

Year	CPV 15	CPV 16
2015	$2.24	
2016	$1.85	$2.66
2017	$1.68	$2.12
2018	$1.45	$1.89
2019	$1.16	$1.60
2020	-$0.35	$0.09
2021	-$0.54	-$0.10
2022	-$1.99	-$1.54
2023	-$2.41	-$1.97
2024	-$3.29	-$2.85
2025	-$3.15	-$2.70
2026	-$2.99	-$2.55
2027	-$2.83	-$2.39
2028	-$2.66	-$2.22
2029	-$2.48	-$2.03
2030	-$2.28	-$1.84
2031	-$2.07	-$1.63
2032	-$1.84	-$1.39
2033	-$1.59	-$1.14
2034	-$1.32	-$0.87
2035		-$0.58
2036		

Strategic Considerations

The target quantity for the RFP is 1,500 MW. This target quantity was determined by an analysis of the risk factors facing the State, including load swings, failure of transmission lines to be built and plant retirements. We found that these risk factors usually created a need for a single utility that could be filled by a single combined-cycle facility and further recommended a second facility as a "buffer".

Based on the above analysis we would recommend only accepting the CPV bid. We say this for several reasons; a) the CPV bid is the cheapest bid for customers, with a net payment to ratepayers forecast over several scenarios, b) while the CPV bid is acceptable and priced in line with market conditions, if we were to take multiple units we would prefer to have a larger pool of bids, with more time for bidders to sharpen their offers, c) accepting only one offer limits the risk for ratepayers should payments under these contracts be higher than expected, d) continued slow growth means that there is less of an urgent reliability need for the 2015/2016 time frame, and e) we have yet to see what legal challenges will result from this contract.

For all these reasons, we would only accept the CPV bid and if the Commission is interested in another procurement, we could hold another RFP in due time, giving bidders more time to put together their proposals.

NEXT STEPS

If the Commission so chooses, the next scheduled action in the RFP is to direct one or more of the EDCs to sign the Contract for Differences with CPV. The EDC (or EDCs) will the sign with the bidder. We caution that this step will not be automatic. While CPV did not have major edits to the CfD, they still did propose some edits.