STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

Investigation into Effect of Customer Migration on Energy Service Rates	))	Docket No. DE 10-160

Direct Testimony of

DANIEL W. ALLEGRETTI

On Behalf of

CONSTELLATION NEWENERGY, INC.
CONSTELLATION ENERGY COMMODITIES GROUP, INC.
and
RETAIL ENERGY SUPPLY ASSOCIATION

September 15, 2010

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<u>Direct Testimony of Daniel W. Allegretti</u>

I. <u>INTRODUCTION</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Daniel W. Allegretti and my business address is 1 Essex Drive, Bow, New Hampshire 03304.

Q. PLEASE DESCRIBE YOUR RELATIONSHIP TO CONSTELLATION ENERGY COMMODITIES GROUP, INC. ("CCG") AND CONSTELLATION NEWENERGY, INC. ("CNE", COLLECTIVELY, "CONSTELLATION").

A. I am a Vice President of Energy Policy with Constellation.

Q. WHAT ARE YOUR RESPONSIBILITIES AS VICE PRESIDENT OF ENERGY POLICY FOR CONSTELLATION?

A. I am responsible for representing Constellation's retail and wholesale commodity business interests on matters related to regulatory and government affairs throughout the New England, New York and the Mid-Atlantic regions.

Q. WHAT IS YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE?

A. My resume is attached as an exhibit to this testimony, as Constellation/RESA Exhibit No. 1.1.

Q. PLEASE DESCRIBE THE RETAIL ENERGY SUPPLY ASSOCIATION ("RESA").

A. RESA is a nonprofit organization and trade association that represents the interests of its members in regulatory proceedings in the Mid-Atlantic, Great Lakes, New York and New England regions. RESA's members include providers of competitive supply and related services throughout the five New England states that have implemented electric deregulation, including in the service territories of Public Service Company of New Hampshire ("PSNH") and other New Hampshire electric utilities. CNE is a RESA member company, as are ConEdison Solutions; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; Energy Plus Holdings, LLC; Exelon Energy Company; GDF SUEZ Energy Resources NA, Inc.; Gexa Energy; Green Mountain Energy Company; Hess Corporation; Integrys Energy Services, Inc.; Just Energy; Liberty Power; PPL EnergyPlus; Reliant Energy Northeast LLC; and Sempra Energy Solutions LLC.[1]

Q. ARE YOU APPEARING TODAY ON BEHALF OF BOTH CONSTELLATION AND RESA?

A. Yes.

Q. HAVE YOU REVIEWED THE PRE-FILED DIRECT TESTIMONY OF PSNH WITNESS ROBERT A. BAUMANN AND OFFICE OF CONSUMER ADVOCATE ("OCA") WITNESS KENNETH E. TRAUM FILED ON JULY 30, 2010 IN THIS PROCEEDING?

A. Yes. My testimony today will address issues raised in both of these witnesses' direct testimony.

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[1] The comments expressed in this filing represent the positions of Constellation and of RESA as an organization, but may not represent the views of any particular member of RESA.

II. PURPOSE OF TESTIMONY AND CONCLUSIONS

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. At the June 11, 2010 technical session, the parties agreed that the scope of the proceeding will include customer migration and the interplay of power procurement with migration.[2] In this testimony, I will address important policy considerations the Commission should consider related to the manner in which PSNH procures its commodity supply for its Energy Services ("ES") customers. If adopted, my recommendations will not only address the immediate issue of stranded commodity cost recovery, but also will enhance the retail competitive market in New Hampshire leading to increased residential and small commercial supply options.

In addition, I will address some of the issues raised in the pre-filed direct testimony of PSNH witness Baumann and OCA witness Traum.

In his prefiled direct testimony, Mr. Baumann expressed his concerns related to the fairness of having PSNH's customers that receive commodity supply from PSNH pay increasing Energy Service ("ES") rates due to increased levels of customer migration to third party suppliers. Mr. Bauman's proposed fix for this situation is to require all customers, even those that no longer receive their commodity from PSNH, to pay for the commodity costs associated with ES customers via a non-bypassable charge on their bill.

Finally, Mr. Traum notes that it is the policy of the State of New Hampshire to encourage competition and migration to alternative suppliers, but not when it results in unfairly shifting costs to customers who do not have the opportunity to migrate. Mr. Traum then suggests

[2] *See* July 2, 2010 Technical Session Report at 2.

four alternatives on how PSNH's ES methodology and management can be changed so as to be more equitable for small customers while achieving the policy principles outlined above, including the suggestion that PSNH bid out its ES requirements using a competitive request for proposal ("RFP") procurement process consistent with how other New Hampshire utilities manage their obligations to provide default service.

Q. HOW DOES PSNH CURRENTLY PROCURE COMMODITY SUPPLY FOR ITS ES CUSTOMER LOAD?

A. As Mr. Baumann testifies, to meet current and future ES load obligations, PSNH manages a portfolio of power sources including owned generation, unit entitlements, independent power producer ("IPP") generation, bilateral contracts and spot market purchases. Baumann at 3:13-18. This is referred to as a "Managed Portfolio" model.

Q. IS THERE A RISK ASSOCIATED WITH PSNH UTILIZING SUCH A MANAGED PORTFOLIO APPROACH?

A. Yes. As Mr. Baumann acknowledges in his testimony, because PSNH's ES load obligation has declined in recent years due to customer migration to alternative suppliers, PSNH has a smaller pool from which to recover its costs associated with supplying the commodity to the ES customers, resulting in excess supply. Thus, there is upward pressure on the ES rates that PSNH imposes in order to recover those excess supply costs. Baumann at 4:22-24 through 5:1-18.

Q. WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO THE INTERPLAY OF MIGRATION AND CURRENT PSNH PROCUREMENT PRACTICES FOR ITS ES CUSTOMER LOAD VIA THE MANAGED PORTFOLIO MODEL?

A. I conclude that a Full Requirements Service ("FRS") procurement structure ("FRS Structure") will best meet the needs of PSNH and its ES customers. Implementing a FRS

Structure will avoid: (1) the excess supply costs that have caused upward pressure on the ES rate; (2) cost shifting from ES customers to switched customers; and (3) the imposition of costs on customers for supply they neither want nor need. I will describe very recent evidence which I rely upon to support my recommendation for a FRS Structure. In addition, I will provide other tools the Commission can consider implementing that will further promote retail competition, especially in the small commercial and residential classes, further addressing the policy objectives of the State for encouraging migration and competition.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION REGARDING THE ISSUES PRESENTED IN THIS PROCEEDING?

A. Yes. Most recently I provided written testimony in Docket No. 07-096 on November 9, 2007,[3] and appeared for cross examination before the Commission in the same proceeding.

Q. CAN YOU PLEASE RECAP BRIEFLY YOUR CONCLUSIONS IN DOCKET NO. 07-096 REGARDING THE APPROPRIATE STRUCTURE FOR PROCURING PSNH'S ES OBLIGATIONS?

A. Certainly. In Docket No. 07-096, I provided an analysis of the benefits associated with utilizing a FRS Structure versus a Managed Portfolio approach. In addition, I have testified on the benefits of the FRS Structure in other state proceedings, including proceedings in Connecticut,[4] New York,[5] Pennsylvania[6] and Rhode Island.[7] In my prior testimony I have provided a thorough explanation regarding the benefits of FRS products and the inherent deficiencies in relying upon a Managed Portfolio approach. I have explained that FRS

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[3] *See Prefiled Direct Testimony of Daniel Allegretti on Behalf of Constellation NewEnergy, Inc. and Constellation Energy Commodities Group, Inc.*, Commission Docket No. 07-096 (submitted November 9, 2007). A copy of this testimony is attached hereto as Exhibit 1.2.

[4] *See, e.g.*, Connecticut Department of Utility Control, Docket Nos. 06-01-08RE01 and 07-06-58.

[5] *See* New York Public Service Commission Case No. 10-E-0050.

[6] *See* Commonwealth of Pennsylvania Public Utility Commission Docket No. P-2010-2157862.

[7] *See* State of Rhode Island and Providence Plantations Public Utilities Commission Docket No. 4149.

products relieve utilities such as PSNH from active load, weather and market volatility management responsibility and, in turn, relieve such utilities and their customers from risk management exposure. FRS products more effectively eliminate the uncertainty associated with fuel, availability, volumetric and spot price risks that are inherent in managing load supply. These FRS products have the added benefit of avoiding after-the-fact reviews that may question the effectiveness or reasonableness of hedges necessary to limit risk. Furthermore, potential bidders are interested in well-defined FRS products and are comfortable with pricing such products through competitive processes such as the procurements in the FRS Structure.

In Docket No. 07-096, I concluded that a FRS Structure relying largely on FRS products would most effectively and best meet PSNH and its ES customers' needs. Moreover, I recommended that it is best to rely on such FRS products to allocate to wholesale suppliers – rather than PSNH and, in turn, its ES consumers – the risks and responsibilities associated with portfolio management.

Q. DO YOU CONTINUE TO SUPPORT THE USE OF A FRS STRUCTURE TO MEET PSNH'S CUSTOMERS' ES REQUIREMENTS?

A. Yes. As detailed below, for all of the reasons I explained in Docket No. 07-096, I continue to support a FRS Structure for PSNH and encourage the Commission to move away from a Managed Portfolio procurement methodology. I will also provide the Commission with additional recent evidence of the benefits associated with the FRS Structure in the form of a recently-released study by the NorthBridge Group comparing the benefits and risks associated with FRS and Managed Portfolio procurement models. Finally, I will detail several other tools that the Commission can implement that will encourage the migration of small commercial and residential customers to take advantage of their right to choose to take third party supply – all of which will enhance the state of competition in New Hampshire in accordance with the restructuring principles detailed in RSA 374-F.

III. DIRECT TESTIMONY

Q. PLEASE DESCRIBE HOW A MANAGED PORTFOLIO MODEL WORKS.

A. Under a Managed Portfolio procurement model like the one PSNH currently utilizes, the utility pieces together a portfolio from a range of different physical and financial products. These products could and often do include short, medium, and long-term physical contracts, financial swaps, financial collars, and transmission rights, combined with purchases from the day-ahead and real-time markets. Additionally, under the Managed Portfolio model, the utility must actively monitor the market and attempt to time procurement to achieve the lowest possible cost while maintaining the desired level of hedging to protect against market volatility. Prior to the development of competitive electricity markets, the Managed Portfolio procurement model was the most common among utilities.

Q. HOW DOES THE FRS STRUCTURE DIFFER FROM THE MANAGED PORTFOLIO PROCUREMENT MODEL?

A. Many of the same functions are performed under a FRS procurement model; however, under the FRS Structure competitive wholesale providers manage those functions, relieving the utility and its customers from the risks and costs inherent in such an approach. Utilities and regulators are able to then choose the wholesale provider that provides the lowest and best all-in price for default service customers such as those taking ES from PSNH.

Q. CAN YOU PLEASE EXPLAIN IN ADDITIONAL DETAIL THE BENEFITS OF SHIFTING RISKS TO WHOLESALE SUPPLIERS?

A. Of course. Under the Managed Portfolio approach, the results of PSNH's power purchase decisions, good or bad, are passed on to its ES customers through its periodic ES rate adjustments. By contrast, under the FRS approach that National Grid and Unitil utilize, Full Requirements contracts shift price and quantity risk to the wholesale suppliers – thus providing consumers with price insurance for the duration of the contract. Because they have bid a fixed price, these suppliers cannot seek to increase rates to default customers when market conditions change and the effects of customer migration impact their total cost of supply. The Managed Portfolio approach leaves with PSNH the risk that as power prices fall and customers leave default service, the Company will be left holding purchased power supply in excess of its default service load. The oversupply can be re-sold in the market, but if prices have fallen, it will have to be sold at a loss. Under a FRS Structure, the supplier bears any such loss; under a Managed Portfolio approach, the Company incurs such a loss and the Commission will have to address the issue one way or another.

Such is the circumstance PSNH now finds itself facing. Specifically, PSNH provided information in response to Staff Data Request Q-STAFF-002 that indicates the annual cost attributable to PSNH power purchases and the above-market portion of the total costs for those purchases. Total purchases from 2006 through July 2010 were $839,128,484 and PSNH estimates the above-market portion at $233,585,606, or around 28 percent. Clearly PSNH has failed over the last several years to match, let alone beat, the market in making its purchasing decisions. As PSNH also notes, over the past 24 months, the ES load obligation has decreased significantly. This has prompted PSNH to seek recovery of its Managed

Portfolio costs from both ES and non-ES customers. Poor trading decisions by an FRS supplier may affect its bottom line, but do not affect the customers. With a Managed Portfolio approach, trading losses are passed on to the customers. In this regard, PSNH's performance as a portfolio manager (28% above market) is not encouraging. To protect customers from the risk and consequences of these un-economic purchasing decisions, I strongly recommend moving PSNH to a FRS procurement approach instead.

Q. IN HIS TESTIMONY, MR. TRAUM DISCUSSES THE ELECTRIC RESTRUCTURING LAW AND ITS POLICIES RELATED TO COST-SHIFTING. TRAUM AT 6:14-21. DO YOU HAVE ANY REACTION?

A. Yes. Mr. Traum references RSA 374-F:3, VI, which precludes cost shifting among customers, and states that the "policy of the State is to encourage electric competition and migration, but not when it results in unfairly shifting costs to customers who do not have the opportunity to migrate." Traum at 6:19-21. I agree with Mr. Traum that cost-shifting is unfair and violative of the principle laid out in RSA 374-F:3, VI. However, just as shifting costs between classes is inconsistent with this principle, so too is shifting costs between those customers that receive their supply via PSNH's ES services to those that have taken advantage of their right to receive their supply from a competitive supplier.

Q. MR. TRAUM OBSERVES THAT CUSTOMER MIGRATION IN THE NATIONAL GRID AND UNITIL SERVICE TERRITORIES DOES NOT HAVE THE SAME NEGATIVE IMPACTS ON SMALL CUSTOMERS. TRAUM AT 7:1-10. DO YOU HAVE ANY THOUGHTS ON HIS OBSERVATION?

A. Yes. Mr. Traum correctly observes that both National Grid and Unitil bid out the full requirements of their default ES customers' load in New Hampshire to third party wholesale suppliers through competitive procurements under a FRS Structure. I agree with Mr. Traum that, as a result of adopting the FRS Structure for those utilities, the wholesale suppliers have assumed the migration risks and, consequently, those risks and related costs are embedded in the product those FRS suppliers provide to those utilities to meet their default service customers' requirements.

Q. PLEASE DESCRIBE THE BENEFITS OF THE FRS PROCUREMENT MODEL IN MORE DETAIL.

A. The FRS procurement process provides a proper balance between the goal of obtaining the most competitive prices for consumers and maintaining a reasonable level of price stability from year-to-year. The FRS model results in prices that are reflective of the market, while still insulating customers from excessive volatility. Moreover, requiring PSNH to expend resources to actively manage an energy portfolio continues to be an inefficient way to achieve competitive ES prices for consumers. As PSNH's load must always be met with full requirements products – whether under a Managed Portfolio approach or a FRS Structure – in order to actively manage its load obligations, PSNH needs to retain or hire outside individual experts who understand and follow not only electric energy and other commodity markets, but also fuel, ancillary services, capacity and renewable products markets.

A diverse pool of wholesale suppliers – rather than a small group of independent consultants or utility employees – provides the most cost-effective method of ES supply management. Wholesale suppliers are experts in the area of portfolio management, and have greater resources, expertise, and ability to appropriately manage portfolios of supply at the least possible cost by allocating the costs for their operations over much larger load obligations throughout the country. These wholesale suppliers pass on the savings they achieve due to their sophisticated risk management skills in the form of more competitive bids for full requirements ES products in the RFPs. Wholesale suppliers have invested and will continue to invest significantly in acquiring experts and developing management tools for programming in each specific type of market that make up full requirements ES supply.

Q. WHAT TYPES OF RESOURCES DOES A FRS SUPPLIER LIKE CONSTELLATION UTILIZE IN SERVING FRS CONTRACTS?

A. At Constellation (as at other competitive wholesale FRS suppliers), there are a number of employees involved in the process of providing FRS to utilities and customers around the country, including, but not limited to, portfolio managers, traders, meteorologists, asset operators, power managers, schedulers, dispatchers and related regulatory and legal support.

For instance, Constellation employs a team of seasoned portfolio managers that manages large regional portfolios for serving Constellation's customers' full requirements loads. Constellation must ensure that it properly and fully accounts for any transaction that goes into its portfolio, and that requirements for the entire load are met continuously for every hour of every day of every week. A team of 'strategists' continuously develops and improves computer models to keep track of all of the variable inputs that go into providing full requirements service; these strategists provide and analyze various scenarios that Constellation's portfolio managers may face. In addition, a 'fundamentals' group constantly researches basic supply and demand in fuel and power markets in order to monitor macroeconomic trends that affect the costs of serving load. Full-time meteorologists on Constellation's team continually monitor and predict the weather, so that Constellation's team can plan for weather effects on load requirements, and adjust supply accordingly. A 24-hour power trading desk trades power in the hour ahead, day ahead, and week ahead markets each day of the week, in order to help manage Constellation's supply portfolio. Moreover, power managers and traders monitor and trade in not only ISO-NE's market, but also those in Canada, New York, the PJM Interconnection, L.L.C. region, and other markets throughout the U.S.; fuel managers do the same as fuel markets directly affect power markets. Similar resources focus on fuel oil, currency, emissions and renewable energy markets. The task of meeting full requirements load supply additionally requires controllers, schedulers and dispatchers. Supporting all of these operations is a team of regulatory specialists and attorneys that monitor and participate in regulatory and legal activities impacting energy markets.

Q. MAINTAINING ALL OF THESE RESOURCES MUST BE COSTLY. WOULDN'T THIS RESULT IN HIGHER FRS PRICES?

A. No. The expertise of such a team of employees as that assembled at Constellation, and their advanced programs and systems, drive costs down by utilizing a well-developed infrastructure and spreading the overhead for such activities across Constellation's entire portfolio, in this way producing a far better result than a small team of people at a regulated utility company or its consultant. The very competitive nature of this business constrains the costs for providing such service for PSNH's customers; that is, because sophisticated wholesale suppliers throughout the market have operations similar in structure to those of Constellation, they must compete through the RFPs to serve PSNH's ES load at the lowest cost.

Q. WITH ALL OF THE DECISIONS THAT PSNH HAS TO MAKE UNDER ITS MANAGED PORTFOLIO MODEL, HOW WOULD THE COMMISSION DETERMINE WHETHER THE LOWEST POSSIBLE ES RATES HAVE BEEN SECURED?

A. This is a very difficult determination for the Commission to make. Utilizing a Managed Portfolio model raises a host of regulatory oversight and prudence issues that are not present under the FRS Structure. The Commission has an obligation to ensure that PSNH has acted prudently in procuring its ES obligations. Under a FRS approach, the Commission can be assured that PSNH has acted prudently by choosing the lowest all-in price through a well-designed, standard competitive procurement and through which, as discussed below, the FRS supplier wears the migration risk. However, under a Managed Portfolio approach, the Commission by necessity has to conduct an after-the-fact review to determine the prudence of PSNH's various trading practices, choices on mix of contracts, and timing of contracts, as well as the migration risk that can be passed on to the ES customers via stranded cost recovery. Such a review requires a tremendous amount of data, and takes a significant amount of the Commission's and parties' time and resources. Moreover, because PSNH faces a risk of after-the-fact disallowances of certain portfolio costs on the grounds of imprudence, it may be reluctant to develop and take advantage of more complicated risk strategies to mitigate its portfolio risks which might otherwise provide lower costs and greater benefits to ES customers. In addition, under a Managed Portfolio approach, PSNH's suppliers and lenders – cognizant of the potential for after-the-fact disallowances – may be more likely to charge premiums to PSNH (and, in turn, its ES customers) due to concerns regarding the utility's creditworthiness.

Q. BEYOND THE BENEFITS OF THE FRS STRUCTURE THAT YOU HAVE ALREADY DESCRIBED, ARE THERE OTHER REASONS WHY REGULATORY AGENCIES AND UTILITIES HAVE CHOSEN THE FRS OVER THE MANAGED PORTFOLIO MODEL IN THE PAST?

A. Yes. Under the FRS procurement model, the FRS provider assumes 100 percent of the risk should the all-in price be too high and customers decide to switch to a competitive retail provider. In this scenario, the consumers are protected against the cost of over- or under-hedging that results from changes to market prices over time. The FRS model also places the risk on the supplier in the event that the all-in price is too low. By contrast, as is apparently the case with PSNH, when customers migrate to competitive retail suppliers, it leaves a small volume of stranded customers to pay the stranded costs for prices that were locked under an MP contract.

Q. IS THE FRS PROCUREMENT STRUCTURE WIDELY USED?

A. Yes, as Mr. Traum indicates, both National Grid and Unitil utilize a FRS Structure here in New Hampshire, with beneficial results for their customers. Traum at 7:3-10. In addition FRS is the predominant approach throughout the rest of New England. It is used in Connecticut, Maine, Massachusetts, and Rhode Island. In particular, I note that PSNH's sister companies, Connecticut Light and Power and Western Massachusetts Electric both employ FRS procurements.

Q. DO YOU HAVE ANY OTHER COMMENTS ON THE BENEFITS OF FRS OVER THE MANAGED PORTFOLIO MODEL?

A. There is one last point for the Commission to consider. One issue that is often overlooked when comparing these two models is that FRS is more compatible with competitive retail markets. Under the FRS model, a customer has an all-in fixed price rate against to which it can compare offers from competitive retail providers. This sort of certainty is a valuable tool to a customer in making an informed and accurate determination of its energy options. With the Managed Portfolio model, however, such an option is not available to the customer because the true cost of serving a customer for a certain period of time is not reflected in rates until a later date when the utility trues-up its rate with its actual costs to serve.

Q. MR. BAUMANN OPINES THAT THE OVERSUPPLY SCENARIO "IS AN UNANTICIPATED RESULT OF RESTRUCTURING AND IS UNFAIR TO THE MANY CUSTOMERS WHO REMAIN ON THE ES RATE." BAUMANN AT 6, 20-21. IS IT ACCURATE TO SAY THE OVERSUPPLY ISSUE IS UNANTICIPATED?

A. No, it is not accurate to state that an oversupply of ES power is an unanticipated effect of restructuring. In fact, this scenario is a direct result of the decision by PSNH and the Commission to pursue a Managed Portfolio procurement strategy. Constellation pointed this out as far back as 2003, where it stated at the time that:.

> Another issue Constellation argues that PSNH has not considered is migration risk. According to Constellation, migration risk is a form of volume risk. Constellation states that it is a risk that comes with Transition Service because customers are free to leave at any time to take service from a competitive supplier. Where a competitive supplier provides the power for Transition Service, Constellation avers, that firm estimates the rate of customer migration, and procures supply to service the expected load over time. Constellation points out that the supplier bears a risk that the rate of migration will be higher or lower than expected, leaving it with either excess supply or inadequate supply. Competitive firms supplying Transition Service power reflect the cost of that risk in their price, states Constellation. Constellation states that it appears that PSNH has estimated zero customer migration. Constellation notes that as customers leave Transition Service, PSNH plans to sell the excess generation into the market. Constellation argues that there is a risk that the price that PSNH realizes in the market for that generation will be less than the Transition Service price, causing PSNH's Transition Service revenues to be lower than expected. *Public Service Company of New Hampshire*, DE 02-166, Order No 24, 117 (January 30, 2003) at 15-16.

Similarly, in 2007, I myself noted to the Commission that:

> Mr. Allegretti opined that competitive suppliers could provide better management of risk and reduced uncertainty in power purchases as compared with PSNH. Mr. Allegretti also said that, if Constellation's proposal were to be adopted, all risk in market price volatility would be borne by the winning supplier and that no costs would shift to customers in the event that the market price exceeded the contract price. *Public Service Company of New Hampshire, DE07-096, Order No. 24,814 (December 28, 2007), at 13.*

And even more recently, TransCanada witness Michael Hachey has gone so far in his testimony as to suggest that the power purchases PSNH has made that will be used to serve customers in 2010 were not reasonable and prudent. In line with my recommendations in the past and herein, Mr. Hachey suggests that PSNH should move to a FRS solicitation similar to what National Grid and Unitil employ. Prefiled Testimony of Michael E. Hachey, DE09-180 (December 2, 2009) at 9-14.

Q. HAS THERE BEEN ADDITIONAL EVIDENCE SINCE YOUR 2007 TESTIMONY IN DOCKET NO. 07-096 THAT SUPPORTS YOUR POSITION IN FAVOR OF A FRS STRUCTURE?

A. Absolutely. At the direction of the Rhode Island Commission in its Docket No. 4041, National Grid committed to perform an empirical study comparing default service approaches for mass market customers, including a comparison of the FRS Structure to the Managed Portfolio model. National Grid commissioned the NorthBridge Group to conduct the analysis, which then released its study in January 2010 ("NorthBridge Study").[8] The NorthBridge Study provides significant and well-developed analytical support for the use of a FRS Structure to meet National Grid's default supply requirements. Looking at a wealth of *actual* data, the NorthBridge Study finds that, in comparison to other approaches, a FRS Structure: results in lower risks allocated to customers, lower supply cost surprises and minimal deferral account balances; reduces the potential effects of additional costs and risks that the NorthBridge Group did not model; and will require lower internal resources for the utility to implement.[9] The NorthBridge Study finds that the FRS Structure provides all of these benefits, while resulting in only a *minimally* higher expected rate level for consumers.[10]

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8 *See* "Analysis of Standard Offer Service Approaches for Mass Market Consumers", attached hereto as Constellation/RESA Exhibit 1.2. ("NorthBridge Study")

9 *See* NorthBridge Study at p. 20.

10 *See* NorthBridge Study at p.13 (illustrating that a FRS Structure results in an expected SOS rate of only $2.93/MWh more than the least expensive, 100% spot approach) and p.15 (explaining that the FRS Structure results in an expected SOS rate of only $0.72/MWh more than the alternative, "managed portfolio" approach).

Q. WHY DO YOU BELIEVE THAT THE NORTHBRIDGE STUDY PROVIDES "SIGNIFICANT AND WELL-DEVELOPED ANALYTICAL SUPPORT" FOR A FRS STRUCTURE?

A. The NorthBridge Group was not commissioned to perform a study that would justify a particular result. Rather, National Grid asked the NorthBridge Group to help them determine which approach would be better for their customers. I believe this objective approach gives the Northbridge Study added credibility. Further, because the NorthBridge Study is based on *actual* market data, rather than conjecture about the relative merits of various procurement approaches, it represents a sound empirical foundation on which to evaluate the benefits of different procurement approaches. Finally, the analysis involves a comparison of default approaches against several metrics that pertain to various objectives with respect to default service, and therefore allows for an assessment of the tradeoffs with respect to key objectives, such as rate stability and rate minimization.[11]

Q. IN YOUR VIEW, WHAT ARE THE EFFECTS ON COMPETITION OF MOVING TO A FRS STRUCTURE?

A. The New Hampshire Electric Policy Principles provide that:

> Allowing customers to choose among electricity suppliers will help ensure fully competitive and innovative markets. Customers should be able to choose among options such as levels of service reliability, real time pricing, and generation sources, including interconnected self generation. Customers should expect to be responsible for the consequences of their choices. The commission should ensure that customer confusion will be minimized and customers will be well informed about changes resulting from restructuring and increased customer choice.

RSA 374-F:3II.

Moving to a FRS structure will advance these goals in several ways. First, as discussed above, utilizing a FRS Structure removes any risk of over-supply costs being imposed on

[11] January Compliance Filing at p.3.

customers who have left default service. Significantly, the FRS Structure increases the relative portion of the customer's bill that is subject to competitive forces. This gives customers more incentive to choose alternate suppliers and, equally important, more ability to take full advantage of alternate products, such as "real time pricing" and "interconnected self generation." The more customers are burdened with commodity-based charges that are non-bypassable, the less ability the customers will have to "be responsible for the consequences of their choices." Moving to a FRS Structure therefore promotes customer choice and customer responsibility and minimizes cost-shifting consistent with the Restructuring Policy Principles in RSA 374-F.

Q. IN HIS TESTIMONY, MR. BAUMANN DISCUSSES THE ISSUE OF FAIRNESS WITH REGARD TO THE RECOVERY OF COSTS INCURRED TO PROVIDE DEFAULT SERVICE. BAUMANN AT 4:10-6:21. WHAT ARE YOUR THOUGHTS WITH REGARD TO WHAT MR. BAUMANN REFERS TO AS "THE FAIRNESS ISSUE"?

A. I agree with Mr. Bauman that PSNH should have an opportunity to recover its reasonable and prudent costs of supplying default service. I disagree, however, with his recommendation that the Commission establish a new non-bypassable charge to pass these costs on to customers who have left default service. To do so would be akin to the imposition of an "exit fee," something which discourages customer choice and is expressly disfavored in New Hampshire. "Entry and exit fees are not preferred recovery mechanisms." RSA 374-F:XII.(d). To the extent PSNH continues with its Managed Portfolio approach to providing default service, it is reasonable to allow the recovery of its commodity-based costs through the ES rate. If a higher ES rate causes customers to migrate to competitive supply, then the policy of customer choice will have been advanced and those departing customers will realize the benefits of lower prices and more varied products in the competitive market.

Q. DOESN'T THAT CREATE A POTENTIALLY UNSTABLE SITUATION IN WHICH FEWER AND FEWER REMAINING DEFAULT SERVICE CUSTOMERS FACE HIGHER AND HIGHER ES RATES UNTIL THERE IS NO ONE LEFT?

A. Yes, potentially, due to the prior and current reliance on a Managed Portfolio approach. This underlines the fact that there is no benefit to be realized from PSNH continuing to provide default service through the Managed Portfolio approach. If that situation is occurring, then the solution is for PSNH to divest (or in appropriate cases retire) its generation assets and its portfolio of power purchase contracts and replace its Managed Portfolio approach with a FRS Service to meet the needs of remaining default service customers.

While not offering a legal opinion, I would observe that RSA 369-B:3 appears to contemplate the ability of the Commission to approve divestiture or retirement of PSNH's generation assets if the Commission makes certain factual determinations:

> Divestiture of PSNH Generation Assets. **–** The sale of PSNH fossil and hydro generation assets shall not take place before April 30, 2006. Notwithstanding RSA 374:30, subsequent to April 30, 2006, *PSNH may divest its generation assets if the commission finds that it is in the economic interest of retail customers of PSNH to do so, and provides for the cost recovery of such divestiture*. Prior to any divestiture of its generation assets, PSNH may modify or retire such generation assets if the commission finds that it is in the public interest of retail customers of PSNH to do so, and provides for the cost recovery of such modification or retirement.

RSA 369-B:3-a (emphasis added).

Q. HOW DOES THE RECOVERY OF STRANDED COSTS ASSOCIATED WITH DIVESTITURE OR RETIREMENT DIFFER FROM THE NON-BYPASSABLE CHARGE THAT PSNH PROPOSES?

A. Stranded cost recovery is a transitional feature of electric restructuring designed to facilitate migration to competitive supply in a manner that is fair to the former monopoly utility. It is a mechanism to recover those costs to serve customers that were incurred prior to the amendment of the regulatory compact through the introduction of customer choice. What PSNH is proposing is an ability to keep all of its distribution customers captive to its ongoing and future commodity purchase and investment decisions. This is not the imposition of charges that are necessary to make the transition to customer choice, but rather is the re-imposition of new and ongoing commodity costs upon customers who neither request nor purchase their power from PSNH.

Q. WHAT IF PSNH CHOOSES NOT TO DIVEST OR RETIRE SOME OF ITS GENERATION?

A. This would still not prevent the Commission from moving to an FRS Service procurement approach for PSNH. While I believe the best approach is for PSNH to effect a complete divestiture and to net sale proceeds against stranded cost recovery, a partial divestiture could be accomplished. In the event the Commission determines any of PSNH's generation assets remain economic to operate and does not compel PSNH to divest such asset, the Commission could require PSNH to deliver the generation assets' output to the ES suppliers in proportion to their share of the ES load. The suppliers would then pay PSNH the day-ahead clearing price for the power when the unit clears in the day-ahead market. PSNH would be free to establish the day-ahead bid. The impact of this structure is to keep the physical power, if any, that the plants produce within the supply portfolio that serves the ES customers as appears to be contemplated or required under RSA 369-B:3.[12] From an economic perspective, the effect is the same as if PSNH simply bid the asset into the day-ahead market.

[12] Alternatively, nothing would prevent PSNH from selling the output under a bilateral agreement rather than into the day-ahead market, so long as the physical power is sold to the FRS supplier and the terms of the sale are reasonable and prudent.

Under this less-than-optimal approach I recommend that any generation plant revenues be netted against their operating costs, and the balance used to offset stranded cost recovery. This is an equitable approach that allows for the distribution customers who pay stranded cost recovery on the non-economic assets that are or have been sold or retired to benefit from the retention of the economic assets and is therefore consistent with PSNH's duty to mitigate stranded costs under RSA 374-F:3XII.

Q. HAS YOUR PROPOSED APPROACH BEEN UTILIZED IN ANY OTHER JURISDICTIONS IN ORDER TO INTEGRATE NON-FULL REQUIREMENTS ENERGY SUPPLY PRODUCTS INTO A FULL REQUIREMENTS PORTFOLIO?

A. Yes. This approach is not without precedent. For instance, in Massachusetts, where the Massachusetts Department of Public Utilities ("DPU") approved a petition by NSTAR Electric Company ("NSTAR Electric") to enter into two long-term contracts to purchase physical wind power to supplement its purchases of FRS products, the Massachusetts DPU utilized the very same approach. In its Order, the Massachusetts DPU explains that:

> NSTAR Electric proposes to sell the energy supply purchased through the contracts into the wholesale energy spot market administered by the Independent System Operator-New England . . . on an hourly basis . . . . NSTAR Electric will compare the contractual costs it incurs for the energy supply output with the revenues generated through sales into the wholesale market . . . . The net proceeds from the energy settlement will be credited to or debited from [residential and small commercial and industrial] customers . . . .[13]

In making its decision, the Massachusetts DPU states:

> [t]his proposed treatment of the wind projects' electricity output would not affect the semi-annual solicitations through [NSTAR Electric] procures its approximately 2,500 MW of [full requirements] basic service supply. It would, however, affect the rates that basic service customers pay, in that the rates would no longer be based solely on the results of those

[13] *Order,* Massachusetts DPU Docket No. 07-64-A (issued Apr. 30, 2008) ("MA DPU Order") at p. 9.

> solicitations. Instead, the prices that result from the solicitations would be adjusted to account for the incremental costs or savings associated with the wind power contracts.[14]

In addition, in Pennsylvania, Metropolitan Edison Company and Pennsylvania Electric Company ("Met-Ed/Penelec") use just such an approach to incorporate existing legacy non-utility generator ("NUG") contracts' output in such a way as to refrain from having a potentially negative effect on the outcome of their competitive solicitations under the FRS Structures.[15] The Pennsylvania Public Utility Commission ("Pennsylvania PUC") explains in its order approving such structure that:

> Under the [Met-Ed/Penelec] proposal, they will continue to sell all of the non-utility generation they are contractually obligated to purchase into the market. [Met-Ed/Penelec] will establish a non-bypassable NUG Charge Rider that will charge or credit the bills of all customers for the difference between the contract prices and the proceeds of the market sales of NUG output. This mechanism will reflect NUG costs and benefits in a manner similar to the existing Competitive Transition Charge (CTC). When NUG contract prices are above market prices, customers will pay a charge for the difference. When NUG contract prices are below market, customers will receive a credit for the difference. All customers will participate and the [Administrative Law Judge ("ALJ")] found that this mechanism mirrors the way stranded costs and benefits are reflected in the current CTC.[16]

Importantly, the Pennsylvania PUC also supported the ALJ's reasoning that:

> Inserting the output of the NUG contracts into the default supply for commercial customers will create a default service procurement plan that will eliminate or minimize competition because the default rate will not be reasonably based on the market." R.D. at 69. The ALJ found that this result was at odds with this Commission's statement in PPL Electric Utilities Corporation Retail Markets, Docket No. M-2009-2104271 (Order entered August 11, 2009). There, we stated that "competition among

[14] MA DPU Order at p. 55.

[15] *See, generally, Joint Petition of Metropolitan Edison Company and Pennsylvania Electric Company*, Pennsylvania Public Utility Commission Docket Nos. P-2009-2093053 and P-2009-2093054.

[16] *Opinion and Order*, Pennsylvania PUC Docket Nos. P-2009-2093053 and P-2009-2093054 (issued Nov. 6, 2009) ("Pennsylvania PUC Order") at p. 10.

> utilities and independent suppliers of generation is the best means available to keep the cost of electricity down. *PPL* at 1.[17]

Q. IN HIS TESTIMONY, MR. TRAUM CONCLUDES THAT MIGRATION UNDER PSNH'S MANAGED PORTFOLIO APPROACH PRODUCES COST SHIFTING TO THE DISADVANTAGE OF SMALL CUSTOMERS. TRAUM AT 5:14-7:10. DO YOU AGREE?

A. Yes. As customers migrate off of default service to competitive supply, the remaining ES service customers are exposed to upward pressure on the ES rate. To the extent these remaining default customers are disproportionately small customers, then small customers experience a cost shift. As Mr. Traum points out, this problem does not occur with the FRS approach National Grid and Unitil adopted because migration costs are managed by the wholesale FRS suppliers through the bidding process, relieving the upward pressure on the ES rate. Thus, moving to an FRS approach, as I recommend, provides a solution to this cost shifting. In concert with a FRS Structure, another step that can mitigate the cost shift to small customers is to enhance the competitive options available to those customers.

Q. BOTH MR. TRAUM AND MR. BAUMANN INDICATE IN THEIR TESTIMONY THAT THE MIGRATION RATE FOR SMALL CUSTOMERS REMAINS LOW. TRAUM AT 3:10-13; BAUMANN AT 5:10-14. ARE THERE OTHER POLICIES OR TOOLS THE COMMISSION CAN CONSIDER IMPLEMENTING THAT WILL ENHANCE THE COMPETITIVE RETAIL ENERGY MARKET IN NEW HAMPSHIRE FOR RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS?

A. Yes. Along with the implementation of a FRS Structure, there are several policies or tools that the Commission could implement that will assist in the development of retail markets for the residential and small commercial customer segments. I recommend that the Commission investigate and implement all or at least most of the following tools in order to foster mass market competition in the State:

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[17] Pennsylvania PUC Order at p. 13.

- Purchase of Receivables Program ("POR") – The first and the most important prerequisite from my perspective is the purchase by utilities of supplier accounts receivables, known as Purchase of Receivables or POR. This program, when coupled with utility consolidated billing, is a key component in developing a successful retail energy market. With POR, customers still receive a single bill from the utility, comprised of the delivery components provided by the utility and supply components from the supplier. The utility bills and collects payment on behalf of the competitive supplier and the supplier receives payment from the utility for the commodity portion of the bill, minus a discount and in some instances minus utility administrative costs, when the bill is rendered. The utility continues to handle disconnection and reconnection of all customers. As a transitional tool to an end state where the supplier will provide the consolidated billing service, POR attracts suppliers to a service territory that offers this service, as evidenced by the growth in Connecticut's, New York's and New Jersey's residential and small commercial markets, as well as several other states. POR provides clear benefits to suppliers through reduced customer care and overhead costs. In addition, POR allows suppliers to market to all residential and small commercial customers in a service territory, which is a significant benefit from a public policy perspective.

- Customer Referral Program – This type of program addresses the hesitancy of residential and small commercial customers to seek out competitive market offerings because they are unsure of and/or lack awareness of their choices. This program is a utility run program that facilitates retail access enrollment generally through a two-month price discount funded by the supplier. A utility customer who contacts the utility call center for a service initiation, high bill inquiry, or other type of question is asked by a utility representative if it is interested in participating in this program. If the customer agrees, the customer then selects a specific supplier from a pool or agrees to be assigned at random to one of the participating suppliers, and the customer receives for two months a discount off the commodity portion of its bill. At the end of the two-month period, the customer chooses to stay with the competitive supplier starting in month three based on affirmatively agreed-to terms and conditions or returns to the utility with no penalty or fees. To promote the referral program, a utility can send out periodic bill inserts and/or dedicated mailings about the program, including a postage paid card that the customer could return to the utility to facilitate its enrollment with a competitive supplier.

- Electronic Interfacing – A dedicated web-based interface site that allows electronic access to key customer usage and account data that can be accessed via a supplier website that presents data and information in a format that can be automatically pulled and scraped. Such data access should include access to the following types of data:

(a) Customer-specific data such as account and meter numbers, relevant addresses, meter read dates, rate code, historic usage data, payment history and other relevant information;
(b) Validation, Error Detection, and Editing ("VEE") data posted via Electronic Data Interchange ("EDI")- post;
(c) 867 Historical Usage ("HU") and Historical Interval Usage ("HIU") data;
(d) 867 Monthly Usage ("MU") and Interval Usage ("IU") data;
(e) Transmission and capacity Peak Load Contributions ("PLCs") in 867s;
(f) Meter read cycle information;
(g) Accounts requested together should come back together, unless there would be an unnecessary delay for a particular subset of accounts; and
(h) A quarterly updated sync-list should be provided to EGSs on a confidential basis showing the accounts that are enrolled with the EGS. The list would contain information such as service start date, bill method, PLC values.

Provision of these programs allows a retail supplier to provide a prospective customer with a timely, accurate competitive offer for electric service, check the enrollment status of a new customer, and perform other functions designed to better serve customers.

IV. CONCLUSION

Q. CAN YOU SUMMARIZE YOUR TESTIMONY?

A. Customers who do not take their commodity supply from PSNH do not benefit from the PSNH portfolio and should not bear the cost of PSNH decisions to purchase or produce energy for ES customers. If the cost of supply from the PSNH portfolio is above market, then the only basis on which to allow PSNH to recover the costs of their portfolio from all customers is to treat those costs as stranded costs. The quid pro quo for stranded cost recovery, however, should be for PSNH to exit the merchant function so that customers do not remain at risk for future supply decisions. My recommended approach of adopting a FRS Structure accomplishes this task, provides protections from oversupply costs, and enhances the policies set forth in the New Hampshire Restructuring Policy Principles, promoting customer choice of suppliers and of products, ensuring a fully competitive market and avoiding cost shifting.

The alternative approach is to approve a rate increase for the ES customers and allow PSNH to continue to supply them from its managed portfolio. If it ceases to be economically viable for PSNH to remain the ES provider under these terms, then PSNH is free at any time to divest or retire its assets and to seek stranded cost recovery.

Q. DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

EXHIBIT 1.1

RESUME OF DANIEL W. ALLEGRETTI

Daniel W. Allegretti
One Essex Drive
Bow, New Hampshire
(603) 224-9653

Experience

2002-Present - Constellation Energy Commodities Group
Baltimore, Maryland
Vice President Energy Policy

- Advocate, testify and generally represent the interests of the company before federal, state and provincial agencies, executive departments and legislative bodies, and within regional transmission organizations, throughout the Northeastern United States and Eastern Canada.
- Supervised a staff of six professionals who advocate and represent company interests under my direction across the Eastern Seaboard region.
- Provide direct business support to internal teams who originate new business transactions or who manage an active portfolio in support of existing business.
- Maintain and expand a network of contacts and relationships within industry and government to support regulatory and legislative advocacy and information gathering.

2008-2009 – Anbaric Northeast Transmission Development Company, LLC, Wakefield, MA
Senior Vice President

- Conceived, developed and promoted multi-billion dollar independent transmission projects in the Northeastern United States and Canada.
- Represented Anbaric before state, federal and provincial governmental entities and before non-profit and industry organizations.

1996-2001 - Enron Corp., Houston, TX
Senior Director, Government Affairs

- Advocated on behalf of industry-leading company before state utility commissions, executive departments and state legislatures during the critical transformation from regulated monopoly electric service to competitive wholesale and retail electricity markets in New England.

- Represented company within the New England Power Pool organization during the development of a region-wide transmission tariff, organized wholesale electricity markets and creation of an independent system operator. Provided leadership in the reform of NEPOOL governance to include all industry sectors and was elected NEPOOL chairman in 2000.
- Provided direct business support to wholesale business origination, retail sales and wholesale power marketing and trading businesses.

1989-1995 - Brown, Olson & Wilson. Concord, NH
Attorney

- Represented independent power developers, municipal governments and energy trading companies before state and federal agencies and courts and in contract and settlement negotiations.
- Conducted research, met with clients and prepared, filed or submitted a variety of legal memoranda, briefs, contract documents and consulting reports.

Education

1985-1988 - Georgetown University Law Center, Washington, D.C.

- Completed *juris doctor* degree
- Completed internships with U.S. International Trade Commissioner, U.S. Court of Appeals judge and U.S. Senator
- Admitted to the bar in DC, MA and NH

1981-1985 - Colby College, Waterville, Maine

- B.A., Economics, French (*cum laude*, phi beta kappa)

Honors/Positions

- New England Power Pool
    - Chairman Nepool Participants Committee (2001 & 2002)
    - Chairman Nepool Budget & Finance Subcommittee (2005)
    - NEPOOL Supplier Sector elected representative (1996-2006)
    - Chair of various *ad hoc* Nepool committees and working groups (1996-2005)
- Board of Directors, Northeast Power Coordinating Council (2001-2008)
- Board of Directors Independent Power Producers of New York (2002-2008)

- Board of Directors, Electric Power Generators Association of Pennsylvania (2008)
- Board of Directors, Northeast Energy & Commerce Association (2009-2010)
- Management Committee, New York Independent System Operator (2002-2005)
- Maine Energy Advisory Council (appointed by Governor in 2006)
- Ontario Independent Electric System Operator, Market Advisory Council (2002-2005)
- Ontario Electric Markets Investment Group, governing body (2002-2008)

EXHIBIT 1.2

PREFILED DIRECT TESTIMONY OF

DANIEL W. ALLEGRETTI

NH PUC DOCKET NO. 07-096

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Public Service Company of New Hampshire
Energy Service Rate

Docket No. DE 07-096

PREFILED DIRECT TESTIMONY
OF
DANIEL W. ALLEGRETTI

**on behalf of Constellation NewEnergy, Inc.
and Constellation Energy Commodities Group, Inc.**

November 9, 2007

Q. Please state your name and business address.

A. My name is Daniel W. Allegretti. My business address is Constellation Energy Group, Inc., 111 Market Street, 5th Floor, Baltimore, Maryland.

Q. What is your position?

A. I am Vice President of Energy Policy for at Constellation Resources.

Q. Please describe your educational and professional background.

A. I have a B.A. from Colby College and a J.D. from Georgetown University Law Center. I have over 18 years experience in the electric industry with an emphasis on competitive markets and regulatory reform. I served two terms as the chairman of the NEPOOL Participants Committee and am currently a vice chair of the Board of Directors of the Northeast Power Coordinating Council. I have also served on the New York ISO Management Committee, the Market Advisory Council of the Ontario IESO, and the Boards of Directors of the Northeast Energy and Commerce Association and the Independent Power Producers of New York. I have been an active participant in electric restructuring matters, and have regularly appeared and testified before FERC and numerous state and provincial legislative committees and utility commissions.

I. Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss a proposal that Constellation believes will provide the Commission with a proven means to help ensure that PSNH provides power to its customers at least cost, while minimizing the need to reconcile power costs from year to year. Constellation's proposal will provide additional benefits to customers and will be consistent with New Hampshire law and Commission policy by increasing the extent to which PSNH's energy service rates reflect the actual cost of providing power, which, in turn, will send better price signals to customers. According to PSNH, approximately 60% of the power it supplies to its customers is accounted for from generating plants owned by the company. The remainder is purchased in the wholesale market. (See PSNH's response to Q-CONST-002 attached as Appendix DWA-1.) Constellation believes that customers would benefit if wholesale suppliers were able to compete to provide the portion of PSNH's power requirements that are not met through its own generating plants. I will explain below in more detail how such a process would work and what some of the benefits would be.

Q. Please summarize why Constellation believes a change is needed in PSNH's wholesale power procurement process.

A. RSA 369-B requires that PSNH's energy service rate be based on the company's "actual, prudent, and reasonable costs of providing such power," yet PSNH's energy service rate is currently based on a *forecast* of its expected cost. The difference between PSNH's forecasted costs and its actual costs, once known, is charged or credited to customers after the period for which those costs were incurred. This reconciliation process causes PSNH's energy service rate, at any point in time, to be higher or lower than its actual cost for that period. Although customers are told that they are purchasing energy at a fixed price, that is not really the case. If a customer stays on PSNH's system, it is actually charged a rate that appears fixed but has a hidden variable component that is added to the true cost of providing service during the following six or twelve month period. The 40% or so of the power required to serve PSNH's retail load is purchased on the wholesale market through various short term contracts and spot purchases. In order to procure power in the wholesale market, PSNH has to employ staff to monitor those markets and then decide when to enter into contracts, the amount of power to be purchased, the terms of such contracts, whether to enter into hedges, what type of hedges to purchase, and how much power to purchase or sell on a spot basis. These are high risk, complex decisions, the costs of which are ultimately borne by customers. Because the utility's decision-making process is not transparent, it is nearly impossible for the Commission to conduct a meaningful review of the costs incurred by PSNH in the wholesale market, and therefore, it is not realistic to expect the Commission to be able to assess the prudence of PSNH's conduct. Constellation believes that a competitive bidding process for all of PSNH's wholesale power requirements would create a more transparent process that would help ensure that PSNH's power procurement is accomplished at the least cost to customers. Such a process is also consistent with the fact that the procurement activities involved are far from the type of "natural monopoly" activities that may once have warranted their being the exclusive domain of a regulated utility such as PSNH.

II. ISO Settlements Process and PSNH Wholesale Purchases

Q. What does it mean when PSNH says that 60% of the power it supplies to its customers comes from its own generation and 40% is purchased in the wholesale market?

A. As the Commission knows, the power actually generated by PSNH at its facilities is not necessarily the same power that is actually consumed by PSNH's customers. It has been said that electrons follow the laws of physics, not the laws of contracts. What this means from a practical standpoint is that PSNH's power requirements (and thus those of its customers) come entirely from the New England electric grid operated by the Independent System Operator. When PSNH says that it generates 60% of its customers' requirements, it is really giving a shorthand description of the accounting system used by the ISO to ensure that market participants such as PSNH are correctly credited for the value of the power they generate and charged for the power they use. PSNH sells the output from its generation plants into the wholesale market, and through the ISO settlement process I will describe below, it is credited with generation that is roughly equal to 60 percent of the MWH needed to meet its customers' requirements.

Q. Please explain how the ISO settlement process works.

A. The ISO maintains settlement accounts for all participants in the New England wholesale power market. Power prices are set on an hourly basis. As power is purchased and/or generated by a market participant, the participant's account is either charged or credited at the applicable hourly price for the appropriate volume of power. This process continues on an hour-by-hour basis, with the volume of power to be credited or debited and the applicable price changing according to the participant's net power generation/load situation and the price of power that prevails during any given hour. Because the hourly price varies widely during the course of the month and the level of purchases and/or sales by a participant varies on an hourly basis as well, the hourly charges and credits to the participant will also vary from hour to hour. At the end of each month, these hourly charges and credits are totaled and the participant is either billed or paid the net amount reflected in its account.

Q. How does this process relate to the 40% of its requirements that PSNH says it purchases in the wholesale market?

A. The 40% figure is essentially an average of all of this hourly activity. It actually consists of purchases and sales that are made each hour of the year, depending on the relationship between the output of PSNH's plants during each hour and the power requirements of its customers during that hour. For obvious reasons, it is likely that the bulk of PSNH's power purchases occur during periods of peak demand, when market prices are at their highest, because that would be the time when PSNH's own plants are unable to supply all of its customers' requirements. Additional significant purchases can also be expected to occur during periods when PSNH's plants are not operating, either on a planned or unplanned basis. Presumably, PSNH will schedule maintenance outages for its plants during those times of year when replacement power costs are expected to be at their lowest, although it obviously cannot control the timing of unplanned outages. Thus, although PSNH may generate enough power to meet, on average, 60% of the load on its system, one needs to know the time of day and time of year when that generation is operating and how that compares to PSNH's own load profile (i.e., that of its customer base) to understand the true financial impact.

Q. **Doesn't PSNH enter into power purchase agreements with third parties to cover its requirements beyond the power it generates itself and, if so, how is that reflected in the ISO settlement process you described?**

A. Based on information provided by PSNH in this docket and prior energy service dockets, it is my understanding that PSNH enters into contracts with third parties to procure most of the power it needs beyond the output it forecasts from its own plants. For purposes of the ISO settlement process, those contracts are reflected as PSNH's generation assets (i.e., PSNH does not need to purchase power on the spot market at the ISO clearing price, but rather has the right to have another party's generation output credited to its account). The credit PSNH receives for these contracts during any period of time when the contracts are in effect offsets power purchases that are charged to PSNH during the same period. The result is that, rather than being obligated to pay the spot price for power purchased during an hour when a particular contract was in effect, PSNH is instead contractually obligated to pay a third party the previously negotiated price. In PSNH's settlement account at the ISO, power purchased through these agreements appears no different than power generated from PSNH plants.

Q. How does PSNH try to ensure that the power it purchases under contract and on the spot market ends up being at the least cost to its customers?

A. In order to attempt to minimize the cost of purchased power to its customers, PSNH must balance numerous considerations to arrive at the best strategy for purchasing power on the wholesale market. These considerations include significant factors such as the hour by hour requirements of its customers, forecasts for market prices and the anticipated operating schedule and operating costs of its own plants. As I mentioned earlier, PSNH and/or its parent company, employs a staff of individuals who must monitor the markets and make decisions about the increments of power to purchase and when to make such purchases in addition to deciding what other power market products such as hedges, derivatives and the like to enter into. The costs associated with employing these individuals are, of course, also recovered from customers, in addition to the costs of the various power trading products that PSNH purchases.

Q. What happens if PSNH enters into contracts that exceed the amount of power it needs at any point in time or if the amount of power it has procured is insufficient to meet the load on PSNH's system?

A. In any given hour, if the power from PSNH's plants and any contracts it has entered into is less than its customers' requirements, PSNH has to make "spot" purchases of power from the market. The ISO will charge PSNH the hourly clearing (spot) price for these additional last-minute purchases. If PSNH enters into contracts for more power than it needs at any point in time, the excess power can be sold into the market at the hourly clearing price. PSNH will still have to pay the contract price to its supplier for that power, but can offset that cost to the extent of any revenues it receives for having sold the power into the wholesale market. To the extent that PSNH incurs additional costs because it buys additional power at the spot price or because it is unable to cover the full cost of any excess power it had under contract, those costs would normally be passed on to PSNH customers.

Q. **Isn't it possible that such costs would have to be borne by PSNH's shareholder?**

A. In theory, that is a possibility. The Commission can disallow such costs if it finds that they were imprudently incurred. In practice, however, it is nearly impossible to make such a finding because it involves an after-the-fact review and requires the Commission to fully understand the information available to PSNH at the time the company made each decision at issue. This process puts the Commission in the position of essentially trying to second guess PSNH's hour-by-hour decisions, decisions that were made over the course of the prior year or more. A meaningful review of these decisions, if one could be conducted at all, would require the Commission to pore over a staggering amount of data regarding not just the hourly clearing price of power in New England during the period at issue, but also forward price information that was available at each decision point, bilateral arrangements that might have been entered into but weren't, hedging mechanisms and other data. Such a review effectively requires the Commission to have available all of the same real time information that was available to PSNH, much of which is in PSNH's possession or control. The difficulty of fully and fairly putting oneself in the position of another party after the fact and reviewing complex decisions cannot be overstated. Simply put, the many transactions entered into by PSNH and the situation confronting it when it entered into each transaction are not transparent to the Commission. The result is that the Commission faces a serious challenge in attempting to review PSNH's power procurement decisions in any meaningful way.

III. RFP Proposal

Q. What is Constellation's proposal to address this situation?

A. Constellation believes that PSNH should be required to issue a request for proposals ("RFP") for the portion of its power supply requirements that it obtains in the wholesale market, i.e., the approximately 40% that is not accounted for through the credits it receives in its ISO account for its own generating units.

Q. How does Constellation's proposal work as compared to what PSNH does now?

A. As I mentioned, PSNH employs or pays its affiliate to employ a number of individuals who engage in power trading activities. These individuals are tasked with watching the power markets, including the market for related derivative products, and engaging in trading activity on behalf of the utility in order to make up the anticipated difference between the power generated by the facilities owned by PSNH and the demand of the company's customers. PSNH currently attempts to do this through a combination of agreements with multiple third parties on various terms and conditions. I am not privy to the exact terms of PSNH's various power trading arrangements, but I would expect that the purchases it enters into are for various increments of power at various times of the year or day, and that in addition to entering into forward trades, PSNH would also enter into derivative transactions, fuel hedges and other financial swaps or hedging agreements, as well as spot purchases as necessary, to meet its actual requirements. All of this amounts to an extremely complex process, the considerable risks of which, as I noted earlier, are ultimately borne by PSNH's customers.

Aside from attempting to forecast the output that can be anticipated from its own plants on an hourly basis throughout the year, PSNH must also forecast its retail customers' load on an hourly basis and factor in the extent to which retail customers may switch to competitive retail suppliers or back to PSNH's energy service from competitive suppliers throughout the year based on changes in market prices, the price of PSNH's energy service and other factors. Obviously, it is impossible for PSNH to correctly forecast all of the factors that go into determining the quantity and cost of its purchased power requirements. As a result, every six to twelve months, PSNH must tally up the cost of the hourly imbalances it has incurred at the ISO and adjust its rates for prior period over or under collections of its energy service costs. This reconciliation occurs in addition to the need to adjust PSNH's rates for changes in its actual costs for the coming period. Instead of following this approach, the Commission should require PSNH to put out a single request for proposals on a periodic basis to supply the portion of its requirements that its own generating units cannot meet. This is essentially the same process that the Commission has previously approved for National Grid and Unitil. The only difference is that the third party supplier will need to factor in the forecasted output from PSNH's own plants, just as PSNH now does.

Q. If the quantity of power supplied by a third party would be dependent on the output of PSNH's plants, wouldn't any supplier responding to the RFP be at a disadvantage relative to PSNH and wouldn't that add cost to any supplier's bid?

A. No. The uncertainty associated with the operation of PSNH's plants is a factor that faces PSNH as well. To the extent that PSNH has information regarding scheduled outages for the plants, that information can simply be provided to bidders, so that they have the same information PSNH would have. Beyond that, PSNH would simply covenant in any contract with the winning supplier that it would operate the plants in accordance with the same procedures it does now.

Q. How frequently would such an RFP be issued?

A. That is up to the Commission, but, based on its experience in other jurisdictions, Constellation believes that it would make the most sense to recontract every six months to two years, so that the contract period was of a length that would maximize interest among suppliers and thereby lead to the lowest price.

Q. Would Constellation's proposal require the successful bidder on the RFP to purchase the output from PSNH's plants and then resell it to PSNH as part of an arrangement to provide all of PSNH's requirements?

A. No, Constellation is not proposing that a successful bidder purchase or resell PSNH's generation output. Rather, Constellation is proposing to allow the successful bidder to supply the difference between PSNH's customers' hourly power requirements and the power that PSNH sells to the market from its own generating plants. The successful bidder will have the opportunity to quantify the net open position that PSNH would has at the ISO and provide that amount of power at the lowest possible fixed price.

Q. Please explain the benefits of such an approach.

A. There are several benefits. First, a competitive procurement process with sealed bids to provide service at a fixed price is the best way to ensure that PSNH's market purchases are made at the least cost. Such a process, where competitive wholesale suppliers bid against one another, is quite common. In addition, to New Hampshire's experience with such a process, the use of an RFP to procure power from the wholesale market has been implemented in other states as well. For example, in a recent decision by the Department of Public Utilities Control in Connecticut, the Department remarked at the vibrancy of the response to an RFP to supply 20-30% of Connecticut Light and Power Company's load. See Appendix DWA-2 at 2.

Second, by entering into a single contract with a third party supplier for all of PSNH's market purchases, customers will be presented with a true fixed price for their power, at least with regard to the portion that is not supplied by PSNH's own plants, insulating them from price risk. The result will be a significant decrease in the extent of any out-of-period reconciliations. Reconciliations are harmful to the development of a competitive retail market because they distort the relationship between PSNH's actual cost of providing power during a particular period and the market price of power. Reconciliations also create some "intergenerational" issues, by passing back credits or implementing charges on customers who weren't responsible for generating those credits or creating those charges in the first place. The only remaining need for reconciliation of any significance under Constellation's proposal would relate to changes in fuel and operating costs incurred by PSNH. If there are changes in market prices because of hurricanes, heat waves, an unplanned outage at a PSNH plant, or changes in demand because of customer migration to competitive retail suppliers, the price from the winning bidder will still be fixed.

Third, unlike PSNH's current power procurement process, the Commission will have a process that enables it to readily assure itself that PSNH is obtaining its market purchases at the lowest reasonable cost. This will provide transparency to the review process and significantly lessen the burden on the Commission of reviewing PSNH's power procurement and related power product trading activity.

Q. **Are there other elements to Constellation's proposal?**

A. There are additional details that would need to be worked out, but that is the essence of the proposal. I believe that competitive wholesale suppliers with major trading desks and extensive market involvement are better positioned than is PSNH to procure power and enter into other related trading activity at the least cost and insulate customers from the risk of price variation. Constellation and other suppliers who would be interested in bidding on supplying PSNH's power requirements could also supply PSNH's fuel requirements, which would further reduce variations between PSNH's cost forecasts and their actual costs. I would be happy to discuss in more detail how such an element could be added to the RFP process if the Commission is interested in pursuing this avenue.

I am aware from discussions held by the Staff and parties to this proceeding after the procedural hearing that a separate docket may need to be opened to address these issues. At this time, I wanted to provide an overview of Constellation's proposal to bring it to the Commission's attention for further consideration.

IV. Comments on Load Forecast Reporting Regulation

Q. Does Constellation have any comments regarding the load forecast reporting proposal submitted by PSNH, the Commission staff and the Office of Consumer Advocate?

A. Constellation's comments on that proposal were previously filed with the Commission in Docket DG 06-125. A copy of the comments is attached to this testimony as Appendix DWA-3 for ease of reference. Although Constellation understands the motivation behind seeking to adopt a regulation that would require competitive suppliers to provide the Commission and PSNH with the suppliers' proprietary information regarding load forecasts, such a regulation would give PSNH information that is not available to wholesale suppliers who would be willing to supply PSNH's wholesale power requirements. If the Commission were to require suppliers to turn over such information to PSNH, it would simply further entrench the utility in performing a wholesale power procurement function that can be better performed by other more experienced and better staffed participants in the wholesale market. In addition, the proposed regulation requires competitive suppliers to report the number of megawatt hours that are "expected to be sold" during specified future periods. The usefulness to PSNH of such information could be highly questionable given that different suppliers are likely to come up with such data on very different bases. Some will likely provide data based only on those contracts already in place. Others are may provide marketing forecasts. And others may simply guess or rely on equally unreliable data. Ironically, PSNH already has the most important information, which is how many and which specific customers are actually purchasing power from a competitive supplier at any given point in time and which specific suppliers are the customers using. The proposed regulation may be viewed by competitive suppliers as placing an additional administrative burden on them, something which will only serve to make New Hampshire a less desirable market to participate in.

Q. **Does that conclude your testimony?**

A. Yes, at this time.

Public Service Company of New Hampshire
Docket No. DE 07-096

DE 07-096
Appendix DWA-1

Witness: Richard C. Labrecque
Request from: Constellation New Energy and Constellation Energy Commodities Group

Question:
Indicate on a month to month basis for 2008, the quantity of power that PSNH anticipates purchasing to serve the energy service load. For each month, indicate the percentage of PSNH's total load that this quantity represents. The response should not include mandated purchased power (IPP) obligations.

Response:
The response below was compiled from the data provided in the filing (Attachment RAB-2, pg 3). The purchase quantities are in GWH.

	Known Purchases	Peak Purchases	Offpeak Purchases	Total Purchases	Total Energy GWH	% of Energy
Jan-08	44	120	65	228	757	30%
Feb-08	41	117	63	222	713	31%
Mar-08	77	103	68	248	727	34%
Apr-08	221	111	89	421	681	62%
May-08	209	115	79	404	673	60%
Jun-08	110	79	54	242	689	35%
Jul-08	96	117	66	279	786	35%
Aug-08	94	105	101	300	780	38%
Sep-08	126	110	77	314	697	45%
Oct-08	80	134	91	305	698	44%
Nov-08	73	89	80	241	706	34%
Dec-08	79	110	72	261	751	35%
Total	1,249	1,311	905	3,465	8,658	40%

STATE OF CONNECTICUT

DE 07-096
Appendix DWA-2

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 06-01-08PH02 DPUC DEVELOPMENT AND REVIEW OF STANDARD SERVICE AND SUPPLIER OF LAST RESORT SERVICE - REVIEW OF CL&P'S 4TH STANDARD SERVICE AUCTION

September 26, 2007

By the following Commissioners:

Donald W. Downes
Anne C. George
John W. Betkoski, III

DECISION

I. INTRODUCTION

Beginning January 1, 2007, each electric distribution company is required to provide, pursuant to §16-244c(c) of the General Statutes of Connecticut (Conn. Gen. Stat.), electric generation services through standard service to any customer who (A) does not arrange for or is not receiving electric generation services from an electric supplier, and (B) does not use demand meters or has a maximum demand of less than five hundred kilowatts (kW). On June 21, 2006, the Department approved a standard service procurement plan for The Connecticut Light and Power Company (CL&P) which set forth a number of basic criteria and guiding principles to be used by CL&P when procuring standard service generation.

Conn. Gen. Stat. § 16-244c(c)(4) requires that the Department, in consultation with the Office of Consumer Counsel (OCC), retain the services of a third-party consultant to oversee the procurement of standard service contracts. Pursuant to Conn. Gen. Stat. § 16-244c(c)(5), the electric distribution company and the third-party consultant must jointly submit to the Department: 1) an overview of standard service bids received in the procurement, and 2) a joint recommendation as to the preferred bidders. Within ten business days of receipt of the joint recommendation, the Department may reject the preferred bids, causing the service to be rebid.

On September 26, 2007, CL&P filed its joint recommendation with Levitan & Associates, Inc. (Levitan), the third-party consultant selected to oversee the procurement by the Department and the OCC. Also on September 26, 2007, the OCC filed its own extensive report on the procurement process.

The Department held a technical meeting on September 26, 2007, to review the joint recommendation filed by CL&P and Levitan. The provisions of Conn. Gen. Stat. §4-179 were satisfied inasmuch as the Commissioners who are to render the final decision have read the record and were present at the technical meeting.

II. DEPARTMENT ANALYSIS

The Department has carefully reviewed the material submitted by CL&P, Levitan and OCC. The material consists of a joint recommendation of CL&P and Levitan, supported by affidavits submitted on behalf of both, and the comments submitted by OCC.[1] CL&P, Levitan and OCC all testified at the technical session held at the Department on September 26, 2007, that the process was conducted in accordance with the approved procurement plan, was fair and impartial, and accurately reflected the wholesale market at the time of the procurement.

The Department recognizes that a significant amount of time and effort was expended by CL&P, Levitan and OCC that culminated in a professionally run auction that conformed to industry standards. The Department especially credits OCC's efforts in the procurement to ensure that the public interest was protected.

This procurement fills 30% of the first half of 2008 and 20% of the second half of 2008. In addition, CL&P, Levitan and OCC propose that the Department accept contracts for two of the remaining blocks of power needed for 2009 and one for 2010.

Based on the Department's review of the submitted material and the technical session, the Department finds that the auction process was conducted in accordance with the approved procurement plan, and that the market was accessed in a fair and impartial manner. The resulting prices and contracts therefore reflect the workings of a competitive market. The Department notes that total number of bids is the largest submitted to date in any round, and more bidders participated in this round than in any previous Standard Service solicitation. Therefore, the Department approves the

[1] In its June 21, 2006 final Decision in Phase I of this proceeding, the Department specified the types of information to be included in procurement filings. In accordance with the Decision, CL&P routinely includes one table (Table 2 Attachment 2) summarizing pricing results from the current solicitation, and another table summarizing the combined pricing results from the current and previous procurements (Table 3 Attachment 2). Tables such as these have allowed the Department to analyze a significant amount of data in the short period of time associated with procurement reviews. With this in mind, the Department will order minor modifications to procurement filings that will aid in the timely review of the procurement results.

resulting prices and material terms of the energy contracts proposed by CL&P and Levitan.

In past procurement approvals, the Department has been cognizant of market constraints. Therefore, the Department has issued protective orders that prevent public disclosure of the prices and nature of wholesale generation contracts for two weeks following the execution of the contracts to enable the winning bidders to hedge appropriately. In this Decision, the Department reiterates this previous policy.

Furthermore, in its June 21, 2006 Final Decision in this proceeding, the Department committed to a review process similar to that utilized by the Independent System Operator of New England, Inc. such that RFP bid data will not be released until six months have elapsed.

Because the auction results certified by this decision are the product of a fair process, the Department will order that the accepted bids be included in the formulation of the overall standard service rate. In its initial decision in this proceeding, the Department concluded that Conn. Gen. Stat. §16-19b can be utilized to recover standard service generation costs.

III. CONCLUSION AND ORDERS

A. CONCLUSION

The Department certifies that the process of this second auction conducted by CL&P to procure standard service fully adhered to the procurement plan adopted in the June 21, 2006 decision. The Department hereby approves the energy contracts proposed for approval. The Department also issues a protective order for the auction results to allow the winning bidders sufficient time to hedge appropriately.

B. ORDERS

1. The auction results approved herein shall be included in the establishment of the overall standard service rate in a future Conn. Gen. Stat. §16-19b filing.

2. In future procurement filings, CL&P shall modify Tables 2 and 3 of Attachment 2 to include a column indicating the weighted average price of Scenario A and Scenario B bids, including an estimate for congestion for the Scenario B bids. Additionally, CL&P shall submit a third table of summarized pricing results, utilizing the same format, which summarizes the pricing results of previous procurements. This would allow the Department to analyze the price trends by providing the cost of previous procurements, the latest procurement and the combined total to date. In addition, CL&P shall provide the existing wholesale generation cost included in the generation services charge currently in effect, and shall estimate the change in the generation services charge that is expected in the next period on a cents/kWh and percentage basis as a result of the

most recent procurement. CL&P shall also provide the previously approved bids for each tranche on Table 1 of Attachment 2.

This Decision is adopted by the following Commissioners:

Donald W. Downes

Anne C. George

John W. Betkoski, III

CERTIFICATE OF SERVICE

The foregoing is a true and correct copy of the Decision issued by the Department of Public Utility Control, State of Connecticut, and was forwarded by Certified Mail to all parties of record in this proceeding on the date indicated.

Louise E. Rickard

Louise E. Rickard
Acting Executive Secretary
Department of Public Utility Control

Sept. 26, 2007
Date

McLane

McLane, Graf,
Raulerson &
Middleton

Professional Association

STEVEN V. CAMERINO
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MANCHESTER
CONCORD
PORTSMOUTH

July 23, 2007

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 S. Fruit Street, Suite 10
Concord, NH 03301-2429

Re: DE 06-125; Public Service Company of New Hampshire

Dear Ms. Howland:

I am writing on behalf of Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc. (referred to below as "the Constellation companies") concerning the Commission's recent Order No. 24,768 (referred to below as "the energy service rate order"). Constellation NewEnergy, which supplies electricity to customers at retail, is an intervenor in Docket DE 06-125. Constellation Energy Commodities Group, which supplies electricity at wholesale, did not directly intervene in this docket, although it has been an intervenor in prior energy service proceedings involving Public Service Company of New Hampshire ("PSNH") and is extensively involved in policy matters related to the electric industry in New Hampshire and throughout the region.

In its energy service rate order issued on June 29, the Commission urged the parties to complete for consideration by the Commission a proposal under which competitive suppliers would provide information regarding the load they have under contract for the upcoming year. Although the Constellation companies had previously indicated their support for such a concept, further consideration of how such a proposal may work as well as their experience in New Hampshire during the past year have given rise to serious concerns about proceeding with such a proposal. The purpose of this letter is to explain those concerns, and request that the Commission ensure that other suppliers have an appropriate opportunity to comment on any proposal by PSNH before it is acted on by the Commission. It is Constellation's understanding that the Commission does not intend to adopt a specific proposal until all suppliers have had an opportunity to comment, but because Constellation had previously indicated that it believed it could support a new reporting requirement, it felt it appropriate to express its concerns as soon as possible rather than waiting until the Commission staff and PSNH have spent additional time on it.

The concept of asking competitive suppliers to report their load under contract for the coming year was first raised by PSNH during the first phase of this docket as a means of assisting PSNH in forecasting its retail load. Specifically PSNH believed that such data would enable it to better estimate the amount of power it would need to procure in the wholesale market to serve its retail load. As the Commission is aware, PSNH procures approximately 30% of its power requirements in the wholesale market as a supplement to the energy generated by its own assets. While the Constellation companies have a direct interest in ensuring that PSNH's energy service rate reflects as closely as possible the full and true cost of providing that service, they have also made clear that there are real public benefits that could be obtained if PSNH obtained the power it requires for its energy service load from the wholesale market. The Constellation companies have put forth a number of proposals before the Commission and in the New Hampshire legislature that have been aimed at achieving those ends, but PSNH has consistently argued against them. PSNH's primary rationale opposing these proposals has been its claim that it can procure the energy needed by its customers at a lower cost than can competitive suppliers. In particular, with regard to the portion of its load purchased on the wholesale market, PSNH has asserted that it can obtain the needed power more cost-effectively by putting together its own portfolio of firm contracts, spot purchases and hedges than by putting its requirements out to bid in the wholesale market and entering into a load following requirements or partial requirements contract.

The Constellation companies are extremely concerned that a reporting requirement that provides PSNH with suppliers' highly confidential load information, even if such information were provided on an aggregated basis, would give PSNH an unfair competitive advantage. In particular, at least with regard to the portion of its load that it procures from the competitive wholesale market, PSNH should be required to seek bids to serve that load, so the Commission has a point of comparison to PSNH's cost of providing the same service. The Constellation companies are confident that an RFP approach, similar to that followed by National Grid and Unitil Energy Services, to serve PSNH's requirements that its own assets do not satisfy would benefit PSNH's customers.

Because PSNH manages its own power procurement needs for the 30% of its requirements that it obtains from the wholesale market, it effectively operates in direct competition with wholesale suppliers such as Constellation Energy Commodities Group, who provide load following service to utilities throughout the country. For such suppliers, projecting customer migration is one of the risk management functions that they conduct on a regular basis, something which they do through sophisticated load forecasting methods and the use of skilled, experienced portfolio managers. If PSNH were to be given access to retail suppliers' load forecasts—information that is not equally available to competitive suppliers—it would have a significant unfair informational advantage in serving that load. Such an approach would do real harm to the competitive market in New Hampshire. In addition to the obvious harm to the wholesale market, the more PSNH enters into fixed commitments to meet its customers' power needs, the more it will be motivated to seek to retain its retail load in order to ensure that it can recover the costs associated with those commitments. As the Commission is aware, PSNH's energy service customers bear essentially all of the risk associated with PSNH's power supply decisions, whereas competitive suppliers bear that risk when they contract with PSNH in a wholesale transaction or with PSNH's customers in a retail transaction.

The Constellation companies remain interested in working to identify ways to improve PSNH's ability to forecast the costs on which its energy service rate is based, thereby minimizing the potential for over and undercollections that are recovered or returned to customers in subsequent time periods. However, they believe that requiring PSNH to put out a request for proposals for a load following service, rather than allowing it to continue to create that service itself through a portfolio of wholesale contracts, spot purchases and hedges, will provide greater benefits to customers.

The Constellation companies recognize that the current docket does not provide a sufficient opportunity to address these issues, and therefore they request that the Commission include the issues (including consideration of any proposal for load forecast reporting by suppliers) in PSNH's next energy service rate proceeding. Although the Constellation companies do not believe that this request requires any immediate action by the Commission, to the extent the Commission deems it to be a motion for reconsideration, the Constellation companies request that the Commission take such action as the Commission deems appropriate to modify its Order No. 24,768.

The Constellation companies welcome the opportunity to continue to discuss these issues with the Commission staff, the Office of Consumer Advocate and PSNH, in anticipation of PSNH's next energy service rate proceeding. To the extent that the Constellation companies' concerns can be addressed, they remain willing to work on a proposal that enables PSNH to better forecast its energy service costs.

Sincerely,

Steven V. Camerino

cc: Service List

EXHIBIT 1.3

NORTHBRIDGE STUDY

Analysis of Standard Offer Service Approaches for Mass Market Customers

Prepared for National Grid
Re: RI PUC Order #19839

January 2010

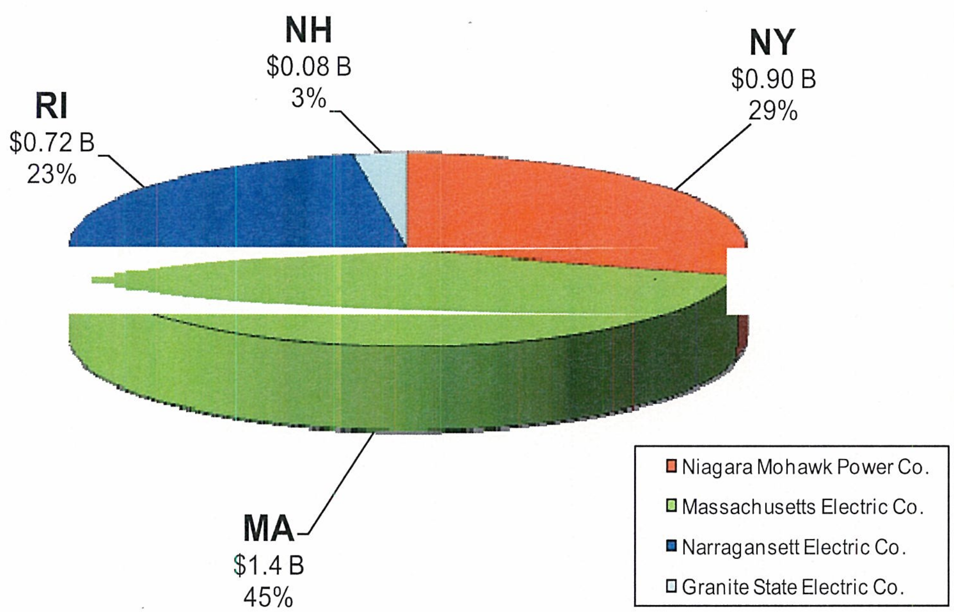
NORTHBRIDGE

This report presents an analysis of the relative costs and risks of different approaches to serve mass market standard offer service customers, and how different approaches could impact customers' standard offer service supply rates. While this report depicts potential future supply costs and rate levels, it is not intended to provide a prediction of absolute levels in the future associated with any particular approach for standard offer service supply procurement and ratemaking. As market prices and conditions change over time, expected absolute supply costs and rate levels would also change.

SOS OVERVIEW — Large Impacts

Electric standard offer service (SOS) supply procurement decisions impact many customers and involve substantial amounts of money:

National Grid
Electric Supply Energy Procurements
July 2008 - June 2009
$3.1 Billon Total



- Currently spending about $3.1 billion annually for 38,000 GWh
- The need for SOS is likely to continue for the foreseeable future

Our forward-looking quantitative analysis of SOS procurement approaches reflects mass market customer load in Rhode Island.

SOS APPROACHES — Full Requirements Products

Most electric utilities in restructured states primarily use full requirements products to secure SOS supply for residential customers:

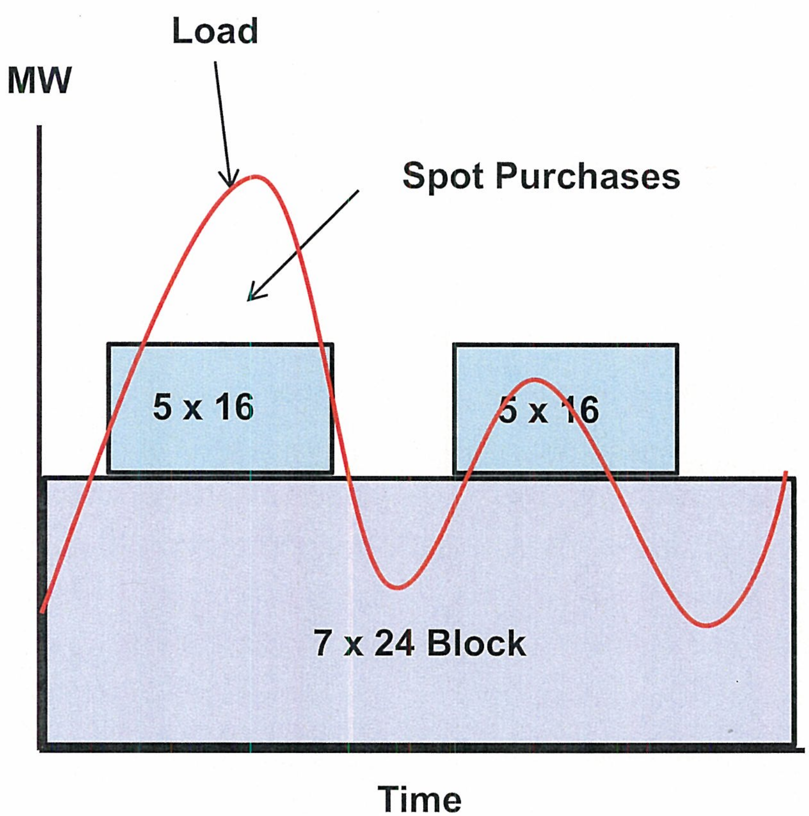
State	Utility
CT	CLP, UI
DC	PEPCO
ME	BHE, CMP
MD	AP, BGE, DPL, PEPCO
MA	NG, NSTAR, WMECO
NJ	ACE, JCPL, PSEG, RECO
PA	FE, PPL, PECO, WPP

Key Features

- RFP/auction process
- Bundles energy, capacity, ancillary services, and often RECs
- Third party supplier assumes volume, price, and regulatory risks during the contract period
- Contracts vary in length and are typically "laddered" to provide rate stability
- Details regarding the procurement process, products, and timing are pre-approved
- Cost recovery process is approved by the Commission in advance
- Results are approved within 1-3 business days of solicitation
- Products do not require utility to post collateral
- Usually no significant cost deferrals
- Relatively easy to implement
- Sellers require compensation for the costs and risks that they bear

SOS APPROACHES — Managed Portfolio

Another approach to SOS procurement involves the use of a "managed portfolio," which generally entails purchases of component products of the full requirements supply obligation, most commonly involving block products for energy supplemented with spot market purchases:



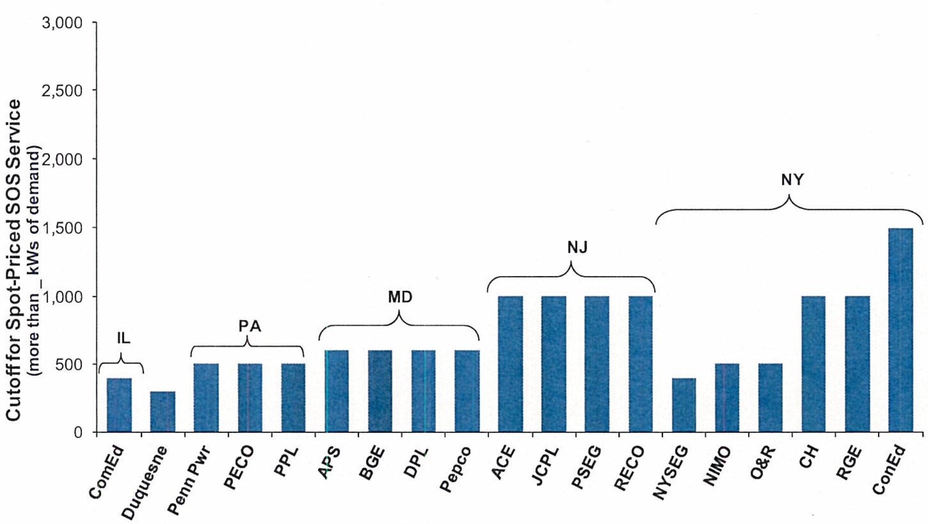
Key Features

- Utility purchases component products
- Customers assume a degree of volume, price, and regulatory risks
- Contracts vary in length and are typically "laddered" to provide rate stability
- Cost recovery process is approved by the Commission in advance
- Standard NYMEX block products may require utility to post collateral
- Potential mismatch of supply and demand (i.e., "too much" or "too little"), especially when unfavorable

Note: Some parties consider some portfolios that include full requirements products to be "managed portfolios." For the purpose of clarity in this presentation, the term "managed portfolio" here refers to portfolios that do not include full requirements products and that are not entirely based on spot procurement.

SOS APPROACHES — Spot Procurement

Spot market procurement and pricing based on customer-specific hourly usage has become more prevalent for large C&I customers:



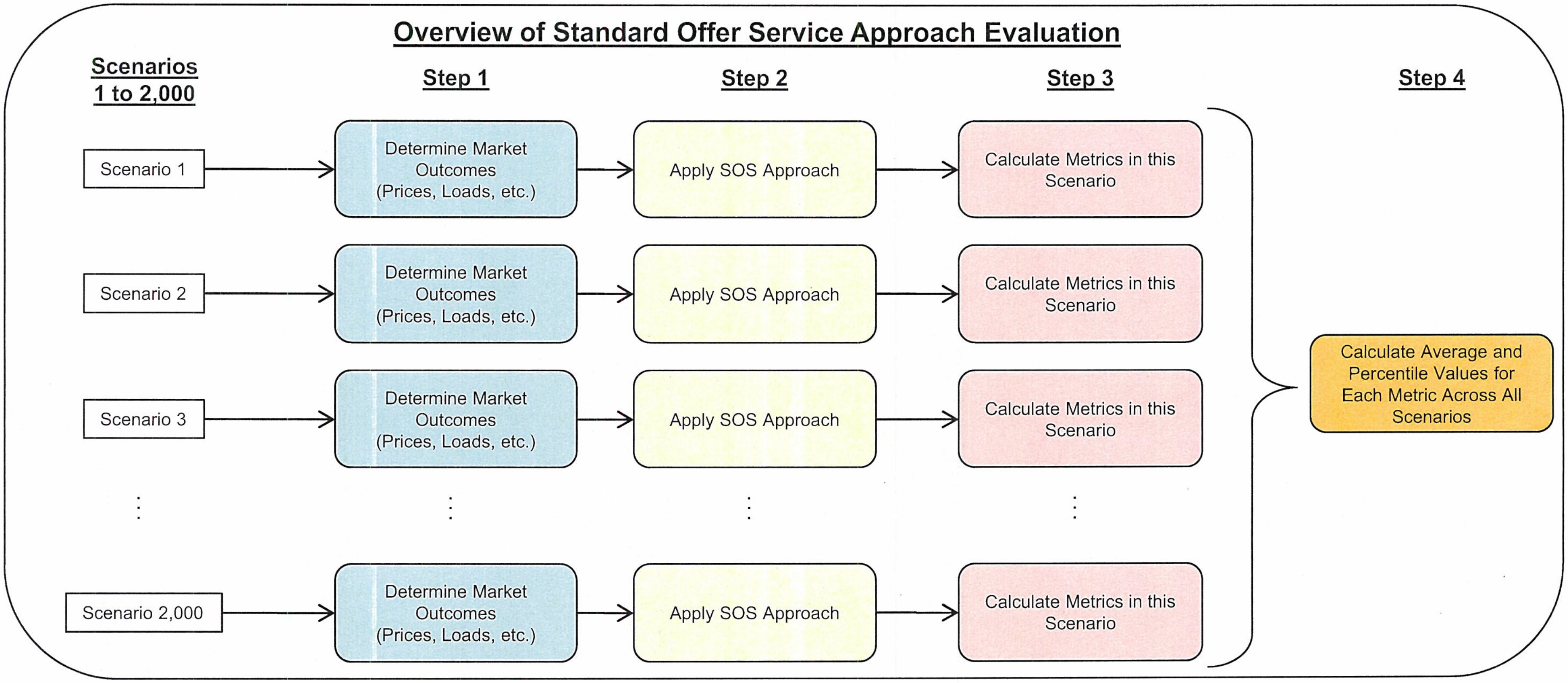
Note: For the purposes of this chart, "spot" includes both day-ahead and real-time pricing.
Note: PECO's spot-priced service has been approved, but is not yet effective.

Key Features

- Real-time or day-ahead energy spot prices
- Promotes efficient customer consumption decisions (e.g., EE and DR)
- Supports retail market development
- Usually no significant cost deferrals
- Generally not considered "acceptable" for small customers due to rate volatility concerns
- Not feasible absent metering / communications / data management

OUR ANALYSIS — Overview

In order to analyze various SOS approaches for mass market customers, we utilized a proprietary Monte Carlo simulation approach to replicate market uncertainty based on actual market data, and modeled and measured the performance of the various SOS approaches:



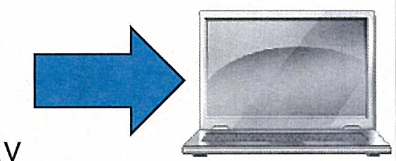
As part of this analysis, we studied bid prices and component costs for SOS products recently solicited by different utilities.

OUR ANALYSIS — Application Of Approaches

Our model allows for evaluation of a wide variety of SOS procurement and cost recovery approaches, including:

Procurement ⟷ **Linkage** ⟷ **Cost Recovery**

Product Duration	Product Type	Hedge Target	Laddering*	Retail Rate Adjustments	Deferral Balance Accruals	
20 yr.	Mix of Products	100%	100%	Annually or Longer	Annually	Recovered over X months @ Y% interest with or without deferral recovery cap
3 yr.	Full Requirements	75%				
		50%	50%	Quarterly		
1 yr.			33.3%			
6 month	Block			Monthly	Monthly	
Hourly	Spot	0%	0%	Hourly	None	



* Amount of supply procured at any point in time.

Procurement events, rate adjustments, customer switching decisions, and deferral balance recovery can be modeled to occur at different times.

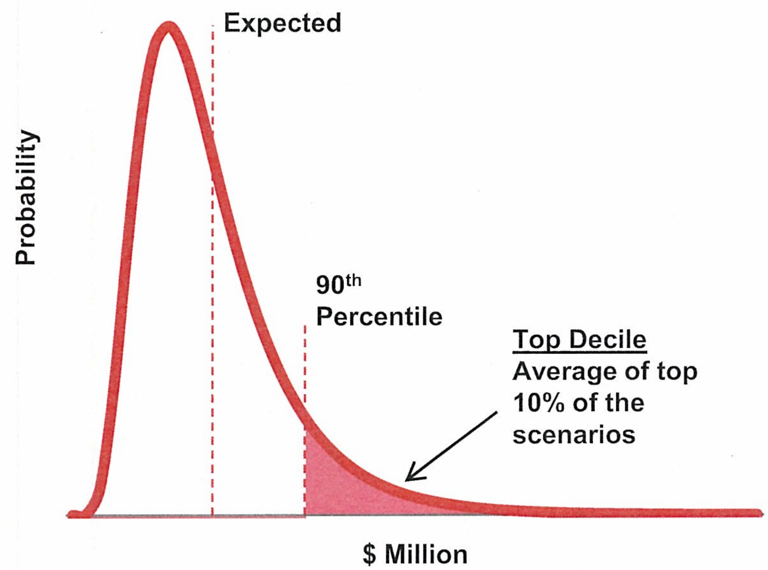
OUR ANALYSIS

Each SOS approach was evaluated using the following metrics:

Category	Metric
Metrics Directly Related to Rates	**Expected Rate Level** Average SOS rate level across scenarios
	Supply Cost Surprise Distribution of difference between actual (ex post) and forecasted (ex ante) supply costs ($MM, $/MWh, %)
	Rate Volatility Distribution of SOS rate movements: • From one year to the next • "Coefficient of variance" (similar to New York)
Metrics Directly Related to Financing/ Liquidity	**Deferral Account Balance** Distribution of accumulated under/(over) collections due to differences between SOS rates and actual supply costs
	Mark-to-Market Exposure Exposure on block energy contracts (how far fixed-quantity commitments are out-of-market; also potentially relevant to credit requirements)

➢ To assess risks, distributions of the metrics were analyzed:

Deferral Account Balance



Note: Rates in this presentation refer to the rate for the supply procured, not including gross-ups for line losses, retail taxes, and other administrative costs.

OUR ANALYSIS — Representative Approaches

While we analyzed many specific SOS approaches/portfolios, our findings can be conveyed through a discussion of three representative SOS approaches/portfolios:

Type of Approach	Description	Standard Offer Service Rate Determination	Treatment of Deferrals
Full Requirements	1-year full requirements products, in which 1/2 is procured every 6 months	Rates reset every 6 months (ex ante)	No deferrals; rates based on actual costs
Managed Portfolio (Block and Spot)	Block energy 25% 4-year (1/4 per year), 25% 2-year (1/2 per year), 25% 6-month, Spot (25%)	Rates reset every 6 months (ex ante)	Prior month balance recovered with 2 month lag; \$5/MWh recovery cap (i.e., deferral rate adjustment in any month cannot exceed \$5/MWh)
Spot	Procurement based entirely on spot	Rates reset each month (ex post)	No deferrals[1]; rates based on actual costs

[1] Deferrals may exist to the degree that RTO settlement adjustments are not available when customers' bills are sent.

SUMMARY OF FINDINGS — Spot Procurement

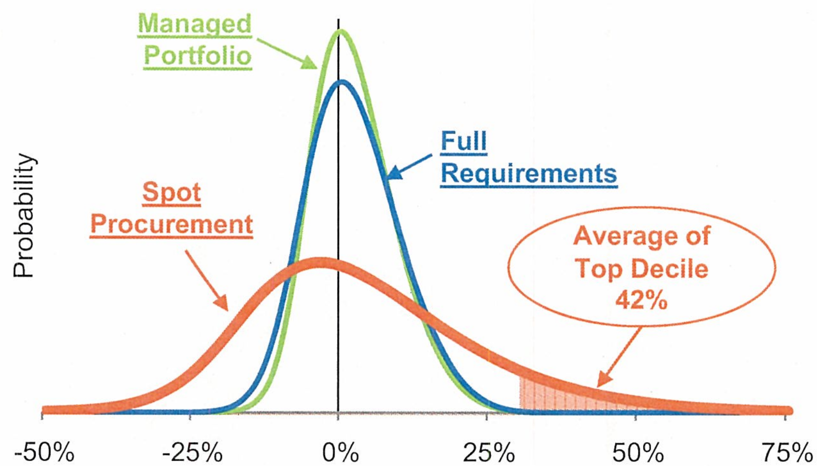
The expected SOS rate under spot procurement is about $2-3/MWh lower than under other approaches, but spot procurement exposes customers to significant rate volatility – annual rate increases across 10 percent of the market scenarios average over 40%:

Expected Rate Levels

Approach	Expected Rate ($ / MWh)	Difference Versus Spot
Spot	$86.01	NA
Managed Portfolio	$88.22	+$2.21
Full Requirements	$88.94	+$2.93

Spot Procurement – High Rate Volatility

Distribution of Annual Rate Changes (%)



Spot Procurement	
Top Decile Supply Cost Surprise ($MM)	$123 MM
Expected Coefficient of Variance (%)	17%
Top Decile Coefficient of Variance (%)	28%

Most regulators and small customer representatives consider 100% spot procurement for mass market customers to be “unacceptable”:

- Our studies indicate that no U.S. utilities only offer spot-priced SOS without some form of hedging for mass market customers
- “Unacceptable rate increases” for mass market customers with few competitive alternatives could result in significant cost deferrals

SUMMARY OF FINDINGS MP vs. FR

Both managed portfolio (MP) and full requirements (FR) approaches can reduce customers' exposure to rate volatility, but key differences exist:

Key Differences	Managed Portfolio	Full Requirements
Risks Allocated to Customers	**Higher**, cost of mistakes/bad market outcomes borne by customers	**Lower**, cost of mistakes/bad market outcomes borne by FR suppliers during delivery period
Expected Rate Level	**Lower**	**Higher**, by about $1/MWh
Supply Cost Surprise	**Higher**, supply costs exceed ex ante forecasts by over $40 MM on average across 10 percent of the scenarios due to unhedged positions and load uncertainty	**Lower**, FR suppliers assume more risks
Deferral Account Balances	**Higher**, could become large ($50 MM or more) depending on several key variables	**Minimal** (if no spot included)
Effect of Additional Costs and Risks Not Modeled	**Higher**, would increase costs and risks of an MP approach (e.g., uncertainty regarding capacity, ancillary services, and RPS costs, greater-than-assumed customer switching, etc.)	**Lower,** risks assumed by FR suppliers
Internal Resources	**Higher**, may require additional staff to manage portfolio and ongoing Commission oversight	**Lower**, risk management functions put out for competitive bid

MP vs. FR — Allocation Of Risks

SOS costs and risks remain in either approach, but who bears these costs and risks is different in each approach:

Standard offer service involves many costs and risks:

- Mismatch between revenues and supply costs
- Customer migration
- Unexpected congestion
- Uncertain load and price levels
- Uncertain load and price shapes
- Adverse selection (competitors can select who they serve; SOS supplier cannot)
- Collateral requirements (potentially)
- Potential changes in laws and regulations
- Administrative expenses

These costs and risks remain in either approach.

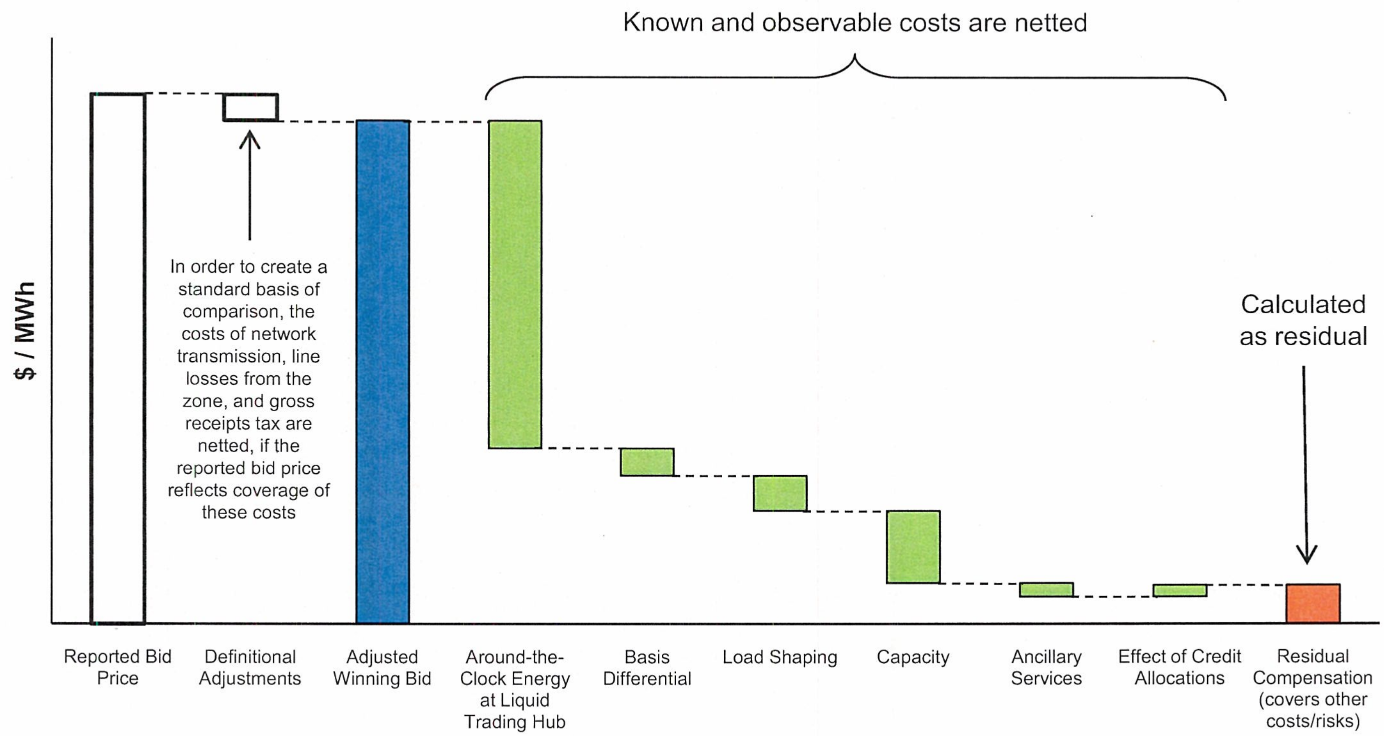
<u>Full Requirements</u>
Suppliers bear costs and risks during the delivery period, but require compensation to do so

<u>Managed Portfolio</u>
Customers are exposed to costs and risks to a higher degree

Our analysis involved a thorough look at the trade-off between compensation and risk.

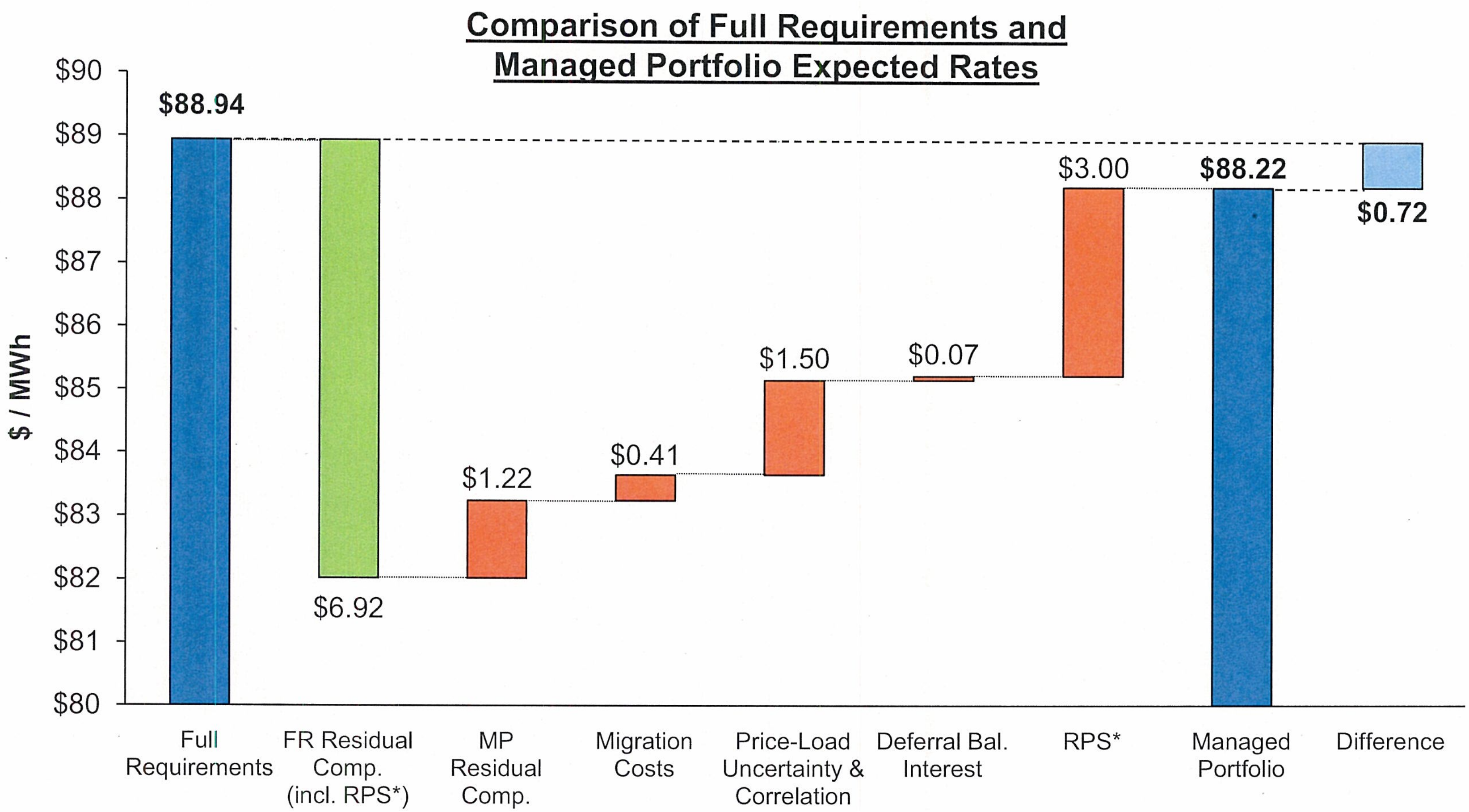
In order to incorporate full requirements product pricing in our analysis, for full requirements SOS supply products recently solicited by different utilities, we used market information to develop estimates of expectations (at the time of the solicitation) regarding the costs of components of the full requirements supply product and compared these costs to the actual prices of the full requirements product:

Illustrative Full Requirements Product Price Analysis



The residual compensation required by full requirements product suppliers, observed through this study of actual product solicitations, was incorporated in our quantitative analysis of SOS approaches.

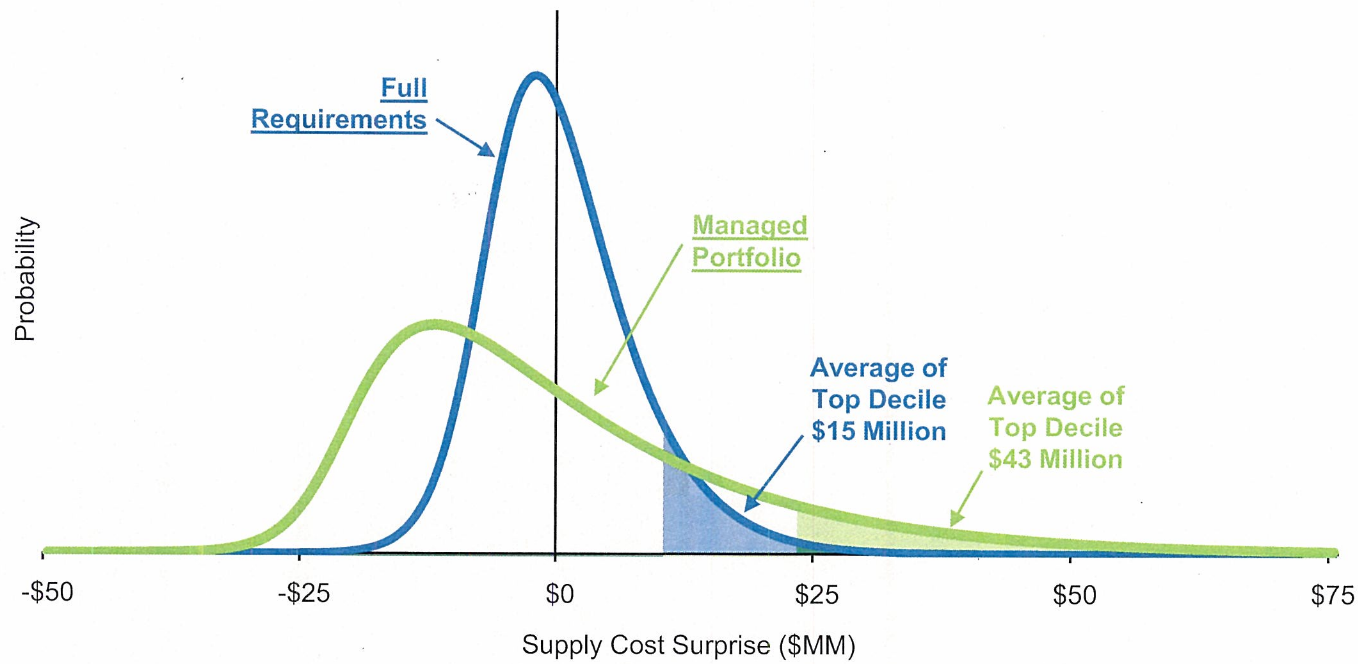
The difference between the expected SOS rate under the FR approach versus under the MP approach is about $1/MWh:



* Under *all* of the procurement approaches that were modeled, the model adjusts the pricing of the supply procured to reflect an RPS cost of $3/MWh *going forward*.

But the MP approach could result in higher unexpected increases in SOS costs, due to unhedged positions and/or unpredictable SOS load levels:

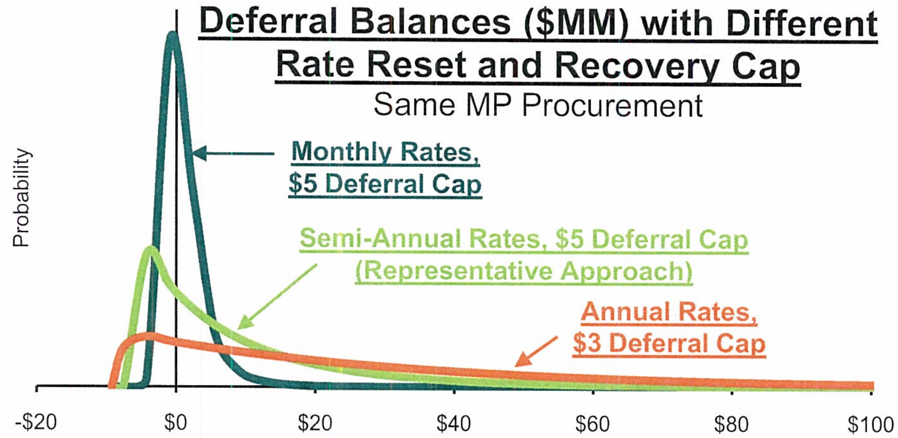
Distribution of Supply Cost Surprise ($MM)



For example, risks associated with price movements such as the 2000 price spikes in California or the 1998-1999 price spikes in the Eastern U.S. would be absorbed by FR suppliers during the supply product delivery period, but customers would absorb more of this risk under an MP approach.

Deferral Balances

MP approaches also involve deferral balances that could become large, and are impacted by how the deferral recovery mechanisms are designed, approved, and implemented:



Deferral Account Balances ($MM)			
	Semi-Annual Rates, $5 Deferral Recovery Cap	Annual Rates, $3 Deferral Recovery Cap	Monthly Rates, $5 Deferral Recovery Cap
Expected Value ($MM)	$10 MM	$28 MM	$1 MM
Average of Top Decile ($MM)	$57 MM	$113 MM	$9 MM

Key Variables in Mechanism Design
- Frequency of rate reset (based on forecasted future costs)
- Frequency of rate reconciliation (based on actual costs and revenues)
- Recovery period
- Interest on deferral balances
- Deferral recovery cap
- Maximum deferral balance

Wellsboro Example
- Based on its unexpected costs incurred under its MP approach in early 2008, Wellsboro Electric reported that supply rates could be twice expected levels without deferrals. As a result, the period for recovery of the unexpected costs was extended from three to twelve months.

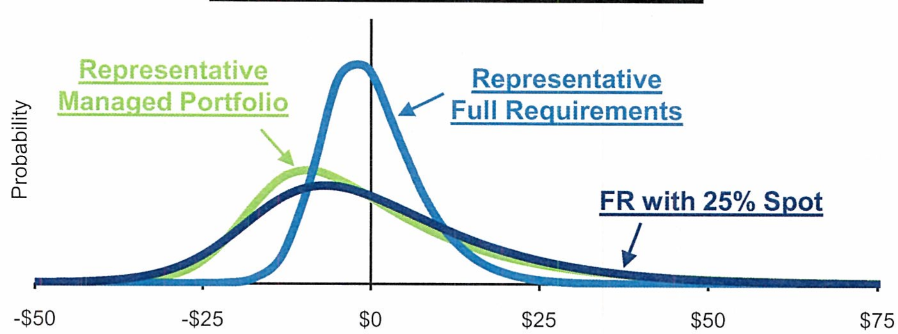
Using an FR approach, supply costs are known when rates are established, therefore no (or minimal) deferrals are required unless spot purchases are also included in the plan.

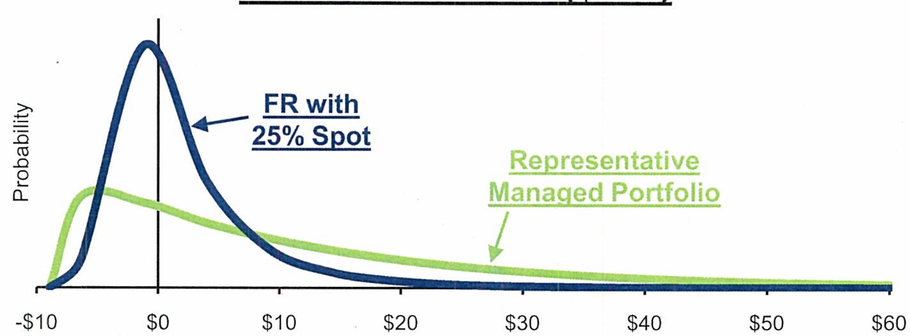
FR with Spot

If the FR approach were modified to include 25% spot purchases, the expected rate level would decrease, but the risk associated with supply cost surprise and deferral balances would increase:

Expected Rate Level ($/MWh)

Approach	Average of Top Decile
Representative MP	$88.22
Representative FR	$88.94
FR with 25% Spot	$88.21





Supply Cost Surprise ($MM)

Approach	Average of Top Decile
Representative MP	$43 MM
Representative FR	$15 MM
FR with 25% Spot	$37 MM

Deferral Account Balances ($MM)

Approach	Average of Top Decile
Representative MP	$57 MM
Representative FR	$0 MM
FR with 25% Spot	$18 MM

Some utilities have adopted an approach involving a mix of full requirements products and spot purchases (although 25% spot is higher than levels generally adopted for mass market customers).

MP vs. FR — Additional Risks

There are additional costs and risks that were not modeled in the quantitative evaluation that would increase the costs and risks of an MP approach:

- Increased administrative costs (e.g., portfolio management staff and systems, regulatory proceedings and/or interaction with regulators, etc.)
- Uncertainty regarding capacity, ancillary services, and RPS costs[1]
- Greater-than-assumed customer switching (e.g., due to additional potential for new technologies, regulatory policies, opt-out customer aggregation, etc.)
- Imputed debt costs

In contrast, full requirements product suppliers compete on price to manage these and other risks, and absorb the costs of any mistakes.

[1] The model assumes constant $/MWh capacity, RPS, and ancillary services costs across all scenarios. Modeling uncertainty around these other variables would make an MP approach less attractive relative to what was quantified in this presentation.

SUMMARY OF FINDINGS

- 100% spot procurement would expose mass market customers to significant rate volatility and is not acceptable to most regulators at this time
- Both a managed portfolio and a full requirements approach can reduce customers' exposure to rate volatility, but key differences exist:

Key Differences	Managed Portfolio	Full Requirements
Risks Allocated to Customers	Higher	Lower
Expected Rate Level	Lower	Higher
Supply Cost Surprise	Higher	Lower
Deferral Account Balances	Higher	**Minimal** (if no spot included)
Effect of Additional Costs and Risks Not Modeled	Higher	Lower
Internal Resources	Higher	Lower

Appendix

SUMMARY OF METRICS

More Approaches

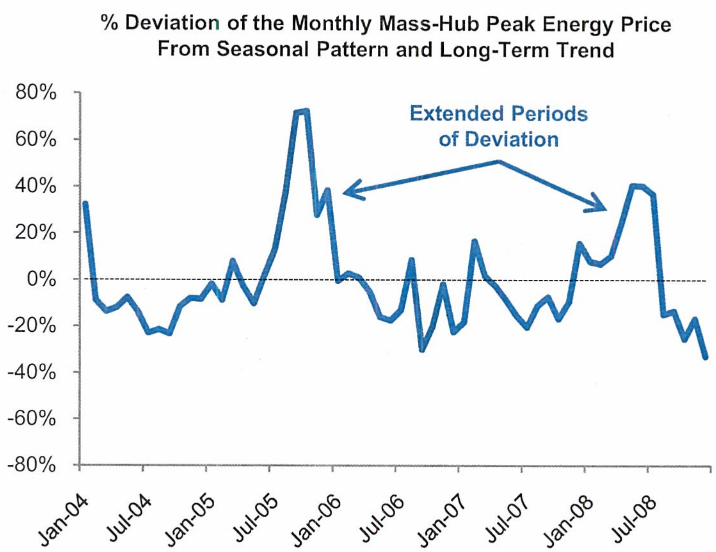
Description of Approach				Comparison of Performance Metrics								
Product Term	Product Type	Hedge Target	Rate Period	2014 SOS Rate Level ($ / MWh)	Supply Cost Surprise ($MM)	Supply Cost Surprise ($/MWh)	Supply Cost Surprise (%)	Deferral Account Balance ($MM)	Annual Rate Movement (%)	Coefficient of Variance (%)	Customer Switching (%)	Mark-to-Market Exposure ($MM)
Ten-Year Laddered	Block Energy	100%	Annual	$92.37 ($84.06 / $105.89)	$0 (-$14 / $29)	$0.00 (-$4.03 / $10.51)	0.0% (-4.5% / 11.8%)	$9 (-$1 / $51)	1.8% (-3.7% / 8.8%)	2.0% (0.0% / 3.5%)	16% (0% / 57%)	-$31 (-$421 / $213)
Five-Year Laddered	Block Energy	100%	Annual	$89.90 ($76.28 / $108.77)	$0 (-$13 / $28)	$0.00 (-$3.48 / $8.63)	0.0% (-4.0% / 10.0%)	$7 (-$1 / $41)	2.0% (-5.2% / 10.6%)	2.1% (0.0% / 3.6%)	12% (0% / 44%)	-$5 (-$169 / $113)
		75%	Annual	$88.60 ($72.41 / $111.25)	$0 (-$23 / $43)	$0.00 (-$6.00 / $10.14)	0.0% (-6.5% / 11.4%)	$14 (-$4 / $77)	2.1% (-6.6% / 13.2%)	2.7% (0.0% / 5.3%)	11% (0% / 40%)	-$4 (-$126 / $84)
Three-Year Laddered	Full Requirements	100%	Annual	$92.19 ($71.87 / $118.74)	$0 ($0 / $0)	$0.00 ($0.00 / $0.00)	0.0% (0.0% / 0.0%)	$0 ($0 / $0)	1.8% (-7.2% / 12.4%)	0.0% (0.0% / 0.0%)	13% (1% / 36%)	$0 ($0 / $0)
		75%	Annual	$90.65 ($69.47 / $119.18)	$0 (-$20 / $29)	$0.00 (-$5.33 / $6.46)	0.0% (-5.6% / 7.0%)	$3 (-$4 / $24)	1.9% (-8.8% / 14.0%)	3.3% (0.5% / 5.7%)	10% (1% / 31%)	$0 ($0 / $0)
	Block Energy	100%	Annual	$89.61 ($69.67 / $115.89)	$0 (-$12 / $27)	$0.00 (-$3.20 / $8.09)	0.0% (-3.7% / 9.2%)	$7 (-$1 / $39)	1.8% (-8.2% / 13.1%)	2.1% (0.0% / 3.6%)	10% (0% / 38%)	$4 (-$82 / $74)
		75%	Annual	$88.63 ($67.69 / $116.87)	$0 (-$22 / $43)	$0.00 (-$5.65 / $10.03)	0.0% (-6.2% / 11.3%)	$14 (-$3 / $77)	2.1% (-8.4% / 14.9%)	2.7% (0.0% / 5.1%)	11% (0% / 41%)	$3 (-$61 / $55)
One-Year Laddered	Full Requirements	100%	Semi-Annual	$88.94 ($65.66 / $121.55)	$0 (-$11 / $15)	$0.00 (-$2.91 / $3.46)	0.0% (-3.3% / 3.7%)	$0 ($0 / $0)	2.0% (-11.2% / 17.0%)	2.1% (0.2% / 5.6%)	8% (0% / 24%)	$0 ($0 / $0)
		100%	Annual	$88.99 ($65.43 / $122.45)	$0 (-$11 / $15)	$0.00 (-$2.87 / $3.47)	0.0% (-3.2% / 3.7%)	$2 (-$3 / $15)	2.1% (-12.8% / 20.2%)	2.3% (0.3% / 4.7%)	8% (1% / 24%)	$0 ($0 / $0)
		100%	Monthly	$88.94 ($65.66 / $121.55)	$0 (-$11 / $15)	$0.00 (-$2.91 / $3.46)	0.0% (-3.3% / 3.7%)	$0 ($0 / $0)	2.0% (-11.2% / 17.0%)	2.1% (0.2% / 5.6%)	8% (0% / 24%)	$0 ($0 / $0)
		75%	Semi-Annual	$88.21 ($64.12 / $121.76)	$0 (-$26 / $37)	$0.00 (-$6.94 / $8.30)	0.0% (-7.6% / 9.2%)	$2 (-$4 / $18)	2.1% (-12.7% / 18.7%)	4.1% (1.9% / 7.3%)	6% (0% / 21%)	$0 ($0 / $0)
	Block Energy	100%	Semi-Annual	$88.02 ($64.75 / $120.65)	$0 (-$17 / $30)	$0.00 (-$4.25 / $7.03)	0.0% (-4.9% / 7.7%)	$4 (-$1 / $26)	2.0% (-11.3% / 17.2%)	3.3% (1.3% / 6.6%)	6% (0% / 25%)	$6 (-$27 / $37)
		75%	Semi-Annual	$87.59 ($63.51 / $121.02)	$0 (-$28 / $49)	$0.00 (-$7.11 / $10.90)	0.0% (-8.0% / 12.4%)	$11 (-$3 / $62)	2.2% (-12.2% / 19.1%)	4.0% (1.1% / 7.2%)	8% (0% / 35%)	$5 (-$20 / $28)
Spot	None	0%	Monthly Ex Post	$86.01 ($56.77 / $127.32)	$0 (-$90 / $123)	$0.00 (-$21.36 / $25.78)	0.0% (-23.7% / 29.8%)	$0 ($0 / $0)	3.5% (-26.0% / 42.1%)	16.9% (9.4% / 27.6%)	0% (0% / 0%)	$0 ($0 / $0)
		0%	Monthly Ex Ante	$86.03 ($56.68 / $126.55)	$0 (-$87 / $118)	$0.00 (-$21.37 / $25.81)	0.0% (-23.8% / 29.9%)	$8 (-$4 / $34)	3.6% (-26.3% / 41.2%)	19.0% (10.6% / 29.9%)	3% (0% / 15%)	$0 ($0 / $0)
		0%	Quarterly Ex Ante	$86.11 ($56.74 / $125.11)	$0 (-$82 / $108)	$0.00 (-$21.41 / $25.89)	0.0% (-23.8% / 30.0%)	$18 (-$9 / $76)	3.6% (-24.7% / 40.1%)	16.1% (6.0% / 29.9%)	9% (0% / 42%)	$0 ($0 / $0)
Hybrid / Mixed	Block Energy[1]	75%	Semi-Annual	$88.22 ($66.68 / $117.88)	$0 (-$23 / $43)	$0.00 (-$5.92 / $9.83)	0.0% (-6.6% / 11.1%)	$10 (-$3 / $57)	2.2% (-9.0% / 16.1%)	3.6% (1.1% / 6.6%)	9% (0% / 36%)	$5 (-$47 / $47)
	Block Energy[1]	75%	Annual	$88.23 ($66.58 / $117.88)	$0 (-$22 / $42)	$0.00 (-$5.76 / $9.83)	0.0% (-6.5% / 11.0%)	$16 (-$4 / $86)	2.3% (-9.7% / 16.9%)	2.6% (0.0% / 5.5%)	12% (0% / 46%)	$5 (-$46 / $46)
	Block Energy[1]	75%	Monthly	$88.04 ($66.63 / $117.86)	$0 (-$24 / $44)	$0.00 (-$5.89 / $9.59)	0.0% (-6.5% / 10.8%)	$1 (-$2 / $9)	2.2% (-8.8% / 16.6%)	5.9% (2.6% / 10.8%)	5% (0% / 18%)	$5 (-$48 / $49)
	Block Energy[2]	75%	Annual	$88.98 ($70.98 / $114.13)	$0 (-$24 / $42)	$0.00 (-$6.42 / $9.85)	0.0% (-7.1% / 11.0%)	$16 (-$3 / $85)	3.6% (-9.3% / 19.0%)	3.4% (0.6% / 6.6%)	14% (0% / 56%)	-$7 (-$129 / $78)

[1] 25% four-year block energy, 25% two-year block energy, 25% six-month block energy, 25% spot.
[2] 25% ten-year block energy, 25% four-year block energy, 25%, one-year block energy, 25% spot.

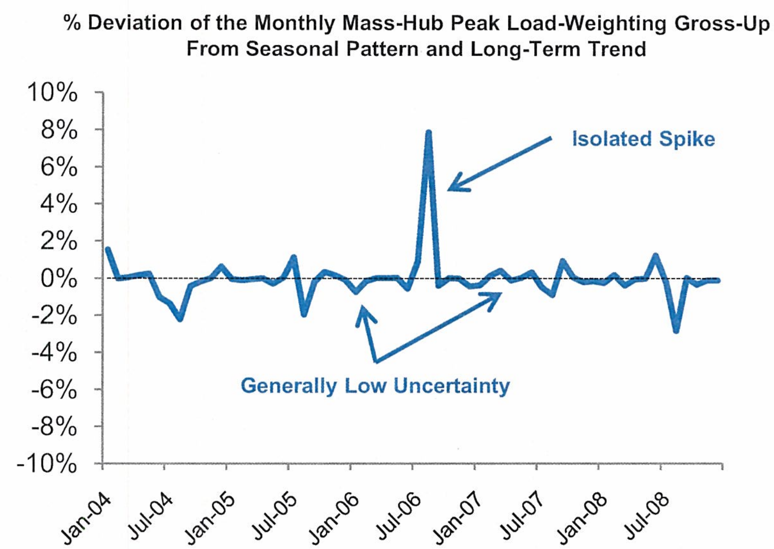
- Each SOS approach is evaluated by examining how the approach would perform under a wide variety of market conditions
- Creating these potential 'states of the world' is a critical part of the evaluation process
  - NorthBridge utilizes a proprietary Monte Carlo simulation approach to replicate the types of uncertainty in energy prices, total load, and load-weighting gross-ups we have seen historically[1]
  - This approach generates correlated[2] scenarios of potential outcomes for energy prices, total load, and load-weighting gross-ups to which we can apply different SOS approaches and observe the range of risks and benefits
- Scenarios of market outcomes are centered around current forecasts or expectations for energy prices, total load, and load-weighting gross-ups, but the intent behind the quantitative evaluation of SOS approaches is to illustrate the relative differences in cost and risk between different approaches rather than identify the precise costs associated with a specific approach

[1] Capacity prices, ancillary services costs, and RPS costs were not modeled to be uncertain in this analysis.
[2] Correlations between energy prices, total load, and load-weighting gross-ups are based on historical relationships.

- We generate scenarios to help us observe how different SOS approaches would perform under different conditions (i.e. what sort of rate volatility, rate levels, deferral balances, etc. would they yield?)
- We need scenarios to exhibit the same types of characteristics (e.g. volatility and mean reversion) we have seen in the past:



- Energy prices tend to be quite volatile and may take considerable time to mean-revert back to a long-term trend



- Gross-up levels are generally far less volatile and mean revert to long-term trends very quickly, but can also exhibit some extreme 'events'

- In order to create scenarios of what might happen in the future, we use a model of how the underlying process (i.e. prices or load) evolve over time
- The model used in this analysis is a three factor mean reverting model with stochastic volatility, and is a variant of the Random Walk / Geometric Brownian Motion (GBM) model commonly used in quantitative finance

Stochastic Differential Equations Defining the Underlying Processes[1]

$$dP = (P - \overline{P}) \cdot h_P \cdot dt + \sigma_P \cdot V \cdot P \cdot dW + drift$$

$$dV = (V - \overline{V}) \cdot h_V \cdot dt + \sigma_V \cdot V \cdot dZ$$

$$r(dW, dZ) = \beta$$

(dW and *dZ* are correlated normally-distributed random variables)

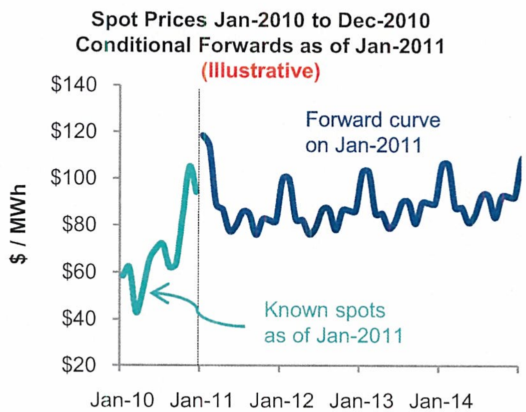
dP = Change in price
P = Price in prior period
$\overline{P}$ = Long term average price
h_P = Rate of mean reversion of price
dt = Time elapsed since prior period
σ_P = Basecase marginal volatility of price
dW = Normally distributed random variable
dV = Change in volatility
V = Volatility in prior period
$\overline{V}$ = Long term average volatility
h_V = Rate of mean reversion in volatility
σ_V = Basecase marginal volatility of volatility
dZ = Normally distributed random variable
β = Correlation between dW and dZ

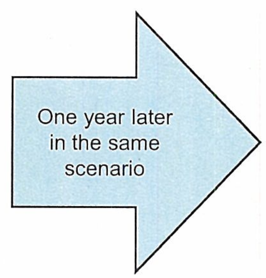
- NorthBridge has developed a proprietary set of tools using a maximum likelihood estimation technique to ‘fit’ the model above to match price / load characteristics and properties observed historically

[1] This model is a variation of the Dixit-Pindyck mean-reverting random walk model used for simulating commodity price movements. The principal difference is the addition of the term for stochastic volatility.

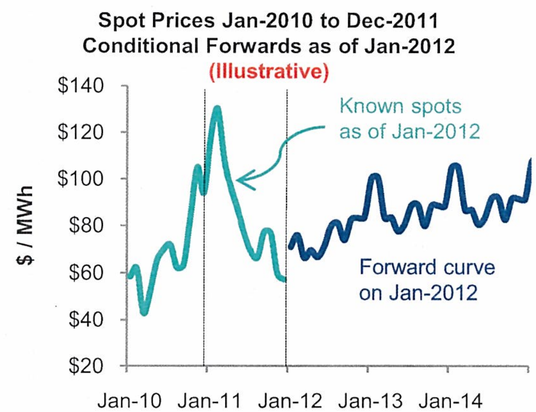
- Scenarios illustrate the uncertainty associated with variables such as wholesale market prices, total load levels, and load-weighting gross-up factors
- Each scenario consists of (1) a time-series of ultimate spot outcomes, and (2) conditional forecasts (i.e. in a given scenario, what would most likely be the forecast at a specific observation date for future delivery periods)

- We might observe spot prices from Jan-2010 through Dec-2010 and then ask what the forward curve might look like as of Jan-2011:





- In that same scenario, we can then track what might have happened during 2011 and then reassess the forward curve as of Jan-2012:



APPLICATION OF APPROACHES

Several steps are needed to analyze the performance of SOS approaches under the scenarios:

Analysis of Standard Offer Service Solicitations
Evaluation of residual compensation for full requirements and block energy products

Market Model
2,000 scenarios using a three-factor stochastic volatility model of how the expectations of price, load, and gross-up may vary over time, and what spot prices, and actual loads and gross-ups might result

1) Specify Procurement Volumes and Prices
Calculate product prices at the time of procurement

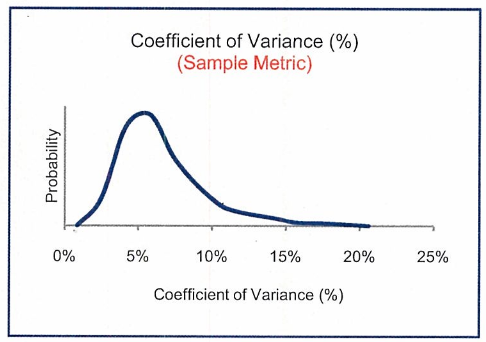
2. Calculate Retail Rates
Rates are based on known costs of completed procurements plus costs of remaining open exposure at forecasted cost

3. Estimate Switching
Customers switch based on knowledge of SOS rates and market price levels

4. Determine Actual Supply Costs
Actual costs to serve SOS customers are based on price of hedged volumes and remainder at spot

5. Determine Under / Over Recovery
Determine over / under recovery of costs and amortization schedule for full recovery

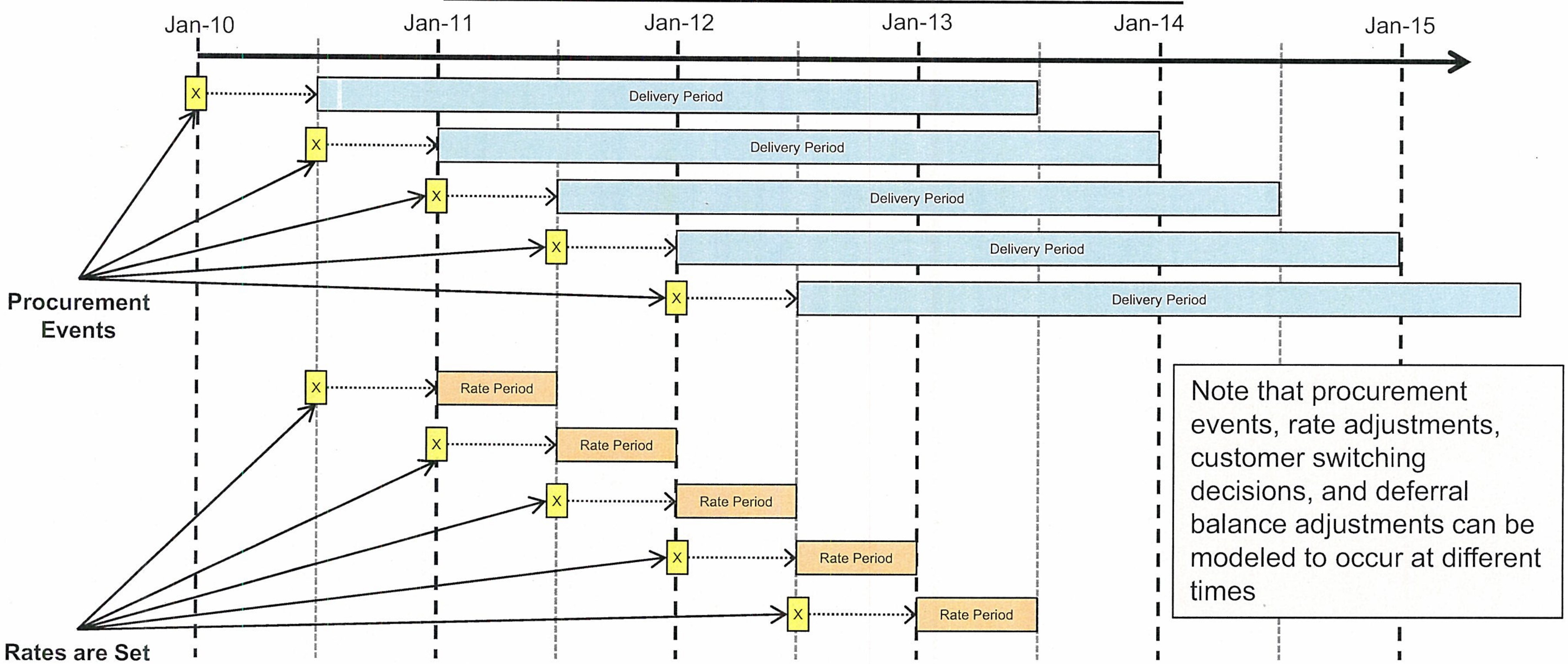
Calculate Evaluation Metrics for Each of 2,000 Scenarios



APPLICATION OF APPROACHES

In each scenario, the model applies the SOS approach, procuring products, setting rates, calculating actual costs and amortizing over/under recoveries as appropriate:

Hypothetical Schedule of Standard Offer Service Events



All actions (e.g. entering into hedges or setting rates) are done only with the information available at the time (i.e. using conditional forecasts), just as would be the case in the real world.

APPLICATION OF APPROACHES Determine Procurements

- Each time a procurement event is scheduled, hedge targets and conditional forecasts of retained load are compared to existing hedges; incremental purchases are made at conditional forward prices:

Illustrative Block Energy Procurement Product Price Calculation

Delivery Month	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
Total Forecasted Load (MWh)	354,272	291,862	286,682	256,802	246,598	440,393	436,106	388,879	327,210	269,360	304,062	365,284
Hedge Target (%)	100%	100%	100%	100%	100%	100%	50%	50%	50%	50%	50%	50%
Existing Hedges (MWh)	159,400	131,300	129,000	115,600	111,000	198,200	0	0	0	0	0	0
Incremental Purchases (MWh)	194,872	160,562	157,682	141,202	135,598	242,193	218,053	194,439	163,605	134,680	152,031	182,642
Market Price ($ / MWh)	$60.34	$60.34	$51.62	$51.62	$48.74	$50.43	$55.92	$55.92	$50.10	$56.24	$56.24	$56.24

Total Cost ($MM)	$113.4
Total Volume (TWh)	2.1
Product Price ($ / MWh)	**$54.56**

- The prices received for different products may include residual compensation (for costs/risks) consistent with historical market evidence for similar transactions

- Rates are determined by calculating the total forecasted cost attributable to SOS customers during the delivery period, including any cost/benefit from hedged volumes:

Illustrative Standard Offer Service Rate Calculation

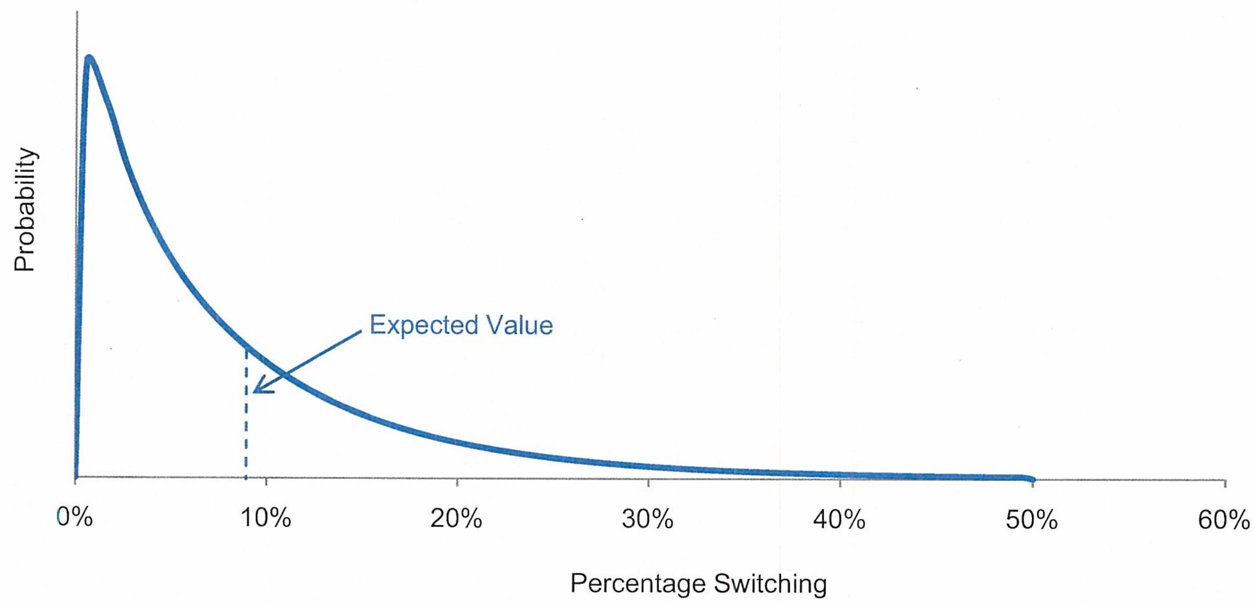
Delivery Month	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11	Oct-11	Nov-11	Dec-11
Total Forecasted Load (MWh)	336,559	277,269	272,348	243,962	234,268	418,374	414,301	369,435	310,850	255,892	288,859	347,020
Forecasted ATC Price ($ / MWh)	$54.31	$54.31	$46.45	$46.45	$43.86	$45.38	$50.33	$50.33	$45.09	$50.62	$50.62	$50.62
Forecasted Price-Load Gross Up (%)	5.79%	11.95%	7.94%	7.28%	6.09%	10.56%	9.87%	11.52%	10.95%	10.98%	8.54%	9.23%
Forecasted Spot Cost ($MM)	$19.34	$16.86	$13.66	$12.16	$10.90	$20.99	$22.91	$20.74	$15.55	$14.37	$15.87	$19.19
Hedged Volume (MWh)	354,272	291,862	286,682	256,802	246,598	440,393	218,053	194,439	163,605	134,680	152,031	182,642
Hedged Price ($ / MWh)	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56	$54.56
Benefit (Cost) of Hedge ($MM)	-$0.09	-$0.07	-$2.32	-$2.08	-$2.64	-$4.04	-$0.92	-$0.82	-$1.55	-$0.53	-$0.60	-$0.72

Total Forecasted Cost ($MM)	$218.92
Total Forecasted Volume (TWh)	3.77
Energy ($ / MWh)	$58.08
Capacity ($ / MWh)	$10.00
Ancillary ($ / MWh)	$3.00
Renewable Energy Credits ($ / MWh)	$3.00
SOS Rate ($ / MWh)	**$74.08**

- This rate only includes forward-looking cost components; recovery of deferral balances is handled separately

- The modeled customer switching dynamic produces a distribution of switching outcomes as follows under one of the SOS approaches:

Customer Switching at EOY 2014
Illustrative



APPLICATION OF APPROACHES — Deferral Accounts

- At the end of each simulated month, the model calculates the amount by which the utility's costs differ from revenues:

Illustrative Cost Under / (Over) Recovery

Month	Jan-11
Actual SOS Load (TWh)	371,986
SOS Rate ($ / MWh)	$74.08
Actual Revenue ($MM)	$27.6
ATC Energy ($ / MWh)	$66.37
Price-Load Gross-Up (%)	6.03%
Shaped Energy ($ / MWh)	$70.38
Capacity ($ / MWh)	$10.00
Ancillary ($ / MWh)	$3.00
Renewable Energy Credits ($ / MWh)	$3.00
Actual Cost ($ / MWh)	$86.38
Actual Cost ($MM)	$32.1
Under / (Over) Collection ($MM)	$4.6

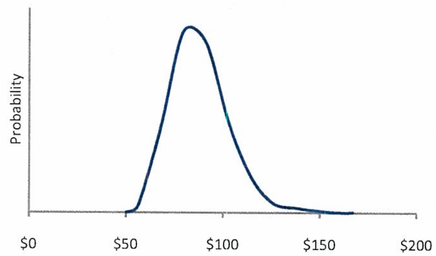
- In this month, actual costs exceeded revenues by $4.6MM
- Any over / under recovery is amortized over future months based on an established schedule as a separate rate rider (e.g. prior month balance recovery with two month delay, potentially subject to a recovery cap)
- This rider is independent of the rates set on the basis of forecasted future costs

METRICS

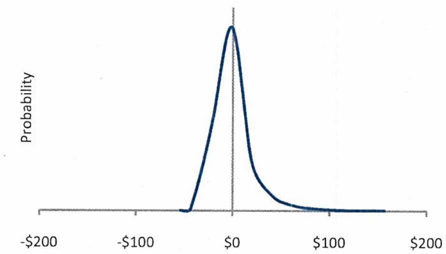
Distributions

Metrics are calculated in each scenario and transformed into distributions which are used to calculate expected values and percentiles:

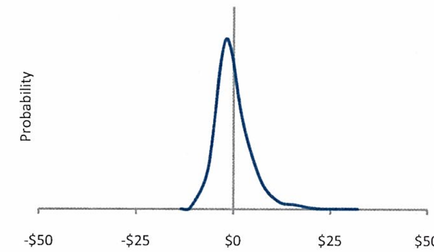
2014 SOS Rate Level ($ / MWh)



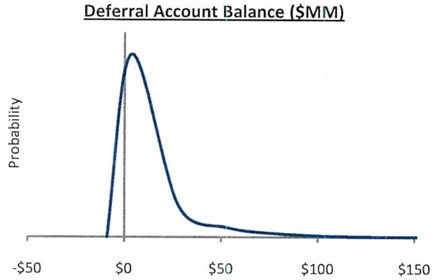
Supply Cost Surprise ($MM)



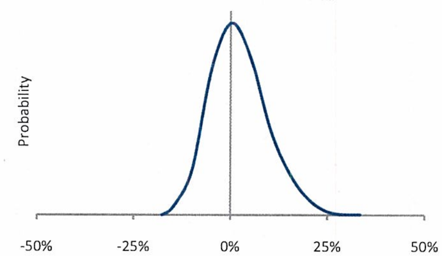
Supply Cost Surprise ($ / MWh)



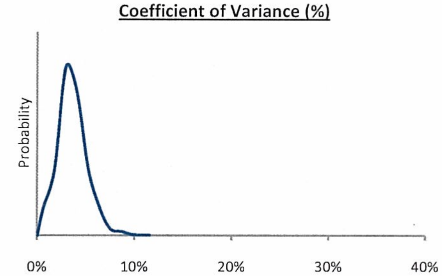
Deferral Account Balance ($MM)



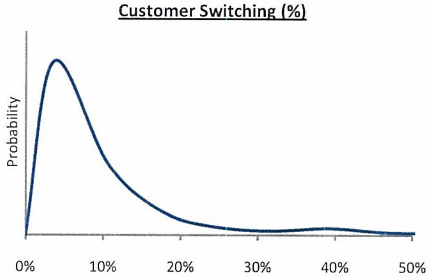
Annual Rate Movement (%)



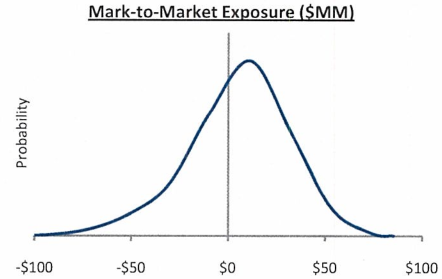
Coefficient of Variance (%)



Customer Switching (%)



Mark-to-Market Exposure ($MM)



Note: Metrics are based on 2014 results (i.e., enough time for the procurement cycle to reach equilibrium).

METRICS

Expected Rate Level

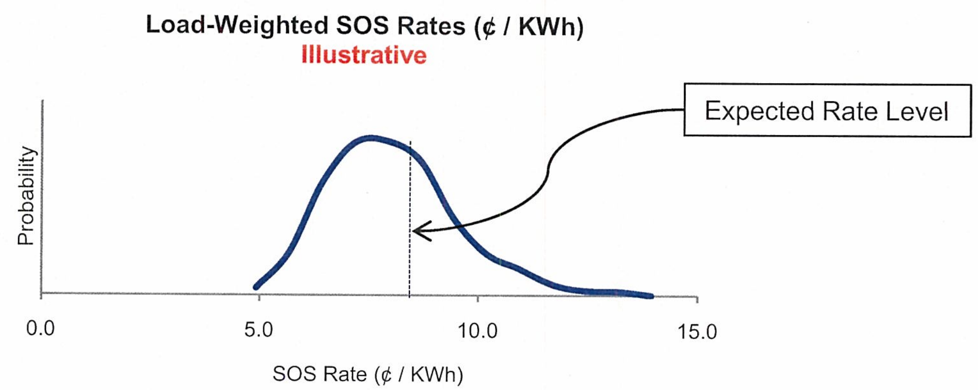
➢ The expected rate level is the average load-weighted rate that an SOS customer would face in a year:

Illustrative Standard Offer Service Rate Level

Delivery Month	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
SOS Rate (¢ / KWh)	7.74	8.04	7.94	8.65	7.81	8.09	7.96	8.37	9.96	10.40	9.36	8.85
Total Eligible Load (MWh)	371,833	327,861	340,913	288,822	293,588	385,558	480,899	412,442	333,331	305,243	323,969	365,015

Load-Weighted SOS Rate (¢ / KWh)	**8.55**

➢ Each scenario will yield a different rate; the mean across all scenarios is the expected rate level:



Supply Cost Surprise Calculation

- Supply cost surprise refers to the difference between ex ante known or forecasted SOS supply costs and the actual cost to serve:[1]

Illustrative Supply Cost 'Surprise' Calculation

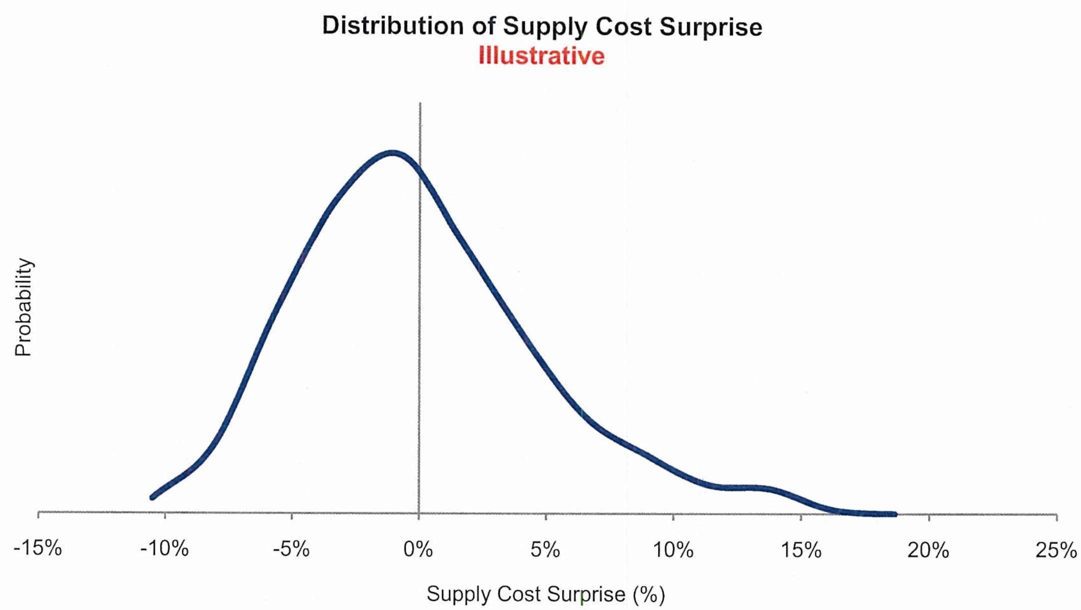
Month	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
Forecasted Supply Costs												
ATC Energy ($ / MWh)	$78.93	$78.93	$65.44	$65.44	$60.71	$63.19	$69.37	$69.37	$62.28	$68.96	$68.96	$68.96
Gross Up (%)	4%	11%	7%	6%	4%	9%	10%	11%	10%	9%	7%	8%
Shaped Energy ($ / MWh)	$81.69	$87.21	$70.02	$69.03	$62.83	$68.88	$76.30	$77.00	$68.20	$74.82	$73.78	$74.13
Capacity ($ / MWh)	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Ancillary ($ / MWh)	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
RECs ($ / MWh)	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
Total Rate ($ / MWh)	$97.69	$103.21	$86.02	$85.03	$78.83	$84.88	$92.30	$93.00	$84.20	$90.82	$89.78	$90.13
Load (MWh)	375,714	329,604	341,612	283,764	291,208	375,872	472,194	388,716	324,172	301,542	327,487	381,201
Forecasted Supply Cost ($ / MWh)	$89.97 ($ / MWh)											
Actual Supply Costs												
ATC Energy ($ / MWh)	$94.71	$94.71	$78.52	$78.52	$72.85	$75.83	$83.24	$83.24	$74.74	$82.75	$82.75	$82.75
Gross Up (%)	4%	12%	8%	6%	4%	10%	11%	12%	10%	9%	8%	8%
Shaped Energy ($ / MWh)	$98.36	$105.65	$84.57	$83.27	$75.65	$83.33	$92.39	$93.31	$82.55	$90.48	$89.12	$89.57
Capacity ($ / MWh)	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00	$10.00
Ancillary ($ / MWh)	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
RECs ($ / MWh)	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00	$3.00
Total Rate ($ / MWh)	$114.36	$121.65	$100.57	$99.27	$91.65	$99.33	$108.39	$109.31	$98.55	$106.48	$105.12	$105.57
Load (MWh)	394,499	346,084	358,693	297,953	305,768	394,665	495,803	408,152	340,381	316,619	343,861	400,261
Actual Supply Cost ($ / MWh)	$105.41 ($ / MWh)											
Supply Cost Surprise ($ / MWh)	$15.44 ($ / MWh)											
Supply Cost Surprise (%)	+17% (%)											

[1] Forecast is for a twelve-month period as of three months prior. While not shown, the supply cost surprise is calculated to ensure an expected surprise of zero.

Note: When the metric for supply cost surprise is expressed in terms of $MM, the calculation is performed by multiplying the $/MWh supply cost surprise by the actual SOS load.

Supply Cost Surprise Risk

- In this case, the supply cost surprise was +17%. This means the cost per MWh of SOS supply was 17% greater than had been forecasted
- We perform this same calculation in each scenario and create a distribution of supply cost surprise:



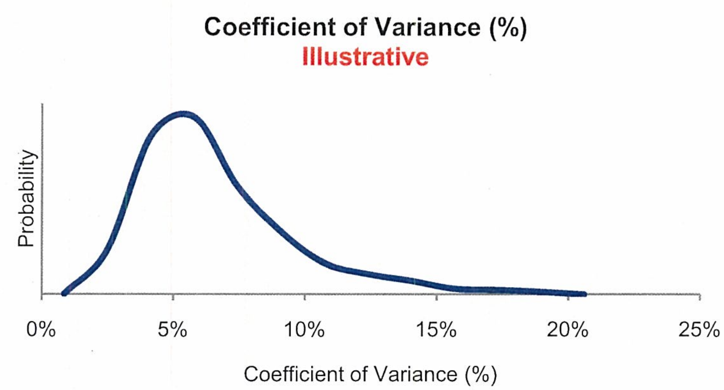
Coefficient of Variance

- The coefficient of variance is a metric used by the New York PSC and relates to the volatility of the SOS rate measured on a monthly scale over the prior 12 months:

Illustrative Coefficient of Variance Calculation

Delivery Month	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
SOS Rate (¢ / KWh)	7.74	8.04	7.94	8.65	7.81	8.09	7.96	8.37	9.96	10.40	9.36	8.85
Standard Deviation of Rate (¢ / KWh)	0.74											
Average Rate Level (¢ / KWh)	8.60											
Coefficient of Variance (%)	**8.6%**											

- This statistic is calculated in each scenario, allowing us to create a distribution of values:

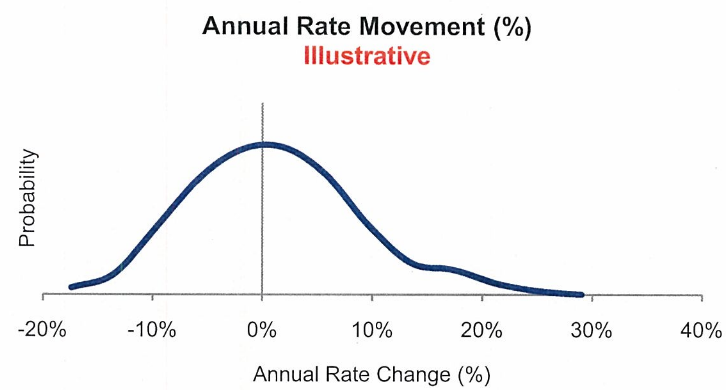


- A variant of the coefficient of variance involves looking at the volatility of year-over-year rate movements:

Illustrative Annual Rate Movement Calculation

Scenario	2013 Rate[1]	2014 Rate[1]	Delta
1	$73.44	$85.51	16.4%
2	$79.97	$84.16	5.2%
3	$76.96	$82.44	7.1%
4	$83.57	$73.11	-12.5%
5	$65.62	$69.12	5.3%
6	$73.08	$75.07	2.7%
7	$77.88	$78.63	1.0%
8	$81.64	$84.54	3.6%
…	…	…	…
2,000	$71.93	$80.77	12.3%

- This statistic is calculated in each scenario, allowing us to create a distribution of values:



[1] Monthly SOS rate is weighted by total eligible load to determine the average rate a customer would face during the year.

Deferral Account Balance

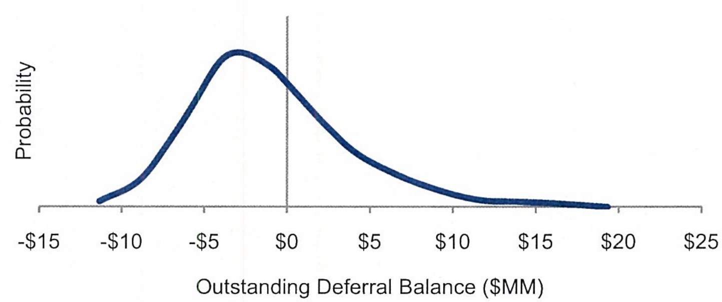
➢ The deferral account balance metric measures the size of the balance sheet item tracking the accumulated over/under level of cost recovery:

Illustrative Deferral Balance Calculations

Month	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14
SOS Rate Revenues ($MM)	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0	$30.0
Deferral Rider ($MM)			-$0.4	$0.1	$1.7	-$2.5	$1.6	$3.8	-$0.4	-$2.9	$2.7	$1.2
Actual Costs ($MM)	$29.6	$30.1	$31.3	$27.6	$33.3	$31.3	$31.3	$30.9	$32.3	$28.3	$32.2	$29.7
Under / (Over) ($MM)	-$0.4	$0.1	$1.7	-$2.5	$1.6	$3.8	-$0.4	-$2.9	$2.7	$1.2	-$0.5	-$1.5
Interest ($MM)	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Deferral Balance ($MM)	-$0.4	-$0.4	$1.3	-$1.1	$0.5	$4.3	$3.9	$1.1	$3.8	$5.0	$4.5	**$3.1**

➢ This statistic is calculated in each scenario, allowing us to create a distribution of values

Outstanding Deferral Balance EOY 2014 ($MM) Illustrative



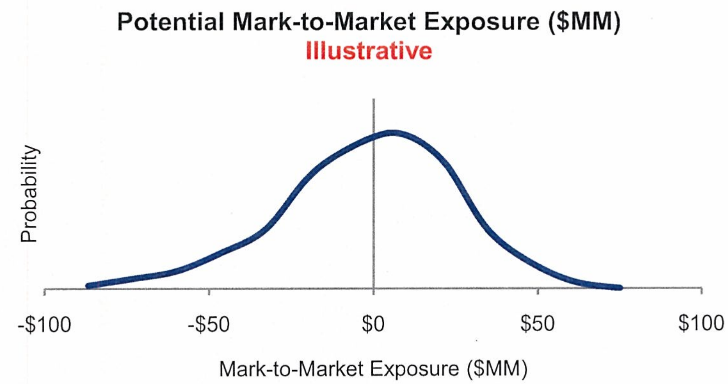
Note: Interest of 6% accrues on deferral balances.

- Mark-to-market exposure indicates how far fixed-quantity commitments are out-of-market, and may be relevant for collateral requirements on block energy products:

Illustrative Mark-to-Market Exposure[1]

Scenario	PV of Payments at Initial Mark	PV of Payments at Market Price	Potential Exposure
1	$11.0	$10.4	$0.6
2	$9.8	$9.9	-$0.1
3	$9.0	$10.3	-$1.3
4	$8.8	$9.4	-$0.6
5	$8.7	$8.8	$0.0
6	$9.5	$9.6	-$0.2
7	$9.5	$8.2	$1.3
8	$8.6	$11.0	-$2.4
…	…	…	…
2,000	$10.2	$9.1	$1.1

- This statistic is calculated in each scenario, allowing us to create a distribution of values:



[1] Mark-to-market exposure can change over the course of the year. Therefore, this metric is calculated by identifying the month during which the average top decile exposure is greatest and then examining the mark-to-market exposure during that month. The calculation involves application of a discount rate of 10%.