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July 6, 2009

**Via Federal Express and Electronic Filing**

Ms. Terry J. Romine  
Executive Secretary  
Maryland Public Service Commission  
William Donald Schaefer Tower  
6 St. Paul Street  
16th Floor  
Baltimore, MD 21202

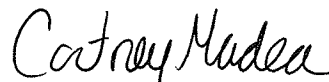
Re: In the Matter of the Commission's Investigation of Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland, Case No. 9117

Dear Ms. Romine:

Enclosed for filing in the above referenced case, please find an original and fourteen (14) copies of CPV Maryland, LLC's Motion for an Order Requiring Investor-Owned Utilities to Enter Into Long-Term Contracts for the Sale of Power from CPV Maryland, LLC's Proposed 640 MW Generating Facility in Charles County, Maryland and Request for Expedited Treatment.

Also enclosed is an additional copy of the filing, which I respectfully request that you date stamp and return in the enclosed self-addressed stamped envelope.

Sincerely,



Cortney L. Madea

**Attorney for CPV Maryland, LLC**

Enclosures

**BEFORE THE  
PUBLIC SERVICE COMMISSION OF MARYLAND**

IN THE MATTER OF THE COMMISSION’S )  
INVESTIGATION OF INVESTOR-OWNED )  
ELECTRIC COMPANIES’ STANDARD OFFER ) Case No. 9117  
SERVICE FOR RESIDENTIAL AND SMALL )  
COMMERCIAL CUSTOMERS IN MARYLAND )  
)

**MOTION OF CPV MARYLAND, LLC  
FOR AN ORDER REQUIRING INVESTOR-OWNED UTILITIES TO  
ENTER INTO LONG-TERM CONTRACTS  
FOR THE SALE OF POWER FROM CPV MARYLAND, LLC’S  
PROPOSED 640 MW GENERATING FACILITY IN CHARLES COUNTY,  
MARYLAND AND REQUEST FOR EXPEDITED TREATMENT**

CPV Maryland, LLC (“CPV Maryland”) hereby requests that the Maryland Public Service Commission (“PSC” or “Commission”) order one or more investor-owned utilities (“IOUs”) under the PSC’s jurisdiction to enter into 20-year long-term contract(s) on the basis of the terms set forth in Exhibit A (“Term Sheet,” and such contract referred to herein as a “St. Charles LTC”), for all the capacity and energy from CPV Maryland’s PSC-approved 640 megawatt (“MW”) combined-cycle natural gas-fired generating station which CPV proposes to build in Charles County, Maryland (the “St. Charles Project” or the “Project”). CPV Maryland further requests that the Commission’s order state that, should the IOUs fail to execute a St. Charles LTC within thirty (30) days of its order, the PSC itself will negotiate one or more such contracts on the IOUs’ behalf.<sup>1</sup>

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<sup>1</sup> The PSC has authority to require its jurisdictional utilities to enter into long-term contracts with CPV Maryland of the type proposed here. The Commission is authorized to “require or allow an investor-owned electric company to procure electricity for [residential and small commercial customers] directly from an electricity supplier through one or more bilateral contracts outside the competitive process.” *See* MD. CODE ANN., PUB. UTIL. COS. § 7-510(c)(4)(ii)(B). Indeed, this section was enacted in 1999 precisely to give the Commission authority to ensure the construction of resources that, for whatever reason, the regional market structure might not support.

## I. INTRODUCTION AND SUMMARY

In the decade since deregulation commenced, the State of Maryland, whether through Commission proceedings, legislative hearings, or the analyses developed at the Legislature's and Commission's request, has repeatedly articulated its desire that new, efficient, and environmentally friendly baseload and intermediate generation facilities be located in Maryland and that Maryland ratepayers be afforded the opportunity to realize the substantial savings that would occur were Maryland's IOUs to enter into long-term contracts with such facilities. Both the Commission and the Legislature increasingly have voiced their frustration that these objectives have yet to be achieved.<sup>2</sup> Plainly, the need to develop such in-State resources only will increase over time, so the value of securing the construction of the St. Charles Project now could not be greater, especially in light of the State's interest in new projects that could begin construction within the next year, reduce retail power prices, create jobs, increase the tax base and support Maryland's recovery from the current economic recession.

As more fully set forth below, over time, the St. Charles Project, if built, unquestionably would reduce rates and rate volatility while providing additional, and considerable, economic and environmental benefits to the State. And, by definition, the Project,

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<sup>2</sup> The PSC stated:

For reasons that are, perhaps, open to debate, the market structures designed to incent new generation in the constrained portions of the State have not yielded *any* new generation that could narrow or close the 2011-12 gap. Indeed, one potential builder testified that it would not begin construction in Maryland without a long-term contract for the output from its new plant, regardless of the level at which the one-year-at-a-time capacity prices might clear. If nothing else, we know from this testimony (and the list of pending CPCN applications and certificated projects not yet under construction) that we cannot expect market forces to give rise to new generation that will appear in time to solve our reliability problems.

*In the Matter of the Investigation of the Process and Criteria for Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland*, Case No. 9149 at 5-6 (Nov. 6, 2008) (citing Transcript of Hearing, Oct. 3, 2008 (D. Egan), at 201-04, 205-07, 215-16).

if completed, would begin to reverse the State's increasingly alarming reliance on out-of-state resources, while contributing to State and regional electric service reliability. Unfortunately, though, it is just as clear from the record in recent Commission dockets that a project such as the St. Charles Project cannot be financed, and therefore, will not be constructed, without long-term contracts. This simply is a fact under both current and reasonably foreseeable economic conditions resulting not only from the increasingly rigorous finance conditions placed upon large capital projects, but the nature of the PJM Interconnection, LLC ("PJM") market structure as well. Simply stated, this Project cannot be built, and neither the millions of dollars in annual ratepayer savings nor any of the Project's other benefits ever will materialize, unless the Project enters into one or more long-term contracts necessary to support its financing.

Accordingly, CPV Maryland respectfully requests that (1) the PSC order one or more of the IOUs to enter into a St. Charles LTC and (2) the Commission review this Motion on an expedited basis, and issue a ruling within sixty (60) days of its filing in order that the Project can be constructed as quickly as possible and its benefits to both ratepayers and the State can be realized as soon as possible.

The issue here is really quite simple. If the Commission continues to believe, as it has stated on numerous occasions, that the development of a facility such as the St. Charles Project would reduce rates, offer statewide economic benefits, improve the environment and enhance electric grid reliability, it should grant the relief requested in this Motion. Indeed, execution of the St. Charles LTC is the only means to deliver these benefits under current economic conditions, the existing State regulatory regime, and the provisions of PJM's Reliability Pricing Model ("RPM"). And lest anyone be concerned as to the reasonableness of the terms and pricing of the St. Charles LTC, CPV Maryland proposes that there be an open book review of CPV Maryland's cost data.

The remainder of this Motion is organized as follows. In Section II, we describe how the St. Charles LTC would both protect ratepayers and deliver substantial economic, environmental and reliability benefits to the State. In Section III, we describe why the Project needs the St. Charles LTC to go forward, and why the Project's benefits will be severely jeopardized unless the Commission intervenes. And finally, in Section IV, we describe why the Project needs an expedited decision in light of its history, characteristics and status, and the timing required for its benefits to be realized by ratepayers in particular and the State in general.

## **II. ECONOMIC, ENVIRONMENTAL AND RELIABILITY BENEFITS OF THE ST. CHARLES PROJECT**

### **A. The St. Charles LTC Offers Significant Benefits to Ratepayers.**

#### **1. The St. Charles LTC provides direct cost savings to Maryland ratepayers.**

The December 1, 2008 "Analysis of Resource and Policy Options for Maryland's Energy Future," prepared at the Commission's request by Levitan & Associates, Inc. and Kaye Scholer LLP (the "Levitan Report"), confirms the benefits to the State of the very path urged in this Motion.<sup>3</sup> According to the Levitan Report, if the Commission orders the IOUs to enter into 20-year contracts with a merchant facility, such as the St. Charles Project, ratepayers' overall power costs will decrease by an estimated \$150-\$400 million per year.<sup>4</sup>

Specifically, the Levitan Report analyzed the addition of 1,080 MW (*i.e.*, two 540 MW combined-cycle natural gas plants) in the Southwest Mid-Atlantic Area Council

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<sup>3</sup> Levitan Report at 110-112 (reflecting millions of dollars in annual savings and low risk to ratepayers under a 20-year contract for a new combined-cycle natural gas-fired generation facility in the State).

<sup>4</sup> *See id.* (calculating annual savings to ratepayers resulting from a 20-year contract for 1,080 MW of new capacity to be approximately \$300 to \$800 million); *see also* Final Report of the Public Service Commission of Maryland to the Maryland General Assembly: Options for Re-Regulation and New Generation at 28 (Dec. 10, 2008) ("PSC Final Report") (noting the cost savings under a 20-year contract calculated in the Levitan Report). The St. Charles Project's 640 MWs of new capacity account for more than half the 1,080 MW, thus the annual savings offered to ratepayers from a long-term contract with the Project should be at least half the savings estimated by Levitan.

(“Southwest MAAC”), and estimated that the annual savings resulting from such additions would be roughly \$300 to nearly \$800 million compared to the “business as usual” reference case.<sup>5</sup> The Levitan Report concluded these substantial ratepayer savings would occur, even though the cost of new generation resources presently is above current capacity market prices. These projected savings derive primarily from the fact that this new generation would be bid into the RPM auction at a price significantly below the then-current market-clearing price for capacity resources,<sup>6</sup> because the addition of any new resources of this size obviously would increase supply and thereby decrease the market-clearing price for that particular auction. The direct result, of course, would be lower prices for all Maryland ratepayers.<sup>7</sup>

Indeed, such an effect was evident in the most recent RPM auction held earlier this year,<sup>8</sup> where the clearing price for the RTO region was substantially lower than the clearing price in the auction just one year before,<sup>9</sup> largely due to a massive increase (of almost 500%, representing approximately 9,800 MW) in the amount of demand resources that were bid, of

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<sup>5</sup> Levitan Report at 110-112; PSC Final Report at 28. The “business as usual” reference case used in the Levitan Report included “the least-cost addition of a gas turbine [ ] peaking plant and/or [combined-cycle] plant in Maryland and [PJM] just-in-time to meet target reserve margin requirements established by PJM. Also embedded in the Reference Case was about 25% of the mix of demand-side management (DSM) programs associated with the [EmPOWER Maryland] initiative.” Levitan Report at 1.

<sup>6</sup> See Levitan Report at 51, 108-109 (finding that “[t]o the extent that a large block of ratepayer-backed capacity creates a temporary surplus of supply, it would have the effect of reducing market prices.”).

<sup>7</sup> See *id.*; see also *State Analysis and Survey on Restructuring and Reregulation: Final Report*, Prepared by Kaye Scholer LLP, Levitan & Associates, Inc. and Semcas Consulting Associates at 110-112 (Dec. 1, 2008) (“Kaye Scholer Report”) (long-term contracts for new generation capacity are likely to lower wholesale market prices by adding supply and pushing RPM prices down on the Variable Resource Requirement demand curve, reducing capacity costs for the entire capacity zone).

<sup>8</sup> PJM Interconnection, LLC, “2012/2013 RPM Base Residual Auction Results,” (May 15, 2009) available at [http://www.pjm.com/markets-and-operations/rpm/~media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx](http://www.pjm.com/markets-and-operations/rpm/~/media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx) (“PJM 2012/2013 Auction Results”).

<sup>9</sup> See *infra* text accompanying note 82.

which approximately 72% or 7,000 MW cleared.<sup>10</sup> As PJM noted, “[t]he RPM auction price was lower because of a growth in the available capacity and a decline in demand. Supply increased because of the significant increases in new capacity from demand resources and energy efficiency resources.”<sup>11</sup>

For the same reasons, then, given the continuing constraints in the Mid-Atlantic Area council (“MAAC”) and Southwest MAAC, clearing prices in the next auction would decrease even further were the 640 MW St. Charles Project bid into it at a price significantly below the most recent clearing price.<sup>12</sup> This would reduce the cost of capacity for the Maryland IOUs and result in direct ratepayer savings.

In addition to lowering RPM clearing prices, the Project’s location in Southwest MAAC will lower locational marginal prices (“LMP”), particularly in Maryland, where the shortage of transmission capacity combined with a lack of in-State generation causes Maryland to be a net importer of electricity.<sup>13</sup> Indeed, this is why LMPs in Southwest MAAC are among the highest in PJM,<sup>14</sup> and why congestion charges cost Maryland ratepayers hundreds of millions of dollars each and every year.<sup>15</sup> Clearly, though, if “[n]ew lower-cost generation [were allowed to] displace more expensive generation that currently sets high LMPs during periods of peak

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<sup>10</sup> PJM 2012/2013 Auction Results at 1.

<sup>11</sup> *Id.* at 2.

<sup>12</sup> *See supra* notes 6-7 and accompanying text.

<sup>13</sup> *See* Kaye Scholer Report at 85 (“strategic contracts to locate new Maryland generation in [Southwest MAAC] should lower both LMPs and RPM prices”).

<sup>14</sup> *Interim Report of the Public Service Commission of Maryland to the Maryland General Assembly, Part I: Options for Re-regulation and New Generation* at 17-18 (Dec. 3, 2007) (“PSC Interim Report”).

<sup>15</sup> *See id.* (stating that Vantage Consulting, Inc. estimated that congestion charges would add approximately \$168 million to the costs of electricity for Maryland ratepayers in 2008 and that the PJM Market Monitor estimated that the cost of congestion to Maryland ratepayers in 2006 was approximately \$500 million).

usage, [b]y contracting for new units with lower marginal costs, utilities will reduce the expected LMPs for all other generation at that energy price node.”<sup>16</sup>

Reports prepared by the Office of People’s Counsel (“OPC”) and the PHI Companies (both Potomac Electric Power Company and Delmarva Power & Light) likewise support the Levitan Report’s conclusions as to the ratepayer savings attributable to long-term contracts.<sup>17</sup> The OPC Report shows that the expected annual costs of a supply portfolio that includes a 15-year contract with a new natural gas-fired combined-cycle generation facility, offers the lowest intermediate to long-term expected annual costs to ratepayers.<sup>18</sup> This analysis supports the value of the St. Charles LTC, because the approach currently in place – referred to in the OPC Report as the “business as usual” or “BAU” approach – carries both the greatest cost and the greatest long-term risk of the options studied.<sup>19</sup>

The PHI Report confirms both the price and stability benefits of a portfolio that includes a long-term contract for natural gas-fired combined-cycle generation as compared to other long-term portfolio options.<sup>20</sup> Here, too, it was concluded that this portfolio provides the lowest average cost and smallest risk of all the portfolios analyzed for both intermediate- (2015)

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<sup>16</sup> Kaye Scholer Report at 85.

<sup>17</sup> *Risk Analysis of Procurement Strategies for Residential Standard Offer Service, A Report to the Maryland Office of People’s Counsel*, Resource Insight, Inc., dated March 25, 2008, Case No. 9117, (filed as Attachment A to OPC’s Initial Comments on Nov. 21, 2008) (“OPC Report”); Response of Pepco Holdings Inc. to Maryland Public Service Commission Order No. 82105, Case No. 9117 (filed Oct. 1, 2008) (“PHI Report”).

<sup>18</sup> OPC Report, Figure ES-1 attached as Exhibit B. The referenced portfolio is designated as “D-W-N” in Exhibit B. *See* OPC Report at 43 and Exhibit B attached hereto. The D-W-N portfolio includes two-year full-requirements contracts, five-year fixed-block contracts for energy efficiency, 15-year wind contracts, and 15-year contracts indexed to the cost of a new natural gas-fired combined-cycle plant. *Id.* at 9. Additionally, the OPC Report found that a portfolio limiting long-term contracts to wind-based generation (“Clean BAU” in Exhibit B) results in higher expected costs and greater long-term risk than a diversified portfolio that includes natural gas-fired combined-cycle generation. *See id.* at 3, 42.

<sup>19</sup> *See id.* at 3-4.

<sup>20</sup> PHI Report at 53.

and longer-term (2024) planning years, under varying regulatory environments.<sup>21</sup> In short, the OPC analysis and PHI's Report, when combined with the Levitan Report's analysis discussed above, present more than sufficient evidence of the economic savings that would flow to ratepayers were the State's IOUs to enter into long-term contracts with the St. Charles Project.

**2. The St. Charles LTC offers fewer risks to ratepayers than utility-built new generation assets.**

The long-term contracts described in the Levitan Report and urged in this Motion additionally offer significant benefits to ratepayers by reducing the risks attendant to new, rate-based utility construction. The Commission, analyzing the Levitan Report and comparing the benefits of such projects to traditional, rate-based utility construction,<sup>22</sup> concluded that "the economic benefits are roughly equal regardless of ownership and cost-recovery structure," specifically stating that "[a]lthough there was a small but insignificant increased benefit of IOU-built new generation, after factoring in the risk of cost overruns, the long-term PPA[s] may edge out the IOU build."<sup>23</sup>

Ordering that power be purchased from CPV Maryland by means of a long-term contract would allow the Commission to shift away from Maryland's ratepayers and to CPV virtually all the risks of building the facility (including construction and operating cost overruns, construction and completion delays, and performance penalties such as those due to mechanical breakdowns, and failure to be available when called upon to deliver power).<sup>24</sup> Neither

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<sup>21</sup> See *id.* at 4-5, 53, 81. The PHI Report concluded that a "100% [Managed Portfolio ("MP")] Plus CC PPA" model for 2015 provides the lowest average cost and smallest risk. *Id.*

<sup>22</sup> Levitan Report at 112-114.

<sup>23</sup> Final Report of the Public Service Commission of Maryland to the Maryland General Assembly: Options for Re-Regulation and New Generation at 28 (Dec. 10, 2008) ("PSC Final Report").

<sup>24</sup> See *In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Case No. 9117, Transcript at 2143-2148 (Dec. 19, 2008) (D. Magill discussing the risks CPV Maryland would be subject to in contrast to the risks the ratepayers would be subject to under a utility build scenario) ("D. Magill Testimony").

Maryland's IOUs (nor its ratepayers) would be obligated to pay a penny unless and until the Project reaches commercial operation, in contrast to a utility build where ratepayers are on the hook once construction commences, if not before. Indeed, there really is little doubt, as confirmed by the Levitan Report, that long-term contracts reduce risk to the ratepayer, provide greater cost certainty and, as more fully described below, help stabilize rates. Furthermore, because the St. Charles Project is the only new combined-cycle facility in Maryland positioned to commence construction in 2010, it is, then, the only option in the State that presently could create the aforementioned ratepayer benefits.<sup>25</sup>

Finally, were it to grant this Motion, the Commission would not need to establish any new policy in favor of long-term contracts. Rather, it would remain entirely free to take up at a later date the issues presented in Docket No. 9117 as to the possibility of utility builds, long-term contracts in general, or some combination thereof in order to address the State's energy and environmental needs in the future.

**3. The St. Charles LTC provides consumers with more future price certainty by spreading the cost of the Project over multiple years.**

This Commission, along with the Maryland Energy Administration ("MEA"), the Commission Staff, and the Maryland Office of People's Counsel ("OPC") have all recognized the many benefits of long-term generation resources. According to the Commission:

Long-term PPAs have the potential to solve some of the market deficiencies that have led to a deficit of new generation in Maryland and other constrained states. They can provide a guaranteed stream of income to the generation owner, which in turn enables project financing and reduces the cost of investment risk built into energy costs. They can allow Maryland to control the timing, location, type and environmental impact of new generation, and to diversify its options as a hedge against market risk. They can encourage new entrants to the Maryland energy

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<sup>25</sup> The Commission is of course also aware that there are no utility baseload projects in the State that could commence construction in 2009 or even 2010.

market, thereby enhancing competition. Finally, strategic placement of new generation under a long-term PPA could lower LMPs and capacity costs, thus lowering wholesale prices.<sup>26</sup>

According to OPC, “the combination of short-term and long-term resources reduces uncertainty around expected portfolio costs compared to a portfolio with just short-term products,” [and] “ratepayers will benefit by fully diversifying the portfolio to include a mix of short-, medium-, and long-term resources.”<sup>27</sup> Staff similarly recognized that “[l]ong-term resources generally enhance the stability of retail rates and reduce the rate volatility as compared to reliance on shorter term resources.”<sup>28</sup> MEA likewise supported long-term contracts as part of a revised “managed portfolio” standard-offer-service (“SOS”) approach, stating that “long term contracts under a properly managed portfolio concept can ultimately reduce energy costs for ratepayers and add price stability.”<sup>29</sup>

CPV Maryland respectfully submits that the St. Charles LTC would provide the optimal means for meeting the State’s need for in-State generation, while improving or at least maintaining reliability, and for achieving the other economic and environmental benefits discussed above, all of which collectively will minimize ratepayer risk and maximize ratepayer benefits. Simply put, the St. Charles LTC establishes a hedge against the short-term price volatility associated with the wholesale markets on which the State has largely relied in recent years, and will over the long term give consumers lower and more certain prices than the spot

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<sup>26</sup> PSC Final Report at 28; *see also* Levitan Report at 79-80.

<sup>27</sup> Initial Comments of OPC, Case No. 9117, at 14-15 (filed Nov. 21, 2008) (“OPC Initial Comments”).

<sup>28</sup> Initial Comments of the Public Service Commission Staff, Case No. 9117, at 3 (filed Nov. 21, 2008).

<sup>29</sup> Initial Comments of the Maryland Energy Administration, Case No. 9117, at 8 (filed Nov. 21, 2008).

market or short-term contracts.<sup>30</sup> The St. Charles LTC represents an additional cost-effective means to further diversify the IOUs' procurement portfolio and to reduce price volatility well beyond the next two years.

One of the key lessons from the 2000 California energy crisis was that customers are poorly served by an overreliance on any one type or tenor of electricity contracts. Rather, ratepayers would be much better protected against volatile market prices were there to be a variety of risk hedging opportunities through the use of short-, intermediate-, and long-term contracts that would provide the backbone of a coordinated energy strategy. Indeed, in its orders addressing the 2000 California energy crisis, the Federal Energy Regulatory Commission ("FERC") recognized that the central flaw in California's "deregulated" market design was its total reliance upon the spot energy market to meet the state's energy needs, such reliance having resulted from a ban by the California Public Utility Commission on forward contracting by the state's IOUs.<sup>31</sup> Consequently, the state's ratepayers were entirely at the mercy of market fluctuations because they had no opportunity to hedge against the risks associated with such volatility. Hence, FERC recognized that an "essential remedy [to this overreliance] is the elimination of rules that prevent market participants from managing their risks,"<sup>32</sup> and, accordingly, eliminated the mandatory spot market purchase requirement, thus permitting "the IOUs to move their purchase power needs to bilateral long-term contracts and adopt a balanced

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<sup>30</sup> See Supplemental and Reply Comments of the Office of People's Counsel, Case No. 9117 at 8 (Dec. 5, 2008) (OPC – "long-term contracts provide a financial hedge against the volatility of shorter-term [standard-offer-service ("SOS")] contracts without affecting SOS prices").

<sup>31</sup> *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Svcs.*, 93 FERC ¶ 61,294, at 61,993 (2000) ("December 15 Order") ("We cannot emphasize enough that the [CPUC] must act decisively and immediately to eliminate the requirement for the IOUs to buy the balance of their load from the [spot market]. This is the most serious flaw in the market design created by AB1890 and the [CPUC's] implementing orders" (footnotes omitted)).

<sup>32</sup> *San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Svcs.*, 93 FERC ¶ 61,121, at 61,359 (2000).

portfolio of contracts to mitigate cost exposure.”<sup>33</sup> Although the FERC did not prescribe or suggest any specific percentage of purchases from the California spot markets or short-term bilateral purchases, it did “strongly urge the IOUs to move their load to long-term contracts of two years or more,” observing that while “there is certainly no single right answer as to what the balance between long and short-term purchases should be, the short-term and spot markets should be used to shape a portfolio, not to define it.”<sup>34</sup>

As is evident from the Commission’s deliberations in Case Nos. 9117 and 9149, unlike California several years ago, the PSC has made it clear that it is not content to await a full-blown crisis, and that it will utilize its authority to ensure that ratepayers get the benefits of a diversified energy portfolio. Granting this Motion and thereby obtaining the value of diversification for hedging against fluctuations in energy prices would constitute an excellent first step. While the Commission has wisely avoided total reliance on spot markets for procuring the IOUs’ SOS requirements, experience has now shown that continuing to rely primarily on a two-year, ladderred SOS procurement mechanism would limit ratepayers’ ability to hedge against price volatility and frustrate other important State objectives, such as the development of new in-State generation.

Additionally, by spreading the cost of new generation over multiple years, long-term contracts in the form of a St. Charles LTC not only enhance price certainty but lower finance costs as well, thereby decreasing the cost of new generation to consumers.<sup>35</sup> Obviously, the shorter the term of firm pricing, the higher the price because a firm capacity price mechanism of

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<sup>33</sup> *December 15 Order*, 93 FERC ¶ 61,294, at 61,982 (2000).

<sup>34</sup> *Id.* at 61,993.

<sup>35</sup> *See In the Matter of: Credit and Capital Issues Affecting the Electric Power Industry*, Federal Energy Regulatory Commission (“FERC”) Docket No. AD09-2-000, Transcript at 28 (Jan. 13, 2009) B. Levy Testimony at 28-31 (testimony of B. Levy on behalf of International Power America noting that new generation projects have become more costly to finance in the current market) (“B. Levy Testimony”).

a longer duration will reduce the Project’s risk profile and enable the Project to attract lower cost financing, all of which would inure to the benefit of ratepayers.<sup>36</sup> Increasing the contract term will also expand the pool of potential lenders to the Project in the current, relatively illiquid financing market, thereby increasing the likelihood of a successful and attractively priced financing. In short, the St. Charles LTC would protect consumers from IOUs being overly reliant on potentially volatile wholesale energy markets, minimize the cost of financing new generation and reduce the prices borne by ratepayers.

**B. The St. Charles Project Will Also Provide Direct Economic Benefits to the State and County**

The St. Charles Project will generate significant State sales tax revenue, state and local income tax revenue, and local property tax revenue to Charles County, Maryland (“Charles County” or the “County”). State revenue generated through sales tax from the purchase of Project equipment during 2009-2012 is estimated to be approximately \$4 million.<sup>37</sup> The Project will create on average approximately 175-200 construction jobs over a 26 month period, and employ as many as 350-400 employees at the peak of construction.<sup>38</sup> Most of this workforce will be drawn from the County and the surrounding region. State personal income tax revenues attributable to construction alone will be approximately \$2.4 million (based on a tax rate of 4.75 percent) and the County personal income tax revenue is expected to be approximately \$1.5 million (based on a 2.9% tax rate) during 2010 through 2012.<sup>39</sup> In order to operate, the

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<sup>36</sup> *Id.*

<sup>37</sup> *In the Matter of the Application of CPV Maryland, LLC for a Certificate of Public Convenience and Necessity to Construct a Nominally Rated 640 MW Generating Facility in Charles County, Maryland – Case No. 9129*, CPV Maryland Application – Environmental Review Document at 4.6.1.2 (Dec. 14, 2007) (“CPV Maryland ERD”).

<sup>38</sup> *Id.* at 4.6.1.1.

<sup>39</sup> The estimated construction payroll for the Project is still evolving and is currently estimated to be approximately \$50 Million.

Project will create approximately 25 permanent, full-time, well-paying jobs, yielding approximately \$27 million in operating wages over twenty (20) years,<sup>40</sup> a total of \$1.1 million in State and local income tax revenue, and, on average, local property tax revenue to Charles County of \$2.4 million dollars a year over the 20-year term.<sup>41</sup> The County will receive approximately \$33.7 million over 20 years from annual sales to the Project of an estimated 650-750 million gallons of reclaimed water, and potentially greater revenues through its participation in the State nutrient trading program. In total, the Project is expected to provide, commencing in 2012, approximately \$97 million directly to the County over 20 years, through payments-in-lieu-of-taxes, connection fees, water and sewer user fees, local income taxes and other fees, and the sale of reclaimed water; and all these benefits will be afforded with minimal impact to State and County services and infrastructure.

**C. The Project Will Provide Major Environmental Benefits to the State**

The St. Charles Project is a state-of-the-art, environmentally friendly, combined-cycle generating facility which will run exclusively on clean-burning natural gas. It will be among the cleanest fossil fuel-fired generation units operating in the country and, as the cleanest natural gas project in Maryland, it will contribute materially to improving the State's overall air quality. The Project will emit virtually no sulfur dioxide ("SO<sub>2</sub>"), and will utilize state-of-the-art controls to minimize the emission of nitrogen oxides ("NO<sub>x</sub>"), volatile organic compounds ("VOCs"), carbon monoxide ("CO") and particulate matter ("PM"). In fact, the St. Charles Project's SO<sub>2</sub> and NO<sub>x</sub> emissions are lower than those of a typical coal power plant by approximately 99.8% and 99.2%, respectively, and lower than those of a typical oil-fired power plant by 99.8% and

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<sup>40</sup> CPV Maryland ERD at 5.6.1.

<sup>41</sup> *Id.* at 5.6.1.3.

98.8%, respectively.<sup>42</sup> Additionally, it is estimated that the Project will emit approximately half the CO<sub>2</sub> of a new similarly-sized coal plant.<sup>43</sup> Furthermore, in addition to these air quality benefits, the Project's use of reclaimed water is expected to reduce the Mattawoman Wastewater Treatment Plant's ("Mattawoman WWTP") nitrogen and phosphorous discharges into the Potomac River and ultimately, the Chesapeake Bay, by up to 18,700 and 1,100 pounds per year, respectively.<sup>44</sup>

The development of new, clean, in-State generation plainly is entirely in the best interests of Maryland ratepayers and were the St. Charles Project not to be constructed, Maryland just as plainly not only would be deprived of the Project's obvious environmental benefits, but also forced to secure the State's electricity needs by yet additional out-of-state resources dependent on long-distance transmission lines, the uncertainty of which would only further exacerbate an already distressing energy picture. It gets worse because the resources serving Maryland's demand almost certainly would be up-wind old coal-fired plants with dramatically inferior environmental profiles, resulting in a net deterioration in Maryland's air quality and the undermining of Maryland's commitment to environmental improvement, as reflected in both the

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<sup>42</sup> See EPA Clean Energy Air Emissions, available at [www.epa.gov/RDEE/energy-and-you/affect/air-emissions.html](http://www.epa.gov/RDEE/energy-and-you/affect/air-emissions.html) ("EPA Emissions Website") (stating that SO<sub>2</sub> and NO<sub>x</sub> emission rates for a typical coal power plant are 13 lbs/MWh and 6 lbs/MWh, respectively, and are 12 lbs/MWh and 4 lbs/MWh, respectively, for a typical oil-fired power plant). The percentages provided above were calculated by comparing the St. Charles Project SO<sub>2</sub> and NO<sub>x</sub> estimated emission rates to the aforementioned emission rates for typical coal and oil-fired plants.

<sup>43</sup> See EPA Emissions Website (stating that the average CO<sub>2</sub> emission rates from U.S. coal-fired generation and natural gas-fired generation are 2,249 lbs/MWh and 1,135 lbs/MWh, respectively); see also "Controlling Power Plant CO<sub>2</sub> Emissions: A Long Range View," available at [http://www.netl.doe.gov/publications/proceedings/01/carbon\\_seq/1b2.pdf](http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/1b2.pdf) (setting forth the CO<sub>2</sub> emissions for a variety of coal-fired generation technologies and underscoring the fact that the greenhouse gas reductions delivered by a new combined-cycle natural gas plant are even more dramatic by comparison to older, operating coal plants).

<sup>44</sup> Estimates are based on the Project's projected reclaimed water use and Mattawoman's State Discharge Permit limits.

Healthy Air Act and the State's participation in the Regional Greenhouse Gas Initiative ("RGGI").

Moreover, given the likelihood of national climate change legislation at some time within the next few years, at such time as the Trans-Allegheny Interstate Line ("TrAIL") or the Potomac-Appalachian Transmission Highline project ("PATH"), or both eventually are constructed, Maryland's ratepayers would at that time be asked to absorb the potentially significant costs (*e.g.*, of carbon offsets) attendant to the purchase of coal-based resources from Western PJM, as well as the considerable line losses associated with the use of these lines. For all of these reasons, then, Maryland should not assume that TrAIL or PATH, even if constructed, would necessarily be a significant cost-effective means of contributing to Maryland's near- or long-term future.

Lastly, with every passing day even the assumption that new coal generation in fact will be developed to serve Maryland appears to be increasingly flawed. New coal generation is not being built in light of local and national opposition, skepticism by some state commissions as to its costs, and the continuing uncertainties as to its timing and the considerable uncertainty associated with pending greenhouse gas legislation. In short, it is imperative that Maryland now take what steps it can to facilitate the development of in-State gas-fired generation resources such as the St. Charles Project.

**D. The Need for In-State Generation and the St. Charles Project's Ability to Provide Enhanced System Reliability and Stability**

**1. Maryland's need for in-State generation**

As noted, the Project would fulfill the State's need for new, clean and reliable electric generation to be built in Maryland. As early as 2007, the Commission's own consultants concluded that the addition of 1,200 MW of "excess" in-State power from combined-cycle gas plants (*i.e.*, in-State capacity beyond the amount needed to maintain reliability) would provide

substantial benefit to the State.<sup>45</sup> To satisfy its needs, then increasingly, Maryland has had to become a substantial net importer of its electricity. In 2008, Maryland imported approximately 30% of its electric energy needs and is currently the fourth largest electric energy importer in the United States.<sup>46</sup> Because the states to the south, east, and north of Maryland also are large electricity importers, West Virginia and Pennsylvania are the only states from which Maryland presently can import electricity in appreciable amounts.<sup>47</sup> Yet, a large percentage of this imported energy comes from coal-fired plants, with coal comprising approximately 96% of West Virginia's electric generation and approximately 45% of Pennsylvania's generation.<sup>48</sup>

Not surprisingly, then, the Maryland Senate recently concluded that, “[t]here continues to be concerns with the reliability of Maryland’s energy supply and the transmission capacity needed to meet Maryland citizens’ demand for energy;”<sup>49</sup> that “[n]o new sizable generation has been constructed in Maryland since 1992;”<sup>50</sup> (Indeed, only 700 MW of new capacity of any size have been built in Maryland since 2000, and none of it baseload capacity);<sup>51</sup> and that the inevitable result of the State’s increasing reliance on out-of-state energy is “ratepayers being assessed high capacity and congestion charges as part of electricity rates.”<sup>52</sup>

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<sup>45</sup> *Interim Report of the Public Service Commission of Maryland to the Maryland General Assembly, Part I: Options for Re-regulation and New Generation* at 3 (Dec. 3, 2007) (“PSC Interim Report”).

<sup>46</sup> Public Service Commission of Maryland, *Ten-Year Plan (2008-2017) of Electric Companies in Maryland* at 5, 82 (Feb. 2009) (“Ten-Year Plan”).

<sup>47</sup> *Id.* at 5-6, 82-83. Other surrounding states, such as Delaware, New Jersey, Virginia and the District of Columbia are also net importers of electricity, importing approximately 34%, 28%, 35%, and 99% of their respective energy needs. *Id.* at 83.

<sup>48</sup> Energy Information Administration, *State Energy Profiles* (reporting electricity generation statistics for March 2009), available at [http://tonto.eia.doe.gov/state/state\\_energy\\_profiles.cfm?sid=WV](http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=WV) and [http://tonto.eia.doe.gov/state/state\\_energy\\_profiles.cfm?sid=PA](http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=PA).

<sup>49</sup> Senate Bill 844, Preamble (2009).

<sup>50</sup> *Id.*

<sup>51</sup> PSC Final Report at 27.

<sup>52</sup> *See* Senate Bill 844, Preamble (2009).

As just noted, this Commission has been of the same view for some time: “Maryland suffers from a State-wide shortfall in net generating capacity” which, unless alleviated, likely will lead to an increase in electricity prices and the potential for statewide rolling blackouts.<sup>53</sup> No doubt it was for this reason that, in 2008, the Maryland Commission opened Docket No. 9149 (the so-called “Gap RFP” docket) to address the potentially critical reliability “gap” expected to occur in 2011-2012 if certain transmission line projects were not completed by 2011 and 2012.<sup>54</sup> Having heard the evidence, the PSC concluded as follows:

Although the specific amount of any shortfall is a matter of some debate, there is no dispute that if we as a State do nothing in the interim – *i.e.*, if we fail to undertake some combination of finding or building new electricity generation, increasing the capability of the transmission system to deliver more electricity into Central and Eastern Maryland, or reducing consumption – the very real threat of rolling blackouts or brownouts will remain.<sup>55</sup>

Specifically, the Commission found that without the development of significant new transmission, “the Mid-Atlantic region faces a gap of approximately 2,600-3,000 MW, of which 600-690 MW are attributable to Maryland;”<sup>56</sup> and that even if the TrAIL line were to go into service, this “gap” likely would reappear in 2013 if the PATH line were not in service by then as well.<sup>57</sup> And, according to PJM’s Senior Vice President for Reliability Services, while PJM’s load projections recently have been reduced due to the economic downturn, the Southwest MAAC forecast has not substantially improved, in part due to growth associated with the Base

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<sup>53</sup> PSC Interim Report at 11.

<sup>54</sup> *In the Matter of the Investigation of the Process and Criteria for Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems in the State of Maryland*, Case No. 9149 (Nov. 6, 2008).

<sup>55</sup> *Id.* at 1.

<sup>56</sup> *Id.* at 3.

<sup>57</sup> *Id.* at 3-4.

Realignment and Closure process in the region.<sup>58</sup> Indeed, as recently as March 11, 2009, the PSC again found that “the possibility remains that PJM, by its own assessment, could ‘be at or near the reliability violations’ pending further clarification of load, generation, and [demand response].”<sup>59</sup>

On the basis of these findings, the Commission ordered the four IOUs to accept bids for 400 MW of demand response resources.<sup>60</sup> But even if all 400 MW of those resources were to come to fruition, and even if one were to assume that, if called upon, these resources actually would all be available when called upon, they still would not alone address the State’s diverse energy policy objectives, which have for close to a decade included a desire for increased reliability, more in-State generation and (as reflected in the Healthy Air Act and the State’s participation in RGGI), a commitment to reducing the carbon footprint of the generation resources serving the State’s load.

In this regard, it bears mentioning that 67% of the State’s total generating capacity is over 31 years old and another 11% is more than 21 years old<sup>61</sup> and in need of environmental upgrades. Maryland’s total in-State generating capacity is nearly 12,500 MW, of which coal-fired generation currently comprises almost 60%.<sup>62</sup> Indeed, at least six of Maryland’s coal-fired

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<sup>58</sup> *In the Matter of the Investigation of the Process and Criteria for Use in Development of Request for Proposal by the Maryland Investor-Owned Utilities for New Generation to Alleviate Potential Short-Term Reliability Problems In the State of Maryland*, Order No. 82511, Case No. 9149, at 7 (March 11, 2009) (“Order No. 82511”).

<sup>59</sup> *Id.* at 8 (quoting PJM).

<sup>60</sup> *Id.* at 9. The Commission’s Gap RFP order, among other things, underscores the PSC’s authority to order its jurisdictional utilities to enter into agreements to secure resources to meet State energy or environmental objectives.

<sup>61</sup> PSC Final Report at 27.

<sup>62</sup> Ten-Year Plan at 12. In March 2009, Maryland produced 58.6% of its energy from coal. *See* Energy Information Administration, Maryland State Energy Profile, available at [http://tonto.eia.doe.gov/state/state\\_energy\\_profiles.cfm?sid=MD](http://tonto.eia.doe.gov/state/state_energy_profiles.cfm?sid=MD) (reflecting 2,087,000 MWh coal-fired generation and 3,559,000 MWh of total net electricity generation).

facilities, equaling 37% of the State's capacity, will require costly upgrades to comply with the Healthy Air Act, and the compliance costs of these older facilities alone might well render some of them uneconomic to operate, or otherwise lead to some of them being retired, thereby further worsening Maryland's already apparent supply shortage and its dependence on imported power.<sup>63</sup>

In short, going forward there should be little doubt that Maryland's increasing reliance on out-of-state electricity, the related phenomenon of steadily increasing transmission congestion, and the recent elimination of retail rate caps, together will result in Maryland's ratepayers continuing to pay among the highest, if not the highest, rates in PJM. There is, however, an alternative path. If the Commission grants the relief CPV Maryland requests, the State will have taken a major first step toward developing the much needed in-State generation. Under no circumstances would it be prudent simply to await the much heralded, though for much too long sought, maturation of the PJM RPM regime, or the emergence of an entirely new State regulatory structure, either of which, regardless of their respective merits, easily could take many more years to occur.

**1. The St. Charles Project offers reliability and stability benefits.**

The Commission has stated that it "will not rely on chance and good fortune to ensure that the lights will stay on amid a myriad of uncertainties."<sup>64</sup> But, as previously mentioned, even if both the TrAIL and PATH lines are constructed, it is still very much unclear whether the State will be able to avoid the risk of rolling blackouts or brownouts in the long term without new in-State generation.<sup>65</sup> On the other hand, though, we can say with a very high degree of confidence that (1) the St. Charles Project would offer new, environmentally friendly native power

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<sup>63</sup> Maryland's Energy Future, Energy Transition Report 2007 at 5; *see also* Ten-Year Plan at 12-13.

<sup>64</sup> Order No. 82511 at 8.

<sup>65</sup> *See supra* text accompanying note 57.

generation to the State, with state-of-the-art efficiency and operational reliability; and (2) if the Project fails to go on-line, the State's increasing dependence on imports via potentially more costly and less environmentally friendly transmission projects and/or out-of-state generation would be exacerbated.

Furthermore, the St. Charles Project unquestionably would not only contribute to satisfying Maryland's energy requirements but, in so doing, would materially increase system reliability and stability both in the State and throughout PJM, most notably by offsetting loading on existing critical transmission infrastructure, by providing system operators with an additional tool for addressing unforeseen system events, and by assisting in resolving the system planners' growing dilemma of how best to supply the increasing load in eastern Maryland without overloading the major corridors from the west.

Indeed, the Commission already has identified the Project and others like it as offering reliability benefits and necessary additions to the State's electricity portfolio. In testimony filed in support of the Project's CPCN application, Commission Staff expert Craig Taborsky concluded that the Project "will contribute to future generation adequacy in the State of Maryland and throughout the PJM control area;" that the "additional power supplied by the [Project] will be a beneficial resource for Maryland and the PJM grid in general;"<sup>66</sup> and that the "[P]roject can be dispatched by the PJM control center for reactive and voltage support [giving] the operators more flexibility in controlling the grid for optimal performance."<sup>67</sup> Finally, by adding generation near one of Maryland's significant load centers and offering system operators an additional resource for dispatch, the Project will assist in meeting eastern Maryland's increasing load requirements, reduce transmission congestion, reduce the need to import

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<sup>66</sup> *CPV Maryland, LLC*, PSC Case No. 9129, Direct Testimony of Craig Taborsky, 2:2-5, 3:22-23 (July 14, 2008).

<sup>67</sup> *Id.* at 9:5-8.

primarily coal-based bulk power from distant locations, and provide local capacity support that could be of significant benefit both under normal operating conditions as well as during contingencies, all to the benefit of overall system reliability.

### **III. WHY THE ST. CHARLES LTC IS NECESSARY**

#### **A. The St. Charles Project Cannot Start Construction in the Current or Reasonably Foreseeable Credit Environment Without Long-Term Contracts**

Competitive baseload and intermediate capacity, including the St. Charles Project, cannot be financed without long-term power sales contracts.<sup>68</sup> During the last ten (10) years, there have been periods when significant debt amounts, often greater than 50% of a project's total costs, have been raised for merchant gas-fired power plants that were supported only by short-term contractual commitments, such as energy hedges for 3-5 years, or no hedges whatsoever for capacity revenues.<sup>69</sup> But these days are gone. Specifically, traditional commercial banks no longer are willing to finance the types of risks they might once have undertaken; nor will they be willing to rely on third party consultant reports estimating a project's potential revenue stream in a particular wholesale market.<sup>70</sup> Rather, since the collapse of the credit markets, debt markets have required, and, for the reasonably foreseeable future unquestionably will continue to require, a fixed revenue stream of significant duration in order for lenders to finance new baseload or intermediate power plants in wholesale competitive

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<sup>68</sup> D. Magill Testimony at 2134 (D. Magill stating that the Project "would most likely not survive" if the Commission were to issue an Order in Docket No. 9117 that did not include some ability for IOUs to enter into long-term contracts as part of SOS procurement).

<sup>69</sup> D. Magill Testimony at 2138-39; *see* B. Levy Testimony at 28 (stating that "during the past few years, the developers of new generation facilities, have had unprecedented access to low-cost capital to support their construction.").

<sup>70</sup> *See* D. Magill Testimony at 2140-41, 2149-50; *see also* B. Levy Testimony at 29 (stating that the "market now views investments [in new generation in the power sector] as being more risky and having less certainty of cost recovery").

markets such as PJM.<sup>71</sup> In short, such plants simply won't be built absent the relative certainty that long-term contracts with creditworthy utilities can provide to satisfy lenders.<sup>72</sup>

CPV Maryland's situation is by no means unique. For example, in their recent testimony before FERC, other competitive power producers likewise noted that "[i]n the interim, in order to encourage the development of the needed long-term investments in new power plants, support in the form of competitive, medium term PPAs will be needed. The term of such PPAs will depend on the nature and amount of the underlying investment; but the fact remains that current terms available in the organized markets, such as 5-year PPAs, are simply inadequate to attract the substantial debt and equity necessary to put steel in the ground today."<sup>73</sup>

CPV Maryland's views on this issue, which are based on actual, real-time discussions with lenders in connection with the St. Charles Project and other projects currently under development in the United States, also were supported by a number of other parties to PSC proceedings.<sup>74</sup> Additionally, numerous state agencies have recognized, even prior to the recent collapse of the credit markets, that long-term contracts can further, and in many cases are

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<sup>71</sup> D. Magill Testimony at 2140-41; *see* B. Levy Testimony at 28 (noting that the recent financial market collapse had made financing more difficult, but that projects with the "correct commercial structure," including long-term contracts, can obtain financing).

<sup>72</sup> D. Magill Testimony at 2140-41, 2149-50 (Chairman Nazarian stated "we can't count on anything from your [P]roject unless we change the rules to get you a guaranteed revenue stream"); *see* B. Levy Testimony at 31 (stating that revenue from long-term contracts can support financing for new generation); *see also* *In the Matter of: Credit and Capital Issues Affecting the Electric Power Industry*, FERC Docket No. AD09-2-000, Transcript (Invenergy, LLC – M. Polsky) at 36 (Jan. 13, 2009) ("M. Polsky Testimony") ("With the current change in the financial markets, [the merchant model and the hedge market model] have totally disappeared. You can't hedge, you can't build merchant, so the only real option, is long-term power purchase agreements.").

<sup>73</sup> Prepared Direct Testimony of Bruce Levy on Behalf of International Power PLC, FERC Docket No. AD09-2-000, at 4 (filed on Jan. 13, 2009).

<sup>74</sup> CPV Maryland's view that a long-term contract is necessary in order to finance the Project was confirmed by the Maryland Energy Administration ("MEA") in Case No. 9117. *See Comments of the Maryland Energy Administration*, Case No. 9117 (Nov. 21, 2008).

necessary for, the development of new generation.<sup>75</sup> For example, the Connecticut statute mandating all-source requests for proposals in that state specifically authorized contracts of up to fifteen (15) years.<sup>76</sup>

Last year, in Case No. 9117, the Commission evaluated a long-term procurement plan for providing standard-offer-service to residential and small commercial customers, and asked whether revisions to PJM's RPM program under consideration at that time might result in the development of resources like the St. Charles Project.<sup>77</sup> Unfortunately, at least for the foreseeable future, the answer plainly is "no." RPM's conditional three-year commitment period is simply insufficient to allow new baseload generation to be financed. As currently configured, the RPM is too short-term, too volatile, and too fraught with continued regulatory uncertainty to provide lenders with anything close to the certainty of a fixed revenue stream required for financing. A new capacity resource within a locational delivery area is allowed to lock in a "new entry price" for only a maximum of three years, and only under certain conditions. For precisely these reasons, PJM asked FERC to approve various proposed changes to RPM, including a request for a 7-year term,<sup>78</sup> which at that time might at least have improved the prospects for

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<sup>75</sup> See Comments of New England Power Pool Participants Committee, FERC Docket No. RM07-19-000, *et al.*, at 19 (filed Sep. 14, 2007) ("Long term power contracting can benefit both consumers and suppliers of electricity and can promote the efficient functioning of the organized markets. . . . Long term power contracts also can provide a predictable revenue stream to suppliers, and thus encourage and support new investment in supply and demand resources, which can lower consumer costs and improve reliability. . . ."). The New York Public Service Commission similarly concluded "that utility long-term contracts may be required to support new construction to maintain reliability, if adequate reliability is not provided by the wholesale market or to be judiciously used to achieve other policy goals (*e.g.*, RPS)," and further noted that "[t]he greater availability of short-, medium-, and long-term contracts, voluntary or mandatory, could temper the risk of entry for generators and render financing more available, as recent projects have suggested." *Order Initiating Electricity Reliability and Infrastructure Planning*, State of New York Public Service Commission, Case 07-E-1507, *et al.*, at 21-23 (Dec. 24, 2007).

<sup>76</sup> CONN. GEN. STAT. § 16-243M (2007).

<sup>77</sup> PSC, Case No. 9117, Transcript at 2128 (Commissioner Freifield) (Dec. 19, 2008).

<sup>78</sup> See Explanatory Statement at 20-21 and Offer of Settlement at 12, submitted by PJM Interconnection, L.L.C. in Docket Nos. ER05-1410-012, *et al.* (filed Feb. 9, 2009).

financing projects such as the St. Charles Project. Indeed, the Maryland Commission, along with the Pennsylvania, New Jersey, Delaware and District of Columbia commissions argued that “[t]he uncontradicted evidence before the Maryland Commission demonstrates that five years is wholly inadequate to provide the revenue stream required for a project costing hundreds of millions of dollars.”<sup>79</sup> Unfortunately, however, and strangely, given RPM’s purpose to provide an accurate price signal to new generation, the FERC rejected PJM’s proposal, finding that the longer term would result in price discrimination between existing resources and new generation suppliers.<sup>80</sup>

The problem of the short commitment period in the PJM is compounded by volatile pricing resulting from uncertain and changing rules for the auction processes. In Southwest MAAC, RPM clearing prices for 2007 to 2011 have ranged from \$174.3 MW-Day to \$237.3 MW-Day.<sup>81</sup> Recently, in the 2012-2013 auction, Southwest MAAC prices fell to \$133.37, and other markets in the PJM saw prices fall from \$110.00 in the 2011-2012 auction to \$16.46 in the most recent auction.<sup>82</sup> PJM’s capacity market as currently configured is accordingly too short-term and too volatile to provide the secure revenue stream necessary to support the financing of the St. Charles Project and projects like it. The St. Charles LTC is required to solve this problem and commercialize the Project.

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<sup>79</sup> *PJM Interconnection, L.L.C.*, FERC Docket No. ER09-412-000, “Protest and Comments of Indicated PJM States,” at 13 (Jan. 9, 2009).

<sup>80</sup> *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, at PP 149-150 (2009) (March 26 Order). Requests for Rehearing are currently pending before FERC.

<sup>81</sup> The Brattle Group, “*Review of PJM’s Reliability Pricing Model (RPM)*” (June 30, 2008), available at [http://www.brattle.com/\\_documents/UploadLibrary/Upload696.pdf](http://www.brattle.com/_documents/UploadLibrary/Upload696.pdf).

<sup>82</sup> PJM Interconnection, LLC, “2012/2013 RPM Base Residual Auction Results,” at 13 (May 15, 2009) available at [http://www.pjm.com/markets-and-operations/rpm/~/\\_media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx](http://www.pjm.com/markets-and-operations/rpm/~/_media/markets-ops/rpm/rpm-auction-info/2012-13-base-residual-auction-report-document-pdf.ashx).

CPV Maryland has been unable to negotiate such long-term contracts with one or more utilities, quite possibly because they primarily are interested in shorter term contracts to match their fixed priced load obligations; possibly because the prices required to justify building a new natural gas plant are higher than short-term market signals for capacity and energy under the current PJM market structure;<sup>83</sup> or possibly because load serving entities are inclined only to compare the cost of new resources to the cost of resources available in the current market without taking into consideration the broader ratepayer price benefits that new in-State generation would have on all Maryland load. Moreover, the Commission (and the Legislature) are continuing to grapple with how to develop new generation in the State and with what the appropriate regulatory structure to govern that development should be.<sup>84</sup> It is not at all surprising, then, that amidst all of this uncertainty, Maryland's IOUs might be reluctant to enter into long-term contracts absent a clear directive from the Commission to do so. This is precisely why the St. Charles Project presently cannot be built without the PSC granting CPV Maryland's requested relief even though, as previously mentioned, the St. Charles LTC would provide ratepayer benefits throughout its term by reducing RPM market clearing prices and LMP energy prices for the broader market, notwithstanding current construction costs.

#### **B. St. Charles LTC Terms**

The St. Charles LTC would (a) put all the pre-commercial risks on CPV Maryland; (b) pass through all fuel costs at a transparent index price; and (c) derive a capacity rate based on

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<sup>83</sup> See Testimony of Ray Henger, attached to Motion to Intervene and Protest of CPV Maryland, LLC filed in FERC Docket No. ER09-412-000, (Jan. 9, 2009) as Attachment 3 at 4-5 (stating that PJM's RPM capacity price and pricing term "is likely insufficient to attract meaningful and economically priced leverage to provide the project sponsors with a reasonable return to justify advancing the project into construction").

<sup>84</sup> *In the Matter of the Commission's Investigation of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, PSC Case No. 9117, Transcript at 2127 (Dec. 19, 2008) (S. Segner) ("S. Segner Testimony").

the Project's actual costs, including a rate of return appropriate to such projects, as recommended by the Levitan Report.

The general terms of the St. Charles LTC are set forth in the attached Term Sheet (Exhibit A). These terms are based directly on the so-called "merchant generator with long-term PPA" financial structure set forth in the Levitan Report, which is described as "a merchant generator, contracted to provide unit capacity, dispatchable energy and associated ancillary products to an IOU under a 20-year PPA with an optional 10-year extension term that would be unilaterally exercisable by the IOU."<sup>85</sup> Under the St. Charles LTC, the Project will transfer its capacity to the IOUs and provide the IOUs the right to receive financial energy based on the variable costs of the Project without a profit margin. In return, the Project will receive a capacity price based on a set price of dollars per installed kilowatt. The price of that capacity will be derived directly from the Project's cost data, which CPV Maryland will provide to the Commission and the IOUs, as applicable, on an open book basis (with appropriate confidentiality protections). Such capacity price will be locked in at the time the St. Charles LTC is signed.

CPV Maryland will remain responsible for the physical energy product, but recognizes that while the IOUs will bid into and clear the RPM auction for capacity, CPV Maryland will bid physical energy every hour in PJM's advanced day-ahead markets, as required under PJM's rules. The IOUs may elect to purchase financial energy in the quantities described in the Term Sheet and at the price calculated by the formula set forth in the contract. The price for financial energy will be determined by the following formula: (i) scheduled quantity of energy times (ii) the difference between (a) the market price and (b) the variable costs for generating the energy, which will be set by the Project heat rate times a transparent market fuel index (plus specific transportation charges) plus a per kilowatt hour operation and maintenance

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<sup>85</sup> Levitan Report at 62.

charge and a start-up charge, if applicable. In other words, if the market clearing price is higher than the variable cost to generate electricity calculated under the above referenced formula, the IOUs and Maryland's ratepayers will reap the benefit of that difference.

Furthermore, and also in keeping with the Levitan Report's suggested financial structure, the St. Charles LTC would be considered iron-clad, without any "regulatory out" provision or price re-opener to account for changes in market prices, technology progress, or state or federal regulation.<sup>86</sup> Under this arrangement, the Project would be responsible for plant construction, construction cost overruns, operational performance, fuel costs outside of the pre-agreed upon index price of gas, and operating cost overruns. The Project would accept the 14.6% return on equity recommended in the Levitan Report for such projects.<sup>87</sup> As previously mentioned, the capacity price will be calculated based on the aforementioned factors, will be evaluated through an open book process discussed in Section C below, and will be locked in at the time the respective St. Charles LTC is executed. Additional terms would include:

- (a) Project-guaranteed forced outage factors, with capacity price penalties for shortfalls;
- (b) dispatchability terms; and (c) standard force majeure language.

Prior to the Commission ruling on CPV Maryland's requested relief, CPV Maryland in conjunction with Commission Staff proposes to fully develop an executable pro forma contract, based on the Term Sheet, that is acceptable to the Commission. This pro forma contract will then be utilized to negotiate the respective St. Charles LTC with the IOUs (or, should that negotiation be unsuccessful, with Commission staff).

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<sup>86</sup> *Id.*

<sup>87</sup> Levitan Report at 63.

### **C. Open Book Process for Reviewing Cost Data**

As discussed in Section B above, CPV Maryland proposes to share its actual cost data with the Commission and the IOUs, and to derive the price per kilowatt for the capacity directly from that actual cost data. At any time subsequent to the Commission issuing an order granting CPV Maryland's requested relief, until such time as the St. Charles LTC is executed, CPV Maryland will also share (to the extent legally permitted) its economic analyses and its pro forma with the Commission Staff and with the IOUs with which it is negotiating. The negotiated capacity price, as derived from the cost data, will be locked into the executed St. Charles LTC for its duration.

## **IV. THE ST. CHARLES PROJECT STATUS AND NEED FOR EXPEDITED TREATMENT**

### **A. Project Milestones**

Over the last 27 months, CPV Maryland already has spent over \$12 million dollars in developing the St. Charles Project. The Project now is in advanced stages of development in preparation for the start of construction. With its location in the transmission constrained Southwest MAAC region, it is one of the few projects actively being developed in PJM's most constrained areas, and it is the only large scale project positioned to prevent the shortfall in electricity that Southern Maryland and the Washington, DC region are forecast to experience as early as 2012, while in addition being able to provide the above-mentioned benefits to Maryland ratepayers. On November 8, 2008, the Commission issued a final Certificate of Public Convenience and Necessity ("CPCN") to CPV Maryland (PSC Case No. 9129, Order No. 82309) for the Project's construction and operation. On January 16, 2009, the United States Army Corps of Engineers granted CPV Maryland's request to modify its wetlands permit. CPV Maryland also expects to receive quite soon the remaining Federal, State and local approvals required for the Project.

On December 10, 2008, CPV Maryland and Charles County executed a Development Agreement governing the County's sale to the Project of potable water, sewer service and reclaimed water; providing for the conveyance of real estate rights for portions of the 13.9 mile long reclaimed water line that lies on County property; providing a payment-in-lieu-of-County taxes; and outlining a tax exempt bond structure that the County will utilize for the construction of the reclaimed water pipeline. Additionally, CPV Maryland continues to work with third parties to secure all necessary equipment for the Project and to put in place the service agreements necessary for construction and operation.

Finally, CPV Maryland has been actively working with PJM in shepherding the Project through the interconnection study process. It executed a Facilities Study Agreement with PJM on December 8, 2008 and expects that PJM will complete the Study by the end of 2009. Because it has one of the highest queue positions in PJM, this will enable the Project to come online faster and with significantly less electrical interconnection costs than any other proposed projects in the area.

#### **B. Request for Expedited Treatment**

CPV Maryland seeks to start construction of the St. Charles Project as soon as possible in order to achieve a June 1, 2012 commercial operation date. Doing so also would result in ratepayers and the State beginning to receive the overall economic and environmental benefits as soon as possible. Before any of this can happen, however, CPV Maryland requires the certainty of a revenue stream produced by a long-term contract in order to commit the additional millions of dollars necessary to move the Project to commercial operation. In particular, without a long-term contract, CPV Maryland cannot complete the Project agreements necessary to construct the St. Charles Project, including the Interconnection Service Agreement ("ISA"), the Engineering, Procurement and Construction Contract, the Turbine Supply

Agreement and the Gas Interconnection Agreement. None of these core Project agreements can be finalized and secured unless CPV Maryland puts down substantial collateral. Indeed, some of these collateral commitments individually exceed the total investment CPV Maryland already has made in development costs, and were it to move forward, it would be forced to incur yet additional substantial obligations that could result in considerably greater penalties should the Project not go forward. In a nutshell, then, the Project will not be able to meet a June 1, 2012 in-service date unless it makes these expenditures and finalizes these core Project agreements, but CPV Maryland cannot make these expenditures and take on these additional risks unless it has a long-term contract in place. So, the absence of a long-term contract, then, jeopardizes CPV Maryland's ability both to meet the critical Project milestones, and to provide the many benefits the Project has to offer.

As noted, the failure to finalize these key Project agreements also would add substantial costs to the Project. For example, as also noted, CPV Maryland is holding a "front of the line" position in the PJM interconnection queue, and expects that PJM will issue its Final Facilities Study and ISA no later than December 1, 2009. At that time, CPV Maryland will have sixty (60) days to execute the ISA, which in turn would require CPV Maryland to post approximately \$18 million in security for the network upgrades covered under the ISA. Without the security of a long-term contract, the Project will face two untenable choices (likely at the very beginning of next year): either to post the \$18 million security or to release its valuable interconnection queue position and re-enter the queue. A preliminary study indicates that relinquishing its queue position and re-entering the queue would cost approximately \$78 million in network upgrade costs, or \$60 million more than the upgrades are estimated to cost were CPV Maryland able to maintain its current queue position. This economic burden is but one example of why the Project needs to enter into a long-term contract prior to the end of 2009.

Accordingly, in order to meet a June 1, 2012 on-line date and to start accruing benefits as early as possible, CPV Maryland requests that the Commission issue an order, within sixty (60) days of the filing of this Motion, i.e. by September 4, 2009, requiring the IOUs (who, to date have expressed no particular willingness to enter into a long-term contract) to negotiate and enter into long-term contracts with CPV Maryland consistent with the Term Sheet and with the pro forma contract to be developed between Commission Staff and CPV Maryland.<sup>88</sup> The parties will then have thirty (30) days to negotiate and execute the St. Charles LTC; should they fail, CPV Maryland respectfully suggests that the Commission, through its Staff, directly negotiate these contracts with CPV Maryland on behalf of the IOUs. Additionally, CPV Maryland requests that by December 4, 2009, the Commission approve all such St. Charles LTCs as executed.

If the St. Charles LTC is in place by December 4, 2009, CPV Maryland will be in a position to close project financing, likely a four month process, by April of 2010, and to meet its obligation under CPCN Permit Condition 10(a) to commence construction by April 8, 2010. The Project could then offer itself as a new capacity resource in the May 2010 PJM capacity auction for delivery year 2013/2014.<sup>89</sup> Reaching financial close in April, combined with the projected 26

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<sup>88</sup> The circumstances do not warrant or allow sufficient time for the PSC to hold a competitive bidding process for the long-term contract requested by CPV Maryland. In any event, there are no valid CPCNs that would allow for the construction of new Maryland baseload or intermediate generation in the same timeframe as the St. Charles Project; thus, the St. Charles Project would be the only eligible bidder for such an RFP. Moreover, the delays associated with developing and holding such an RFP would prevent the Project from being in service by June 1, 2012 and would also likely subject the Project to the additional \$60 million network upgrade cost discussed above. As previously noted, the Commission has authority to require IOUs to enter into long-term contracts “outside the competitive process.” *See* MD. CODE ANN., PUB. UTIL. COS. § 7-510(c)(4)(ii)(B).

<sup>89</sup> Without having bid in the May 2009 capacity auction, CPV Maryland can produce revenues from the sale of energy during the 2012/2013 year and also has the opportunity to bid into the incremental capacity auctions for 2012/2013; however, to economically operate in 2013/2014, the Project must bid into the May 2010 auction.

month construction period, would then allow the Project to achieve a June 1, 2012 commercial operation date.

In short, CPV Maryland's request for expedited treatment is based on the timing and milestones necessary to commence construction and to operate as soon as possible, so as to swiftly allow the Project to go commercial, thereby allowing its many benefits to be realized. But, as noted above, although CPV Maryland would like to commence construction of the Project in 2010, it cannot do so unless the Commission grants its request for expedited review and orders the requested relief no later than sixty (60) days from the date the Motion is filed.

## V. CONCLUSION

Of the more than 3,000 MW of new generation approved by the Commission in recent years, as of the end of 2009, only 200 MW has actually reached commercial operation.<sup>90</sup> Projects in general cannot sit on the shelf indefinitely, and the Commission is well aware that lengthy delays ultimately can threaten the likelihood that a project will ever reach commercial operation.<sup>91</sup>

Therefore, CPV Maryland respectfully requests that the Commission within sixty (60) days grant this Motion, and order the IOUs to negotiate and enter into a long-term contract with the St. Charles Project for the sale of its energy and capacity. CPV Maryland further requests that the order contain a provision that requires the IOUs to finalize the St. Charles LTC within thirty (30) days from the issuance of such order stating that should the parties fail to reach such agreement, the Commission Staff will negotiate the respective St. Charles LTC with CPV Maryland on the IOUs' behalf, which would enable the Commission to approve the St. Charles LTCs as executed by December 6, 2009.

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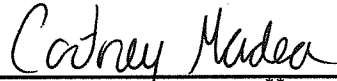
<sup>90</sup> Final Report of the Public Service Commission of Maryland to the Maryland General Assembly: Options for Re-Regulation and New Generation at 27 (Dec. 10, 2008) ("PSC Final Report").

<sup>91</sup> D. Magill Testimony at 2134.

July 6, 2009

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Respectfully Submitted,



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**Counsel for CPV Maryland, LLC**

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\* Not admitted in Maryland, licensed to practice in the District of Columbia, Pennsylvania and Massachusetts.

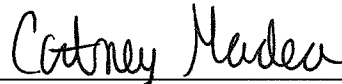
\*\* Not admitted in Maryland, licensed to practice in the District of Columbia and Pennsylvania.

\*\*\* Not admitted in Maryland, licensed to practice in the District of Columbia.

**CERTIFICATE OF SERVICE**

I hereby certify that a copy of the foregoing Motion of CPV Maryland, LLC was served upon all parties of record for Case No. 9117 by either e-mail or first-class mail, postage prepaid.

Dated at Washington, D.C. this 6th day of July, 2009.



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Fax: (202) 420-2201

## Exhibit A – St. Charles Long-Term Contract Terms

<b>Seller:</b>	CPV Maryland, LLC (“Seller”)
<b>Buyer:</b>	Buyer (“Buyer”)
<b>Products:</b>	1) Unit Contingent Physical Capacity 2) Unit Contingent Energy Tolling (financially settled)
<b>Contract Term:</b>	20 Years starting at COD (expected Q2 2012).  Note: Actual COD will be dependent on timing of execution of PPA with Buyer and other key transaction agreements
<b>Collateral:</b>	Seller will provide security, in a form to be mutually agreed upon, based on the following:  a) \$5 /KW at contract execution, b) \$50 /KW at Financial Closing, c) \$25 /KW at Commercial Operations Date and reduced over the contract’s life.
<b>Project Milestones:</b>	Assuming that definitive agreements are executed, Seller shall guarantee the following Construction Milestones:  a) Financial Closing by Q2 2010 b) Delivery of Major Equipment to site by Q2 2011 c) Commercial Operations Date by Q2 2012  Failure to achieve a Project Milestone within 12 months of the specified date not due to Force Majeure or Excused Delays shall be an Event of Default by Seller.
<b>Capacity Transfer:</b>	Seller will transfer physical capacity to Buyer starting with capacity to be delivered in 2012/2013 planning year and annually thereafter via PJM eRPM system. Buyer will be responsible for bidding the capacity into the PJM RPM Auctions.
<b>Capacity Payment (2012 \$):</b>	\$___ <b>per KW-mo (2012 \$)</b> multiplied by the fixed contract capacity of 640 MW (“Contract Capacity”). The Capacity Payment will consist of two components:  Capacity Charge - \$___ <b>per kW-mo [flat (i.e., not escalating)]</b> multiplied by Contract Capacity  Fixed O&M Charge - \$___ <b>per kW-mo escalating</b> annually at

	CPI multiplied by Contract Capacity														
<b>Quantity:</b>	<p>Energy offered to Buyer will be available to be scheduled based on an Annual Capacity Test and adjusted for temperature and humidity conditions for each hour during the year. The following quantities are the expected new and clean outputs at various temperatures:</p> <table style="width: 100%; border: none;"> <tr> <td style="width: 70%;">92F Base Quantity</td> <td style="text-align: right;">517 MW</td> </tr> <tr> <td>59F Base Quantity</td> <td style="text-align: right;">545 MW</td> </tr> <tr> <td>10F Base Quantity</td> <td style="text-align: right;">565 MW</td> </tr> <tr> <td colspan="2"> </td> </tr> <tr> <td>92F Duct Burner Quantity</td> <td style="text-align: right;">113 MW</td> </tr> <tr> <td>59F Duct Burner Quantity</td> <td style="text-align: right;">115 MW</td> </tr> <tr> <td>10F Duct Burner Quantity</td> <td style="text-align: right;">109 MW</td> </tr> </table>	92F Base Quantity	517 MW	59F Base Quantity	545 MW	10F Base Quantity	565 MW			92F Duct Burner Quantity	113 MW	59F Duct Burner Quantity	115 MW	10F Duct Burner Quantity	109 MW
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<b>Contract Heat Rates:</b>	<p>The Hourly Base Load Heat Rate and the Hourly Duct Burner Heat Rate used for the Energy Payment will be based on the Annual Heat Rate Test, which shall be conducted annually including the first year, and adjusted for actual hourly temperature and humidity conditions during the year. The following are the expected new and clean heat rates at ISO conditions.</p> <table style="width: 100%; border: none;"> <tr> <td style="width: 40%;">Base Load Heat Rate</td> <td style="text-align: right;">6.70 MMBtu/MWh</td> </tr> <tr> <td> </td> <td> </td> </tr> <tr> <td>Duct Burner Heat Rate</td> <td style="text-align: right;">9.0 MMBtu/MWh</td> </tr> </table>	Base Load Heat Rate	6.70 MMBtu/MWh			Duct Burner Heat Rate	9.0 MMBtu/MWh								
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<b>Financial Energy Scheduling:</b>	<p>During the Term and subject to the provisions hereof, Buyer may elect to schedule its Financial, Day-Ahead Energy under the provisions set out in clauses (i), (ii) and (iii) below.</p> <p><b>(i) <u>Quantity</u></b> - Buyer may schedule for each hour either: (a) No Energy, (b) the Base Quantity, or (c) the Base Quantity plus the Duct Burner Quantity.</p> <p><b>(ii) <u>Hours of Scheduled Operation</u></b> –</p> <p>(a) The Base Quantity shall be scheduled for no fewer than 6 consecutive hours.</p> <p>(b) The Duct Burner Quantity shall be scheduled only when the Base Quantity has also been scheduled and may be scheduled for any hour or hours contiguous or non-contiguous within any block permitted under the foregoing clause (a) without incurring a Start Charge.</p> <p>(c) Scheduling the Facility will be limited to operating restrictions of the Facility, including but not limited to restrictions in the Air</p>														

	<p>Permit that limit the annual # of starts per year to approximately 200 factored starts.</p> <p>(d) Following the last hour of a schedule, the next scheduled hour cannot be incurred until 6 hours have elapsed, i.e., minimum down time of 6 hours.</p> <p><b>(iii) Daily Scheduling</b> - For each calendar day, Buyer shall notify Seller via an Excel spreadsheet in an email the Quantity that it is scheduling for each hour for such calendar day by 8:00 a.m. EPT on the Gas Business Day immediately prior to such calendar day.</p>
<p><b>Energy Payment and Financial Settlement Procedure:</b></p>	<p>Seller pays Buyer the sum of all hourly Energy Payments (defined below) over the applicable Payment Period plus the aggregate Start Charges for such Payment Period.</p> <p><u>For each hour of exercise (excluding Forced Outage hours), the Energy Payment shall equal:</u></p> $[EIP - (((GIP + GA) * CHR) + VOM)] * NQ$ <p>For the purposes of the above calculation:</p> <p>“EIP” means Electricity Index Price;</p> <p>“GIP” means Gas Index Price;</p> <p>“GA” means Gas Adder;</p> <p>“CHR” means Contract Heat Rate which shall be the weighted average of the Hourly Base Load Heat Rate and Duct Burner Heat Rate;</p> <p>“NQ” means Notional Quantity, which shall equal, as applicable, the total Quantity exercised for each hour; and</p> <p>“VOM” means Variable O&amp;M Charge. See the Major Maintenance Charge section.</p> <p><u>Start Charge</u> – See the Major Maintenance Charge section. A Start Charge will apply based on the Hour/Start Ratio and it will be based on the number of scheduled starts over a Payment Period. Start Charges will be incurred based on the schedule not actual starts of the facility.</p> <p><u>Outages</u> - In the event that there is a Forced Outage or Scheduled Maintenance for a particular hour, there will not be a financial settlement for the Energy Payment for that particular hour, i.e., the</p>

	Transaction is unit contingent.									
<b>Gas Index Price:</b>	The Price per MMBTU of Gas stated in U.S. dollars and published under the heading “Daily Price Survey (\$/MMBTU): Citygates: <u>Transco, Zone 6 Non-NY</u> : Midpoint” for the flow date that corresponds to the Scheduled Energy, as published by Platts, a division of the McGraw-Hill Companies Inc, in the Daily Price Survey Section of Gas Daily.									
<b>Electricity Index Price:</b>	For the applicable hour, the Hourly, Day Ahead Market LMP Nodal price for the Facility (PJM PNode), as published by PJM.									
<b>Gas Adder:</b>	\$0.13 per MMBtu November through March  \$0.02 per MMBtu April through October									
<b>Major Maintenance Charge:</b>	<p>The Major Maintenance Charge is intended to be a pass through of Seller’s variable operating costs. The Seller does not intend to over collect or under collect these variable operating costs. The Major Maintenance Charge is a combination of a Start Charge and a VOM Charge, which depend on the ratio of scheduled starts to operating hours between maintenance intervals.</p> <p>The below Major Maintenance Charges (2012 \$) shall escalate annually at CPI. They are based on a preliminary GE long term service agreement proposal for a similar facility.</p> <table border="1" data-bbox="516 1171 1265 1430"> <thead> <tr> <th><b>Hours/Start Ratio</b></th> <th><b>&lt; 26:1</b></th> <th><b>&gt; 26:1</b></th> </tr> </thead> <tbody> <tr> <td><b>Start Charge (\$ / Start)</b></td> <td>\$30,400 + (3,000 MMBtus * Gas Index)</td> <td>\$0 + (3,000 MMBtus * Gas Index)</td> </tr> <tr> <td><b>VOM (\$ / MWh)</b></td> <td>\$.90 / MWh</td> <td>\$2.85 / MWh</td> </tr> </tbody> </table> <p>Each month, the Project will charge the Buyer a Start Charge and a VOM Charge pursuant to that month’s ratio of hours to start based on the number of scheduled starts and number of scheduled hours. At the end of a maintenance interval, Seller shall true up any difference in monthly Start Charges and VOM Charges paid by Buyer with the corrected Start Charges and VOM Charges using the actual ratio of hours to starts between maintenance intervals. A maintenance interval will occur every 16,000 operating hours or 375 starts, whichever is sooner.</p>	<b>Hours/Start Ratio</b>	<b>&lt; 26:1</b>	<b>&gt; 26:1</b>	<b>Start Charge (\$ / Start)</b>	\$30,400 + (3,000 MMBtus * Gas Index)	\$0 + (3,000 MMBtus * Gas Index)	<b>VOM (\$ / MWh)</b>	\$.90 / MWh	\$2.85 / MWh
<b>Hours/Start Ratio</b>	<b>&lt; 26:1</b>	<b>&gt; 26:1</b>								
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<b>VOM (\$ / MWh)</b>	\$.90 / MWh	\$2.85 / MWh								
<b>Availability:</b>	This Transaction is unit contingent. However, Seller will guarantee									

	<p>that the Facility’s Forced Outage Rate (as defined by GADS) will not be greater than 5% on an annual basis (the Guaranteed Forced Outage Rate).</p> <p>Buyer’s sole remedy for Seller not meeting the Guarantee Forced Outage Rate will be based on the following:</p> <p>a) In the event that the Facility’s Forced Outage Rate is higher than the Guaranteed Forced Outage Rate, the Annual Capacity Charge shall be reduced by 1 percentage point for each 1 percentage point of increased Forced Outage Rate.</p> <p>b) In the event the Facility’s Forced Outage Rate is less than the Guaranteed Forced Outage Rate, the Annual Capacity Charge shall be increased by 1 percentage point for each 1 percentage point of decreased Forced Outage Rate up to a decrease of 2 percentage points.</p> <p>c) Scheduled Maintenance hours will not be considered Forced Outage hours. Scheduled Maintenance will be based on equipment manufacturer recommendations. Seller shall provide Buyer reasonable notice of Scheduled Maintenance periods.</p> <p>d) In the event that there is a Forced Outage or Scheduled Maintenance for a particular hour, there will not be a financial settlement for the Energy Payment for that particular hour, i.e., the Transaction is unit contingent.</p>
<p><b>Scheduling / Fuel Procurement / Transportation:</b></p>	<p>Seller shall be responsible for all scheduling in compliance with PJM protocols.</p> <p>Seller shall be responsible for the management, procurement and transportation of all natural gas for the Project.</p>
<p><b>Carbon Costs:</b></p>	<p>Buyer shall be responsible for the costs of securing all required carbon allowances and shall retain all rights to the benefits of the carbon credits or allowances available to the Project. The Project may be eligible for up to 100% of the CO2 allowances necessary to operate the plant for up to the first 6 years of operation, pursuant to MDE’s Clean Generation Set Aside of the State RGGI program.</p>

Figure ES-1: Expected Annual Portfolio Costs

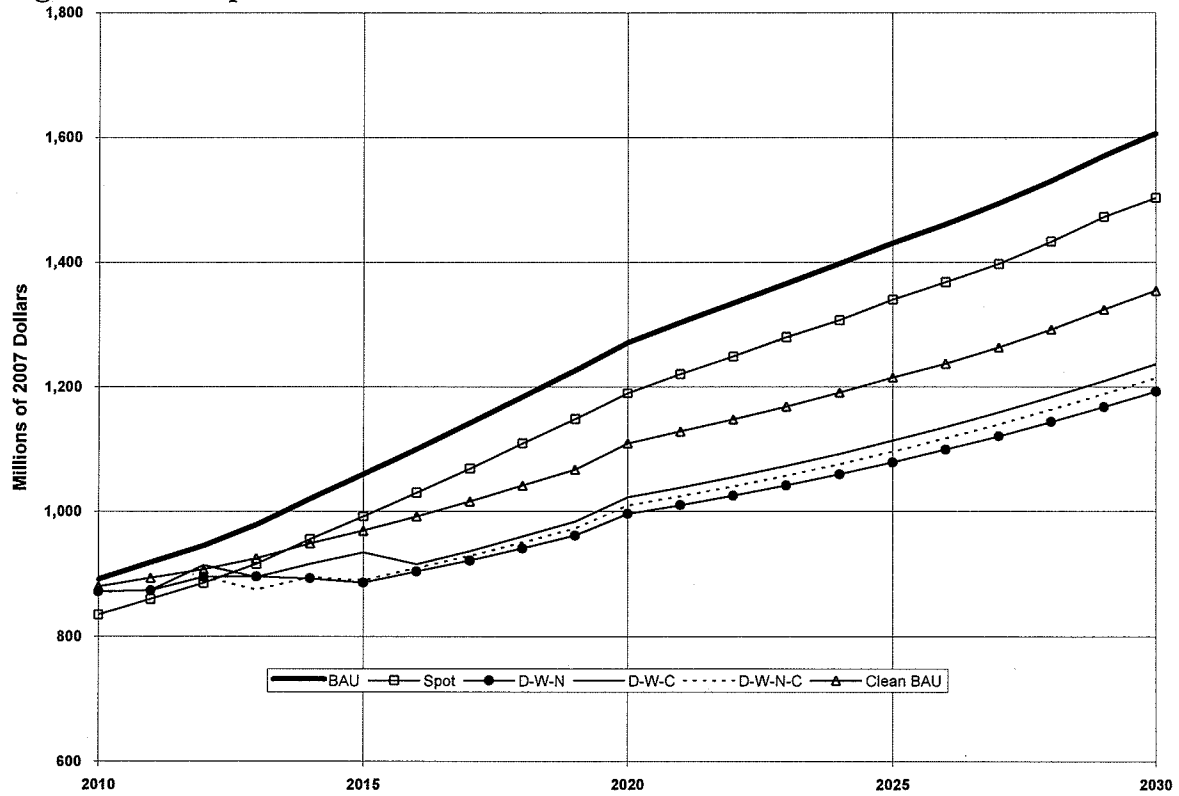


Figure ES-2: Long-Term Cost vs. Risk by Portfolio

