STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

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	**)**	

DIRECT TESTIMONY OF

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ON BEHALF OF

THE OFFICE OF PEOPLE'S COUNSEL

Resource Insight, Inc.

SEPTEMBER 14, 2007

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I. Introduction and Summary

Q: Please state your name, occupation, and business address.

A: I am Jonathan F. Wallach. I am Vice President of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Please summarize your professional education and experience.

A: I have worked as a consultant to the electric-power industry for more than two decades. From 1981 to 1986, I was a research associate at Energy Systems Research Group. In 1987 and 1988, I was an independent consultant. From 1989 to 1990, I was a senior analyst at Komanoff Energy Associates. I have been in my current position at Resource Insight since September of 1990.

Over the last twenty-six years, I have advised clients on a wide range of economic, planning, and policy issues including: electric-utility restructuring; wholesale-power market design and operations; transmission pricing and policy; market valuation of generating assets and purchase contracts; power-procurement strategies; integrated resource planning; cost allocation and rate design; and energy-efficiency program design and planning.

My resume is attached as Exhibit JFW-1.

Q: Please summarize your experience with regard to the issue of electric restructuring in Maryland.

A: In 1997, I co-authored a major study of electric-utility restructuring in Maryland for the Office of People's Counsel ("OPC"). Since then, I have advised and testified on behalf of OPC in most of the major proceedings relating to Maryland's restructuring process. I assisted OPC during settlement negotiations, and testified in support of such settlements, in Case Nos. 8794, 8795, and 8797 (regarding electric restructuring), 8890 (regarding the proposed merger of Potomac Electric Power Company and Delmarva Power & Light), and 8908 (regarding procurement of Standard Offer Service ["SOS"].) I also testified in Case Nos. 8852 (regarding proposed fees for electricity-supplier services), 8994 and 8995 (regarding determination of the residential SOS Administrative Charge), 8985 (regarding Southern Maryland Electric Cooperative's ["SMECo"] SOS procurement plan), 9052 (regarding the transition to market-based SOS rates for Baltimore Gas & Electric's residential customers), 9056 (regarding default service for Type II customers), 9064 (regarding residential SOS procurement), and 9063 (regarding optimal structure.) Most recently, I testified in Case Nos. 9091 (regarding Allegheny Power's transition plan) and 9099 (regarding the Commission's investigation of residential SOS rates.) Finally, on OPC's behalf, I have monitored the SOS procurement process in every year since its inception.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Office of People's Counsel.

Q: What is the purpose of your testimony?

A: On August 16, 2007, the Commission issued Order No. 81563 initiating a proceeding to investigate "alternatives or modifications to the current SOS procedures" for residential and small-commercial customers. Specifically, the Commission's order sets forth a series of questions regarding implementation of a "managed portfolio program." In addition, the Commission's order seeks testimony regarding the merits of a proposal by

Direct Energy Services to aggregate and serve customers enrolled in the Electric Universal Service Program ("EUSP").

This testimony discusses the benefits associated with long-term portfolio planning and procurement, and addresses the Commission's questions set forth in Order No. 81563 regarding the design of a portfolio-management program.[1] In addition, this testimony addresses Direct Energy's proposal to aggregate EUSP customers, as set forth in its August 8, 2007 Petition to the Commission ("Petition").[2]

The Office of People's Counsel is also sponsoring direct testimony by Roger Colton that assesses the impact of Direct Energy's proposal on energy affordability for EUSP customers, and discusses alternative measures for improving affordability for all low-income consumers.

Q: Please summarize your recommendations with regard to portfolio planning and procurement.

A: The Commission should direct the utilities to initiate a comprehensive planning process for the purposes of developing a long-range plan for procuring a diversified portfolio of short-, medium-, and long-term supply, demand, and transmission resources to serve residential SOS load in their respective service territories. In addition, the utilities should be directed to coordinate on the development of a statewide and (where appropriate) regional procurement plan for the purposes of identifying and procuring new resources that provide statewide or regional benefits.

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[1] My testimony addresses these issues solely with respect to the provision of standard offer service for residential customers. However, for the most part, my findings and conclusions would likely also apply with respect to SOS for small-commercial customers.

[2] "Petition of Direct Energy Services, LLC", Case No. 9117, August 8, 2007.

The integrated planning process should be designed to comprehensively and explicitly account for the impact of forecast uncertainty, and to quantify the trade-offs between expected cost and cost risk for each portfolio evaluated during the planning process. The primary objective of the planning process should be to identify preferred resource portfolios and procurement targets that minimize costs at acceptable levels of risk.

The utilities should seek to procure a portfolio of resources consistent with the procurement targets established in the integrated portfolio plan. To the extent feasible, the procurement program should rely on competitive forces to reduce wholesale-power costs. Moreover, the procurement process should be flexible, in order to encourage wholesale-supplier participation and competitive pricing of resource offers, and dynamic, to allow timely adjustments in light of changing market conditions.

Q: Please summarize your findings and conclusions regarding Direct Energy's proposal to aggregate EUSP load.

A: The Commission should reject Direct Energy's Petition as contrary to the public interest. Direct Energy's proposal would substantially increase migration risk to wholesale SOS suppliers, and thus might significantly increase residential SOS prices without offering any guarantee of savings to EUSP participants. Moreover, the proposal inappropriately and unreasonably shifts to residential ratepayers Direct Energy's uncollectible costs associated with serving EUSP customers. Direct Energy offers no valid reason why residential customers should subsidize Direct Energy's costs and contribute to Direct Energy's bottom line.

Finally, Mr. Colton concludes that Direct Energy's proposal is unlikely to significantly improve energy affordability for low-income consumers.

II. Benefits of Portfolio Planning and Procurement

Q: Should the Commission implement a managed portfolio program for residential customers?

A: Yes. For the last three years, in accordance with the settlement agreements in Case No. 8908 and the Commission's order in Case No. 9064, Maryland's investor-owned utilities (with the exception of Allegheny Power) have procured short-term full-requirements contracts to serve residential SOS load. This procurement approach has yielded market prices for residential SOS supply that are contrary to the public interest.[3] With its sole reliance on short-term full-requirements contracts to serve residential SOS load, the 8908/9064 approach has needlessly exposed consumers to the dramatic increases in price levels and volatility that have shaken PJM's spot markets.

The short-term procurement horizon under the current approach is also inconsistent with the utilities' permanent obligation to provide residential SOS, as established in Senate Bill 1 of 2006 Special Session ("SB1").[4] Utilities will need to extend their planning and procurement horizons in order to meet their obligations under SB 1 to provide a best-priced SOS over the long term. This extended horizon, in turn, allows for consideration of longer-term and alternative resources to maximize the benefits from portfolio diversification.

Consequently, the current approach should be modified to allow procurement of a broad portfolio of both longer-term supply and demand options and short-term full-requirements contracts. A portfolio approach, by

[3] These concerns will likely also apply to residential SOS prices for Allegheny Power once Allegheny transitions to market-based SOS prices.

[4] Chapter 5, Senate Bill 1 (2006 Md. Laws, 1st Spec. Sess.)

diversifying the mix of resources relied on to serve SOS load, would likely reduce consumers' exposure to harmful spot-price trends, and allow for the procurement of a "portfolio of electricity supply that provides electricity at the lowest cost with the least volatility."[5]

The benefits of portfolio procurement have been recognized in a number of other jurisdictions. The Delaware Public Service Commission recently ruled that:

> We accept Staff's recommendation that DP&L's SOS requirements be provided from a portfolio of supply that shall include Sustainable Energy Utility concepts (to the extent that they fit). While we understand that we cannot diversify away all risk, we believe that a portfolio approach presents the best way to mitigate risk. Thus, we approve Staff's recommended portfolio approach for energy planning.[6]

The Illinois General Assembly likewise found that:

> Procuring a diverse electricity supply portfolio will ensure the lowest total cost over time for adequate, reliable, efficient, and environmentally sustainable electric service.[7]

Finally, according to Sandra Meyer, President of Duke Energy Ohio:

> As the availability of power in the region declines, we need to protect our customers from the increased volatility that inevitably comes with tighter supplies. Long-term contracting and the addition of new generation will be far less expensive over time than continuing to rely so heavily on the annual wholesale market.[8]

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[5] This is the standard established by SB 1, Section 7.

[6] Delaware Public Service Commission, *Findings, Opinion and Order No. 7199*, PSC Docket No. 06-241, May 22, 2007, Paragraph 51.

[7] Illinois Public Act 095-0481, §1-5(5).

[8] "Duke Energy Ohio Proposes Electric Supply Plan", Press Release, August 30, 2007.

Q: Are you recommending that the Commission direct utilities to implement SMECo's approach to portfolio management?

A: No. As acknowledged by SMECo in Case No. 9099, the cooperative's portfolio-management program incorporates a narrow slate of products and terms, in part due to a prior Commission ruling that limited the procurement horizon to three years.[9] As a result, SMECo's members have not had the opportunity to benefit from a fully diversified long-term portfolio.

However, as discussed below, I do recommend a planning approach akin to SMECo's, which explicitly addresses and measures the impact of planning uncertainty on projected portfolio costs.

Q: What are the likely wholesale-market drivers of the price trends experienced under the current procurement approach?

A: There have been a number of developments in PJM's spot markets that have contributed to generation price trends for residential customers. These developments include:

- A heavy reliance on natural gas as the marginal fuel, along with unprecedented increases in gas prices and price volatility over the last few years.[10]
- Rising congestion costs, due to rising marginal fuel prices and the failure of merchant generation or transmission investors to invest in projects to relieve congestion in response to spot price signals.[11]

[9] This restriction was lifted with the enactment of House Bill 60 in 2007. Ch. 2, HB60 (2007 Md. Laws).

[10] The spot price of natural gas at the Henry Hub *tripled* between 1999 and 2006, representing an annual average escalation rate of 17% over this seven-year period.

- A radical restructuring of PJM's installed-capacity market that, true to market expectations, has significantly increased capacity costs.
- The implementation of scarcity-pricing rules, including exemptions on market mitigation, increasing the risk of higher prices and greater price volatility during high-load hours.

These market developments have increased both spot-market price levels and price risk over the last few years.[12] These spot-price trends have driven trends in the forward markets, which, in turn, have increased the costs and exacerbated the risks associated with providing full-requirements service.

Q: Why are gas prices driving price levels and volatility in electric markets?

A: Natural gas is a predominant "marginal fuel" in the PJM spot market. In other words, prices in PJM's energy market are set by gas-fired generators in a substantial number of on-peak hours, even though gas-fired generation represents a minor share of total energy production.[13] According to PJM's Market Monitoring Unit, in 2006, units fueled by natural gas were the marginal unit 25% of the time, yet represented only 6% of total PJM

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[11] Between 2000 and 2006, congestion costs rose from $132 million to $1,603 million, or about twelve times. Congestion costs peaked in 2005 at $2,092 million. The 23% decline in congestion costs between 2005 and 2006 almost exactly matches the decline in Henry Hub spot gas prices during this same period.

[12] For example, average annual prices in PJM's real-time market increased 75% between 2000 and 2006, for an average escalation rate of about ten percent per year.

[13] As noted above, gas prices are not the sole driver of PJM spot-price levels and volatility. In fact, in 2006, PJM Western Hub daily spot prices were significantly more volatile than Henry Hub daily spot prices.

generation in that year.[14] As a result, PJM spot prices are increasingly driven by natural-gas prices. For example, between 2000 and 2006, PJM real-time on-peak prices increased 51%, while Henry Hub spot prices increased 57%.

Forward electric prices, which reflect expectations regarding future spot prices, also tend to follow natural-gas prices. This effect is illustrated in Exhibits JFW-2 and JFW-3, which compare daily closing prices for PJM on-peak forwards against daily closing prices for Henry Hub natural gas forwards. For both the electric and gas forwards, Exhibit JFW-2 shows for each trading day in 2007 (through September 30, 2007) the closing price for the twelve-month strip for calendar-year 2008.[15] Exhibit JFW-2 shows the extremely tight correlation between gas and electric forward prices. Using the closing-price data shown in Exhibit JFW-2, Exhibit JFW-3 provides the percentage change in daily closing prices relative to the previous day's closing price. Exhibit JFW-3 further illustrates the close correlation between gas- and electric-forward price changes, as well as the fact that both markets exhibit large daily price swings.

Q: Have these developments in PJM's spot markets heightened the risks associated with providing full-requirements service?

A: Yes. Suppliers of full-requirements service assume all price- and volume-related risk associated with serving residential SOS load. These developments – e.g., increased gas prices and volatility, increased congestion

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[14] PJM Interconnection, LLC, *2006 State of the Market Report*, March 8, 2007, Table 2-30, p. 56 and Figure 3-27, p. 131.

[15] For each trading day, Exhibit JFW-2 provides the average of that day's twelve closing prices for the twelve monthly forward contracts for 2008.

costs – amplify the consequences of unanticipated movements in spot prices or changes in load.

Potential suppliers of full-requirements service are likely to respond to this enhanced risk by either increasing risk premiums on price offers or by declining to participate in the bidding process.

Q: Given the apparent correlation between gas prices and pricing of short-term full-requirements contracts, how can the current procurement approach be modified to reduce consumers' exposure to gas-price volatility?

A: The tight linkage between natural-gas and SOS prices can be loosened by: (1) reducing the reliance on short-term full-requirements contracts to serve SOS load (such as those procured under the current approach); and (2) diversifying or staggering contract durations for those full-requirements contracts included in the SOS supply portfolio. Broadening the SOS supply portfolio to include longer-term supply and demand resources should move SOS prices away from the volatile gas-driven margin and toward more-stable cost-based levels. Such long-term options include direct investment, baseload or intermediate bilateral fixed-block contracts, unit-contingent contracts, slice-of-system purchases, demand-response and energy-efficiency resources, peaking capacity and energy contracts, tolling agreements, financial derivatives, options, and other financial products. Diversifying or staggering contract durations for full-requirement contracts should dampen price volatility by limiting the amount of new contracts at prevailing market prices that need to be procured at any one time.

In sum, diversification of wholesale supply for residential SOS load is likely to provide a superior "risk-return profile" (i.e., expected cost relative to cost risk) than the portfolio of full-requirements contracts procured under the current approach.

Q: Have other restructured States implemented programs for procuring long-term resources?

A: Yes. A number of restructured States are in the process of procuring long-term resources, or are considering the issue of long-term procurement, including:

- **Connecticut.** The Department of Public Utility Control recently approved the award of 15-year contracts with new supply resources.[16] In addition, Connecticut Light and Power Company recently filed a motion with the DPUC requesting amendment of the process for procuring default-service supply to allow procurement of bilateral contracts.[17]
- **Delaware.** In May of this year, the Public Service Commission directed Delmarva Power and Light to negotiate long-term contracts with three respondents to an RFP issued in November of 2006.[18]
- **Illinois.** Illinois Senate Bill 1592, recently signed into law, scrapped the auction process then in place for procuring short-term full-requirements contracts and established a statewide power authority to procure a portfolio of resources on behalf of the State's utilities.

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[16] Connecticut Department of Public Utility Control, *Decision: DPUC Review of Energy Independence Act Capacity Contracts*, Docket 07-04-24, August 22, 2007.

[17] "Motion of the Connecticut Light and Power Company to Amend Standard Service Procurement Plan," Docket 06-01-08PH01, August 28, 2007.

[18] Delaware Public Service Commission, *Findings, Opinion and Order No. 7199*, PSC Docket No. 06-241, May 22, 2007.

- **New York.** The Public Service Commission, in Case 06-M-1017, is currently investigating "the use of long term contracts and other means to facilitate the entry of new resources that would further the public policy goals of the State regarding electric infrastructure."[19]
- **Ohio.** On August 29, 2007, Duke Energy Ohio issued an RFP seeking offers for contracts with existing or new resources for the ten-year period 2009 to 2018.[20]

Q: Are you suggesting that an SOS portfolio should consist solely of long-term contracts?

A: No. A portfolio procurement strategy should avoid putting all the eggs in one basket, whether that "basket" is short-term full-requirements contracts, as under the current approach, or long-term contracts. Instead, the objective should be to layer a mix of short- and long-term assets and contracts that minimize costs and avoid excessive price swings.

Q: Why not simply procure a mix of short- and long-term full requirements contracts to serve residential SOS load?

A: Given the substantial price risk, it is unlikely that suppliers would be willing to offer at a reasonable price, if at all, full-requirements contracts for a term longer than three to five years. Suppliers would need to assess a substantial risk premium to compensate for assuming essentially unhedgable spot-price

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[19] New York Public Service Commission, *Order Requiring Development of Utility-Specific Guidelines for Electric Commodity Supply Portfolios and Instituting a Phase II to Address Longer-Term Issues*, Case 06-M-1017, April 19, 2007, pp. 35-36.

[20] This RFP is posted on-line at www.dukeenergyohiorfp.com.

(for expected spot purchases), volumetric (for unanticipated spot purchases), and congestion risk over the term of the contract.[21]

The Maine Public Utilities Commission found this to be the case when it attempted to procure full-requirements contracts with terms longer than three years. In October of 2006, the Maine PUC issued an RFP for full-requirements contracts with terms up to nine years to serve Central Maine Power's residential and small-commercial default-service load. In its order approving a three-year contract, the Maine PUC stated that:

> We decided not to pursue the longer term bids (six and nine years) because our analysis showed that these bids contained a substantial risk premium compared to natural gas forward prices. Thus, acceptance of the longer-term bids would be inconsistent with the goal of providing the lowest cost over time. The three year bids, however, were consistent with forward prices. Accordingly, we will continue with our three-year segmentation approach.[22]

Q: Will reliance on long-term contracts lead to abrupt price changes when those contracts expire?

A: No. Even though a long-term contract may be priced below market at time of expiration, that does not mean that consumers will be exposed to an abrupt transition to market price when that contract expires. Long-term contracts should be considered as part of a diverse portfolio of contracts and investments that dampens price volatility by minimizing reliance on any one resource type or contract term. Thus, a diverse portfolio avoids abrupt price

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[21] Suppliers may eventually be able to effectively and efficiently hedge long-term congestion risk using Long-Term Auction Revenue Rights.

[22] Maine Public Utilities Commission, *Order Designating Standard Offer Provider and Directing Utility to Enter Entitlements Agreement*, Docket No. 2006-585, January 9, 2007.

changes by ensuring that only a small portion of the portfolio rolls over at one time.

Q: Are there other benefits from long-term contracting other than price stabilization?

A: Yes. Long-term purchase contracts provide the level of revenue certainty that developers need to finance capital-intensive resources in the post-Enron wholesale markets. The long-term revenue certainty afforded with these contracts may also reduce a project's overall cost of capital.

Finally, long-term contracts may serve to align consumer and investor interests. For example, a study of diversification benefits in the United Kingdom concluded that diversification away from natural gas *increases* risks to merchant investors:

> The correlation between electricity, gas, and carbon markets makes "pure" portfolios of gas power plants more attractive than diversified portfolios, as gas plants' cash flows are "self-hedged". For a merchant generation company, investing in an additional CCGT [combined-cycle gas turbine] has therefore an externality value as it increases the correlation between electricity and gas prices, thereby not only reducing the volatility of the returns on the new CCGT investment, but also reducing the risk of the other CCGT units that the generating company already operates.[23]

This disconnect between private and public interests is described more broadly in a recent report to the California Energy Commission:

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[23] Roques, Fabien A., et. al., "Nuclear Power: A Hedge Against Uncertain Gas and Carbon Prices?", *The Energy Journal*, Vol. 27, No. 4, 2006, p. 18.

> In deregulated markets, individual power producers evaluate only their own direct costs and risks in making investment decisions. These decisions do not reflect the overall market impacts of the individual generation technology investment decisions. Renewables investors, for example, may be unable to fully capture the risk-mitigation benefits they produce for the overall portfolio, which leads to under-investment in renewables technology relative to levels that are optimal from society's perspective.[24]

Hence, long-term contracting can serve as a powerful policy tool for promoting investment in preferred generation or demand-side resources, promoting socially efficient diversification of resources, and for facilitating investments in resources needed to ensure reliable electricity supply.

Q: Will the recent restructuring of PJM's capacity market provide the long-term revenue certainty needed to promote capacity investments?

A: No. The Reliability Pricing Model ("RPM") transformed the capacity market from a spot to a forward market, allowing suppliers to lock in capacity revenues three years in advance of delivery. However, the annual RPM auctions lock in prices for only one year at a time, thus providing only one-year's worth of revenue certainty. While RPM's forward commitment of a year of capacity revenues provides more certainty than the old daily capacity markets, it does not provide the long-term price certainty and stability that market participants indicate is necessary to finance capacity investments. Long-term contracts between utilities and project developers can fill this gap, enabling financing and construction of assets whenever and wherever needed.

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[24] Bates White, LLC, *A Mean-Variance Portfolio Optimization of California's Generation Mix to 2020*, Draft Consultant Report, July, 2007, p. 1.

III. The Portfolio Planning Process

Q: What would adoption of a portfolio approach imply for resource planning in Maryland?

A: A managed portfolio program requires a long-range procurement plan. The portfolio plan, in turn, requires a planning process that is designed to identify the mix of supply, demand, and transmission resources that maintains reliability (and advances other public-policy goals) at minimum expected cost and at acceptable risk under conditions of uncertainty. Accordingly, the integrated planning process should be designed to quantitatively measure cost risk arising from forecast uncertainty, determine the impact of resource additions on portfolio risk, determine the relationship between expected cost and cost risk for each resource portfolio, and identify preferred resource portfolios and near-term procurement targets that minimize expected costs at acceptable levels of risk. The goal of the planning process is not to achieve diversification for diversification's sake, but to assemble the least-cost mix of resources that mitigates risk to reasonable levels.[25]

Q: How have utilities traditionally developed resource plans for maintaining system reliability?

A: Although the scope and analytical techniques have evolved over time and vary widely across utilities, the primary objective of "traditional" resource planning has been to identify the mix of resources that maintain system reliability and capacity adequacy at minimum cost over the planning

[25] This is not to suggest that the planning process should focus solely on the goal of optimizing the risk-return trade-off, or that the process should rely on only one measure of risk.

horizon.[26] Requiring development of extremely large input data sets, and employing sophisticated models for simulating system operations, the integrated planning process typically involves the following analytical tasks:

- Forecasting of annual energy consumption and peak load over the planning horizon.
- Specification of the cost and operating characteristics of the existing generation and transmission system, including identification of planned modifications and anticipated retirements.
- Identification and specification of the cost and operating characteristics of new generation, transmission, and demand resource options.[27]
- Simulation of the operations of the existing system, in order to: (1) estimate annual system operating costs; (2) determine conformance with minimum requirements for system reliability (e.g., loss-of-load probability) and capacity adequacy (i.e., installed reserve margin); and (3) identify annual need for new capacity.[28]

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[26] The central innovation of "integrated" resource planning ("IRP") was that the set of potential resource options could be expanded to include not only utility-owned central-station generating plant and bilateral contracts between utilities, but also contracts with independent power producers, "distributed" and renewable generation, transmission resources, and, especially, energy-efficiency and load-management resources.

[27] Typically, the forecasts of energy-efficiency and load-response annual costs and savings are developed after completing the task of simulating existing-system operations and estimating annual costs for the existing system. The estimate of existing-system cost is included in the estimate of costs that can be "avoided" (along with avoided transmission and distribution costs) with reductions to load from new energy-efficiency or load-response programs. The avoided costs, in turn, determine the magnitude of savings that can be achieved in a cost-effective manner, i.e., the amount of savings that can be achieved at a cost less than avoided cost.

[28] Depending on the sophistication of the simulation models employed in the planning process, the determination of capacity adequacy and the forecast of annual need for new capacity may be separate from the simulation of system operating costs and performance.

- Simulation of the operations of the system, and estimation of annual system costs, with additions of new resources.
- Determination of the type, amount, and timing of resource additions that maintains system reliability and capacity adequacy at minimum system cost over the planning horizon.

Q: What are the types of input data that are required for a traditional IRP analysis?

A: As noted above, the modeling effort for an IRP analysis relies on an extensive input data set that provides detailed specification of system characteristics and costs for each year of the planning period. Input data for this type of analysis would include:

- Forecasts of annual energy consumption and peak load, net of reductions from existing energy-efficiency or load-management programs.
- Specification of transmission topology, including transfer limits on bulk transmission lines.
- Fuel-price forecasts for all fuel types and for all existing fuel contracts and for spot-market purchases, including commodity and delivery costs.
- Non-fuel operating costs for existing generation plant, including start-up and no-load costs and variable O&M cost.
- Operating characteristics for existing generation plant, including plant capacity; forced outage rate; maintenance schedule; start-up time; ramp rate; minimum run time; minimum, maximum, and emergency

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However, some utilities employ "capacity expansion" models that can both simulate system operations and optimize the size, type, and timing of new resource additions to meet minimum reliability and adequacy requirements at minimum costs.

operating limits; fuel type; dual-fuel capability; and incremental heat-rate curves.

- Contract terms for existing bilateral purchases and sales, including annual price and quantity and contract expiration date.
- Schedule and specification of existing-resource upgrades, mothballing, or retirement.
- Fixed costs for new resources, including capital cost, financing assumptions, fixed O&M costs, and routine capital additions costs.
- Non-fuel operating costs for new resources.
- Operating characteristics for new resources.

Q: How might such an IRP analysis reflect the restructuring of Maryland's wholesale and retail markets?

A: A traditional IRP analysis for Maryland's utilities would likely reflect the effects of restructuring primarily in three ways.[29] First, since the Maryland utilities have divested their generation assets, and since generation in PJM can sell at market-based rates, Maryland's "existing generation" would likely be modeled as short-term contracts priced at wholesale-market rates. Second, the IRP analysis would likely evaluate a broader array of new-resource options, reflecting the increased variety of physical and financial products available in restructured wholesale markets. Finally, to the extent that the IRP analysis is modeling SOS load rather than total system load, load

[29] There are any number of secondary effects that might also be reflected in an IRP analysis for Maryland utilities. For example, the modeling of contract pricing might be adjusted to reflect the impact of RPM on capacity pricing, particularly with regard to implementation of three-year forward procurement. For another, to the extent that the IRP analysis includes analyses of output sensitivity to base-case assumptions, such sensitivities might be adjusted to reflect increased volatility in wholesale-market electricity prices.

forecasts would probably be adjusted to reflect expected rates of customer migration to competitive retail supply.

Q: How does long-term portfolio planning differ from traditional integrated resource planning?

A: Long-term portfolio planning is essentially traditional integrated resource planning with the added consideration of uncertainty. Like traditional IRP, portfolio planning involves assembling a portfolio resources that maintains system reliability at the lowest cost over the planning horizon. Unlike traditional IRP, portfolio planning explicitly accounts for uncertainty in the forecasted values of major cost drivers (such as fuel prices) and quantitatively measures the combined impact of uncertainty in cost drivers on portfolio cost.[30]

Q: How does portfolio analysis reflect uncertainty and measure portfolio risk?

A: Portfolio planning reflects uncertainty in cost drivers by modeling input values as probabilistic distributions around expected values. The modeling of inputs as stochastic variables generates a multitude of "futures" reflecting different combinations of forecast paths for the stochastic input values. Each of these futures, in turn, yields a unique value for portfolio cost. As a result, portfolio analysis generates a distribution of cost outcomes, with the

[30] This is not to suggest that traditional IRP analyses never explicitly accounted for uncertainty, only that the practice was not widespread. For example, the Northwest Power Planning Council (now the Northwest Power and Conservation Council) has for many years explicitly modeled the effects of uncertainty in its 20-year integrated resource plans. Moreover, a number of studies of IRP, including a report to the Pennsylvania Energy Office I co-authored in 1993, discussed the need to explicitly address uncertainty and described techniques for modeling uncertainty.

expected portfolio cost reflecting the average over the entire distribution of outcomes and cost risk measured based on a portion of the distribution representing high-cost outcomes.[31]

Q: What benefit is derived from the modeling of uncertainty and measurement of portfolio risk?

A: Modeling portfolio performance under uncertainty provides the means for measuring the risk-mitigation benefits, and the cost-risk trade-offs, of portfolio diversification.

For example, assume that there are two supply options for serving load, one with an expected cost of 5¢/kWh and a standard deviation of 3¢/kWh, and the other with an expected cost of 6¢/kWh and a standard deviation of 1¢/kWh. Furthermore, assume that the cost distributions for these two supply options are uncorrelated.

Under traditional IRP, the focus of the analysis would have been on minimizing the cost of serving load. In this simple example, the least-cost plan would have been to serve 100% of the load with the first supply option, since its expected cost is less than that of the second option.

In contrast, a portfolio planning analysis would consider both portfolio cost and portfolio risk. In this case, sole reliance on the first supply option would yield the lowest expected cost, but the highest risk (as measured in this example by standard deviation.) However, because the costs for these two

[31] For example, in its development of a 20-year energy plan for the Pacific Northwest, the Northwest Power and Conservation Council measures: (1) *cost outcome* for one "future" as the present value of annual costs over the planning horizon; (2) *expected portfolio cost* as the mean of the distribution of cost outcomes; and (3) *portfolio risk* as the "average value for the worst 10 percent of outcomes." See *The Fifth Northwest Electric Power and Conservation Plan*, May, 2005, Section 6.

options are uncorrelated, diversifying the portfolio with a mix of the second supply option reduces risk to a greater degree than it increases expected cost relative to the 100% option-one portfolio. For example, a 50/50 mix of the two supply options would reduce the portfolio standard deviation by about 50%, but increase expected portfolio cost by only 10% relative to the 100% option-one portfolio.

IV. Commission Questions Regarding Program Design

Q: If the Commission were to implement an actively managed portfolio for residential SOS customers, how should the Commission design such a process consistent with the best-price standard in the PUC Article?

A: There are a number of design principles that the Commission should rely on to guide the design process.

First, the procurement program should be built on the foundation of a comprehensive long-range portfolio plan. As discussed above, the planning process, in turn, should be designed to explicitly model planning uncertainty, determine future resource needs, examine a wide range of supply, demand, and transmission resource options, quantify the trade-offs between expected cost and cost risk, and identify preferred resource portfolios and procurement targets that minimize costs at acceptable levels of risk.[32]

Second, the planning process needs to be dynamic to allow adjustment to account for future changes, and to incorporate results from the procurement process.

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[32] The planning process should also identify likely environmental and other public-policy impacts and risks.

Third, to the extent feasible, the procurement program should rely on competitive forces to reduce wholesale-power costs. For example, utilities should rely on competitive solicitations such as Requests for Proposals to acquire new resources.

Fourth, the procurement process should be flexible, in order to promote robust wholesale-supplier participation and competitive pricing of resource offers. For example, rather than prescribe limits on eligible resource types (e.g., baseload vs. peaking; generation vs. demand-response) or project capacity, an RFP for long-term resources could provide bidders the portfolio targets established under the long-term planning process, clarifying that such targets are not proscriptive, and then invite project proposals of type and size that serve respondents' commercial interests.[33] The procurement process should also provide for flexibility in the procurement of short-term resources, allowing for changes to resource targets and flexibility in acquisition timing in response to changing market conditions.

Finally, the planning and procurement process should be transparent, to promote participation by wholesale suppliers and to allow effective oversight by the Commission and other stakeholders.

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[33] In certain instances, it may be appropriate to set aside contracts for renewable resources, transmission projects, or advanced technologies such as IGCC, to advance environmental and other public-policy objectives. Moreover, to secure long-term market improvements with new, efficient generation, it may be appropriate either to limit eligibility to new capacity or major upgrades, repowering, or overhauls of existing capacity, or simply to establish weighting criteria for RFP bid applications that express preferences for certain resources or combinations of resources that are viewed as particularly desirable.

Q: Should a managed portfolio program be administered by the IOUs directly?

A: As the entity with the ultimate obligation to serve residential customers, and as the Load-Serving Entity for PJM transactions, the utilities appear to be the best situated to serve as administrators of managed portfolio programs. The utilities already maintain customer load and other billing data that would be used as inputs to the portfolio planning, procurement, and management process. Moreover, the utilities, as transmission owners in PJM, are active participants in PJM's transmission-planning and congestion-management process, and therefore likely have in-house capability to evaluate the impact of transmission resources as part of the planning process, and to manage congestion hedges in the resource portfolio.

In its role as administrator, the utility would be responsible for the development of a long-term integrated portfolio plan, the procurement of portfolio resources consistent with the plan, ongoing management of spot and other short-term balancing transactions, and monitoring and assessment of portfolio performance.

While it seems reasonable for a utility to directly manage the portfolio of resources serving residential SOS load in its service territory, statewide coordination may be appropriate for procurement of resources that provide statewide or regional (e.g., Southwest MAAC) benefits, such as investment in new clean or renewable generation, or for procurement of transmission resources that span multiple zones or control areas. Where a statewide or regional planning process identifies a need for such resources, the Commission, in consultation with participants in the statewide or regional planning process, could be responsible for: (1) designating the utility or utilities responsible for conducting the procurement; (2) overseeing the technical evaluation and selection of project proposals; and (3) coordinating with PJM on issues of resource deliverability and conformance with reliability standards.[34]

Q: Should a managed portfolio program be administered by a third party that reports directly to the Commission?

A: See the response to the previous question.

Q: Should the portfolio be managed statewide or by service territory?

A: As discussed above, it seems reasonable for each utility to be responsible for assembling and managing a portfolio of resources to serve SOS load in its service territory. However, that portfolio may include resources that have been procured through a regional or statewide process.

Moreover, it is reasonable for portfolios to be managed by service territory, due to the fact that each service territory presents unique load characteristics and wholesale-market conditions, such as congestion patterns.

Q: Should the portfolio be managed by rate class?

A: It is unlikely that load characteristics and migration patterns are sufficiently different between time-of-use and non-TOU residential rate classes to justify management of separate portfolios for each rate class.[35] However, it may be

[34] Alternatively, an agency such as a state power authority could be established for the purposes of coordinating the statewide or regional planning process and procuring resources on behalf of all affected utilities. Illinois Senate Bill 1592, recently signed into law, creates an Illinois Power Agency to procure power on behalf of the State's utilities.

[35] I have not evaluated whether such differences between the residential and small-commercial customer classes would justify managing separate portfolios for these two classes. However, there are likely to be significant differences in load shapes and migration rates between the residential and small-commercial customer classes.

appropriate to include in the portfolio demand resources that are tailored to the unique characteristics of a specific rate class or sub-class (e.g., demand response for time-of-use customers.)

Q: What is the proper organization and level of expertise for the portfolio management function?

A: OPC does not have any additional comments in this regard.

Q: How should the program be monitored and adjusted?

A: The utility should monitor program performance, credit exposure, and market conditions on a daily basis, in order to generate information needed to support the utility's risk-management procedures and to support short-term supply planning and procurement.

In addition, the Commission should establish an annual process to allow for regulatory review of program performance and adjustments to the long-term plan. The Commission should also direct the utilities to submit monthly or quarterly reports on program performance, to provide the Commission the opportunity to modify the procurement program between annual reviews.

Q: How should wholesale power costs be allocated to the retail rate classes, if it is not procured on a class-specific basis?

A: As is standard practice for regulated cost recovery, wholesale-power costs should be allocated among residential rate classes based on generally accepted principles of cost causation.[36]

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[36] The same principle holds with regard to the allocation between the residential and small-commercial customer classes, in the event that these two classes are served under a single portfolio.

Q: What is the frequency and basis of retail price changes, and what should the accounting be for deferred purchase power costs between retail rate changes?

A: Although the current procurement approach has led to excessive year-to-year price volatility, consumers have enjoyed monthly price stability with fixed seasonal pricing of full-requirements contracts.[37] The process for setting retail prices for a managed portfolio should strive for comparable levels of price stability pursuant to the statutory mandate, while balancing the goal of minimizing the accrual of deferred power costs.[38]

SMECo's basic approach for pricing its managed portfolio appears to be a reasonable model for rate-setting for the residential SOS portfolio. Under SMECo's approach, fixed "base" rates are set based on forecasted supply costs for the upcoming year. Any differences between base rates and actual power costs are accrued in a deferral account and then recovered through a monthly "PPCA" charge. In order to dampen PPCA volatility, the monthly charge is set based on a rolling 12-month average (6 months historical, 6 months projected) of monthly deferrals. In order to minimize accrued balances, accrued amounts are rolled into base rates whenever the PPCA charge is more than 5% of the base rate for three consecutive months.

[37] Wholesale suppliers likely price a risk premium in those fixed seasonal SOS prices, reflecting the expected costs (e.g., accrual) and risks to suppliers associated with charging a fixed price for a product whose costs vary by hour.

[38] Minimizing accruals benefits both customers, by reducing carrying costs on accruals, and utilities, by mitigating the impact on operating cash flow and interest coverage ratios.

Q: Will recovery of wholesale power costs through fixed base rates distort price signals and discourage retail competition?

A: To the contrary, if the goal is to promote *sustainable* retail competition, consumers need to see SOS prices that reflect likely power costs over the next season or year, not just the next month. Monthly pricing may discourage risk-averse consumers from entering into longer-term agreements with retail suppliers, or even encourage frequent switching between SOS and competitive supply in response to differences between monthly prices for SOS and retail supply.

Q: What should the procurement timeframe be?

A: There is no fixed procurement timeframe under a managed portfolio program, since procurement is an ongoing process that assembles resources of varying duration through a variety of market purchases. For example, a utility might solicit a mix of 15-year unit-contingent contracts and 2-year full-requirements contracts in one year, and then solely 5-year fixed-quantity contracts the following year. Moreover, after having procured 15-year unit-contingent contracts and 2-year full-requirements contracts through an RFP, the utility might then purchase a three-month strip of NYMEX on-peak monthly forwards, and then engage in daily spot transactions for balancing purposes. While these purchases would have varying timeframes, they would all be part of a long-term portfolio plan.

Q: What entity should assume the credit risk?

A: Default risk is an unavoidable by-product of most bilateral power transactions.[39] There are two basic elements of default risk: (1) settlement risk, when there are payments outstanding at the time of default; and (2) replacement-power risk, when market prices for replacement power exceed contract prices.[40] In either situation, there is a risk that, contract remedies notwithstanding, payments due will not be recovered from the defaulting party either directly or through bankruptcy court. Ultimately, ratepayers assume counterparty default risk, since un-recovered payments will be passed through to retail SOS rates.

As is the case with full-requirements contracts awarded under the current procurement approach, counterparty credit risk can be managed with a variety of contractual measures, such as collateral requirements, clearly defined events of default, remedies in the event of credit downgrades, netting provisions in the event of default, provisions for transferring contract

[39] Exceptions are transactions through "clearinghouses" such as NYMEX or PJM, since the clearinghouse effectively assumes counterparty credit risk as part of the clearing and settlement function.

[40] In Case No. 9063, utilities raised an additional concern that procurement of long-term contracts might degrade their credit ratings. The Connecticut Department of Public Utility Control investigated this issue, and found that: "Debt imputation associated with Connecticut PPAs has not reduced confidence in the financial soundness of Connecticut utilities, their ability to maintain and support investment-grade credit ratings, or their ability to raise money necessary for the proper discharge of duties." (*Decision*, Docket No. 05-07-18, December 28, 2005, p. 13.) Nonetheless, this risk should be addressed by subjecting all potential resource portfolios to comprehensive testing of financial impacts.

obligations, and provisions for procuring and recovering the costs of replacement power.[41]

Q: What risk modeling techniques should be used?

A: See the discussion of risk modeling in Sections II and III.

Q: What are the appropriate levels of commodity price risk?

A: This question cannot be answered in the abstract. The appropriate level of commodity risk should be determined on the basis of a thorough, comprehensive assessment and quantification of costs, cost risks, and the trade-offs among portfolios between expected cost and risk. This is the essence of the long-term portfolio planning process described above in Sections II and III.

Q: What is the appropriate portfolio planning horizon?

A: The planning horizon should be a minimum of ten to fifteen years, to allow for the full evaluation and integration of a wide array of resource options and terms.

Q: What is the proper mix of resource or product diversity and term?

A: This question also cannot be answered in the abstract. The appropriate mix of products and terms should be determined on the basis of a thorough, comprehensive assessment and quantification of costs, cost risks, and the trade-offs among portfolios between expected cost and risk. This is the essence of the long-term portfolio planning process described above in Sections II and III.

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[41] Credit risk can also be managed by diversifying across creditworthy suppliers.

Q: What is the appropriate level of supplier diversity?

A: Unfortunately, this question also cannot be answered in the abstract. As discussed above, the managed portfolio program should be designed to minimize barriers to participation in competitive solicitations and to promote robust competition. The Commission should monitor all such solicitations and evaluate the outcomes to determine whether supplier response was reasonable and reasonably diverse.[42]

Q: What additional portfolio management risks and controls should be considered?

A: OPC does not have any additional comments in this regard.

V. Direct Energy Proposal for EUSP Aggregation

Q: Please describe Direct Energy's proposal for aggregating EUSP participants.

A: According to its filing of August 8, 2007, Direct Energy proposes implementation of an opt-out aggregation program for EUSP participants. Although the filing is not specific with regard to certain design details, the major elements of Direct Energy's proposal appear to be:

- Direct Energy will provide on a daily basis to the Maryland Energy Administration ("MEA") a price to serve EUSP load for the upcoming summer (i.e., June 1 to September 30) or non-summer (i.e., October 1 to May 31) period.

[42] The Commission's evaluation would likely benefit from an independent assessment of these solicitations by PJM's market monitor.

- The MEA will determine whether to execute aggregation at that strike price. If so, Direct Energy commits to serving EUSP load for the upcoming season at that strike price.
- The process will then be repeated for each seasonal period. Aggregated load in one season will be switched back to SOS in the next season if MEA determines that the strike price for the following season does not provide adequate savings off the retail SOS price.
- The utilities commit to dollar-for-dollar purchase of receivables for aggregated EUSP accounts (as well as for all other residential accounts served by competitive supply.)

Direct Energy's proposal apparently presumes continuation of the current 8908/9064 procurement process.

Q: Should Direct Energy's proposal be implemented?

A: No. Direct Energy's proposal is contrary to the public interest in two key respects. First, it would substantially increase migration risk to wholesale SOS suppliers, and thus might significantly increase SOS prices without offering any guarantee of savings to EUSP participants. Second, the proposal requires ratepayers to assume Direct Energy's uncollectible costs associated with serving EUSP customers (as well as all other customers on competitive supply.) In other words, Direct Energy's proposal would increase Direct's profits by shifting costs to ratepayers.[43]

[43] Indeed, the profitability of Direct Energy's aggregation of EUSP load apparently hinges on this cost shifting, since Direct Energy states that: "The willingness of Direct Energy to participated in the Program is contingent on the utilities' provision of [Purchase of Receivables] …." Petition, Attachment A, page 6.

Moreover, Mr. Colton finds that Direct Energy's proposal is unlikely to yield substantial savings for EUSP participants.

Q: Why would Direct Energy's proposal increase migration risk for wholesale SOS suppliers?

A: Under Direct Energy's proposal, the process of providing daily strike prices for the upcoming season, and MEA's determination of whether to execute aggregation on the basis of that day's strike price, will start after the final SOS solicitation for that season has been completed and retail SOS prices for that season have been established. This sequence is logical, since MEA's decision whether to execute aggregation will depend on whether the daily strike price provides sufficient savings relative to the retail SOS price to justify shifting EUSP load to Direct Energy supply.

However, this sequence also creates a substantial risk to bidders in that season's solicitation that a significant portion of residential SOS load will migrate to or from Direct Energy's service following completion of the solicitation. If market prices decline after the solicitation, triggering aggregation, SOS suppliers may be left holding (now) excess supply that was purchased at market prices prevailing at the time of the solicitation, but which is now out of the money under current market prices. Conversely, if market prices increase after the solicitation, EUSP load aggregated during the previous season may be transferred back to residential SOS. If so, SOS suppliers might need to purchase additional supply to cover returning EUSP load at market prices that exceed the fixed price charged to those returning customers.[44]

[44] The risk from returning load might be partially mitigated if the wholesale contracts include the type of "Volumetric Risk Mitigation" provisions currently incorporated in

Q: How might potential SOS suppliers respond to this substantial increase in migration risk?

A: Potential suppliers of full-requirements service might respond by either pricing this risk into their bids or simply by declining to participate in the bidding process. The result in either case is likely to be higher SOS prices.

Q: Wouldn't there be an offsetting benefit of lower prices for EUSP load?

A: Not necessarily. EUSP customers would benefit only in the event that market prices decline sufficiently for MEA to justify triggering aggregation. In contrast, SOS bidders will price in the potential risk arising from the *opportunity* to aggregate, regardless of whether aggregation is actually implemented.

Q: What is Direct Energy's rationale for requiring utility purchase of receivables for aggregated EUSP accounts?

A: According to Direct Energy's August 8, 2007 Petition, the current treatment of uncollectible expenses provides windfall profits to the utility and places retail suppliers at a competitive disadvantage:

> Currently, the utilities socialize the collection risks associated with all of their own customers, including customers with high risk of non-payment, such as customers receiving EUSP assistance, by recovering allowances for uncollectible expenses in their base distribution rates. But absent adopting POR [purchase of receivables], a significant portion of bad debt costs will be shifted to the competitive supplier chosen, while the cost associated with such debts will continue to be recovered in the utilities' base rates.[45]

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residential SOS contracts by order of the Commission in Case No. 9064. However, such provisions simply, and inefficiently, shift this price risk from bidders to ratepayers, including those returning EUSP customers.

[45] Petition, p. 11.

Q: Is this an accurate description of the current treatment of uncollectible SOS costs?

A: No. Contrary to Direct Energy's assertions, an allowance for uncollectible SOS expenses is not recovered through distribution rates. Instead, residential SOS customers are charged an allowance for uncollectible SOS expenses through the 4 mill/kWh Administrative Charge included in retail SOS rates. Customers that migrate to competitive supply do not pay the Administrative Charge.

This treatment prevents the type of unjust enrichment or preferential advantage that concerns Direct Energy. From the utility's perspective, customer migration reduces both the utility's uncollectible SOS expenses <u>and</u> the revenues recovered through the Administrative Charge to cover those expenses. Thus, this treatment provides solely for the recovery of uncollectible costs associated with SOS customers, not for those costs that have been shifted to competitive suppliers.

As Direct Energy correctly observes, customer migration to a retail supplier increases that supplier's bad-debt costs. However, this supplier is free to include a charge for uncollectible supply expenses in the retail-supply price in the same fashion as utilities include in SOS prices. Thus, retail suppliers are not at a competitive disadvantage with respect to the recovery of uncollectible costs.

Q: Will residential SOS customers be harmed by utilities' purchase of Direct Energy's receivables?

A: Yes. The purchase of Direct Energy's receivables will shift the bad-debt costs associated with serving EUSP load back onto the utility. However, since aggregated EUSP customers will no longer pay an Administrative

Charge, the utility will no longer be recovering revenues to cover these customers' uncollectible costs. This shortfall is likely to be recovered from remaining SOS customers, increasing the charge for uncollectible costs in retail SOS rates.

VI. Impact on Retail Competition

Q: How should a managed portfolio program be designed so as to facilitate the development of the competitive retail market or minimize, to the extent possible, any harm to the retail electric market?

A: As discussed above in Section II, a managed portfolio program should be *designed* to procure a diversified portfolio of resources that minimizes long-term costs to consumers at an acceptable level of risk. In other words, the managed portfolio program should be "designed to obtain the best price for residential and small commercial customers in light of prevailing market conditions balanced by the need to guard against excessive price increases."[46]

In order to facilitate truly efficient retail competition, the SOS portfolio assembled under the managed portfolio program should be *priced* at the actual or expected current costs (and only those costs) of the resources comprising the SOS portfolio. Consumers will benefit if retail suppliers can offer alternative products that are priced competitively against actual SOS-portfolio costs.

[46] Maryland Public Utility Companies Article §7-510(c)(4)(ii).

Q: Does the potential for a divergence between portfolio and "market" prices pose a barrier to sustainable retail competition?

A: No. In almost every major Commission proceeding regarding SOS, starting with Case No. 8908, retail suppliers have argued that prices for a portfolio of short- and long-term resources will deviate from current "market" prices, and that this deviation impedes development of sustainable competition. By this argument, retail suppliers cannot retain customers over a sustained period, since their products are priced at short-term market prices, and thus may be competitive against SOS portfolio prices in one year, but not in the next.

The problem of sustainability reflects a possibly flawed business strategy, not a barrier to competition. Retailers may have chosen to price their supply at short-term market, rather than at actual costs of their wholesale supply portfolio, or may have made the business decision to not include longer-term wholesale products in their supply portfolios. In either case, the procurement of a diversified portfolio to serve residential SOS load is not to blame.

Q: Would the fact that residential customers appear unwilling to contract for retail supply for longer than one year effectively preclude procurement of longer-term resources by retail suppliers?

A: No. There is no apparent reason why the competitive electricity market should differ from other retail markets, where businesses enter into long-term contracts with wholesale suppliers or engage in long-term leasing of facilities and equipment without any type of long-term contractual relationship with their retail customers.

Q: How does retail choice affect the wholesale cost to serve residential SOS load?

A: Retail choice introduces risk, specifically migration risk. Under the current procurement approach, migration risk likely increases full-requirements contract costs, as wholesale suppliers add a premium to compensate for assuming this risk.[47] Under a portfolio approach, migration uncertainty would likely increase either expected cost or cost risk, degrading a portfolio's risk-return profile. According to a 2004 study for the Edison Electric Institute:

> As if wholesale price uncertainty were not enough of a problem, retail service obligations entail volumetric uncertainty as well, particularly around the most volatile peak months. The volumetric risk associated with retail services under traditional regulation has been amplified – and rendered asymmetric – by customer switching rights. Building or buying supply for such conditions is likely to require risk-control targets and to entail risk premiums that were not a part of traditional least cost planning or IRP…. Again, the development of the appropriate portfolio of spot market purchases, standard contracts, bilateral long-term contracts or utility-owned resources should be done to achieve low and stable costs for the consumers.[48]

Q: Does this conclude your testimony?

A: Yes.

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[47] See the discussion above in Section V of the impact of migration risk on SOS prices with respect to Direct Energy's EUSP aggregation proposal.

[48] Graves, Frank C., et. al., *Resource Planning and Procurement in Evolving Electricity Markets*, prepared for Edison Electric Institute, The Brattle Group, January 31, 2004, p. 29.

Exhibit JFW-1

Qualifications of

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SUMMARY OF PROFESSIONAL EXPERIENCE

1990–Present **Vice President, Resource Insight, Inc.** Provides research, technical assistance, and expert testimony on electric- and gas-utility planning, economics, regulation, and restructuring. Designs and assesses resource-planning strategies for regulated and competitive markets, including estimation of market prices and utility-plant stranded investment; negotiates restructuring strategies and implementation plans; assists in procurement of retail power supply.

1989–90 **Senior Analyst, Komanoff Energy Associates.** Conducted comprehensive cost-benefit assessments of electric-utility power-supply and demand-side conservation resources, economic and financial analyses of independent power facilities, and analyses of utility-system excess capacity and reliability. Provided expert testimony on statistical analysis of U.S. nuclear plant operating costs and performance. Co-wrote *The Power Analyst*, software developed under contract to the New York Energy Research and Development Authority for screening the economic and financial performance of non-utility power projects.

1987–88 **Independent Consultant.** Provided consulting services for Komanoff Energy Associates (New York, New York), Schlissel Engineering Associates (Belmont, Massachusetts), and Energy Systems Research Group (Boston, Massachusetts).

1981–86 **Research Associate, Energy Systems Research Group.** Performed analyses of electric utility power supply planning scenarios. Involved in analysis and design of electric and water utility conservation programs. Developed statistical analysis of U.S. nuclear plant operating costs and performance.

EDUCATION

BA, Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.

Massachusetts Institute of Technology, Cambridge, Massachusetts. Physics and Political Science, 1976–1979.

PUBLICATIONS

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"Electricity Market Design: Incentives for Efficient Bidding, Opportunities for Gaming." NASUCA Northeast Market Seminar, Albany, N.Y., February 2001.

"Direct Access Implementation: The California Experience." Presentation to the Maryland Restructuring Technical Implementation Group on behalf of the Maryland Office of People's Counsel. June 1998.

"Reflecting Market Expectations in Estimates of Stranded Costs," speaker, and workshop moderator of "Effectively Valuing Assets and Calculating Stranded Costs." Conference sponsored by International Business Communications, Washington, D.C., June 1997.

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1989 **Mass. DPU** on behalf of the Massachusetts Executive Office of Energy Resources. Docket No. 89-100. Joint testimony with Paul Chernick relating to statistical analysis of U.S. nuclear-plant capacity factors, operation and maintenance costs, and capital additions; and to projections of capacity factor, O&M, and capital additions for the Pilgrim nuclear plant.

1994 **NY PSC** on behalf of the Pace Energy Project, Natural Resources Defense Council, and Citizen's Advisory Panel. Case No. 93-E-1123. Joint testimony with John Plunkett critiques proposed modifications to Long Island Lighting Company's DSM programs from the perspective of least-cost-planning principles.

1994 **Vt. PSB** on behalf of the Vermont Department of Public Service. Docket No. 5270-CV-1 and 5270-CV-3. Testimony and rebuttal testimony discusses rate and bill effects from DSM spending and sponsors load shapes for measure- and program-screening analyses.

1996 **New Orleans City Council** on behalf of the Alliance for Affordable Energy. Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.

1996 **New Orleans City Council** Docket Nos. UD-92-2A, UD-92-2B, and UD-95-1. Rates, charges, and integrated resource planning for Louisiana Power & Lights and New Orleans Public Service, Inc.; Alliance for Affordable Energy. April, 1996.

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Reasonableness of proposed revisions to standard-offer-supply energy costs. Implications of revisions for other elements of proposed settlement.

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Evaluation of innovative rate proposal by PJM transmission owners.

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Reasonableness of proposed fees for electricity-supplier services.

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Costs and benefits to ratepayers. Assessment of public interest.

Maryland PSC Case No. 8796, Potomac Electric Power Company stranded costs and rates, Maryland Office of People's Counsel. December 2001; surrebuttal, February 2002.

Allocation of benefits from sale of generation assets and power-purchase contracts.

2002 **Maryland PSC** Case No. 8908, Maryland electric utilities' standard offer and supply procurement, Maryland Office of People's Counsel. Direct, November 2002; Rebuttal December 2002.

Benefits of proposed settlement to ratepayers. Standard-offer service. Procurement of supply.

2003 **Maryland PSC** Case No. 8980, adequacy of capacity in restructured electricity markets; Maryland Office of People's Counsel. Direct, December 2003; Reply December 2003.

Purpose of capacity-adequacy requirements. PJM capacity rules and practices. Implications of various restructuring proposals for system reliability.

2004 **Maryland PSC** Case No. 8995, Potomac Electric Power Company recovery of generation-related uncollectibles; Maryland Office of People's Counsel. Direct, March 2004; Supplemental March 2004, Surrebuttal April 2004.

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Calculation and allocation of costs. Effect on administrative charge pursuant to settlement.

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Reasonableness and risks of resource-procurement plan.

2005 **FERC** Docket No. ER05-428-000, revisions to ICAP demand curves; City of New York. Statement, March 2005.

Net-revenue offset to cost of new capacity. Winter-summer adjustment factor. Market power and in-City ICAP price trends.

FERC Docket No. PL05-7-000, capacity markets in PJM; Maryland Office of People's Counsel. Statement, June 2005.

Inefficiencies and risks associated with use of administratively determined demand curve. Incompatibility of four-year procurement plan with Maryland standard-offer service.

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Inefficiencies and risks associated with use of administratively determined demand curve. Effect of proposed reliability-pricing model on capacity costs.

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Transition to market-based residential rates. Price volatility, bill complexity, and cost-deferral mechanisms.

Maryland PSC Case No. 9056, default service for commercial and industrial customers; Maryland Office of People's Counsel, April 2006.

Assessment of proposals to modify default service for commercial and industrial customers.

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Assessment of effects and risks of proposed merger on ratepayers.

Illinois Commerce Commission Docket No. 06-0411, Commonwealth Edison Company residential rate plan; Citizens Utility Board, Cook County State's Attorney's Office, and City of Chicago, Direct July 2006, Reply August 2006.

Transition to market-based rates. Securitization of power costs. Rate of return on deferred assets.

Maryland PSC Case No. 9064, default service for residential and small commercial customers ; Maryland Office of People's Counsel, Rebuttal Testimony, September 2006.

Procurement of standard-offer power. Structure and format of bidding. Risk and cost recovery.

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Distorting effects of proposed reliability-pricing model on clearing prices. Economically efficient alternative treatment.

Maryland PSC Case No. 9063, optimal structure of electric industry; Maryland Office of People's Counsel, Direct Testimony, October 2006; Rebuttal November 2006; surrebuttal November 2006.

Procurement of standard-offer power. Risk and gas-price volatility, and their effect on prices and market performance. Alternative procurement strategies.

Maryland PSC Case No. 9073, stranded costs from electric-industry restructuring; Maryland Office of People's Counsel, Direct Testimony, December 2006.

Review of estimates of stranded costs for Baltimore Gas & Electric.

2007 **Maryland PSC** Case No. 9091, rates and rate mechanisms for the Potomac Edison Company; Maryland Office of People's Counsel, Direct Testimony, March 2007.

Cost allocation and rate design. Revenue decoupling mechanism.

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Cost allocation and rate design. Revenue decoupling mechanism.

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Cost allocation and rate design. Revenue decoupling mechanism.

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Cost allocation and rate design. Revenue decoupling mechanism.

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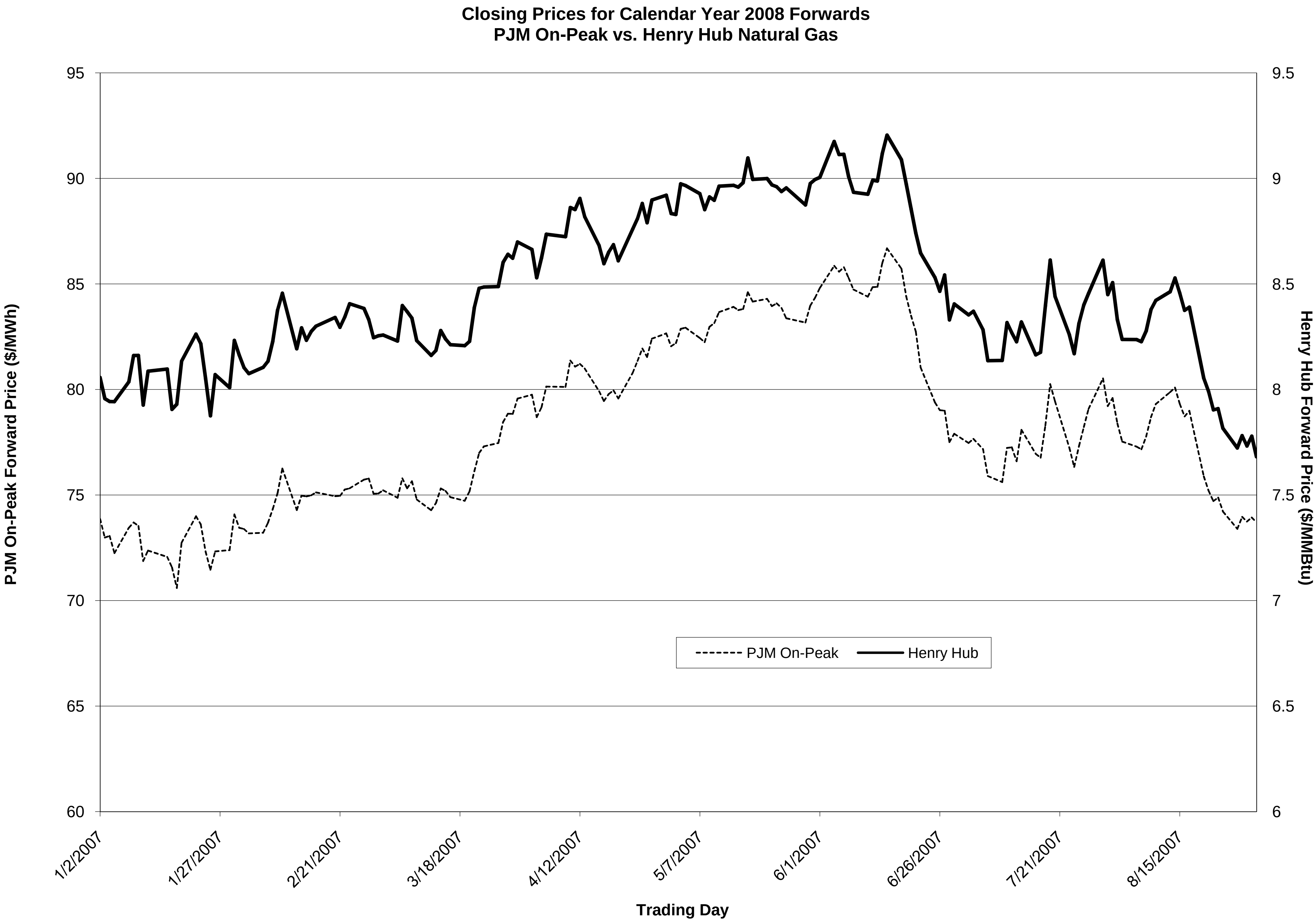
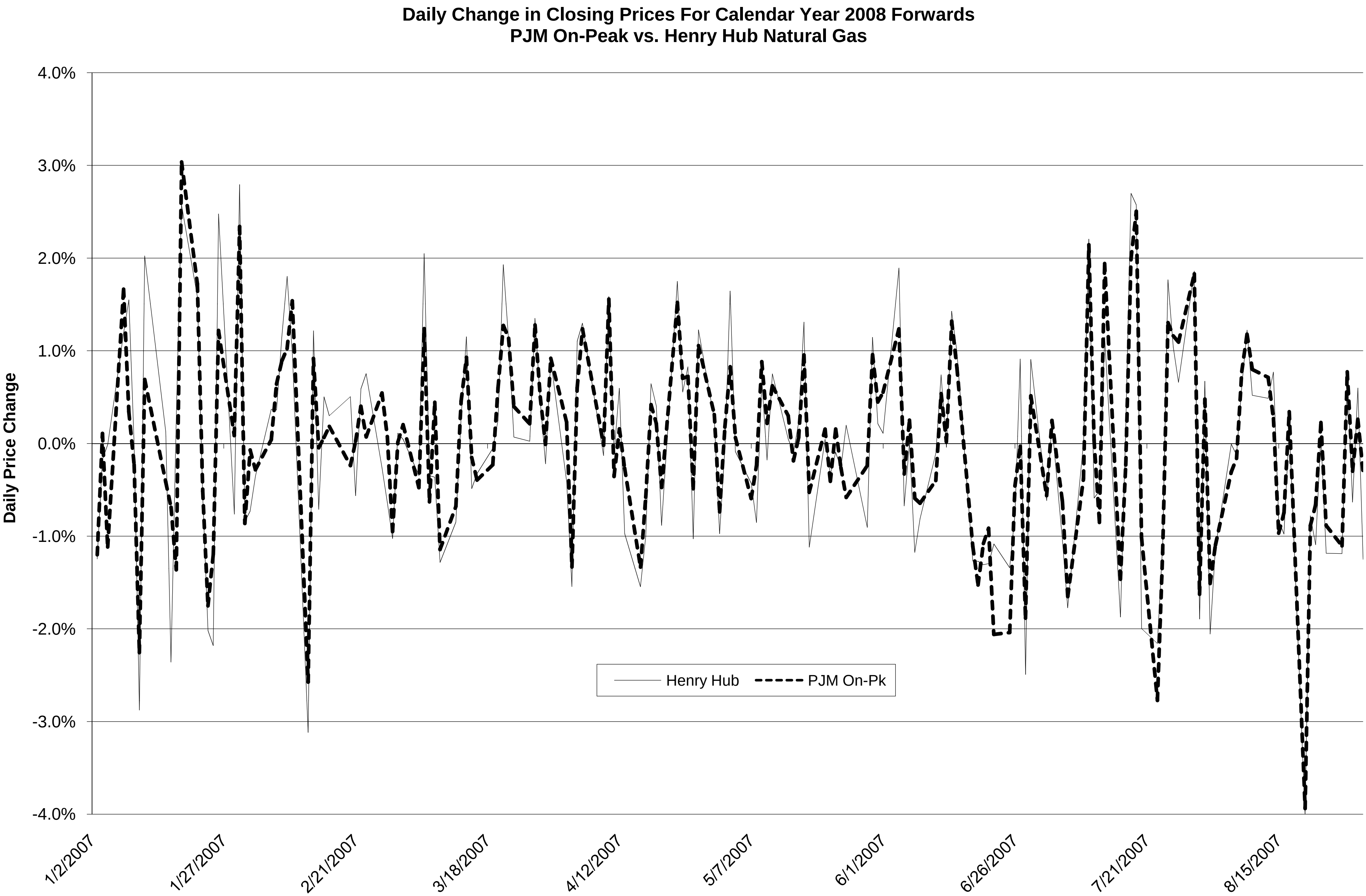
Assessment of proposed capacity contracts.


Closing Prices for Calendar Year 2008 Forwards
PJM On-Peak vs. Henry Hub Natural Gas
PJM On-Peak Forward Price ($/MWh)
Henry Hub Forward Price ($/MMBtu)
95
90
85
80
75
70
65
60
9.5
9
8.5
8
7.5
7
6.5
6
PJM On-Peak
Henry Hub
1/2/2007
1/27/2007
2/21/2007
3/18/2007
4/12/2007
5/7/2007
6/1/2007
6/26/2007
7/21/2007
8/15/2007
Trading Day


Daily Change in Closing Prices For Calendar Year 2008 Forwards
PJM On-Peak vs. Henry Hub Natural Gas
4.0%
3.0%
2.0%
1.0%
0.0%
-1.0%
-2.0%
-3.0%
-4.0%
Daily Price Change
Henry Hub
PJM On-Pk
1/2/2007
1/27/2007
2/21/2007
3/18/2007
4/12/2007
5/7/2007
6/1/2007
6/26/2007
7/21/2007
8/15/2007