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	**)**	

ADDITIONAL REPLY TESTIMONY OF

JONATHAN WALLACH

ON BEHALF OF

THE OFFICE OF PEOPLE'S COUNSEL

Resource Insight, Inc.

DECEMBER 21, 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: Are you the same Jonathan F. Wallach that filed direct, reply, and supplemental reply testimony in this proceeding?

A: Yes.

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Office of People's Counsel ("OPC").

Q: What is the purpose of your additional reply testimony?

A: On November 15, 2007, Mr. John Nelson Trimble of South River Consulting testified in this proceeding regarding the use of spot-market purchases to serve residential SOS load. Specifically, Mr. Trimble asserted that over the last six years the "spot market, that is the localized marginal price has been historically about 15 percent lower than the forward price at any point in time."[1] On December 6, 2007, Staff filed Mr. Trimble's responses to discovery by Allegheny Power, including an electronic spreadsheet file that Mr. Trimble alleges provides the analysis supporting his claim of a consistent 15% price difference between spot and forward prices.

This additional reply testimony addresses Mr. Trimble's assertion that spot prices have been consistently 15% lower than forward prices, and describes my independent analysis of the historical relationship between spot

[1] *Transcript*, Case No. 9117, November 15, 2007, p. 1624.

and forward prices in the PJM wholesale market. In addition, this testimony describes a modeling analysis Resource Insight is currently conducting for OPC of the long-term costs and risks associated with reliance on spot-market purchases to serve residential SOS load, as well as the costs and risks associated with a variety of diversified resource portfolios for serving residential SOS load.[2]

Q: Please summarize your findings and conclusions regarding Mr. Trimble's testimony on the relationship between spot and forward prices.

A: Mr. Trimble has not provided any basis for his claim that spot prices have been consistently 15% less than forward prices. The analysis that Mr. Trimble provided to support this claim does not even compare spot prices against actual forward prices. Instead, it compares spot prices against Mr. Trimble's estimate of the price for full-requirements service. As a result, the results of Mr. Trimble's analysis bear no relevance to, and therefore fail to support, his claim.

I conducted an independent analysis of the historical relationship between spot and forward prices, in order to determine whether spot prices have been 15% lower than forward prices, as Mr. Trimble claims. In contrast with Mr. Trimble's unsupported allegation, I find that spot prices have on average been 7% *higher* than prices for forward contracts.

The Commission should therefore reject Mr. Trimble's contention that reliance on spot purchases will reduce residential SOS costs. As my analysis

[2] Resource Insight retained the consulting firm Synapse Energy Economics to develop the spreadsheet model and assist in the specification of input assumptions. All work by Synapse has been conducted under my direct supervision.

shows, spot prices have historically been higher than forward prices. Moreover, my analysis shows a wide variation in the historical ratios of spot to forward prices, indicating that there is a substantial risk that reliance on spot purchases will increase long-term costs relative to continued reliance on full-requirements contracts.

Q: Please summarize the results of your modeling analysis of long-term portfolio costs and risks.

A: Resource Insight, with the assistance of the consulting firm Synapse Energy Economics, is currently conducting a modeling analysis of long-term costs and risks associated with the current procurement process and alternative portfolio approaches. This analysis was designed to explore portfolio performance under conditions of uncertainty, and to assess the potential trade-offs between long-term expected cost and risk associated with portfolio diversification. As part of this analysis, we are investigating the long-term costs and risks associated with serving residential SOS load with spot purchases.

Although we have not yet finalized the analysis, results from the simulation modeling confirm my expectations regarding the cost and risk trade-offs associated with serving residential SOS load with spot purchases. Specifically, these results indicate that the long-term costs of serving residential SOS load with spot purchases are expected to be slightly less than serving load under the current procurement approach. This expected cost savings is due solely to the fact that we assume that spot purchasing reduces the premium for risk and transaction costs relative to the current procurement approach. However, this slight reduction in the assumed risk premium comes at the cost of a substantial increase in annual price risk.[3] In other words, under spot purchasing, consumers will likely be exposed to significant price risk in order to avoid paying wholesale suppliers a small premium to assume that risk.

Simulation results also confirm my expectation that diversification of the residential SOS portfolio will improve the portfolio's risk-return profile. Model results indicate that a diversified portfolio – combining DSM resources, medium-term fixed-block contracts, long-term contracts with new conventional and renewable resources, and two-year full-requirements contracts – substantially reduces both long-term expected cost and cost risk relative to a portfolio that consists solely of two-year full-requirements contracts.

II. Spot-Market vs. Forward-Contract Prices

Q: Please describe Mr. Trimble's testimony regarding the historical relationship between spot and forward prices.

A: During hearings in this proceeding on November 15, 2007, Mr. Trimble made the rather astounding claim that over the last six years spot prices have consistently been lower than forward prices:

> I hate to say this, because I didn't believe it myself, but it is true, spot market, that is the localized marginal price has been historically about 15 percent lower than the forward price at any point in time.[4]

[3] As I discussed in my direct testimony in this proceeding, the current procurement approach also exposes consumers to a substantial risk of volatile prices. The modeling analysis confirms this expectation, but also shows even greater risk with reliance on spot purchases.

[4] *Transcript*, p. 1624.

Specifically, Mr. Trimble alleged that during the last six years the average spot price for a 12-month period was l5% less than the price of a 12-month forward contract for that same time period:

> COMMISSIONER FREIFELD: Can I ask a follow-up to make sure I got it now. If you were to buy a forward for the next 12 months today and pay whatever the price is for the next 12 months, and then a year from now to ask yourself how did I do and you went back and looked at the LMP for every hour of that prior 12 months, are you saying it is likely that the result would be those 50,000 LMP would be 15 percent lower than the forward?
>
> THE WITNESS: On average, except, and I will also say this, July and August you would be paying higher. For the rest of the year, you would be paying significantly less.[5]

In response to discovery from Allegheny Power, Mr. Trimble provided a one-page spreadsheet analysis of PJM spot and forward prices that purports to support his testimony in this regard.

Q: What is the relevance of Mr. Trimble's assertion to the issues under consideration in this proceeding?

A: Mr. Trimble cited this finding in support of his assertion that residential SOS customers would have paid lower prices in the past, if the SOS procurement process had not purchased all wholesale supply on a forward basis using annual or multi-year contracts, but instead had served load with a mix of forward contracts and spot purchases:

> CHAIRMAN LARSEN: Well, is it true that if it is, what you say is true, that the spot is 15 percent lower historically than having a 20 percent position in the spot market will lower, relatively lower price compared to 100 percent price in the forward market, is that true or not true?
>
> A. That is true.[6]

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[5] *Id.*, pp. 1644-1645.

Q: Please describe the analysis of spot and forward prices that Mr. Trimble provided in response to discovery from Allegheny Power.

A: It is impossible to definitively determine what Mr. Trimble analyzed, since the one-page spreadsheet he provided consists solely of multiple columns of monthly data, without any explanation as to what the data represents and without any of the underlying input data or formulas used to derive the monthly results.

As best as I can discern, Mr. Trimble first calculates for each month the percentage ratio of: (1) the forward price for that month's contract, assuming purchase one month in advance; and (2) the average spot price for that month. Mr. Trimble denotes this percentage ratio as the "Commodity Forward Premium." Mr. Trimble then increases each month's Commodity Forward Premium by a "FR Premium" of ten percentage points to yield a monthly "Full Requirements Premium." Mr. Trimble then calculates the average of these monthly Full Requirements Premiums over various time frames, deriving average values that range from 11% to 18%.

Q: Is Mr. Trimble's claim of consistently lower spot prices reasonably supported by the analysis he provided in response to discovery?

A: No, since his analysis bears little relevance to his testimony. Mr. Trimble testified that, over the last six years, purchasing commodity energy on spot over a 12-month period would have been less expensive than buying a 12-month forward contract for that same commodity over the same time period. In contrast, his analysis was designed to show that purchasing commodity energy on spot over a 12-month period would have been less expensive than

[6] *Id.*, p. 1629.

procuring *full-requirements service* over that same time period using a monthly procurement scheme. According to Mr. Trimble's response to Allegheny Power's discovery:

> In summary, the attached shows that standard products (i.e., spot and standard forward products) allow for the reduction of risks by the end user compared to a full service product. The full service product must add risk premiums for such things as Peak Load Contribution, transmission services, changing RPM costs, potential congestion, credit, etc.[7]

Thus, Mr. Trimble compared commodity spot prices not against actual commodity forward prices, but against full-requirements prices estimated using an arbitrary adder of 10% on commodity forward prices. Moreover, Mr. Trimble compared commodity spot prices not against prices for a 12-month forward contract purchased in advance of the 12-month period, but against prices for monthly contracts purchased a month at a time over that 12-month period. As such, the results bear no relevance to, and therefore fail to support, Mr. Trimble's claim.

Q: Have you investigated the merits of Mr. Trimble's claim?

A: Yes. I conducted an independent analysis of the historical relationship between spot and forward prices, in order to determine whether spot prices have been 15% lower than forward prices, as Mr. Trimble asserts. My analysis yields a dramatically different result: I find that spot prices for various 12-month periods have on average been 7% *higher* than prices for 12-month forward contracts for the same 12-month periods.

[7] Responses to Informal Allegheny Energy Data Requests, Case No. 9117, December 6, 2007, Response #1.

Q: Please describe your analysis of historical spot and forward prices.

A: For each 12-month delivery period, I calculated two price averages and then took the ratio of those two averages. First, I calculated the 12-month average of the on-peak hourly prices in the day-ahead market for the PJM Western Hub. Second, I calculated the 12-month average of the clearing prices for NYMEX-traded PJM Western Hub on-peak monthly forward contracts.[8] For this latter calculation, I assumed that the twelve monthly forward contracts would be procured at one time, five months in advance of the start of the 12-month delivery period, as under the current SOS procurement approach.[9]

Exhibit JFW-AR1 provides for each 12-month delivery period the spot and forward price averages, and the resulting ratio of spot to forward prices. As indicated in Exhibit JFW-AR1, the first delivery period runs from October of 2003 to September of 2004; May of 2003 was the first full month of NYMEX trading of PJM forwards, so October is the earliest feasible start date when assuming procurement five months in advance. Each successive delivery period starts one month later than the previous period, with the last period ending in November of this year, corresponding to the last 12-month period for which spot prices are available.

As shown in Exhibit JFW-AR1, the ratios of spot to forward prices for the 12-month delivery periods range from a maximum of 44% to a minimum

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[8] I did not analyze off-peak prices, because there is a limited history for NYMEX trading of off-peak forwards and because trading volume for off-peak forwards has been thin. My experience has been that the ratio of on-peak to off-peak forward prices closely matches the ratio of on-peak to off-peak spot prices. Thus, I would expect that the ratio of off-peak spot to forward prices would be comparable to the on-peak ratio.

[9] To simulate procurement five months in advance of delivery, I used the clearing prices for the trading date five months prior to the start of the 12-month delivery period.

of -33%, with an average over all delivery periods of 7% and a standard deviation around that average of plus or minus 24%. In other words, on average, spot prices for a 12-month period exceeded forward prices for that same period by approximately 7%. However, there is significant variation around that average, as indicated by the fact that the standard deviation of the price difference is more than three times the average difference.

Q: Based on the results of your analysis, is it reasonable to expect that spot prices will exceed forward prices in the future?

A: Given the limitations in the underlying historical data, and the wide variation in the experienced ratios, it is not possible to predict with any reasonable certainty that spot prices will be either greater or less than forward prices. There is simply too much variability in the small historical sample to forecast a difference between average spot and forward prices with a reasonable degree of confidence.[10]

Q: What does the wide variation in historical ratios indicate about the impact of relying on spot purchases to serve residential SOS load?

A: The variance in historical ratios indicates that there is significant uncertainty concerning future values of the ratio between spot and forward prices, and indicates that there is a substantial risk that reliance on spot purchases will increase long-term costs relative to continued reliance on full-requirements contracts.

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[10] Statistical testing of the historical data indicates that the difference between the mean of historical 12-month average spot prices and the mean of historical 12-month average forward prices is not statistically significant. In other words, we cannot reject the hypothesis that there is in fact no difference between average spot and forward prices.

Q: Given the relationship you have found between forward and spot prices, what information should the Commission review before making a decision regarding procurement approaches for residential SOS?

A: To make a fully informed decision, the Commission should consider an analysis of the potential costs and risks of including various resource options, such as spot energy purchases, in an SOS supply portfolio. This analysis should evaluate portfolio costs and risks over a long-term horizon.

III. Modeling Analysis of Long-Term Costs and Risks

Q: Have you analyzed the long-term risks to consumers associated with reliance on spot purchases to serve residential SOS load?

A: Yes. Resource Insight, with the assistance of the consulting firm Synapse Energy Economics, is currently conducting a modeling analysis of long-term costs and risks associated with the current procurement process and alternative portfolio approaches. This analysis was designed to explore portfolio performance under conditions of uncertainty, and to assess the potential trade-offs between long-term expected cost and risk associated with portfolio diversification. As part of this analysis, we are investigating the long-term costs and risks associated with serving residential SOS load with spot purchases.

The simulation model developed for this analysis is designed to explicitly account for uncertainty in the forecasted values of major cost drivers (such as fuel prices), and to quantitatively measure the combined impact of uncertainty in cost drivers on portfolio cost. Forecast uncertainty is captured by modeling input values for these cost drivers as probabilistic distributions around expected values. The simulation model uses these stochastic inputs to generate a multitude of "futures," reflecting different combinations of forecast paths for these stochastic input values, with each future yielding a unique long-term portfolio cost.[11] Thus, the simulation modeling generates a distribution of cost outcomes, with the 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.

Q: What did your modeling analysis reveal about the long-term costs and risks associated with spot purchases to serve residential SOS load?

A: Although we have not yet finalized the analysis, modeling results confirm my expectations regarding the cost and risk trade-offs associated with serving residential SOS load with spot purchases. Specifically, these results indicate that the long-term costs of serving residential SOS load with spot purchases are expected to be about 6% less than serving load under the current procurement approach. This expected cost savings is due solely to the fact that we assume that spot purchasing reduces the premium for risk and transaction costs relative to the current procurement approach. However, this slight reduction in the assumed risk premium comes at the cost of greater annual price risk. In other words, under spot purchasing, consumers will likely be exposed to significant price risk in order to avoid paying wholesale suppliers a small premium to assume that risk.

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[11] A stochastic variable is an input variable whose value is subject to random variation in the simulation modeling.

A. *Modeling Approach*

Q: Please describe the modeling approach used to forecast portfolio costs and risks.

A: As noted above, the primary objective of the modeling analysis was to forecast expected annual costs, and the distribution around those expected costs, for a variety of resource portfolios for serving residential SOS load. For the purposes of this analysis, we structured the resource portfolios to meet forecasted demand for Potomac Electric Power Company's residential customers, and simulated costs for those portfolios over a 20-year planning horizon. All cost inputs and results are expressed in constant 2007 dollars.

Our goal was not to develop a fully-specified least-cost integrated resource plan for PEPCo's residential class, but to evaluate the potential trade-offs between expected cost and cost risk associated with the current procurement process and alternative portfolio approaches. As such, we did not engage in a comprehensive evaluation of demand-, transmission-, and supply-resource options, as is typical for an integrated planning process. Instead, we analyzed a limited set of "candidate portfolios" designed to illustrate the cost and risk trade-offs associated with portfolio diversification.

The candidate portfolios are as follows:

Portfolio	Composition
Business As Usual (BAU)	Annual rolling procurement of 2-year full-requirements contracts[12]
Clean BAU	Mix of 2-year full-requirements contracts, energy efficiency, and 15-year contracts indexed to cost of new wind resources

[12] Although the current approach procures contracts twice a year, we assumed annual procurement to simplify the modeling effort.

DSM-Wind-Natural Gas (DWN)	Mix of 2-year full-requirements contracts, 5-year fixed-block contracts, energy efficiency, 15-year wind-indexed contracts, and 15-year contracts indexed to new natural gas combined-cycle (NGCC) plant
DSM-Wind-Coal (DWC)	Same as DWN, with 15-year contracts indexed to new pulverized-coal plant substituting for 15-yr NGCC-indexed contracts
DWNC	Combination of DWN and DWC
Spot	100% of energy requirements met with spot purchases, with additional costs for market products needed to provide full-requirements service

We simulated annual costs for each of these portfolios using an Excel-based model with Monte Carlo simulation capability. The annual cost of each resource option included in a portfolio is modeled as a combination of deterministic (e.g., capital cost) and stochastic (e.g., fuel price) cost inputs. Using a Latin Hypercube sampling technique, the spreadsheet model generates 1,000 forecasts (“futures”) of annual portfolio costs over a 20-year planning horizon, with each forecast representing a series of annual random draws from the user-specified probability distributions for the stochastic cost inputs. In each year of each of these 1,000 forecasts, the stochastic cost values from these random draws are combined with deterministic cost inputs to derive the annual cost for each resource included in the candidate portfolio; the annual resource costs are then summed to derive the annual portfolio cost. Thus, each model run for a candidate portfolio generates a distribution of 1,000 cost outcomes for each year of the 20-year planning horizon.

Q: Which cost inputs did you model as stochastic variables?

A: We modeled natural gas and CO_2 allowance prices as stochastic variables, because these two factors are expected to be primary drivers of future uncertainty in wholesale power prices. In addition, we modeled spot prices as a stochastic function of forward prices, due to the wide variance in the historical ratios of spot to forward prices, as discussed in Section II.

We did not model any uncertainty in the construction or fixed operating costs of new plants. Although future construction and fixed costs are uncertain today, the modeling analysis assumes that such costs will be fixed by contract at the time such contracts are acquired. Since I am not proposing that the Commission commit to any particular resource at any particular cost at this time, it is not necessary to model uncertainty in the future acquisition cost for a new-resource contract. Instead, the risk analysis ultimately adopted by the Commission should be updated at the time that new-resource contracts are solicited, to reflect current market conditions and actual prices offered for these contracts.

We also did not explicitly model uncertainty in load growth. However, the model captures uncertainty in load and supply conditions by applying a random variable to the forecast of electric forward prices.

Q: How are long-term costs and risks measured in the modeling analysis?

A: Long-term portfolio costs are measured and compared on the basis of expected 20-year net present value ("NPV") costs, i.e., the net present value over the 20-year planning horizon of expected annual costs. The expected cost in any planning year is simply the mean over the 1,000 forecasts of the portfolio cost for that year.

We followed the approach used by the Northwest Power and Conservation Council and formulated two summary measures of portfolio risk: (1) "TailVaR_{90}"; and (2) "Exceedance Probability."[13] TailVaR_{90} measures long-term risk over the planning horizon. For any portfolio, it is derived by first calculating the 20-year NPV cost for each of the 1,000 futures. The portfolio TailVaR_{90} is then calculated as the average of the 10% highest values of the 1,000 NPV costs.

Exceedance Probability is a summary measure of annual price volatility over the 20-year planning horizon. For each portfolio, Exceedance Probability measures the probability that year-to-year price changes will exceed a threshold percentage level.[14] In other words, Exceedance Probability measures the risk that annual price increases will exceed a threshold percentage level.

B. Input Assumptions

Q: Please describe how the costs for full-requirements contracts are derived in the modeling analysis.

A: Prices for two-year full-requirements contracts are calculated as the sum of forecasted costs for energy, congestion, capacity, ancillary services, and risk and transaction costs.[15] Specifically, the market price for energy is derived from a forecast of forward prices for fixed-block annual forward contracts,

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[13] See Appendix P of Northwest Power and Conservation Council, *The Fifth Northwest Electric Power and Conservation Plan,* May, 2005. This report is available on-line at http://www.nwcouncil.org/energy/powerplan/plan/.

[14] In this case, the threshold level is a real, i.e., net of inflation, price increase, since all costs in the modeling analysis are expressed in constant 2007 dollars.

[15] The costs associated with compliance with the Renewable Portfolio Standard and with transmission and distribution losses are common to, and therefore excluded from the cost accounting for, all portfolios. However, the pricing of new-wind contracts assumes that wind resources receive RPS revenues.

and then adjusted to account for residential load shape. Congestion and ancillary-service prices are estimated by applying percentage multipliers to forecasted forward energy prices. These multipliers, in turn, are derived from historical ratios of congestion and ancillary-service costs to energy costs. Capacity costs are assumed to be constant at PJM's updated estimate of the net Cost of New Entry for the RPM capacity market.[16] Finally, we apply a risk and transaction-cost premium of 5% in the first year and 10% in the second year of the contract.

The forecast of market prices for annual forward contracts is driven by stochastic forecasts of market prices for natural gas forward contracts and for CO_2 mitigation costs, along with assumptions derived from historical data regarding spark spreads in on- and off-peak periods. In essence, the model generates in each year of each of the 1,000 futures: (1) a two-year forecast of market prices for one-year gas forward contracts; and (2) an estimate of the market price for CO_2 mitigation. The model applies the on- and off-peak spark spreads to the forecasted gas forward prices, adds CO_2 compliance costs based on assumptions regarding the mix of marginal resources, and then applies a random variable reflecting load and supply uncertainty to derive a two-year forecast of electric forward prices.[17]

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[16] Ray Pasteris, "RPM CONE Revenue Requirements Update", presentation to the PJM Market Implementation Committee, December 13, 2007.

[17] In order to represent the impact of rolling procurement under the current approach, the simulation model calculates the electric forward price in the current planning year as the average of: (1) the first-year price for the current planning year's two-year forecast; and (2) the second-year price for the prior planning year's two-year forecast. This calculation is performed for each of the 20 planning years for each of the 1,000 futures.

Q: Please describe the derivation of the price forecast for natural gas.

A: We developed a price forecast for natural gas by analyzing the historical data for one-year forward prices at the Henry Hub over the period 1992 through 2007. In addition, we analyzed historical price data from 2002 through 2007 for basis spread from Henry Hub to PJM. From that data, we developed a statistical distribution of the year-to-year percentage changes in prices for one-year forward contracts for natural gas delivered to PJM. We adjusted this statistical distribution so that the expected growth trend would correspond to the growth trend in current NYMEX futures prices and the Department of Energy's current long-term forecast in the *Annual Energy Outlook* for 2007. This adjustment removes the impact of significant price rises experienced in the last several years, which are not expected to occur with the same frequency in the future. The resulting projection of annual natural gas prices follows a "random walk with drift" based on that distribution.

Exhibit JFW-AR2 provides the expected values, and standard deviations around those expected values, of the 1,000 forecasts of annual natural gas prices.

Q: Please describe the derivation of the forecast of carbon-mitigation costs.

A: For CO_2 compliance costs, we derived a price forecast that reflects both regulatory and market uncertainty. The basis for this forecast is a major study by Synapse Energy Economics of the likely costs of compliance associated with proposed greenhouse gas legislation.[18] The Synapse study developed projections of carbon-mitigation costs for Low, Mid, and High regulatory scenarios. For this modeling analysis, we converted the mitigation-cost

[18] Synapse Energy Economics, *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning*, June 8, 2006.

projections for those scenarios into a distribution, such that 90% of the simulated outcomes were within a range bounded by the Low and High regulatory-scenario prices. In addition, we added uncertainty about the start year for regulation of CO_2 and a small element of uncertainty for year-to-year market conditions.

Exhibit JFW-AR3 provides the expected values, and standard deviations around those expected values, of the 1,000 forecasts of annual CO_2 prices.

Q: How are spot-market prices forecasted in the modeling analysis?

A: Spot prices are derived by applying a multiplier to forecasted forward prices. This multiplier is derived based on the historical ratios of 12-month average spot to 12-month average forward prices, as discussed above in Section II. As discussed in Section II, spot prices have on average exceeded forward prices by 7%. However, that difference is not statistically significant, so we assume for the purposes of the modeling analysis that spot prices on average are equal to forward prices.

As shown in Exhibit JFW-AR1, there is significant variance in the historical ratios of spot to forward prices. We model this uncertainty in the relationship of spot to forward prices based on the distribution of those historical ratios.

Finally, in order to derive the cost of serving residential SOS load with spot purchases, we adjust the forecasted annual spot price to account for the costs of congestion, capacity, ancillary services, and risk and transaction costs.

Q: What did you assume for energy-efficiency costs and savings levels?

A: The modeling analysis assumes new DSM savings in each year equivalent to 1.5% of annual energy requirements. However, savings are assumed to decay over time with load growth and as installed DSM measures reach the end of their useful lives. As a result, cumulative savings levels increase to 15% after ten years, but grow only slightly thereafter to reach a maximum of 17% by the end of the planning horizon. This level of savings is consistent with levels achieved through comprehensive utility-sponsored efforts in other States, as well as with the savings targets in Governor O'Malley's EMPower Maryland initiative.

We further assume that this savings level can be achieved at a cost of 3.5¢ per saved kWh. Again, this cost assumption is consistent with the cost of achieved savings in other jurisdictions.

Q: How did you estimate prices for five-year fixed-block contracts?

A: As with two-year full-requirements contracts, five-year fixed-block contracts are priced at forecasted market prices for five years forward. In each year of the planning horizon for each of the 1,000 futures, the model does a random draw from the distributions for natural gas price changes and carbon-mitigation costs. These random draws, in turn, determine the forecast of market prices for the next five years. This five-year forecast sets the annual prices for a five-year contract procured in that year. This process is then repeated in the next planning year, in order to derive a new five-year forecast of market prices for pricing five-year contracts procured in that next planning year.

The derivation of the cost to serve residential SOS load with five-year contracts is also the same as for two-year full-requirements contracts: the contract price for fixed-block energy is adjusted to account for residential load shape, and to account for congestion, capacity, ancillary services, and risk and transaction costs.

Q: Please describe how you estimated the costs of 15-year contracts with new resources.

A: For all 15-year contracts with new resources, we assume that such contracts would be priced to recover capital (including financing) and operating costs (both fuel and non-fuel, including emissions) over the term of the contract. Capital costs are assumed to be recovered on a levelized basis, while operating costs are recovered on a flow-through basis. Exhibit JFW-AR4 summarizes the cost and performance assumptions for new NGCC, pulverized coal, and land-based wind resources.

We estimate the cost to serve residential SOS load with a 15-year contract by modeling that contract as a financial hedge. That is, we assume that residential load requirements are met with two-year full-requirements contracts. The output of the resources behind the 15-year contract, in turn, is assumed to be sold into the wholesale market, with the market price received, net of the contract price, applied as an offset to the full-requirements contract price.[19] Consequently, the net cost of "serving" load with a 15-year contract is calculated as the two-year full-requirements contract price plus the 15-year contract price minus the market price received for the sale of the contract supply.

Q: What mix of resources was assumed for each of the alternative portfolios?

A: Exhibit JFW-AR5 provides the annual mix of resources assumed for each of the candidate portfolios other than the BAU and Spot portfolios. As discussed above, all of these portfolios include new DSM savings equivalent

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[19] In any year, that offset – market price less contract price – may have a positive or negative value.

to 1.5% of annual energy requirements, less savings decay. In addition, all of these alternative portfolios include supply from 15-year contracts indexed to the cost of new wind resources. Wind contracts are assumed to be phased in over time, reaching a maximum amount equivalent to 12% of energy requirements in the sixth year of the planning horizon.

For the portfolios with NGCC or coal contracts, we assume that these contracts are phased in over time, with a maximum contribution to annual energy requirements of 40%.[20] Five-year fixed-block contracts contribute between 5% and 15% of annual energy requirements, once the conventional-resource 15-year contracts are fully phased in; these five-year contracts contribute up to 45% during the phase-in of the 15-year contracts. Finally, we assume that sufficient two-year full-requirements contracts are procured each year to serve the outstanding energy requirements in that year.

C. Simulation Results

Q: Please discuss the results of your modeling analysis.

A: Exhibit JFW-AR6 provides a tabular and graphical summary of the results of the simulation modeling of the six candidate portfolios.[21] The table and graph in Exhibit JFW-AR6 provide summary statistics (expected value, one standard deviation, and TailVaR_{90}) based on the distribution of discounted annual costs for the 1,000 futures. As discussed above, this distribution is derived by calculating for each of the 1,000 futures the net present value of

[20] For the candidate portfolio with both coal and NGCC, each resource type provides a maximum of 20% of the annual energy requirement.

[21] As mentioned above, Resource Insight has not yet finalized its modeling analysis for OPC. However, I do not anticipate that the remaining work will markedly change the results cited herein.

annual costs over the 20-year planning horizon. The expected value is thus the mean of the 1,000 values for NPV cost.

As shown in JFW-AR6, the BAU portfolio – representing continuation of the current procurement approach – is the most expensive of the candidate portfolios on an expected-value basis, at a discounted cost of about $12.7 Billion. Relying on spot purchases to serve residential SOS load is estimated to reduce expected NPV cost by approximately 6%, reflecting our assumption that spot purchasing shifts price risk from suppliers to consumers and thus reduces the risk premium on those spot purchases.

Adding energy efficiency and new wind resources to the BAU portfolio substantially reduces the expected value of discounted costs. The expected NPV cost for the Clean BAU portfolio is about 12% less than for the BAU portfolio. Although not shown in Exhibit JFW-AR6, energy efficiency accounts for the bulk of the 12% savings; adding just energy efficiency to the BAU portfolio reduces expected NPV cost by 10%.

The candidate portfolios with a diversified mix of energy efficiency and short-, medium-, and long-term contracts produce the greatest expected savings relative to the BAU portfolio. Whether the candidate portfolio includes 15-year contracts with new natural gas combined-cycle plant (DWN portfolio), pulverized coal (DWC portfolio), or a combination of the two (DWNC portfolio), portfolio NPV costs are expected to be about 20% less than for the BAU portfolio.

Q: Given this finding of expected-cost savings, would you recommend that the Commission direct the utilities to procure 15-year contracts at this time?

A: No. These results are based on a number of predictions regarding the capital and operating costs of new resources, and regarding the price structure of 15-year contracts indexed to the cost of new resources, that are likely to differ from their actual values. These results are merely indicative of the value of long-term contracts as part of a diversified resource portfolio. The cost-effectiveness of a 15-year contract (or any other resource option, for that matter), and the value of adding such contracts to an SOS portfolio, should be determined on the basis of actual offers tendered in a competitive solicitation process, and on the basis of a detailed cost and risk analysis reflecting prevailing market conditions.

Q: What do these results indicate about the candidate portfolios' long-term risks?

A: As indicated in Exhibit JFW-AR6, continuation of the current procurement approach (BAU portfolio) is not only the most expensive, but also the riskiest option for serving residential SOS load. The extreme riskiness of the BAU portfolio is indicated by the fact that the $6.1 Billion spread between its TailVaR_{90} and its expected cost exceeds that of all other portfolios, and is about 75% greater than the average spread for the most-diversified portfolios (i.e, DWN, DWC, and DWNC).[22] In other words, while there is a one-in-ten chance that the cost of the most-diversified portfolios will increase by about

[22] As described earlier, TailVaR_{90} is calculated as the average of the 100 worst outcomes out of the 1,000 modeling runs for each candidate portfolio.

$3.5 Billion, or about 35%, it is just as likely that the cost of the BAU portfolio will increase by $6.1 Billion, or about 48%.

As expected, the addition of energy efficiency and wind resources to the BAU portfolio improves overall portfolio performance, reducing both expected cost and long-term risk. As shown in Exhibit JFW-AR6, adding clean resources to the BAU portfolio reduces the spread between expected cost and $TailVaR_{90}$ from $6.1 Billion to about $4.8 Billion.

Finally, the simulation results illustrate the dramatic improvement in portfolio performance and reduction in long-term risk from portfolio diversification. As noted above, the average spread between expected cost and $TailVaR_{90}$ for the DWN, DWC, and DWNC portfolios is less than 60% of the spread for the BAU portfolio. Moreover, the spread as a percentage of expected cost is lower for the diversified portfolios than for the BAU portfolio. This suggests that the $TailVaR_{90}$ would still be lower for the diversified portfolios than for the BAU portfolio, even if the diversified portfolios had the same expected cost as the BAU portfolio.

Q: Is one diversified portfolio clearly superior to the other two in terms of overall performance?

A: No. While these diversified portfolios are clearly superior to the BAU, Spot, and Clean BAU portfolios in terms of both cost and risk, there are trade-offs between expected cost and risk among the three diversified portfolios. These trade-offs between long-term cost and risk are illustrated in Exhibit JFW-AR7. As indicated in that exhibit, the portfolio with 15-year gas-indexed contracts is expected to have the lowest long-term cost, but the highest risk among the diversified portfolios. In contrast, the portfolio with 15-year coal-indexed contracts is expected to have the highest cost, but lowest risk.

Q: Does the lower TailVaR$_{90}$ value for the Spot portfolio indicate that reliance on spot purchases is a lower-risk option for consumers than continued reliance on two-year full-requirements contracts?

A: No. While the Spot portfolio produces a slightly lower risk of higher costs over a 20-year planning horizon, that slight improvement is outweighed by a significant increase in the risk of substantial annual price volatility. This increased risk is illustrated in Exhibit JFW-AR8, which provides the Exceedance Probability curves for the year 2025 for each of the candidate portfolios. For example, Exhibit JFW-AR8 shows for the BAU portfolio that there is an 11% risk that the price increase from 2024 to 2025 will exceed 20%. In contrast, spot purchasing doubles the risk to 22% that the price increase will exceed 20%.[23]

Reliance on spot purchases to serve residential SOS load imposes too much price risk for the small amount of potential savings. While spot purchases allow consumers to avoid a small risk premium on fixed-price, full-requirements supply, it doubles the odds that price volatility will reach levels that are contrary to the public interest.

Q: Does this conclude your additional reply testimony?

A: Yes.

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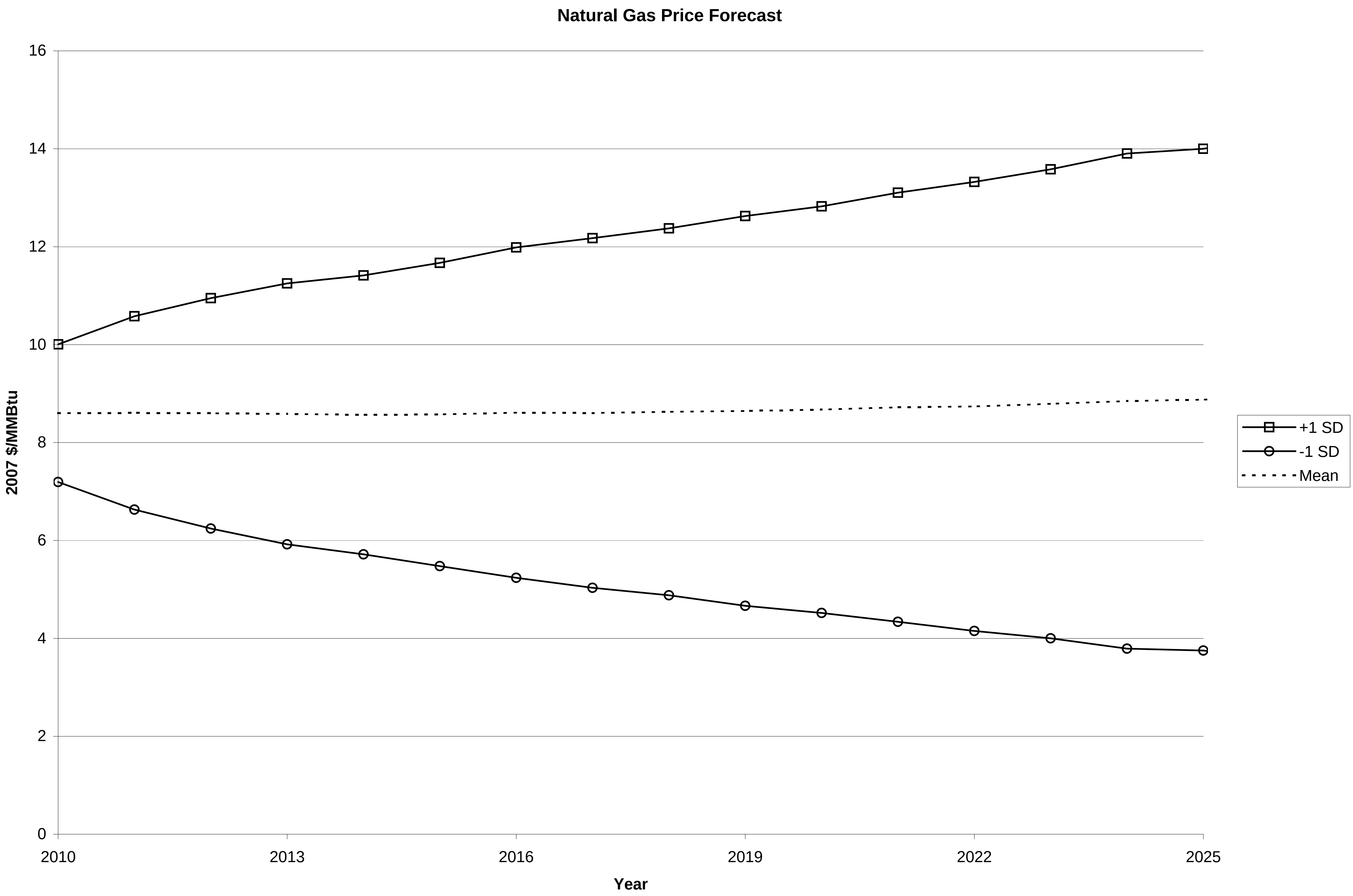
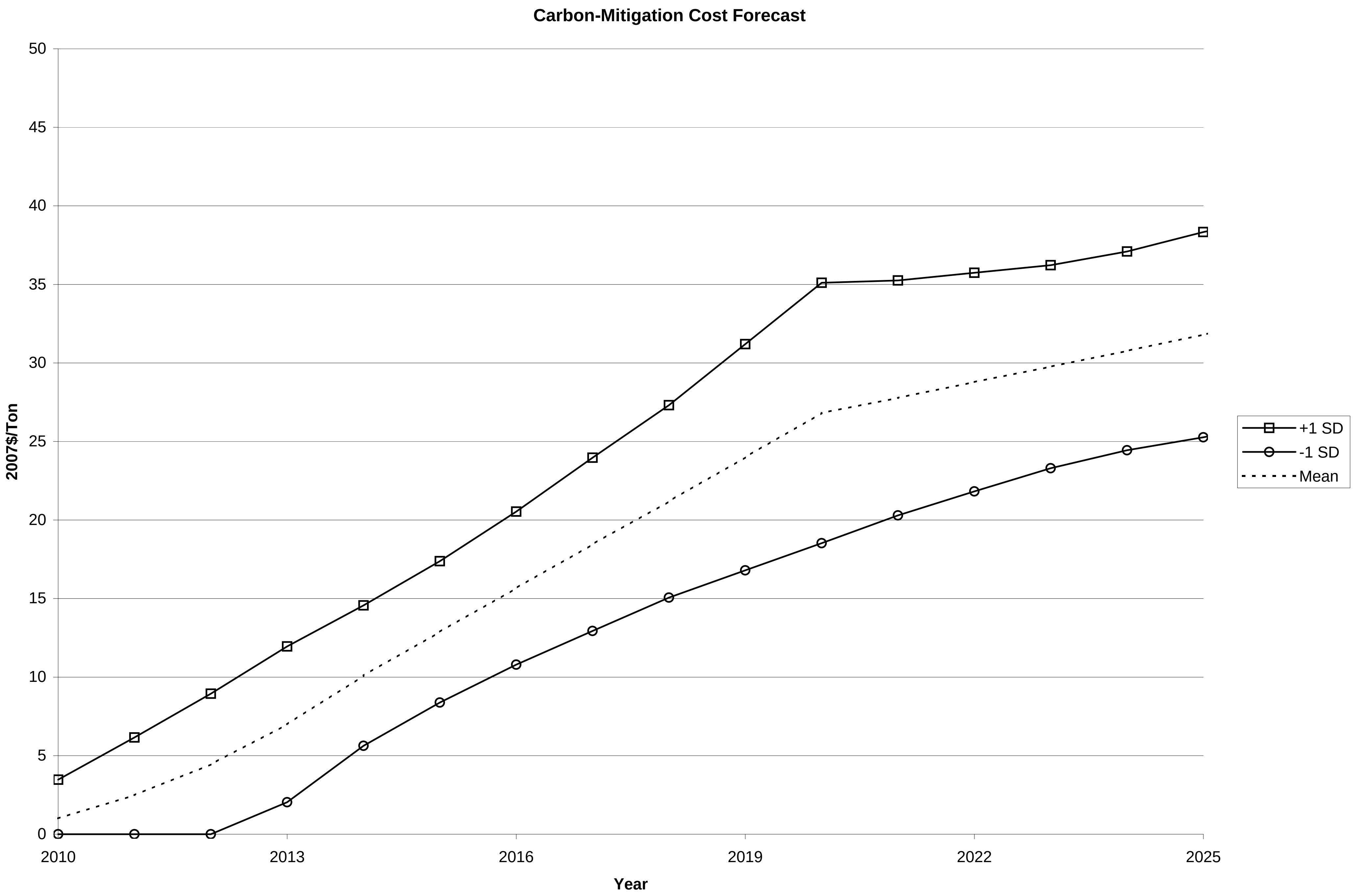
[23] This increase in price risk in 2025 is not an isolated event. We have calculated the Exceedance Probabilities over all years in the planning horizon for the BAU and Spot portfolios, and find the same doubling of the probability of a greater-than-20% price increase.

Historical Ratio of Spot to Forward Prices

Delivery Period		Delivery Period Average Price: On-Peak Day-Ahead	Delivery Period Average Price: On-Peak Forward Contract	Day-Ahead / Forward Price Ratio
Oct-03	Sep-04	48.57	49.01	-1%
Nov-03	Oct-04	49.70	51.34	-3%
Dec-03	Nov-04	50.50	44.65	13%
Jan-04	Dec-04	50.73	43.46	17%
Feb-04	Jan-05	49.87	43.18	15%
Mar-04	Feb-05	49.63	41.34	20%
Apr-04	Mar-05	50.59	41.81	21%
May-04	Apr-05	51.13	42.21	21%
Jun-04	May-05	50.83	46.16	10%
Jul-04	Jun-05	52.38	46.90	12%
Aug-04	Jul-05	55.29	49.41	12%
Sep-04	Aug-05	59.96	51.53	16%
Oct-04	Sep-05	64.77	51.87	25%
Nov-04	Oct-05	68.91	56.15	23%
Dec-04	Nov-05	71.07	54.31	31%
Jan-05	Dec-05	75.42	54.04	40%
Feb-05	Jan-06	76.07	53.33	43%
Mar-05	Feb-06	76.98	55.76	38%
Apr-05	Mar-06	77.26	61.99	25%
May-05	Apr-06	77.58	57.76	34%
Jun-05	May-06	77.42	53.70	44%
Jul-05	Jun-06	76.80	57.92	33%
Aug-05	Jul-06	76.09	60.38	26%
Sep-05	Aug-06	75.59	66.66	13%
Oct-05	Sep-06	70.53	62.18	13%
Nov-05	Oct-06	66.33	63.17	5%
Dec-05	Nov-06	64.76	68.43	-5%
Jan-06	Dec-06	60.72	72.28	-16%
Feb-06	Jan-07	59.94	84.28	-29%
Mar-06	Feb-07	61.20	90.77	-33%
Apr-06	Mar-07	61.65	88.53	-30%
May-06	Apr-07	62.55	93.40	-33%
Jun-06	May-07	63.89	90.68	-30%
Jul-06	Jun-07	64.84	87.01	-25%
Aug-06	Jul-07	64.43	75.14	-14%
Sep-06	Aug-07	63.56	81.90	-22%
Oct-06	Sep-07	65.41	86.46	-24%
Nov-06	Oct-07	67.65	78.79	-14%
Dec-06	Nov-07	68.45	79.39	-14%
			Average	7%
			St Dev	24%
			Minimum	-33%
			Maximum	44%


Natural Gas Price Forecast
2007 $/MMBtu
16
14
12
10
8
6
4
2
0
2010
2013
2016
2019
2022
2025
Year
+1 SD
-1 SD
Mean


Carbon-Mitigation Cost Forecast
2007$/Ton
50
45
40
35
30
25
20
15
10
5
0
2010
2013
2016
2019
2022
2025
Year
+1 SD
-1 SD
Mean

New-Resource Cost and Performance Assumptions

Category	Conv Coal	NGCC	Wind	
Source	NE SA & AEO	NE SA & AEO	AEO & Levitan	
Total Capital Cost	2,500	1,000	2,250	$/kW
Debt Rate	8.00%	8.00%	8.00%	
Equity Rate	13.00%	13.00%	13.00%	
Debt Mix	50%	50%	50%	
Equity Mix	50%	50%	50%	
Nominal WACC	10.50%	0.105	0.105	
Tax Rate	40%	40%	40%	
After Tax WACC	8.90%	8.90%	8.90%	
Nominal Discount Rate	8.90%	8.90%	8.90%	
Real Discount Rate	6.24%	6.24%	6.24%	
Capital Levelization Period	30	30	30	years
Real Capital Levelization Rate	9.65%	9.65%	9.65%	%
Annualized Capital Value	241.2	96.5	217.1	$/kW-yr
Fixed Operating Costs	26.7	11.3	29.3	$/kW-yr
Total Fixed Costs	267.8	107.8	246.4	$/kW-yr
Operating Capacity Factor	85%	85%	35%	%
Fixed Energy Costs	35.97	14.47	80.35	$/MWh
Heat Rate	9,500	6,500	0	Btu/kWh
Fuel Usage Factor	9.5	6.5	0	MMBtu/MWh
Variable O&M Costs	4.44	2	0	$/MWh
NOx Rate	0.08	0.02	0	lbs/MMBtu
SOx Rate	0.05	0	0	lbs/MMBtu
NOx Cost	1,705	1,705	1,705	$/ton
SOx Cost	680	680	680	$/ton
Environmental Costs	0.81	0.11	0	$/MWh
Non Fuel Variable Costs	5.25	2.11	0	$/MWh
CO2 Rate	208	117	0	lbs/MMBtu
CO2 Rate	0.988	0.380	0	ton/MWh

Resource Mix of Candidate Portfolios

	DWN Portfolio						DWC Portfolio						DWNC Portfolio					
	DSM	Wind	Coal	NGCC	5-yr	BAU	DSM	Wind	Coal	NGCC	5-yr	BAU	DSM	Wind	Coal	NGCC	5-yr	BAU
2010	1.5%	2.0%	0.0%	0.0%	10.0%	86.5%	1.5%	2.0%	0.0%	0.0%	15.0%	81.5%	1.5%	2.0%	0.0%	0.0%	10.0%	86.5%
2011	3.0%	4.0%	0.0%	0.0%	20.0%	73.0%	3.0%	4.0%	0.0%	0.0%	35.0%	58.0%	3.0%	4.0%	0.0%	0.0%	20.0%	73.0%
2012	4.5%	6.0%	0.0%	10.0%	30.0%	49.5%	4.5%	6.0%	0.0%	0.0%	45.0%	44.5%	4.5%	6.0%	0.0%	10.0%	30.0%	49.5%
2013	5.9%	8.0%	0.0%	20.0%	30.0%	36.1%	5.9%	8.0%	20.0%	0.0%	45.0%	21.1%	5.9%	8.0%	20.0%	10.0%	30.0%	26.1%
2014	7.4%	10.0%	0.0%	30.0%	30.0%	22.6%	7.4%	10.0%	20.0%	0.0%	45.0%	17.6%	7.4%	10.0%	20.0%	10.0%	30.0%	22.6%
2015	8.8%	12.0%	0.0%	40.0%	20.0%	19.2%	8.8%	12.0%	20.0%	0.0%	35.0%	24.2%	8.8%	12.0%	20.0%	20.0%	20.0%	19.2%
2016	10.2%	12.0%	0.0%	40.0%	15.0%	22.8%	10.2%	12.0%	40.0%	0.0%	15.0%	22.8%	10.2%	12.0%	20.0%	20.0%	15.0%	22.8%
2017	11.6%	12.0%	0.0%	40.0%	15.0%	21.4%	11.6%	12.0%	40.0%	0.0%	10.0%	26.4%	11.6%	12.0%	20.0%	20.0%	15.0%	21.4%
2018	12.7%	12.0%	0.0%	40.0%	15.0%	20.3%	12.7%	12.0%	40.0%	0.0%	15.0%	20.3%	12.7%	12.0%	20.0%	20.0%	15.0%	20.3%
2019	13.7%	12.0%	0.0%	40.0%	15.0%	19.3%	13.7%	12.0%	40.0%	0.0%	15.0%	19.3%	13.7%	12.0%	20.0%	20.0%	15.0%	19.3%
2020	14.6%	12.0%	0.0%	40.0%	15.0%	18.4%	14.6%	12.0%	40.0%	0.0%	10.0%	23.4%	14.6%	12.0%	20.0%	20.0%	15.0%	18.4%
2021	15.3%	12.0%	0.0%	40.0%	10.0%	22.7%	15.3%	12.0%	40.0%	0.0%	10.0%	22.7%	15.3%	12.0%	20.0%	20.0%	10.0%	22.7%
2022	16.0%	12.0%	0.0%	40.0%	5.0%	27.0%	16.0%	12.0%	40.0%	0.0%	10.0%	22.0%	16.0%	12.0%	20.0%	20.0%	5.0%	27.0%
2023	16.4%	12.0%	0.0%	40.0%	10.0%	21.6%	16.4%	12.0%	40.0%	0.0%	10.0%	21.6%	16.4%	12.0%	20.0%	20.0%	10.0%	21.6%
2024	16.8%	12.0%	0.0%	40.0%	10.0%	21.2%	16.8%	12.0%	40.0%	0.0%	10.0%	21.2%	16.8%	12.0%	20.0%	20.0%	10.0%	21.2%
2025	17.1%	12.0%	0.0%	40.0%	10.0%	20.9%	17.1%	12.0%	40.0%	0.0%	10.0%	20.9%	17.1%	12.0%	20.0%	20.0%	10.0%	20.9%
2026	17.3%	12.0%	0.0%	40.0%	10.0%	20.7%	17.3%	12.0%	40.0%	0.0%	10.0%	20.7%	17.3%	12.0%	20.0%	20.0%	10.0%	20.7%
2027	17.4%	12.0%	0.0%	40.0%	10.0%	20.6%	17.4%	12.0%	40.0%	0.0%	10.0%	20.6%	17.4%	12.0%	20.0%	20.0%	10.0%	20.6%
2028	17.4%	12.0%	0.0%	40.0%	10.0%	20.6%	17.4%	12.0%	40.0%	0.0%	10.0%	20.6%	17.4%	12.0%	20.0%	20.0%	10.0%	20.6%
2029	17.4%	12.0%	0.0%	40.0%	10.0%	20.6%	17.4%	12.0%	40.0%	0.0%	10.0%	20.6%	17.4%	12.0%	20.0%	20.0%	10.0%	20.6%
2030	17.4%	12.0%	0.0%	40.0%	10.0%	20.6%	17.4%	12.0%	40.0%	0.0%	10.0%	20.6%	17.4%	12.0%	20.0%	20.0%	10.0%	20.6%

Summary Results of Modeling Analysis

Portfolio	Expected Cost ($M)	Difference from BAU	StdDev ($M)	$TVaR_{90}$ ($M)	Spread Between $TVaR_{90}$ and Expected Cost ($M)	
BAU	12,720		2,840	18,838	48%	6,118
Spot	11,910	-6%	2,661	17,648	48%	5,738
Clean BAU	11,238	-12%	2,240	15,997	42%	4,758
D-W-N	10,050	-21%	1,889	14,046	40%	3,996
D-W-C	10,364	-19%	1,516	13,441	30%	3,077
D-W-N-C	10,171	-20%	1,686	13,669	34%	3,497

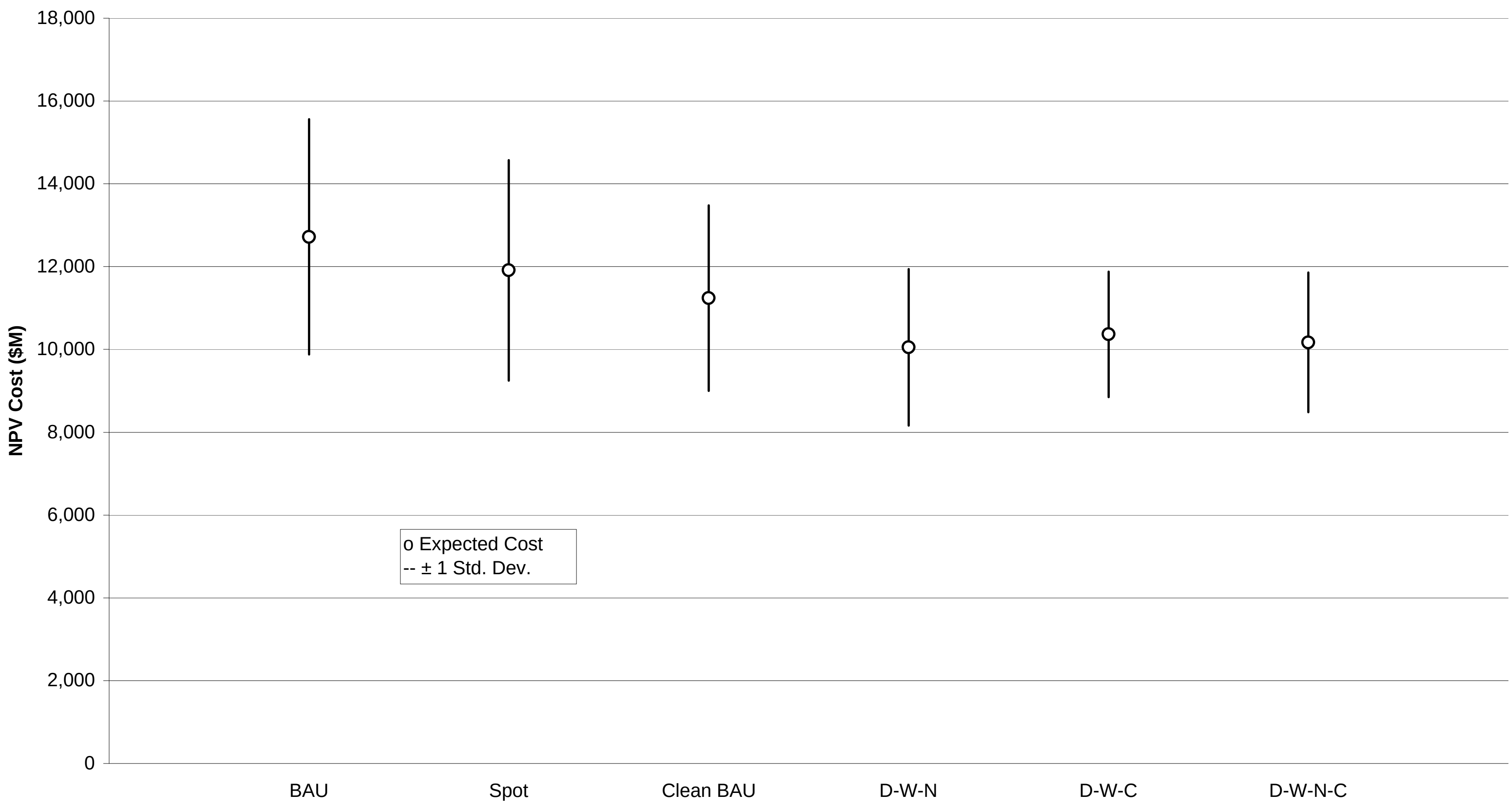
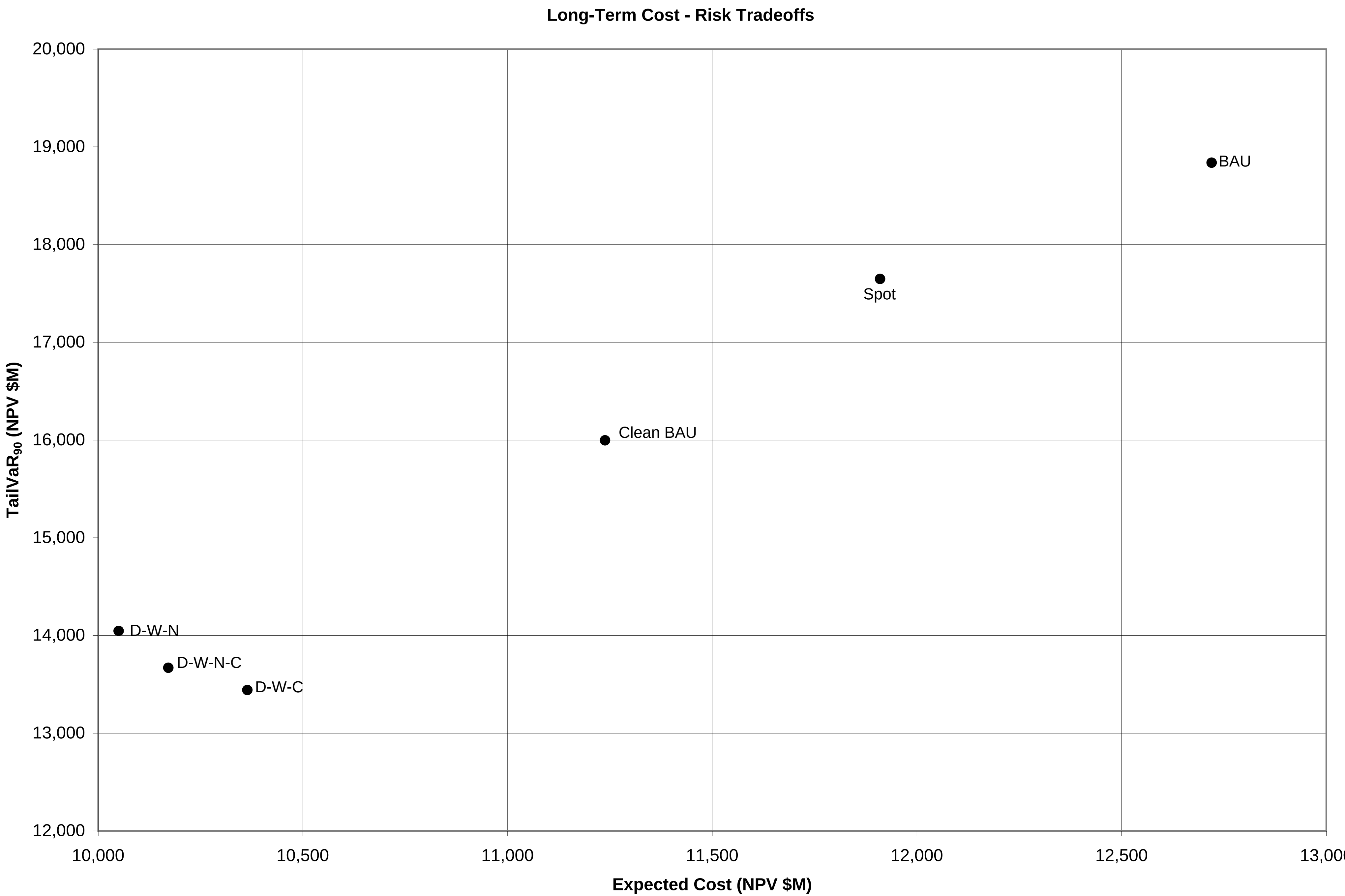


Exhibit JFW-AR7



Resource Insight, Inc.

12/21/2007

Annual Price Risk

Probability of Annual Cost Increases Greater Than Threshold Percentage