STATE OF NEW HAMPSHIRE

BEFORE THE

PUBLIC UTILITIES COMMISSION

DOCKET NO. DE 14-238

2015 PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE RESTRUCTURING AND RATE STABILIZATION AGREEMENT

REBUTTAL TESTIMONY OF JAMES R. SHUCKEROW

November 19, 2015

INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position, employer and address.

A. My name is James R. Shuckerow. I am the Director, Electric Supply for Eversource Energy Service Company. My business address is 107 Selden Street, Berlin, Connecticut.

Q. Please provide a brief summary of your background.

A. I received a B.S. in Mechanical Engineering from Purdue University and an MBA from University of Connecticut. I joined Northeast Utilities, now Eversource Energy, in 1979.

Q. Have you ever testified before the New Hampshire Public Utilities Commission (NHPUC or Commission) or any other regulatory agency?

A. Yes. I have provided testimony before the Connecticut Department of Public Utility Control, the Connecticut Public Utility Regulatory Agency, the Connecticut Siting Council, the Massachusetts Department of Public Utilities and the Federal Energy Regulatory Commission, as well as before this Commission.

Q. Please describe your responsibilities as Director, Electric Supply.

A. In my present position as Director, Electric Supply, my responsibilities include procurement of wholesale power supply contracts for Eversource customers in Connecticut and Massachusetts who have not selected retail power supply, contracting for renewable power, and dispatch and scheduling of PSNH's generation resources.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut the recommendations made in the September 18, 2015, prefiled direct testimony of Richard A. Norman on behalf of the Granite State Hydropower Association ("GSHA") concerning the establishment of the proper avoided cost under the Public Utility Regulatory Policies Act ("PURPA") which PSNH would have to pay qualifying facilities ("QFs") that put their generating output to PSNH. My testimony also rebuts Mr. Norman's supplemental prefiled testimony dated November 12, 2015.

Q. Please provide an overview of your testimony in this proceeding.

A. My testimony will demonstrate that for both the "hybrid" (near-term until divestiture) and "generic" (post-divestiture) periods as set forth in Mr. Norman's testimony, the proper avoided cost that QFs are entitled to receive under PURPA is the price that PSNH presently pays, which is the ISO-NE real time energy market price; i.e., the locational marginal price as the term is used in ISO-NE which has three components: energy, loss and congestion.

Q. What is PURPA?

A. PURPA is the Public Utility Regulatory Policies Act of 1978, as amended. For purposes of this docket, I will only be discussing the portions of PURPA that relate to the requirement that utilities must purchase the output from QFs at avoided cost rates established by the appropriate state regulatory agency. Section 210 of PURPA is captioned "Cogeneration and Small Power Production." Section 210 required the Federal Energy Regulatory Commission ("FERC") to establish rules regarding QFs which in relevant part would "require electric utilities to offer to – (2) purchase electric energy from such facilities." PURPA §210(a)(2). PURPA further required that the rates established for purchase of QF output by utilities had to be "just and reasonable to the electric consumers of the electric utility and in the public interest." PURPA §210(b). PURPA also requires that the purchase price established by the state regulator shall not exceed "the incremental cost" to the utility. *Id.*

Q. Did FERC ever promulgate the rules required by PURPA Section 210?

A. Yes. FERC's QF regulations are found at 18 CFR, Part 292, "Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 With Regard to Small Power Production and Cogeneration."

Q. Are there portions of the FERC PURPA rules relevant to your testimony?

A. Yes.

18 CFR 292.101(b)(1) defines "qualifying facility." For purposes of this proceeding, I do not think there is any dispute over which generators are QFs under PURPA.

18 CFR 292.101(b)(6) defines "avoided cost" – "Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."

18 CFR 292.301(b)(1) allows "any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart." It is this authority that allows power purchase agreements such as those PSNH has with the Lempster Wind and the Burgess Biopower facilities.

18 CFR 292.303(a) requires electric utilities to purchase the output from QFs, regardless of whether a QF is directly interconnected with that utility or whether the output is transmitted to that utility.

18 CFR 292.304 regulates the rates that utilities must pay QFs. That regulation begins by stating:

> § 292.304 Rates for purchases.
>
> (a) Rates for purchases.
>
> (1) Rates for purchases shall:
>
> (i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and
>
> (ii) Not discriminate against qualifying cogeneration and small power production facilities.
>
> (2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

Subparagraph (c) of §292.304 requires state regulatory agencies to establish standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less. Section 292.304 sets forth other details concerning the establishment of an avoided cost rate.

Finally, at 18 CFR 292.309, FERC implements the process whereby a utility may seek a waiver of the obligation to purchase the output from QFs when a QF has nondiscriminatory access to markets, such as that in ISO-New England. I will note that PSNH applied for a waiver from the PURPA “must buy” requirement, and FERC granted PSNH’s request, but only relating to QFs with a net capacity in excess of 20 MW. *Public Service Co. of New Hampshire,* 131 FERC ¶ 61,027 (April 15, 2010).

Q. Has the New Hampshire Public Utilities Commission ("NHPUC") ever considered the proper avoided cost that utilities must pay QFs?

A. Yes. The NHPUC dealt with the PURPA avoided cost issue in myriad proceedings beginning in the late 1970s. In those proceedings, the NHPUC has, *inter alia,*

- found that the term avoided cost is another way of expressing the concept of incremental cost. For purposes of uniformity with the FERC rules, the commission said it would use the term "avoided costs" with the understanding that the use of the term equates to the concept of "incremental costs." *Re Small Energy Producers and Cogenerators,* 65 NHPUC 291 (1980).

- held that the avoided cost for a utility that does not generate its own power would be based on that utility's supplier's avoided cost, and that a full avoided cost rate equaling the price set by the competitive market brings on line the optimal amount of power at an optimal price. *Re Purchases for Nongenerating Utilities*, 67 NHPUC 825 (1982)

- found that calculation of the proper avoided cost rate is dependent upon the identification of the generating units operating on the margin. *Re Industrial Cognerators Group,* 72 NHPUC 8 (1987)

- specifically recognized that QFs are not bound by state franchise boundaries, but have the right to compel purchases of their output from distant utilities. *Re New Hampshire Electric Cooperative,* 80 NHPUC 489 (1995).

Q. Has the NHPUC implemented any regulations setting an avoided cost rate under PURPA?

A. Yes. In 2011 the NHPUC implemented a PURPA avoided cost rate in its Net Metering Rules in Puc 903. In this regulation, the Commission specifically states that the ISO-NE hourly real time locational marginal price is intended to set "the rates for utility avoided costs for energy and capacity consistent with the requirements of the Public Utilities Regulatory Policy Act of 1978 (PURPA) (16 USC § 824a-3 and 18 CFR § 292.304)." Puc 903.02(i). (Attachment JRS-R-1).

Q. Is the avoided cost standard contained in Puc 903.02(i)(2) consistent with PURPA avoided cost determinations made in other New England states?

A. In general, yes. As part of my job responsibilities for Eversource Energy, I am directly involved in transactions in the ISO-New England energy market and have specific duties relating to electricity supply in New Hampshire, Connecticut and Massachusetts. In both Connecticut and Massachusetts, the avoided cost rate established for the purchase of power from QFs under PURPA with respect to energy is set in the same manner as the avoided cost rate in Puc 903.02(i)(2); i.e., using the ISO-NE real-time energy market price.

In Massachusetts, avoided costs are set by regulation at 220 CMR 8.00, "Sale of Electricity by Qualifying Facilities and On-Site Generating Facilities to Distribution Companies, and Sales of Electricity by Distribution Companies to Qualifying Facilities and On-Site Generating Facilities." (Attachment JRS-R-2). The purpose of this Massachusetts regulation includes implementation of PURPA avoided cost requirements. 220 CMR 8.01(1)(c). The Massachusetts avoided cost rate is called the "Short-run Rate" and "means the hourly market clearing price for energy and the monthly market clearing price for capacity, as determined by the ISO and its successors." 220 CMR 8.02. Massachusetts utilities "must offer a Standard Contract providing for payment at the Short-run Rate to any Qualifying Facility making a request for such a contract." 220 CMR 8.05(4).

In Connecticut, avoided cost rates are set by tariff. Eversource Energy's Connecticut operating company, The Connecticut Light and Power Co., offers Rate 980, Non-Firm Power Purchase, to electric generators. (Attachment JRS-R-3). The rate paid under Rate 980 is "the appropriate hourly Connecticut ISO-NE Wholesale Electric Market Real-Time Locational Marginal Price ("RT-LMP") clearing price for such hour" for generators with time differentiated meters; without such metering, generators receive "the appropriate RT-LMP average clearing price over the billing period." Under Rate 980 QFs do not receive capacity payments, rather any capacity revenues received as a result of the resources being in the wholesale market flow to distribution customers through a non-bypassable bill line item.

In Maine, the Maine Public Utilities Commission has also established "the ISO-NE real-time nodal clearing price for the node on which the generator is located" as the avoided cost rate to be paid. 65-407 Code of Maine Rules, ch. 315, §3(B). (Attachment JRS-R-4).

Similarly, in Rhode Island, Narragansett Electric pays QFs "the hourly clearing prices at the ISO-NE for the hours in which the qualifying facility generated electricity in excess of its requirements." Narragansett Electric Tariff RIPUC No. 2098, para. III.2. (Attachment JRS-R-5).

It is my understanding that the practice of using real time locational marginal prices to determine avoided costs is followed fairly uniformly throughout New England. A recent survey of the various PURPA compliance methods used in the New England states conducted by La Capra Associates shows that with the exception of Vermont, a state that has not embraced retail competition, all the New England states use ISO-NE prices to set the avoided cost for energy for QF purchases under PURPA. I have attached a copy of the La Capra study as Attachment JRS-R-6.

Q. Have avoided cost rates been set for other PURPA-jurisdictional utilities in New Hampshire?

A. Yes. The NHPUC has approved tariff provisions for Liberty Utilities ("Liberty"), Unitil Energy Systems, Inc. ("Unitil"), and the New Hampshire Electric Cooperative, Inc. ("NHEC") which set avoided costs for their QF purchases based on the hourly prices these utilities receive for sales of IPP output into the ISO-NE real-time energy market. See N.H.P.U.C. No. 19 Electricity, Liberty Utilities (Granite State Electric) Corp. D/B/A/ Liberty Utilities, Original Page 9 Attachment JRS-R-7); N.H.P.U.C. No. 3 Electricity Delivery, Unitil Energy Systems, Inc., Original Page 76 (Attachment JRS-R-8); N.H.P.U.C. No. 21 Electricity, New Hampshire Electric Cooperative, Inc., Original Page 18 (Attachment JRS-R-9).

Q. Are you aware of any jurisdiction that sets avoided costs for PURPA "based upon the lowest default service bid rate accepted by [a utility] for the period when the IPP purchases are made"?

A. No. I am not. And, Mr. Norman has not provided any evidence that his suggested avoided cost standard has been implemented by any regulatory agency.

Q. What is the avoided cost standard in effect for PSNH at this time?

A. The avoided cost standard in effect for PSNH was approved by the Commission as part of its approval of the 1999 PSNH Restructuring Settlement Agreement. That 1999 Agreement as approved by the Commission states at Article V,G:

> G. Avoided Costs for IPPs
>
> PSNH's responsibilities and avoided cost rates on and after Competition Day for short-term purchases of IPP power pursuant to the federal Public Utility Regulatory Policies Act and the New Hampshire Limited Electrical Energy Producers Act shall be equal to the market price for sales into the ISO-New England power exchange, adjusted for line losses, wheeling

> costs, and administrative costs. This Agreement is not intended to impair existing rate orders or contracts.

Q. How has that 1999 Agreement standard been implemented?

A. Since that standard has been in effect, PSNH has paid the real-time energy market price for energy as the applicable PURPA avoided cost. Notably, although having authority to do so, PSNH has not imposed any administrative fee for dealing with the dozens of small generators that have put their output to PSNH pursuant to PURPA.

Q. How does the 2015 PSNH Restructuring Settlement change the current avoided cost standard?

A. The 2015 PSNH Settlement makes no changes to the existing avoided cost methodology. The 2015 PSNH Settlement at Article III,C reads:

> C. Avoided Costs for IPPs
>
> Unless otherwise found by the Commission or other appropriate authority, PSNH's responsibilities and avoided cost rates for purchases of IPP power pursuant to PURPA and LEEPA shall be equal to the market price for sales into the ISO-NE power exchange, adjusted for line losses, wheeling costs, and administrative costs. This Agreement is not intended to impair existing rate orders or contracts. Nothing in this Agreement shall be construed as limiting the Commission's authority with respect to calculating avoided costs. The Settling Parties agree not to oppose the opening of a generic docket or rulemaking upon petition by any Settling Party to consider the proper calculation of Avoided Costs under PURPA and LEEPA for all electric distribution companies in New Hampshire.

This standard is exactly the same as the avoided cost standard that has been authorized for PSNH for the past 15 years, is identical to the avoided cost standard for Unitil, Liberty Utilities, and the N.H. Electric Cooperative, and is similar to the avoided cost standard in place throughout New England (other than Vermont).

Q. What could happen if the Commission were to approve an avoided cost standard for PSNH that was higher than for other utilities in the region?

A. As noted earlier, 18 CFR 292.303(a) states and the NHPUC has acknowledged that QFs are not bound by state electric franchise boundaries, but instead, have the right to sell their output to any utility they can transmit their output to. Hence, if PSNH had to pay QFs an avoided cost rate higher than other utilities in the region, QFs throughout the region would be incented to put their output to PSNH, and PSNH's customers would ultimately pay the resulting higher costs. This is similar to what one sees when there is an intersection with four gasoline stations, and one of the stations has prices less than the others. Customers line up and wait at the low-cost station.

Q. In your opinion is the real-time energy market price the appropriate measure of avoided cost for a supplier, such as PSNH, that must provide all-requirements, load following service?

A. Yes. An entity providing full requirements, load following service, whether it is PSNH, another utility, or a merchant supplier responding to an RFP, is always in the ISO-New England real-time energy market at the margin. No supplier has exactly the precise amount of energy through owned generation and energy purchases to meet demand at every instant. At the margin, load following suppliers must rely upon the real-time energy market to take up the slack or surplus. Recall that in *Re Industrial Cogenerators Group*, 72 NHPUC 8 (1987), this Commission found that calculation of the proper avoided cost rate is dependent upon the identification of the generating units operating on the margin. Thus, the value of an additional kilowatt-hour of generation has a value equal to the real-time energy market price. Any other price would be disparate.

Q. In his supplemental testimony at page 4, Mr. Norman suggests that an appropriate avoided cost rate should be weighted based upon a utility's relative participation in the real-time and day-ahead markets. Do you agree with that suggestion?

A. No. The suggestion ignores the Commission's *Re Industrial Cogenerators Group* decision finding that the proper avoided cost rate is based upon the marginal price of the utility. In today's ISO-NE market, that marginal price is always set by the real-time market because all load imbalances are resolved in the real-time energy market. Furthermore as GSHA's resources only participate in the real-time energy market; they do not and cannot allow PSNH to avoid day-ahead energy market purchases. His suggestion that some type of weighted average of day-ahead energy market and real-time energy market prices is an appropriate price is unprecedented and given how the resources operate in the current wholesale energy market would create a valuation mismatch. In organized wholesale markets the value of resources to customers is straightforward. Wholesale energy transactions to which GSHA member facilities are a party occur in the real-time market. That defines their worth to customers and the remainder of PSNH's wholesale transactions (in whatever market) are irrelevant to the value GSHA resources provide. Unless and until that changes that is how they should be compensated, for the straightforward value which they provide. Any other outcome is illogical and would not conform with the structure of the ISO-NE wholesale energy market.

Q. In the near term period until a generic avoided cost for all New Hampshire utilities is established, Mr. Norman testifies that the appropriate avoided cost for QF purchases by PSNH should be set at the "Day Ahead ISO-NE New Hampshire Locational Marginal Price" in lieu of the real-time energy market price. Do you agree with Mr. Norman?

A. No, I do not, for several reasons. First, an avoided cost standard for all QFs based on day-ahead energy market prices is inappropriate for many types of QFs. Not all generators can or want to participate in the day-ahead energy market. Small QFs, such as all of Granite State Hydropower Association member plants, would likely find participating in the day-ahead energy market very burdensome. Every individual generator must offer its generation into the day-ahead energy market every day – 7 days per week, 365 day per year. If a plant is not timely offered into the day-ahead energy market, it is not entitled to receive day-ahead energy market prices from ISO-NE.

Indeed, GSHA has admitted that its members do not have the capability to provide the information necessary to participate in the day-ahead market. In GSHA's "Opening Scoping Memorandum" filed in this docket on December 5, 2014, at page 1, GSHA admitted:

> PURPA serves to provide small generators with non-discriminatory access to the market; "Qualified Facilities" ("QFs"), such as GSHA's members, often do not have the resources to bid production hourly and bear all the administrative burdens associated with ISO-NE market rules.

GSHA also told FERC the same thing:

> Granite State states that developers of small hydroelectric plants do not have the software, computer and monitoring equipment to integrate to RTO/ISO operations and, in many regions, would not even be eligible to bid their energy into these markets because they are too small for the applicable minimum block.

FERC Order No. 688, "Final Rule, New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities," October 20, 2006, p. 40.

If a utility had the obligation to pay day-ahead energy market prices to a generator, in order to protect customers from paying too much, that utility would have to ensure that each QF receiving day-ahead energy market prices is timely offered into and cleared in the day-ahead energy market every day, necessitating daily timely input from each QF's owner. But the information necessary to participate in the day-ahead market is the very information GSHA has admitted earlier in this docket, as well as to FERC, that its members do not have the resources to provide.

Furthermore, even if a QF timely offers into the day-ahead market, that QF must satisfy its daily cleared offers or be subject to monetary penalties from ISO-NE by replacing what it failed to provide at real-time energy market prices plus an allocation of real-time net commitment period compensation costs. These bidding requirements would be administratively burdensome and time consuming for a utility to handle, potentially requiring the hiring of additional personnel to deal with the daily offering, recordkeeping, accounting, and general administration of the day-ahead energy market process.

Q. If a QF wanted to participate in the day-ahead energy market, could it do so on its own?

A. Yes. There is nothing stopping any QF from joining ISO-NE and directly participating in the day-ahead energy market if it felt such pricing was desirable. That way, all administrative costs and requirements would be borne by the generator, and not subsidized by electric distribution company customers. But, as GSHA has admitted in its "Opening Scoping Memorandum," retail electric customers are bearing the administrative costs of QF generators today, and those QFs are not desirous of losing that subsidy.

Q. Initially, in the future "generic" period described by Mr. Norman, he testified that the appropriate avoided cost for QF purchases by PSNH should be "based upon the lowest default service bid rate accepted by PSNH for the period when the IPP purchases are made." In his supplemental testimony, he disregards his "generic" period and now testifies that post-divestiture PSNH should continue to use day-ahead prices as the appropriate avoided cost until such time as the Commission establishes a new avoided cost methodology for all utilities. Do you agree with Mr. Norman?

A. Yes and no. First of all I would like to point out that divestiture has zero impact on the value to customers provided by GSHA members' QF resources. Their interaction in wholesale markets is unaffected by divestiture. However, I agree that post-divestiture, if and when the Commission establishes an appropriate avoided cost methodology for all PURPA-jurisdictional utilities in New Hampshire, that would be the applicable avoided cost rate under PURPA.

But, until such a generic Commission determination applicable to all of the state's PURPA-jurisdictional utilities is rendered, my answer is "no" – I do not agree with Mr. Norman. Recall that the original purpose of PURPA's small generator provisions was to allow QFs to interconnect with the grid and to create a market for their output, i.e., energy and capacity. As previously noted above 18 CFR 292.101(b)(6) defines "avoided cost" to mean "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.". Today, with open access transmission and vibrant competitive organized day-ahead and real-time energy markets, the need for PURPA's QF provisions have waned.

Congress signaled this when it added section 210(m) to PURPA in the Energy Policy Act of 2005 (EPAct 2005). On October 20, 2006, FERC issued Order No. 688, revising its regulations governing utilities' obligations to purchase electric energy produced by QFs by implementing §292.310 of its regulations.. Order No. 688 implements PURPA §210(m) which provides for termination of the requirement that an electric utility must purchase the electric energy from QFs if FERC finds that the QFs have nondiscriminatory access to markets.

FERC specifically found in Order No. 688 that the market administered by ISO-NE was one of four markets nationwide that satisfy the criteria of PURPA §210(m)(1)(A). In Order No. 688, FERC noted that it was the intent of Congress in section 210(m) to have QF development "stimulated by market forces," much like the New Hampshire Legislature has determined that this state's retail electricity market should "harness[ ] the power of competitive markets" in the Restructuring Law at RSA 374-F:1. In Order No. 688, FERC stated, "These RTOs [including ISO-NE] are independently administered and offer auction based day ahead and real time wholesale markets for the sale of electric energy; and within the regions represented by these RTOs there is nondiscriminatory access to wholesale markets for long-term sales of capacity and electric energy."

In light of the Congressional intent for enacting section 210(m) of PURPA and FERC's finding that the ISO-NE market meets the criteria set forth in that statute by offering markets for the sale of electric energy, it is clear that the prices set by the ISO-NE market are what FERC would find to be the "fair and reasonable" prices required by both statute (PURPA Section 210(b)) and by FERC regulation (§ 292.304). A full-requirements, load-following retail RFP price is not what PURPA intends that utilities, and ultimately its customers, must pay a QF.

FERC has expressly agreed with my understanding that competitive market rates are the fair and reasonable rates required by PURPA in *Southern California.Edison*, 70 FERC ¶ 61,215 (1995) at 61,676 & n.14. In that decision, FERC agreed that "Congress did not intend QFs to have any rate benefit above a market rate level." FERC went on to say that setting avoided costs above market levels "will … give QFs an unfair advantage over other market participants (non QFs)," and this, in turn, "will hinder the development of competitive markets and hurt ratepayers, a result clearly at odds with ensuring the just and reasonable rates required by PURPA section 210(b)." FERC has also expressed "concern that the mandatory QF purchase obligation under PURPA in conjunction with administratively avoided cost rates may be inconsistent with the operation of an effective competitive market." *Cogen Lyondell, Inc*., 95 FERC ¶ 61,243 (2001) at 61,838.

Q. Does the energy output from a QF have the same value as the energy obtained via an RFP process to serve retail consumers?

A. No. The default service bid rate described by Mr. Norman is a load-following, full-requirements rate which is not the appropriate payment rate to a generator that provides specific electricity products such as energy and capacity.

GSHA has admitted that its members participate in the *wholesale*, not retail, market. In paragraph 3 of GSHA's August 12 Motion to Compel, GSHA stated, "In its order granting GSHA's petition to intervene in this docket, *the Commission recognized that GSHA's members primarily sell power at wholesale* to distribution utilities, including some sales under the 1999 Settlement Agreement. Order No. 25,733 (Nov. 16, 2014), p. 6." (Emphasis added). In the Petition to Intervene of GSHA, September 29, 2014, at paragraphs 5 and 7, GSHA stated

> *Most GSHA member projects sell power at wholesale* to one or another of New Hampshire's electric distribution companies under rate orders, via negotiated power purchase agreements, or in

> PSNH's case, in accordance with the 1999 restructuring settlement agreement with PSNH in docket DE 99-099; GSHA members operate in a competitive marketplace in which they must net meter, undertake contracts with distribution utilities, or sell power into the market to deliver their produced electricity to consumers. This circumstance puts them in the same position *(offering to sell power at wholesale)* as PSNH's hydroelectric power projects if those projects are divested."

(Emphases added.)

The distinction between the wholesale products produced by a QF and the retail product supplied under a default service RFP was recently discussed in Docket No. IR 14-338, "Review of Default Service Procurement Processes for Electric Distribution Utilities." During the hearing in that proceeding on May 27, 2015, Mr. Allegretti (who is also a witness in this proceeding) provided a detailed explanation of that distinction. His explanation from pages 61-63 of the Transcript of that hearing is appended hereto as Attachment JRS-R-10.

GSHA's member QF generators do not provide full-requirements, load-following service. Even GSHA's President and witness, Mr. Norman, has admitted that he "is unaware of QFs providing ancillary services." (Response to data request Q-PSNH-18, Attachment JRS-R-11). The table below identifies: a) the composition of full requirements load following service, b) how each component's cost is determined, and c) what QFs provide. As can be seen, QFs do not fully avoid the costs of a full requirements load following power supply, but rather offset the need to purchase a portion of some discreet components of full requirements load following power supply. Thus the expression "market price for sale into the ISO-NE power exchange" used in both the 1999 Restructuring Settlement and the current 2015 Settlement refers to the costs avoided by purchasing discrete power supply products from the QF rather than buying the discrete power supply product in the ISO-NE power exchange. Since GSHA's clients' resources are presently

ISO-NE registered assets they provide discrete wholesale power supply products and are not capable of providing anything more.

Whether Eversource NH self-supplies or procures a full requirements load following power supply it does not change the fact that the QFs provide only discrete power supply components.

Full Requirements Load Following Service Components	Cost Basis	What Hydro QF Provides
Energy	Purchase exact amount customers require on an hourly basis. Some may be bought day ahead based on forecast customer demand, but ultimately actual amount bought is refined in real time. In addition, load serving entities have Marginal Loss Revenue allocations, Net Commitment Period Cost allocations, Inadvertent Energy Flow cost allocations, and Emergency Energy Purchase allocations.	Energy amounts tied to hourly water flows. Do not participate in the day-ahead energy market.
Capacity	Current customers' share of prior year's annual system peak, times total amount of capacity required to cover peak load plus a required reserve margin for load uncertainty and supply unavailability.	Its capacity supply obligation, no greater than its seasonal MW capabilities.
Forward Reserves	Hourly load share times payments to resources providing the service.	None.
Real-time Operating Reserves	Hourly load share times payments to resources providing the service.	None.
Regulation	Hourly load share times payments to resources providing the service.	None.
ISO & NEPOOL Expenses	Allocated to load serving entities under various metrics tied to load and/or transactions.	None.
Renewable Portfolio Standards	Must purchase RECs equal to percentages of sales for each renewable class bilaterally, and pay alternative compliance rate for any deficiency.	If qualified, based on generation amounts. RECs are retained by owner and not part of QF avoided cost.

Q. In the "generic" time period, PSNH will no longer have generating assets, and instead would rely upon a competitive RFP solicitation to obtain the full requirements, load following power supply needed to meet its default energy service needs. Has the NHPUC ruled on what the appropriate avoided cost standard is for such a non-generating utility?

A. Yes. This Commission has already considered and decided what the appropriate avoided cost standard is for utilities that do not generate their own power, but instead rely upon full requirements supply contracts. As I noted earlier, in *Re Purchases for Nongenerating Utilities*, 67 NHPUC 825 (1982), the Commission held that the avoided cost for a utility that does not generate its own power would be based on that utility's supplier's avoided cost, and that a full avoided cost rate equaling the energy and capacity prices set by what the competitive market brings on line is the optimal amount of power at an optimal price. I also testified earlier that any entity providing full requirements, load following service, whether it is PSNH, another utility, or a merchant supplier responding to an RFP, is always in the ISO-New England real-time energy market at the margin, and that therefore, the real-time energy market price is the appropriate avoided energy cost for purposes of PURPA.

Q. Has the FERC made any similar rulings concerning the appropriate avoided cost standard for a non-generating utility?

A. Yes. In *Western Farmers Electric Cooperative,* 115 FERC ¶ 61,323 (2006), FERC stated, "The Commission has consistently held that the avoided costs of an all-requirements customer to be those of its all-requirements supplier." FERC also noted in this decision:

> The Commission first made this determination in Order No. 69 which implemented section 210 of PURPA. *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC Stats. & Regs. ¶ 30,128 at

> 30,871, *order on reh'g*, Order No. 69-A, FERC Stats. & Regs. ¶30,160 (1980), *aff'd in part aad vacated in part, American Electric Power Service Corp. v. FERC*, 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part, American Paper Institute, Inc. v. American Electric Power Service Corp.*, 461 U.S. 402 (1983). The Commission has consistently followed this determination in case law. *See, e.g., Carolina Power & Light Co.*, 48 FERC ¶ 61,101 at 61,390 (1989) (citing *City of Longmont*, 39 FERC ¶ 61,301 (1987)) (in the case of a QF selling to a full requirements customer instead of selling to that customer's supplying utility, the Commission will measure "the avoided cost of the full requirements customer as the avoided cost of the full requirements supplier since it is the supplier that avoids generation when the full requirements customer purchases from a QF"). To the extent protesters argue that the avoided cost should be the purchase price, they have not offered any compelling reason to change our policy. *See North Little Rock Cogeneration, L.P. and Power Systems, Ltd. v. Entergy Services, Inc.* and *Arkansas Power & Light Company, Entergy Services, Inc.*, 72 FERC ¶ 61,263 at 62,172 (1995).

It is clear from these FERC decisions that the proper avoided cost for a non-generating utility is <u>not</u> the power cost of the requirements contract, but instead is the avoided cost of the supplier. Mr. Norman's suggestion that the retail price established by a default energy service RFP is the proper standard for establishing a PURPA avoided cost is contrary to FERC's decisions

Q. Has FERC ever ruled on whether use of market-based prices is an appropriate means of determining the proper avoided cost under PURPA?

A. Not that I am aware of. The issue was brought to FERC in its Docket No. EL13-43 that arose from a petition filed by the Mississippi Public Service Commission, the Arkansas Public Service Commission, and the City of New Orleans, all three of which exercise regulatory authority over Entergy. In its decision at 145 FERC ¶ 61,057 issued in October, 2013, the FERC said it would not determine in that case whether use of market-based locational marginal prices ("LMPs") to establish an avoided cost would comply with PURPA because none of the petitioning regulators had adjudicated that issue and, "It is the state's responsibility in the first instance to determine an avoided cost rate consistent with the Commission's regulations." However, the FERC noted, "It appears that various states have opted to use LMPs in calculating avoided costs. *See* Entergy February 21, 2013 Answer at 19-20. The record in this proceeding does not contain extensive evidence on the particular methodologies that are being used by these states, and these methodologies have not otherwise been the subject of Commission proceedings."

So, FERC is aware that various states have opted to use LMPs to determine the proper avoided cost under PURPA, as New Hampshire has done since industry restructuring, and to date has not interfered with those states' determinations.

Q. Has GSHA discussed the PURPA avoided cost issue at FERC?

A. Yes. On November 8, 2005, GSHA filed, "Comments of Granite State Hydropower Association, Inc. Regarding Proposal to Eliminate FPA Exemption for Small Power Production Facilities," in FERC Docket RM05-36-000. In that filing (at page 6), GSHA stated:

> [W]hat constitutes an "avoided cost" rate has changed considerably over the years, especially in states with operating regional transmission organizations. When contracts were executed in the 1980s and 1990s, each utility calculated its avoided costs periodically and these rates were posted and available to QFs. That is no longer the case. In New Hampshire and Vermont, for example, the public utility commissions have not formally calculated avoided cost rates for years. Today, QFs typically sell their power to the utility at the locational marginal price ("LMP") rate- a market-based rate. Yet, the rate is an avoided cost rate that is sanctioned by the state for purposes of the sale of power from the QF to the utility. Thus, the Commission should expand its proposal to exempt projects purchasing under avoided cost rate schemes to take into account the evolution and expanded definition of what constitutes an avoided cost rate.

GSHA expressly told FERC that ins states with operating RTOs, and specifically in New Hampshire, the LMP rate is an avoided cost rate sanctioned by the state for purposes of the sale of power from the QF to the utility.

Q. Unitil and Liberty Utilities have relied upon full requirements RFP solicitations for many years to obtain their default energy service needs. Has GSHA sought to change the avoided costs prices they pay QFs in order to benefit its members?

A. The only attempt I am aware of is discussed in Docket No. IR 14-338, where Messrs. Locke and Norman of GSHA testified on behalf of Briar Hydro Associates. In his filing dated "February 11, 2105" (sic), Mr. Locke stated that Briar Hydro Associates "approached Unitil representatives twice in 2014 to discuss the possibility of selling … power to Unitil at a rate discounted off of Unitil's default service rate," but Unitil declined to do so.

New Hampshire's other utilities have been restructured for many years. Unitil and Liberty Utilities have relied upon RFP solicitations since restructuring to procure default service supply for their customers. If Mr. Norman's suggestion that their RFP results establish the appropriate standard for setting their avoided cost rates for purchases from QFs, I cannot understand why the Granite State Hydropower Association or its members have taken no action to enforce their PURPA rights and obtain significantly higher prices for their generating output. They cannot say that electric franchise boundaries preclude their members from selling to Unitil or Liberty – this Commission (and 18 CFR 292.303(a)) has ruled that they do not. I discussed earlier where the Commission specifically recognized that QFs are not bound by state franchise boundaries, but have the right to compel purchases of their output from distant utilities. See *Re New Hampshire Electric Cooperative,* 80 NHPUC 489 (1995).

Q. Did GSHA just ignore tens of millions of dollars of additional revenues?

A. That prospect is unlikely – the more believable answer is that GSHA never really felt that a full requirements RFP price was an appropriate avoided cost for purposes of PURPA. Their involvement in this Settlement proceeding appears to me to be opportunistic. Otherwise, GSHA would be protecting its members' economic interests by asserting their rights under PURPA to receive what they deem to be the proper avoided cost rate for the output from its members from the state's other utilities that already rely upon RFPs for their default energy service.

Q. Do you have a recommendation for the proper PURPA avoided cost rate for QFs that put their output to PSNH?

A. Yes. Both during the near-term "hybrid" period and post-divestiture until a uniform avoided cost methodology is adopted for all of New Hampshire's PURPA-jurisdictional utilities, the proper avoided cost rate that QFs are entitled to remains what this Commission decided in *Re Industrial Cogenerators Group,* 72 NHPUC 8 (1987), the price at the margin, i.e., the real-time ISO-NE energy market nodal price for energy and whatever the capacity market provides them. At the margin, the supplier's price (whether the supplier is PSNH itself during the hybrid period, or a competitive supplier in the generic period) is that real-time energy market price.

As FERC has ruled, any other energy price would be inconsistent with a competitive marketplace and would hurt customers – outcomes that are contrary to the express findings of the Legislature in the Restructuring Law when it stated, "Restructuring of electric utilities to provide greater competition and more efficient regulation is a nationwide phenomenon and New Hampshire must aggressively pursue restructuring and increased customer choice in order to provide electric service at lower and more competitive rates." 1996 N.H. Laws, 129:1, III. A properly established avoided cost rate set by the competitive market at the real-time energy market price is consistent with the competitive marketplace and would not hurt customers.

In conclusion, it is important to note, Commission Staff recently agreed that "the current situation where [QFs are] eligible for short-term avoided costs is appropriate." Transcript, IR 14-338, May 27, 2015, p. 57, line 18.