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August 1, 2012

Kimberley J. Santopietro
Executive Secretary
Public Utilities Regulatory Authority
10 Franklin Square
New Britain, CT 06051

Re: **Docket No. 12-06-02: Request for PURA Review of Power Procurement Plan**

Dear Ms. Santopietro:

Enclosed please find the Comments of the Retail Energy Supply Association in connection with the above-referenced matter.

I certify that a copy hereof has been sent to all participants of record as reflected on the Public Utilities Regulatory Authority's (Authority) service list as of this date. A copy has also been filed with the Authority as an electronic web filing and is complete.

Please do not hesitate to contact me if you have any questions or require additional information. Thank you.

Very truly yours,

JL Miranda

Joey Lee Miranda

Enclosure

Copy to: Service List

STATE OF CONNECTICUT

PUBLIC UTILITIES REGULATORY AUTHORITY

REQUEST FOR PURA REVIEW OF POWER PROCUREMENT PLAN	:	DOCKET NO. 12-06-02
	:	AUGUST 1, 2012

COMMENTS OF THE
RETAIL ENERGY SUPPLY ASSOCIATION

The Retail Energy Supply Association ("RESA")[1] hereby submits initial comments in response to the Public Utilities Regulatory Authority's ("Authority") Notice of Proceeding and Request for Written Comments, dated July 19, 2012 ("Notice"), in the above-captioned proceeding. As discussed more fully below, RESA requests that the Authority reject the option of allowing The Connecticut Light and Power Company ("CL&P") to engage in active portfolio management for any portion of its Standard Service load requirements.

BACKGROUND

During the 2011 legislative session, the Connecticut General Assembly passed Public Act 11-80, *An Act Concerning the Establishment of the Department of Energy and Environmental Protection and Planning for Connecticut's Energy Future* (the "Act"). Section 92 of the Act requires the Department of Energy and Environmental Protection's ("DEEP") Power Procurement Manager ("Manager") to "develop a plan for the procurement of electric generation services and related wholesale electricity market products that will enable each electric

[1] RESA's members include: Champion Energy Services, LLC; ConEdison *Solutions*; Constellation NewEnergy, Inc.; Direct Energy Services, LLC; Energetix, Inc.; Energy Plus Holdings LLC; Exelon Energy Company; GDF SUEZ Energy Resources NA, Inc.; Green Mountain Energy Company; Hess Corporation; Integrys Energy Services, Inc.; Just Energy; Liberty Power; MC Squared Energy Services, LLC; Mint Energy, LLC; NextEra Energy Services; Noble Americas Energy Solutions LLC; PPL EnergyPlus, LLC; Reliant; Stream Energy; TransCanada Power Marketing Ltd. and TriEagle Energy, L.P.. The comments expressed in this filing represent the position of RESA as an organization but may not represent the views of any particular member of RESA.

distribution company to manage a portfolio of contracts to reduce the average cost of standard service while maintaining standard service cost volatility within reasonable levels"[2] Pursuant to Section 92 of the Act:

> Each procurement plan ***shall*** provide for the competitive solicitation for load-following electric service and ***may*** include a provision for the use of other contracts, including, but not limited to, contracts for generation or other electricity market products and financial contracts, and ***may*** provide for the use of varying lengths of contracts. If such plan includes the purchase of full requirements contracts, it shall include an explanation of why such purchases are in the best interests of standard service customers.[3]

Pursuant to Section 91 of the Act:

> Such plan shall require that the portfolio of service contracts be procured in such manner and duration as the authority determines to be ***most likely*** to produce ***just, reasonable and reasonably stable retail rates while reflecting underlying wholesale market prices over time***. The portfolio of contracts shall be assembled in such manner as to invite competition; guard against favoritism, improvidence, extravagance, fraud and corruption; and secure a reliable electricity supply while ***avoiding unusual, anomalous or excessive pricing***.[4]

On June 1, 2012, pursuant to Section 92 of the Act, the Manager submitted a proposed Power Procurement Plan for Standard Service ("Plan") for review and approval.[5] The Plan establishes the following procurement strategies for The United Illuminating Company ("UI"): For the remaining 30% of its 2013 Standard Service load, UI will continue to procure full requirements service ("FRS") in accord with its usual practice. However, the procurement will be for twelve (12) month contracts for ten percent (10%) tranches to be procured quarterly, creating a portfolio of overlapping service terms, with the start of delivery not exceeding six (6) months from bid day. The Manager, in consultation with UI, may revise the number of tranches

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[2] P.A. 11-80 at § 92(a).

[3] *Id.* (emphasis added).

[4] P.A. 11-80 at § 91(c)(3) (emphasis added).

[5] *See, generally,* State of Connecticut Power Procurement Plan for Standard Service, dated June 1, 2012.

per service term (or the percentage of load per tranche) in the future if the total Standard Service load changes significantly due to migration or reverse migration.[6]

The Plan further "recommends that CL&P continue to procure full requirements Standard Service . . . ."[7] However, it also gives CL&P the option to propose to serve as the load-serving entity ("LSE") and to engage in active portfolio management for up to twenty percent (20%) of its Standard Service load for 2013.[8] The portfolio for that portion of CL&P's Standard Service load that is not self-managed will be procured in the same manner as described for UI.[9]

On July 16, 2012, the DEEP Commissioner delegated his authority to review and approve the Plan to the Authority.[10] On July 19, 2012, the Authority issued the Notice offering interested persons an opportunity to submit written comments on the Plan, including without limitation:

- Whether the proposed Plan will enable each electric distribution company to manage a portfolio of contracts to reduce the average cost of standard service while maintaining standard service cost volatility within certain reasonable levels;
- Whether the proposed Plan will provide for the competitive solicitation for load-following electric service; and
- Whether the proposed Plan makes appropriate use of other contracts, including but not limited to, contracts for generation or other electricity market products and financial contracts and contracts of varying lengths.[11]

RESA hereby submits its comments in response to the Notice.

COMMENTS

While RESA acknowledges that it is prudent practice to periodically review the State's approach to Standard Service procurement, in doing so, the Authority should determine first

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[6] Plan at 111-12.

[7] Plan at 113.

[8] *Id.*

[9] Plan at 113-16.

[10] *See, generally,* July 16, 2012 Revision to the July 12, 2011 Delegation of Authority.

[11] *See* Notice at 1.

what precipitated its review and then, if it determines changes are necessary, evaluate what changes will best achieve the State's energy goals. In evaluating what is precipitating the review, RESA urges the Authority to be careful not to mistake changes in market prices for deficiencies in current procurement practices. Further, to the extent the Authority determines that market changes warrant changes to the procurement process, it should ensure that whatever changes are made are designed to maximize market participation, provide accurate price signals and avoid passing unnecessary risk onto ratepayers.

Generally, consumers realize the best results possible by having all their Standard Service load procured through competitive, fully transparent requests for proposals in the wholesale market because this procurement mechanism maximizes the opportunity for market participation, provides the most accurate price signals and avoids forcing Connecticut ratepayers to shoulder risks that are better managed by the competitive market. Conversely, allowing the EDCs, who have not shown that they are in a better position to serve this function than the wholesale suppliers currently doing so, to self-manage their load would reduce market participation, add potential stranded costs and send distorted price signals to customers. Thus, rather than making wholesale changes to procurement strategies in response to market changes, the Authority should approve modifications to the timing, frequency, duration and layering of the procurements that will allow consumers to receive the benefits of positive market changes without the need for increased risks to ratepayers and adverse effects on the competitive market.

RESA appreciates the Plan's recognition that a modified FRS procurement strategy (as proposed for UI and recommended for CL&P) provides a proper balance between the goal of obtaining the most competitive prices for consumers and maintaining a reasonable level of price stability. However, RESA urges the Authority to reject the Plan's option to allow CL&P to actively manage up to twenty (20%) percent of its 2013 Standard Service load ("Managed Portfolio") because such an approach will impose added risks and costs on ratepayers and adversely affect the competitive retail market for electricity. In particular, under a Managed Portfolio approach, the following risks and costs will all be ***higher***: (a) risks of mistakes/bad market outcomes; (b) risk of supply cost surprises (a/k/a rate shock); (c) deferral account balances; (d) costs and risks associated with uncertainty regarding capacity, ancillary services and renewable portfolio standards; and (e) internal EDC resource costs.[12]

I. FRS PROCUREMENTS ARE IN THE BEST INTEREST OF STANDARD SERVICE CUSTOMERS

Pursuant to the Act, if the Plan "includes the purchase of full requirements contracts, it shall include an explanation of why such purchases are in the best interests of standard service customers."[13] An FRS structure is in the best interests of Standard Service customers because it avoids: (1) excess supply costs that will cause upward pressure on Standard Service rates; (2) cost shifting from Standard Service customers to switched customers; and (3) the imposition of costs on customers for supply they neither want nor need.

FRS products relieve EDCs, such as CL&P, from active load, weather and market volatility management responsibility and, in turn, relieve such EDCs 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.

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[12] *See Analysis of Standard Offer Service Approaches for Mass Market Customers*, prepared for National Grid re: RI PUC Order #19839, dated January 2010 ("NorthBridge Study"), at 13.

[13] P.A. 11-80 at § 92(a).

At the direction of the Rhode Island Public Utilities Commission ("RI PUC"), National Grid performed an empirical study comparing default service approaches for mass market customers, including a comparison of the FRS structure to the Managed Portfolio model.[14] 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. The analysis also 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. Based on these evaluations and looking at a wealth of actual data, the NorthBridge Study found 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; and requires fewer EDC internal resources.

Under the Managed Portfolio approach, the results of CL&P's power purchase decisions, good or bad, are passed onto its Standard Service customers through its periodic Standard Service rate adjustments. By contrast, under the FRS approach that the Plan recommends, FRS 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 Standard Service customers when market conditions change and the effects of customer migration impact their total cost of supply. Conversely, the Managed Portfolio approach would leave CL&P with the risk that, as power prices fall and customers leave Standard Service, CL&P (and, ultimately, Standard Service customers) will be

[14] *See generally,* NorthBridge Study.

left holding purchased power supply in excess of Standard Service load requirements; thereby, unnecessarily increasing the cost of supply to those customers that remain on Standard Service. The oversupply can be resold in the market, but if prices have fallen, it will have to be sold at a loss. Under a FRS Structure, the wholesale supplier bears any such loss; under a Managed Portfolio approach, the ratepayers incur such a loss.

Moreover, requiring CL&P to expend resources to actively manage an energy portfolio is an inefficient way to achieve competitive Standard Service prices for consumers. As CL&P'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, CL&P must have the expertise to 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 EDC employees – provides the most cost-effective method of Standard Service 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 Standard Service products in the requests for proposals. 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 Standard Service supply.

Under the FRS procurement model, the FRS provider assumes one hundred percent (100%) of the risk should the all-in price be too high and/or 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 wholesale supplier in the event that the all-in price is too low. By contrast, under a Managed Portfolio approach, when customers migrate to competitive retail suppliers, a small number of Standard Service customers are left to pay the stranded costs associated with the EDCs' procurement and hedging activities.

In addition, under the FRS model, a customer has an all-in fixed price rate against 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 EDC trues-up its rate against its actual costs to serve.

Since FRS procurements are "most likely to produce just, reasonable and reasonably stable retail rates while reflecting underlying wholesale market prices over time" and will "invite competition; guard against favoritism, improvidence, extravagance, fraud and corruption; and secure a reliable electricity supply while avoiding unusual, anomalous or excessive pricing," they are in the best interest of ratepayers.[15] Thus, the Authority should approve the modified FRS procurement strategy (as proposed for UI and recommended for CL&P) and reject the Plan's option to allow CL&P to undertake a Managed Portfolio approach.

II. A MANAGED PORTFOLIO APPROACH WILL LIKELY LEAD TO HIGHER RISKS AND INCREASED COSTS TO CONNECTICUT RATEPAYERS

Today, the full requirements suppliers manage and price certain financial risks: principally, energy prices, load growth, weather variation and customer switching. According to

[15] *Cf.* P.A. 11-80 at § 91(c)(3).

the Plan, FRS contracts promote retail rate stability but do so at added cost.[16] In particular, the Plan finds that FRS includes risk management costs for hedging price and quantity risks as well as other financial and administrative costs.[17] However, as the Plan recognizes "a ***significant*** portion of the risk-management and credit cost components can be ***avoided*** when the service term begins less than 12 months following the contract award date."[18] Based on this, the Plan revises the current full requirements procurement process to procurements of twelve (12) month contracts for ten percent (10%) tranches procured quarterly with overlapping service terms with the start of delivery not to exceed six (6) months from bid day.[19] However, the Plan goes further and finds, without supporting evidence, that "[o]ne approach to achieving additional cost savings relates to the EDCs' potential self-management of a portion of the Standard Service portfolio."[20]

Stripped to its core, the essential claim of those advocating change is that given the opportunity, the EDCs can manage their portfolios in a manner that will be cheaper for ratepayers than the current procurement process. In essence, the claim of advocates for change amounts to little more than "if you give us the chance, we will derive better results." Yet, this purported hypothesis is unsupported by little more than conclusory assertions as to potential benefits. In fact, the Plan provides no detail on how CL&P could potentially achieve cost savings; rather, it leaves to CL&P the discretion to prepare an active portfolio management

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[16] Plan at 22 (indicating that the wholesale suppliers' risk management/hedging, credit, administrative costs and profits constitute roughly 8% of the total cost of FRS).

[17] Plan at 19.

[18] *Id.* (emphasis added).

[19] Plan at 7.

[20] Plan at 6.

proposal without further opportunity for public input, including input from wholesale suppliers who engage in such activities on a regular basis.[21]

Under a Managed Portfolio procurement model, the EDCs piece 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. There is no evidence that the EDCs are able to disaggregate the elements of all requirements, load following service, acquire those elements separately, and reassemble the elements into a deliverable load following service more efficiently than the wholesale suppliers currently performing that function. Additionally, under the Managed Portfolio model, the EDCs 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. There is also no evidence to support a finding that the EDCs can perform this function any better than wholesale suppliers.

In fact, the Plan recognizes that allowing the EDCs to assume the LSE role "must take into consideration the ***additional*** costs of investments that are required to manage a portfolio of resources, which would otherwise be the responsibility of the full requirements service supplier."[22] Under the FRS Structure, competitive wholesale providers manage those functions, relieving the EDCs and their customers from the risks and costs inherent in such an approach. While FRS contracts include the cost of energy portfolio management, credit and administrative costs of making forward and other derivative transactions, the costs of trading with bilateral and

[21] Plan at 116-17 (requiring that, prior to procuring any products under a Managed Portfolio, CL&P submit a portfolio management plan to the Manager for his approval).

[22] Plan at 105 (emphasis added).

exchange counterparties, and setting aside capital or credit capacity to meet ISO New England ("ISO-NE") and/or other counterparty requirements,[23] all of those same costs will be incurred by CL&P if it undertakes a Managed Portfolio approach.

As the Plan recognizes, allowing the EDCs to engage in active portfolio management creates "staffing requirements, infrastructure costs, and a need to develop and implement policies and procedures for front-office, middle-office, and back-office functions."[24] In particular, "[a]ctively managing Standard Service load requires an LSE to have the capability and resources to forecast, bid and schedule load each day with ISO-NE, and to develop and implement hedging strategies."[25] Based on the increased cost associated with these functions alone, the Plan does not recommend that UI engage in a Managed Portfolio approach.[26] Nevertheless, the Plan finds that "there would be little incremental cost for NUSCO to also provide the LSE function to CL&P."[27] While it may be true that ***NUSCO's*** incremental costs may not increase significantly, the costs that Connecticut ***ratepayers*** pay for these services could increase substantially as employee and overhead costs that are currently allocated entirely to Public Service Company of New Hampshire's ("PSNH") customers are reallocated to and imposed on Connecticut Standard Service customers.

There will also be added costs associated with Dodd-Frank compliance, a marked increase in ISO-NE credit assurance, credit support and other indirect costs (e.g., unfavorable

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[23] Plan at 71.

[24] Plan at 73.

[25] Plan at 106.

[26] Plan at 111-12 (finding that "the incremental cost for UI to add the requisite manpower resources, credit facilities, infrastructure, and risk management policies and procedures to assume the LSE responsibility for Standard Service is likely to exceed the expected benefit . . . .")

[27] Plan at 106.

accounting impacts, etc.).[28] In fact, the Plan specifically recognizes that as the LSE, "a number of rigid credit requirements would also apply to the EDCs."[29] Additionally, long-term contracts with unregulated generators would likely entail significant counterparty credit risks and collateral costs. For instance, depending on the agreement and counterparty, the EDCs may be required to consolidate the financials of the counterparty into the EDCs' financial reporting. This consolidation can lead to increased ratepayer costs.[30] However, these costs are not quantified, which could have significant impact on the costs of a Managed Portfolio, in the Plan.

Moreover, as the Plan recognizes, CL&P will be required to engage in risk management through hedging to reduce the exposure to market price, quantity, and regulatory risk and "the cost of hedging necessarily adds to the expected cost of the hedged portfolio."[31] Indeed, in order to procure power in the wholesale market, the EDCs would be required to employ staff to monitor energy markets and then make decisions as to 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. The EDCs would be required to 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. The EDCs would also enter into derivative transactions, fuel hedges and other financial swaps or hedging agreements, as well as spot purchases as necessary, to meet their actual requirements. The EDCs' staff would need to

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[28] Plan at 107-09.

[29] Plan at 13.

[30] *See, generally, DPUC Investigation into the Financial Impact of Long-Term Contracts on Electric Distribution Companies*, Final Decision, dated December 28, 2005.

[31] Plan at 70.

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. These are high risk, complex decisions, the costs of which are ultimately borne by customers. Indeed, as the Plan recognizes: (a) load-following energy products are high cost products and would require load management resources that are otherwise avoidable; (b) block forward energy products cannot be one hundred percent (100%) hedged and impose ISO-NE credit assurance requirements; (c) indexed block forward energy products offer limited value compared to other products; (d) dispatchable energy products involve a premium payment and could result in unfavorable accounting impacts and increased direct and indirect costs; and (e) other options and derivatives require rigorous assessment to determine their usefulness.[32] These hedging costs are currently borne by wholesale suppliers, not ratepayers.

The most significant risk from putting the EDCs into the active portfolio management role is the possibility that they will assemble a portfolio that becomes "above market" or "out of the money." That is, the average cost to supply customers from the portfolio is higher than the cost to serve those customers at the prevailing wholesale market price. In any given hour, if the power from any contracts CL&P enters into is less than its customers' requirements, CL&P has to make "spot" purchases of power from the market. ISO-NE will charge CL&P the hourly clearing (spot) price for these additional last-minute purchases. If CL&P 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. CL&P 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 CL&P incurs additional costs because it buys

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[32] *See* Plan at 73-78.

additional power at the spot price or because it is unable to recover the full cost of any excess power it has under contract, those costs would be passed onto CL&P customers.

Lastly, supplementing FRS procurement could create a problem with load shaping that could increase the costs associated with procuring the balance of Standard Service load that continues to be procured through FRS. To the extent the EDCs supply Standard Service customers directly, the residual quantity to be served by full requirements suppliers could be more uncertain, and would be reduced and likely have a lower load factor – because some of the base demand is now supplied by EDC purchases. A lower load factor will generally translate to higher prices in the competitive FRS solicitation.

There is simply no basis upon which to believe that the EDCs can obtain results that exceed those currently derived. Indeed, the empirical evidence would suggest otherwise. Prior to restructuring, the EDCs' customers bore the risk of uneconomic decisions, which resulted in billions of dollars in stranded costs that are still being recovered from ratepayers today and will be for years to come.[33] As a consequence, one of the primary rationales for the restructuring of the electric industry in the State of Connecticut was to remove the risk of uneconomic investment from ratepayers and place it on the shareholders of market players.

Post-restructuring, the EDCs have not performed any better. For instance, NUSCO's purchases on behalf of PSNH, from 2006 through July 2010, were estimated to be above-market

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[33] *See* Docket No. 99-02-05, *Application of The Connecticut Light and Power Company for Calculation of Stranded Costs*, Final Decision, dated July 7, 1999, at 83 (finding that CL&P's stranded costs were $3,582,126,000); Docket No. 99-03-04, *Application of the United Illuminating Company for Calculation of Stranded Costs*, Final Decision, dated August 4, 1999, at 75 (finding that UI's stranded costs were $801,300,000); Docket No. 99-03-35RE13, *DPUC Determination of the United Illuminating Company's Standard Offer – 2006 Reconciliation of CTA and SBC*, Final Decision, dated August 29, 2007, at 3 (finding that UI will not collect all of its stranded costs until 2015).

by $233,585,606 or around ***28 percent*** of total purchases ($839,128,484).[34] Clearly, NUSCO has failed over the last several years to match, let alone beat, the market in making its purchasing decisions and there is no reason to believe that NUSCO's future results will improve. Under a Managed Portfolio approach, the costs associated with such poor trading decisions are passed onto ratepayers.

As customer migration increases, these cost impacts become exacerbated. As the Plan recognizes, there has been significant migration of Standard Service customers to competitive supply.[35] Indeed, as of June 30, 2012, in the CL&P service territory, 45.4% of residential customer load and 82.9% of Standard Service business load has switched to competitive supply.[36] As customers migrate off of Standard Service to competitive supply, the remaining Standard Service customers are exposed to upward pressure on the Standard Service rate.[37] This problem does not occur with the FRS approach because migration costs are managed by the wholesale FRS suppliers through the bidding process, relieving the upward pressure on Standard Service rates.

It is difficult to see how Standard Service customers will come out ahead in the long run, relative to the current policy of exclusive FRS procurement. Thus, RESA encourages the

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[34] *See* New Hampshire Public Utilities Commission, Docket No. DE 10-160, *Investigation into Effect of Customer Migration on Energy Service Rates*, Direct Testimony of Daniel W. Allegretti on Behalf of Constellation NewEnergy, Inc., Constellation Energy Commodities Group, Inc. and Retail Energy Supply Association, dated September 15, 2010, at 8-9 (*citing* PSNH Response to Data Request Q-STAFF-002).

[35] Plan at 59 (finding that, as of December 2011, 44% of CL&P residential customers and 81% of CL&P Standard Service eligible business customers have switched to competitive supply). RESA believes that the Plan should refer to "load" rather than "customers." *See* Docket 06-10-22, *DPUC Monitoring of the State of Competition in the Electric Industry*, December 2011 CL&P Report (indicating that, in the CL&P service territory, 44.2% of residential customer load and 81.4% of Standard Service eligible business load had switched to competitive suppliers).

[36] *See* PURA Docket 06-10-22, *DPUC Monitoring of the State of Competition in the Electric Industry*, June 2012 CL&P Report.

[37] P.A. 11-80 at § 92(c) ("[t]he costs of procurement for standard service shall be borne solely by the standard service customers.").

Authority to continue the existing FRS paradigm in Connecticut (as modified by the Plan) in which competitive providers concentrate on what they do best - providing market based generation supply options - and the EDCs concentrate on what they do best - providing reliable and cost effective transmission and distribution services. Accordingly, RESA requests that the Authority reject the Plan's option for allowing CL&P to engage in a Managed Portfolio approach for any portion of its Standard Service load.

III. A SHIFT TO ACTIVE PORTFOLIO MANAGEMENT BY THE EDCS WOULD NOT SEND CUSTOMERS PROPER PRICE SIGNALS

The current Standard Service FRS procurement process means that customers are presented with a true fixed price for their power. Such would not be the case were a Managed Portfolio approach implemented. Indeed, as the Plan recognizes, under a Managed Portfolio structure, the true-up of retail rates from one rate period to the next may be small or large.[38]

Under the Managed Portfolio approach, the EDCs' customers would pay Standard Service rate that is based on a forecast of the EDCs expected cost. The difference between the forecasted costs and actual costs, once known, would be charged or credited to customers after the period for which those costs were incurred. This reconciliation process means that the EDCs' Standard Service rates, at any point in time, would be higher or lower than the actual cost for that period. As a consequence, although customers would be told that they are purchasing energy at a fixed price; that is not really the case. If customers stay on the EDCs' systems, they would actually be charged a rate that appears fixed but has a hidden variable component that is added to the true cost of providing service during the subsequent reconciliation period.

The EDCs would also be required to forecast their retail customers' load on an hourly basis and factor in the extent to which retail customers may switch to competitive retail suppliers

[38] Plan at 73.

or back to Standard Service from competitive suppliers throughout the year based on changes in market prices, the price of the EDCs' energy service and other factors. Obviously, it is impossible for the EDCs to correctly forecast all of the factors that go into determining the quantity and cost of its purchased power requirements. As a result, the EDCs would have to periodically tally up the cost of the hourly imbalances incurred 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 the EDCs' rates for changes in their actual costs for the coming period. Conversely, by entering into contracts with third party suppliers for all of the EDCs' Standard Service requirements, customers are presented with a true fixed price for their power, insulating them from price risk. The result is that out-of-period reconciliations are minimized.

Reconciliations undermine the State's conservation and energy efficiency goals. Only when customers know the true cost of their power supply can they make appropriate decisions regarding demand response and energy efficiency modifications to better manage their electricity consumption and costs. Conversely, if customers do not know the true cost of their power supply, they are discouraged from adopting new solutions to meet their energy needs.

Reconciliations are also harmful to the development of a competitive retail market because they distort the relationship between the EDCs' 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 were not responsible for generating those credits or creating those charges in the first place.

Thus, in order to ensure that customers are presented with the true cost of their power supply options, with the need for minimal reconciliations, the Authority should approve the modified FRS procurement strategy (as proposed for UI and recommended for CL&P) and reject the Plan's option to allow CL&P to undertake a Managed Portfolio approach.

IV. A MOVE TO A MANAGED PORTFOLIO APPROACH WOULD MAKE A DETERMINATION AS TO THE PRUDENCE OF DECISIONS VIRTUALLY IMPOSSIBLE TO MEASURE

Because the EDCs' decision-making processes are not transparent, a change in the Standard Service procurement methodology would make it is nearly impossible for the Authority to conduct a meaningful review of the costs incurred by each EDC in the wholesale market. Consequently, it would not be realistic to expect the Authority to be able to assess the prudence of the EDCs' conduct.

In order to attempt to minimize the cost of purchased power to customers, the EDCs would need to 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 customers and forecasts for market prices. In any given hour, if the power from the contracts that the EDCs have entered into is less than customer requirements, the EDCs would have to make "spot" purchases of power from the market. In such cases, ISO-NE will charge the EDCs the hourly clearing (spot) price for these additional last-minute purchases. If the EDCs enter into contracts for more power than needed at any point in time, the excess power can be sold into the market at the hourly clearing price. The EDC 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 the EDCs incur additional costs because they buy additional power at the spot price or because they are unable to recover the full cost of any excess power under contract, those costs will be passed onto customers.

While it is theoretically possible that the Authority could require that such costs be borne by the EDCs' shareholders, the Authority can only 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 Authority to fully understand the information available to the EDCs at the time they made each decision at issue. This process puts the Authority in the position of essentially trying to second guess the EDCs' 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 Authority to comb through 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 were not, hedging mechanisms and other data. Such a review effectively requires the Authority to have available all of the same real time information that was available to the EDCs, much of which is in the EDCs' possession or control.

In sum, the many transactions entered into by the EDCs and the situation confronting them when they entered into each transaction are not transparent to the Authority. The result is that the Authority would face a serious challenge in attempting to review the EDCs' power procurement decisions in any meaningful way. Conversely, maintenance of third party supply for Standard Service requirements provides a vehicle by which the Authority can ensure that the EDCs are obtaining their market purchases at the lowest reasonable cost. Thus, the Authority should approve the modified FRS procurement strategy (as proposed for UI and recommended for CL&P) and reject the Plan's option to allow CL&P to undertake a Managed Portfolio approach.

CONCLUSION

Since, for all the reasons discussed above, an FRS structure is in the best interests of Standard Service customers, the Authority should approve the modified FRS procurement strategy (as proposed for UI and recommended for CL&P) and reject the Plan's option to allow CL&P to undertake a Managed Portfolio approach for any portion of its load. RESA appreciates the Authority undertaking this review and looks forward to discussing these issues in more detail during the course of this proceeding.

Respectfully submitted,
RETAIL ENERGY SUPPLY ASSOCIATION

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CERTIFICATION

I hereby certify that a copy of the foregoing was sent via electronic mail or first-class mail, postage pre-paid to all participants of record, on this 1st day of August 2012.

JL Miranda

Joey Lee Miranda