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

PREFILED DIRECT TESTIMONY OF

RICHARD A. NORMAN
ON BEHALF OF
GRANITE STATE HYDROPOWER ASSOCIATION

September 18, 2015

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

A. My name is Richard A. Norman. I am President of Granite State Hydropower Association ("GSHA"). The business address of GSHA is Two Commercial Street, Boscawen, New Hampshire 03303.

Q. Please describe GSHA and your responsibilities.

A. I am the President of Granite State Hydropower Association ("GSHA). GSHA is the association for the small independent hydroelectric power industry in New Hampshire. Its members own, operate and manage approximately 60 hydroelectric projects located throughout New Hampshire with a cumulative gross capacity of approximately 50 MWs. Twenty-six (26) of the GSHA member projects are "qualifying facilities" ("QFs") as that term is used in the Public Utilities Regulatory Policy Act of 1978 ("PURPA") and are independent power producers ("IPPs") that presently sell their power to PSNH pursuant to the 1999 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement ("1999 RRSA"). As GSHA President, my duties include representing GSHA's interests before the New Hampshire legislature and regulatory bodies and the Federal Energy Regulatory Commission ("FERC").

Q. Please summarize your educational background.

A. I received a Bachelor of Science degree in general science from the United States Naval Academy in 1961. In 1970, I received a Master's Degree in Business Administration from the Harvard Graduate School of Business Administration. I also am a graduate of the Navy's Nuclear Power School training program.

Q. Please summarize your professional experience.

A. My business experience is described in a resumé attached to this testimony as Exhibit 1. As it relates to this docket, my experience includes the development, construction and subsequent operations of small scale hydroelectric projects. From 1976 to 1983, I was Senior Vice President of J. Makowski Associates, Inc. ("JMAI"), an energy development company located in Boston, Massachusetts. In that capacity I held offices in several related companies including that of President of Essex Company, developer of the Lawrence Hydroelectric project in Lawrence, Massachusetts. Upon leaving JMAI in 1983, I cofounded Essex Hydro Associates, LLC ("EHA"), a developer, operator of and investor in small power producer ("SPP") hydroelectric facilities. I served as President of EHA from 1983 through late 2014 and currently I am its Chairman. EHA now directly or indirectly has an ownership interest in, operates and manages eleven (11) hydroelectric projects, five of which are located in New Hampshire; the other six are located in Vermont and Maine. As the result of my business experience with small hydroelectric power projects, I am familiar with some of the federal and state laws and rules that apply to that sector of the electric industry.

My business experience includes familiarity with the operation of regulated and non-regulated companies. I have participated in several dockets concerning avoided cost determinations and have led or co-led the negotiation or renegotiation of a number of IPP power purchase agreements with companies including New England Power Company, Niagara Mohawk Power Corporation, Green Mountain Power Corporation, Pacific Power and Light Company, Central Vermont Power Service Corporation, Public Service Company of New Hampshire ("PSNH") and the Vermont Electric Power Producers, Inc.

Q. Have you testified previously before the New Hampshire Public Utilities Commission or other regulatory bodies?

A. Yes. I have testified before the New Hampshire Public Utilities Commission ("NH PUC or Commission") in Docket Nos. DE 09-174 (Petition for Declaratory Ruling – Penacook Lower Falls) and DE 99-099 (Public Service Company of New Hampshire – Proposed Restructuring Settlement). I also have testified before FERC on behalf of New Hampshire Hydro Associates in Docket ER94-692-000 and before the Vermont Public Service Board in Docket No. 8010 and related workshops on behalf of Boltonville Hydro Associates and North Hartland Hydro LLC.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address issues arising from the manner in which the 2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement (the "2015 RRSA") proposes to treat PSNH's power purchases from QFs/IPPs.

Q. How does the 2015 RRSA propose to treat PSNH's purchases of IPP power?

A. The sections of the 2015 RRSA that relate to IPP purchases are as follows:

Section III.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. ..."*

Section VI. B. Purchases from Qualifying Facilities ("QFs"), Independent Power Producers ("IPPs") and Power Purchase Agreements:

> *"Unless otherwise found by the Commission or other appropriate authority, for so long as PSNH purchases output from QFs, IPPs, or pursuant to the PPAs, PSNH shall sell or bid such purchases into the pool at the ISO-NE market clearing price, with the resulting costs or credits recovered via Part 2 of the SCRC as a Non-Securitized Stranded Cost. ...."*

Because the first sentence of Section VI. B. of the 2015 RRSA uses the terms QF and IPP, and the first sentence of Section III.C. references avoided cost rates for purchases of IPP power under PURPA, I presume this means or includes QF power sales made pursuant to Section 210 of PURPA and associated federal regulations (18 C.F.R. §292.301 et seq).

Q. Please describe GSHA's concerns about the above-referenced provisions of the 2015 RRSA.

A. GSHA believes that Section III.C. of the 2015 RSSA describes "avoided costs" in a manner that is inconsistent with PURPA. PURPA provides that federal rules requiring the purchase by any electric utility of electric energy from any qualifying small power producer ("QF") must, among other things, not discriminate against QFs and not exceed "the incremental cost to the electric utility of alternative electric energy." 16 U.S.C. §824a-3(b).

"Incremental cost of alternative electric energy" is defined as "the cost to the electric utility of the electric energy which, but for the purchase from such …small power producer, such utility would **generate or purchase from another source.**" 16 U.S.C. §824a-3 (d)(emphasis added). Federal regulations implementing these statutory provisions establish electric utilities' obligations to purchase QF power. *See* 18 C.F.R. §292.303(a). The regulations also indicate that payments for such purchases satisfy federal regulatory rate requirements if they are equal to the purchasing utility's avoided costs determined after consideration of factors set forth in §292.304(e). *See* 18 C.F.R. §292.304(a)(2).

Q. Please explain why you believe the 2015 RRSA conflicts with the requirements of PURPA.

A. Section IIII.C. of the 2015 RRSA conflicts with the provisions of PURPA and the federal regulations promulgated thereunder which require that utilities purchasing power from QFs/IPPs must pay for that power at rates that are based upon the utility's avoided costs (i.e. costs that a utility like PSNH would incur to generate electricity itself or buy from another source) – not market prices. In order to establish that market prices are, in fact, equal to PSNH's avoided costs, one must examine the costs PSNH incurs to generate and make supplemental electricity purchases to serve its default service customers. The 2015 RRSA makes no provisions for doing that. In addition, using a single rate (i.e. the ISO-NE market price) as PSNH's avoided cost rate for all of PSNH's purchases throughout the duration of the 2015 RSSA is problematic because there are two different periods of PSNH's operations under the 2015 RRSA.

Q. Please describe the two periods to which you refer.

A. The two periods are the pre- and post-divestiture periods. The pre-divestiture period, which I refer to as the ***hybrid period***, is the time when QF/IPP purchases are made while PSNH owns and operates generating assets that, along with supplemental power purchases, are used to meet its default service load obligations. No other New Hampshire utility owns generating assets that are used to meet default service load. The hybrid period exists today and will continue to exist from the date the 2015 RRSA is approved until the date PSNH fully divests its generating assets and begins to acquire default energy service consistent with the process determined by the Commission in Docket IR-14-338.

The second period addressed by the 2015 RRSA will begin following full divestiture of PSNH's assets. The 2015 RRSA at Section III.B. specifies that, post-divestiture, PSNH will acquire power to meet its default service load in a manner consistent with the process determined by the Commission in its Docket IR-14-338, and like other utilities in this state, will use periodic requests for proposals ("RFPs") or similar competitive bidding processes to procure electricity from the market to meet default service needs. I refer to this post-divestiture period as the ***generic period***, because at that time, PSNH and other New Hampshire electric utilities will all be purchasing default service power similarly, so their avoided costs will be calculated in a similar or "generic" fashion.

Q. Turning first to the hybrid period, please explain why Section III.C. of the 2015 RRSA (which defines PSNH's avoided costs in terms of ISO-NE's "market price") is improper and therefore should not be approved.

A. Neither the prefiled testimony submitted by PSNH nor any other information in this docket provides facts to demonstrate that ISO-NE's market price is actually equal to PSNH's avoided costs, i.e. the costs it incurs to generate electricity and make supplemental purchases to serve default service load.

To conclude that the ISO-NE market price is an avoided cost rate for PSNH as is done in the 2015 RRSA, one must first demonstrate that the ISO-NE market price is the cost (or "rate" on a per unit basis) that PSNH would actually incur to generate that amount of power or purchase it from another source if it did not buy QF power. In other words, the ISO-NE market price must be equal to PSNH's marginal or incremental cost of generating or procuring needed power if that market price is to apply to PSNH's purchases under PURPA. This is the case because PURPA defines avoided cost as the "the incremental cost to the electric utility of alternative electric energy" i.e., "the cost to the electric utility of the electric energy which, but for the purchase of from…[the] small power producer, such utility would **generate or purchase from another source**." 16 U.S.C. §824a-3(b) and (d)(emphasis added).

Q. How does PSNH interpret "market price"?

A. The term "market price" appears in both the 1999 Settlement Agreement and the 2015 RRSA. PSNH currently purchases IPP power pursuant to the 1999 Settlement Agreement which contains "market price" language similar to Section III.C. of the 2105 RRSA. However, the term "market price" is not defined in either the 1999 Settlement Agreement or the 2015 RRSA. Despite the absence of a definition, PSNH interprets "market price" to mean the ISO-NE hourly New Hampshire real time locational marginal energy price ("LMP") ("the RT price"). Using that interpretation, PSNH currently pays for QF/IPP power purchases at the RT price pursuant to Section VI. B. of the 1999 Settlement Agreement.

Q. Please explain why GSHA believes that the Commission should not approve the use of the RT price as PSNH's avoided cost during the hybrid period.

A. Neither the 2015 RRSA nor PSNH's pre-filed testimony in this docket provide any evidence or basis upon which the Commission may properly conclude that the RT price is PSNH's actual avoided cost in the hybrid period. In the hybrid period, PSNH will still own generation, which it is required by RSA 369-B:3, IV(b)(1)(A) to use for default service, along with supplement power purchases (when needed). Absent a supplemental power purchase, PSNH's avoided cost in the hybrid period must be based on its own generation costs. Neither the 2015 RRSA nor PSNH has provided this cost data. If PSNH does supplement its own supply for default service, PSNH has not shown that it does so at ISO-NE RT market prices, or that such purchased power is the supply cost that would be avoided by PSNH's purchase of the QF power.

Furthermore, RT prices did not exist in 1999, so the parties to the 1999 Settlement Agreement could not possibly have intended that RT prices be used to determine PSNH's payments to IPPs. At that time, ISO-NE administered the New England electricity market using a *single* financial settlement procedure. IPPs selling energy in the short term energy market were paid that single price. Thus, that single price was understood in 1999 to mean the "market price" for energy.

Beginning in 2001, ISO-NE adopted and began to implement a Standard Market Design ("SMD") that included a multi-settlement procedure similar to that used in the PJM electrical system. The SMD system dramatically changed the way electric energy is priced within the ISO-NE system. The SMD system established two hourly prices: the Day Ahead ("DA") and RT prices. The ISO-NE SMD also established Locational Marginal Pricing ("LMP") under which hourly energy prices in the DA market vary depending upon a generator's location in New England. Due to the changes in market pricing that have occurred at ISO-NE since 1999, I do not believe there currently exists a single, commonly accepted definition of "market price."

Q. Are you aware of how PSNH uses its IPP power purchases?

A. My understanding is that PSNH purchases generation from IPPs and uses it to meet its load requirements for default service customers. When PSNH purchases IPP energy, title to that energy transfers to PSNH. PSNH then uses IPP power to meet its default load.

Q. Is PSNH's use of IPP power to serve default service load consistent with the 1999 Settlement Agreement?

A. No. Section IX. B.2. of the 1999 Settlement Agreement states that "[f]or so long as PSNH is required to purchase the output from IPPs under short term avoided cost rates, it shall be deemed prudent for PSNH to sell or bid IPP power into the pool at the ISO New England market clearing price."

Q. At those times when PSNH has surplus energy from its collective generating resources do you know whether PSNH sells such surplus at the DA or RT market prices?

A. No. PSNH has failed to respond to GSHA's first set of data requests that would provide information that would enable me to respond specifically to this question. However, in response to technical session data requests, PSNH has indicated that it offers its owned generation resources in the DA market and re-offers them in the RT market. PSNH accounts for resources that clear in the DA market using DA LMPs and uses RT LMPs for resources that clear in the RT market.

Q. Please explain the difference between the Day Ahead and Real Time markets.

A. The DA energy market lets market participants commit to buy or sell energy one day before the operating day in which the energy is to be used. The DA market operates to help avoid price volatility. Market participants submit bids to buy and sell energy for each hour of the operating day (i.e., the day following when commitments are made to buy and sell energy). Hourly LMPs, are established by the highest hourly energy price that is bid by generators sufficient to meet forecast load for the operating day. This market produces one daily hourly financial settlement for the LMP DA energy price for the operating day to be paid to generators and by purchasers that have participated in the day ahead bid process.

The RT energy market lets market participants buy and sell wholesale electricity during the course of the operating day. The RT energy market balances differences between day ahead commitments and the actual real time demand for and production of electricity. The RT energy market produces a separate hourly financial settlement for each operating day. It establishes the RT LMP that is either paid by or charged to participants in the DA energy market for demand or generation that deviates from the day ahead commitments. The RT hourly LMP price can be either more or less than the comparable DA LMP Price.

Q. Are there any other differences between the Real Time and Day Ahead markets?

A. The vast majority of ISO-NE power transactions settle in the DA market. The RT market represents but a very small percent of overall ISO-NE transactions and therefore does not truly reflect the "market price" of energy. For example, ISO-NE's June 2015 monthly operating report indicates that 98.7% of the energy transactions settled in the DA market in May 2015, and 97.9% in June 2015. The RT market simply reflects the settling price to account for the minor differences between the generation that is bid into the DA market and that which actually serves load.

There is also a difference in DA and RT market prices that results from changes in the way ISO-NE operates its system. Primarily to address price volatility during winter months and localized grid reliability problems, ISO-NE operates generating plants out of economic order to maintain grid reliability, and pays subsidies to certain generators using oil and liquefied natural gas ("LNG"). ISO-NE also has adopted negative pricing to address transmission constraints during low demand periods. As a result of these changes, a cumulative price difference now exists between the DA market price and the RT market price. For example, for the period January 1, 2015 to September 1, 2015, cumulative RT prices were 3.96% less than the cumulative DA prices.

Q. Is there any other problem with the 2015 RRSA as it relates to IPP purchases?

A. Yes. Section VI. B. directs PSNH to sell or bid such purchases into the pool at the ISO-NE market clearing price. GSHA believes, as explained in my testimony, that PSNH is not bidding and selling IPP power into the pool. GSHA believes that PSNH uses IPP power to meet its default service load obligations. In that regard, GSHA does not object to IPP power being so used since such use reduces the amount of power needed to be purchased from the pool thereby avoiding both distribution and transmission losses. However, GSHA believes the value of IPP power so used should reflect PSNH's actual avoided costs.

Q. What methodology does GSHA believe should be used for determining the price that PSNH pays for IPP power purchases under PURPA during the hybrid period?

A. GSHA believes that PSNH should pay IPPs based upon PSNH's avoided costs as required by and defined in PURPA and the federal regulations cited previously. The proper avoided cost rate PSNH should pay to IPPs until PSNH divests its generation assets is a rate that reflects PSNH's cost of producing energy and any additional energy purchases to serve PSNH's default service load. PSNH has not provided information regarding its cost of producing energy and the cost of its additional energy purchases. Those costs would determine PSNH's avoided cost and establish the price PSNH should pay for IPP power purchases to meet its legal PURPA obligations during the hybrid period. In the absence of that information there is no specific methodology that has been presented in this docket that would meet the legal requirements of PURPA and that would correctly describe PSNH's responsibilities and avoided cost rates for purchases of IPP power pursuant to PURPA.

Q. Turning now to the generic period covered by the 2015 RRSA, do you believe the 2015 RRSA conforms with PURPA and correctly describes PSNH's responsibilities and avoided cost rates for purchases of IPP power pursuant to PURPA?

A. No, I do not. Section III.C. of the 2015 RRSA does not limit the use of ISO-NE market prices as PSNH's avoided costs to just the hybrid period. That section applies to both periods and specifies that IPP power will be purchased by PSNH at the ISO-NE market rates. As I explained previously, PURPA obligates electric utilities to offer to purchase electrical output of QFs that are equal to the electric utilities "avoided cost" which, under PURPA, is "the incremental cost to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or facilities, such utility would generate for itself or purchase from another source."

For the post-divestiture period, Section III.B. of the 2015 RRSA states that "PSNH will transition to a competitive procurement process for default service." Once the competitive process begins, PSNH no longer will own any generating assets. PSNH will procure default service power by competitive bids from suppliers or sources other than ISO-NE. Therefore, the costs associated with PSNH's default service procurement will form the basis for PSNH's avoided costs, not the ISO-NE market price (be it the DA price or the RT price). In these circumstances, I believe Section III. C. is contrary to the legal requirements of PURPA.

Additionally, the 2015 RRSA does not specify how PSNH will transition from the hybrid period to a competitive procurement process. The generic period may consist of two parts, Part A, a transition period that will begin when the first asset is sold and a Part B, once all generating assets are sold and PSNH receives Commission approved default service rates based upon PSNH's first competitive procurement process. There is no evidence in this docket to show that the ISO-NE market price will be PSNHs avoided cost in either Part A or Part B of PSNH's generic period. Once the competitive procurement process is fully implemented and the Commission has approved PSNH default rates, it will be those rates, not the ISO-NE market price existing at that time, that will form the basis for PSNH's avoided costs.

Q. Do you believe this proceeding is the proper forum in which to address questions relating to the IPP price to be paid during the generic period?

A. Yes, I do. PSNH has argued that questions relating to the proper price to be paid to IPPs for power during its generic period should be addressed in a separate docket. PSNH argues that such a docket would apply not to just PSNH, but to other New Hampshire utilities purchasing IPP power pursuant to the requirements of Docket No. IR 14-338. However, the instant docket will continue and the legal deficiencies in the wording of the 2015 RRSA relating to IPP purchases will remain an issue here. Moreover, as I have testified, the hybrid period of PSNH's operations is specific to PSNH and does not apply to the other

New Hampshire utilities. Therefore, it would not be applicable in a generic docket. Regarding the generic period, there is a no assurance such a generic, adjudicative avoided cost docket would, in fact, be opened nor any assurance of the time by which an order establishing PSNH's avoided costs would be issued in that proposed docket. If an order were not issued prior to PSNH's divestiture of its assets, then the provisions of the 2015 RRSA (assuming it is approved) would continue to apply to PSNH's IPP purchases.

Q. PSNH has filed a rulemaking request (docketed as DRM 15-340) to address the IPP avoided cost issue and has argued that a rulemaking would be the most administratively efficient and fair process to address the issue of establishing an avoided cost methodology at this time. Do you agree?

A. No. First of all, the rule making request is contrary to the joint motion filed by PSNH on June 10, 2015 in this docket requesting an expedited adjudicative proceeding, not a rulemaking. However, with respect to the rulemaking request, I believe it would be neither administratively fair nor efficient to address IPP issues in a separate docket. GSHA has submitted an objection to that rule making request that sets forth arguments against such a rulemaking for legal, equitable and administrative efficiency reasons. GSHA and other parties have invested considerable time and effort in the instant proceeding. GSHA believes that a rulemaking is inappropriate since the matter of PSNH's avoided cost is clearly a contested matter. Further, a generic rulemaking proceeding involving other utilities is inappropriate because, as explained previously in this testimony, PSNH's avoided costs are different than other electric utilities'.

A rule making proceeding will create unnecessary delay and duplication of efforts that have occurred in this docket. Discovery on the avoided cost issue has commenced and is ongoing, and a merits hearing scheduled for November 16-17, 2015 in the instant proceeding. Requiring interested parties to participate in two proceedings that consider the same issues would be inefficient, duplicative and time consuming, and will prejudice GSHA's interests in resolving this important financial issue expeditiously. Moreover, opening a rule making will not halt the ongoing proceedings in the instant docket. Even if the avoided cost matter were placed in a separate adjudicative docket with an unknown procedural schedule, such a parallel proceeding would create duplication, delay and uncertainty and will not change the need for modifying the language of the 2015 RRSA in this docket to comport with PURPA.

Q. On page 3 of its Rulemaking Petition in DRM 15-340, PSNH states that the purpose of including language in the 2015 RRSA similar to the avoided cost/market price language contained in the 1999 Settlement Agreement is "to continue the status quo until the Commission determines that some other methodology should be implemented." Do you agree that the "status quo" should be continued?

A. No, I do not agree. It has been 15 years since the 1999 Settlement Agreement was signed. In 1999, Section V. G. of the 1999 Settlement Agreement was of little importance to most IPP generators because, at that time, most IPP power was sold under long term rate orders or contracts that specified what rates PSNH would pay for the IPP power. In addition, to the extent that the 1999 Agreement governed the rate paid for IPP purchases, in 1999 there was only one "market price," so there was little question as to how that term could be interpreted. However, as explained above, in the intervening 15 years there have been significant changes in the New England electricity markets – most notably that there are now two "market prices." Accordingly, I do not believe it is appropriate to continue using the same problematic, unclear and outdated language from the 1999 Settlement Agreement in the 2015 RRSA, or to continue to apply PSNH's interpretation of it.

Q. How should the proposed 2015 RRSA be changed to comply PURPA requirements during the hybrid and generic periods?

A. As I mentioned before, to the extent QF power purchases avoids PSNH generated power, QFs should be paid a rate based upon PSNH's generation costs. However, in the absence of information to determine a precise avoided cost rate, and as a reasonable compromise to be effective effect during the hybrid period only (i.e. until PSNH is fully divested of its generation assets), GSHA suggests that PSNH avoided cost rates for purchases of IPP power pursuant to PURPA should be the DA ISO-NE NH LMP prices.

With respect to the generic period, GSHA suggests that PSNH's avoided cost rates be based upon the Commission approved default service rates resulting from PSNH's competitive procurement process, as thereafter adjusted by subsequent Commission determination.

In view of the foregoing, I believe that Section III. C. of the proposed 2015 RRSA should be amended to read as follows:

> 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 ***Day Ahead ISO-NE New Hampshire Locational***

Marginal Price for those purchases occurring from the effective date of this Agreement until PSNH fully divests its generating assets and begins to purchase default service pursuant to NH PUC Docket No. IR 14-338. Once PSNH begins to procure default service in accordance with NH PUC Docket IR 14-338 (or any other Commission order), PSNH's responsibilities and avoided costs for purchases of IPP power pursuant to PURPA shall be based upon the lowest default service bid rate accepted by PSNH for the period when the IPP purchases are made, as adjusted by subsequent Commission orders. 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, ***or any other party***, to consider the proper calculation of Avoided Costs under PURPA and LEEPA for all electric distribution companies in New Hampshire.

Q. Does this conclude your testimony?

A. Yes.

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