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 AGREEEMENT

GRANITE STATE HYDROPOWER ASSOCIATION'S MEMORANDUM OF LAW REGARDING AVOIDED COST PAYMENTS TO QUALIFYING FACILITIES UNDER PURPA

Granite State Hydropower Association ("GSHA") submits the following memorandum of law on the avoided cost issue implicated by Section III. C. of the 2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization Agreement dated June 10, 2015 ("2015 Settlement Agreement"). Section III. C. of the 2015 Settlement Agreement provides 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[1] power pursuant to PURPA[2] and LEEPA[3] 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."*

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[1] "IPP" refers to Independent Power Producers that are qualifying facilities ("QFs") under the Public Utility Regulatory Policies Act of 1978 (PURPA"), 16 U.S. C. §2601, et. seq.
[2] "PURPA" refers to the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. §2601, et. seq.
[3] "LEEPA" refers to the Limited Electrical Energy Producers Act, N.H. RSA 362-A.

Section III.C. of the 2015 Settlement Agreement describes "avoided costs" in a manner that is inconsistent with federal law. Under 16 U.S.C. §824a-3(b), 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." "Incremental cost of alternative electric energy" is defined by applicable federal law 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 have established that electric utilities are obligated to purchase QF power. *See* 18 C.F.R. §292.303(a). The regulations at 18 C.F.R. §292.304(a)(2) further provide that payments for such purchases will 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). Such factors include, among other things, the expected or demonstrated reliability of the QF, and the savings resulting from variations in line losses from those that would have existed in the absence of purchases from a QF. *See* 18 C.F.R. §292.304(e) (2)(ii) and §292.304 (e)(4).

Because Section IIII.C. of the 2015 Settlement Agreement defines PSNH's avoided costs for QF purchases as "the market price for sales into the ISO-NE power exchange", it conflicts with the above-referenced federal law and regulations which require that utilities purchasing power from IPPs/QFs must pay for that power at rates that are based upon the utility's costs to generate electricity itself or buy from another source. Neither the federal law nor the federal regulations refer to "market prices" as avoided costs.

The term "market price" is undefined in the 2015 Settlement Agreement. It is also undefined in PSNH's 1999 Restructuring Settlement Agreement (Docket DE 99-099), which contains a provision worded similarly to Section III.C. of the 2015 Settlement Agreement and pursuant to which PSNH is currently paying for QF purchases. Despite the absence of a definition of market price in either the 1999 Settlement Agreement or the 2015 Settlement Agreement, PSNH interprets "market price" to mean the ISO-NE hourly New Hampshire real time locational marginal energy price ("LMP") ("the real time price").

The Commission may not properly conclude that the real time price is PSNH's actual avoided cost prior to divestiture of its generating assets ("the hybrid period"). During this time when PSNH still owns generation, it is required by RSA 369-B:3, IV(b)(1)(A) to use that power 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. However, the evidence in this docket shows that when PSNH does supplement its own supply for default service, PSNH makes 90% of its supplemental power purchases in the ISO-NE day ahead market. *See* Exhibit Z. Thus, 90% of the time during which PSNH makes energy purchases, it is the day ahead price that PSNH avoids by purchasing QF power. Thus, GSHA asserts it is the day ahead market price -not the real time market price- that constitutes PSNH's avoided costs when PSNH makes supplemental power purchases.

To the extent that PSNH is relying on the 1999 Agreement as authorizing payment of real time prices to QFs, that argument is unpersuasive because the real time market did not even exist in 1999. *See* Exhibit BB. Therefore, the parties to the 1999 Settlement Agreement could not possibly have intended that real time 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. Exhibit K, page 8, lines 21-22. Thus, that single price was understood in 1999 to mean the "market price" for energy. Exhibit K, page 9, lines 1-2.

Beginning in 2003, ISO-NE adopted and began to implement a Standard Market Design ("SMD") with two core components – locational marginal pricing ("LMP") and a multi-settlement system for energy. *See* Exhibit BB. Under the SMD, wholesale power ceased to be priced uniformly across New England. *Id.*, p.1. The SMD system established two hourly prices: the day ahead and real time prices. *Id.* In announcing the creation of the SMD, ISO-NE stated that the SMD structure "will provide financial certainty for market participants because prices will be 'locked in' in the day-ahead market." *Id.*, p. 2.

An explanation of the differences between the day ahead and real time energy markets is found in Mr. Norman's prefiled direct testimony, Exhibit K, at pages 10 to 11. As Mr. Norman's testimony indicates, the vast majority of ISO-NE power transactions settle in the day ahead market. Exhibit K, p. 11, line 10. The real time market represents but a very small percent of overall ISO-NE transactions and therefore does not truly reflect the "market price" of energy. Exhibit K, p. 11, lines 10-12. The real time market simply reflects the "settling price" to account for the minor differences between the generation that is bid into the day ahead market and that which actually serves load. Exhibit K, p. 11, lines 14-16.

The Federal Energy Regulatory Commission ("FERC") has ruled that a locational imbalance market price or settling price is not properly considered a utility's avoided cost for purposes of rates paid to QFs under PURPA. *See Exelon Wind 1, LLC, et al.,* 140 FERC ¶61,152 (Aug. 28, 2012). In the *Exelon Wind* decision, FERC found that the Public Utility Commission of Texas erred by accepting an energy imbalance service market locational imbalance price at a QF's node as the utility's avoided cost under PURPA. *Id.* at ¶52. "The problem with the methodology...adopted by the Texas Commission is that it is based on the price that a QF would have been paid had it sold its energy directly in the EIS[4] Market, instead of a methodology of calculating what the costs to the utility would have been for self-supplied, or purchased, energy 'but for' the presence of the QF or QFs in the markets, as required by [FERC's] regulations." *Id.* FERC noted that it had denied the purchasing utility's request to be relived of is mandatory PURPA purchases because the affected QFs lacked access to market purchasers. *Id.* Thus, according to FERC, the utility's payment of locational imbalance market prices unreasonably assumed full access by the QFs to third-party buyers in the EIS market. *Id.*

The *Exelon Wind* decision is instructive. It establishes that a state commission cannot adopt a settlement/imbalance market rate, like ISO-NE's real time market rate, as a purchasing utility's avoided cost under PURPA. Like the purchasing utility in *Exelon Wind,* PSNH has not been relieved of its obligation to purchase power from small QFs (i.e. those under 20 megawatts) because PSNH failed to demonstrate that particular individual QFs have access to ISO-NE markets. *See Public Service Company of New Hampshire,* 131 FERC ¶61,027 (Apr. 15, 2010) at ¶22. PSNH submitted data to FERC in an effort to show that *all* small QFs have access to ISO-NE's markets. *Id.* FERC refused to accept this evidence to rebut the presumption established in 18 C.F.R. §292.309(d)(1) (Exhibit FF), that QFs at or below 20 megawatts do not have nondiscriminatory access to the market. Thus, under the above-cited cases, PSNH may not treat QFs as if they are selling their power in the real time energy market. This position is further supported by the fact that PSNH uses its QF purchases to meet its own load obligations. *See* Exhibits DD and EE.

[4] "EIS" refers to Energy Imbalance Service.

At hearing, PSNH discounted the *Exelon Wind* decision, citing a footnote in a subsequent FERC order which states: "[i]t appears that various states have opted to use LMPs in calculating avoided costs…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." *Council of the City of New Orleans, Lousiana, et al.,* 145 FERC ¶61, 057 (Oct. 17, 2013), ftnt. 64. In support of its position that the *Exelon Wind* decision is of no consequence, PSNH also points to dicta in the *New Orleans* case which states that no state regulatory authority had addressed an avoided cost filing for "as available sales." *Id.* at ¶ 30. PSNH's arguments about the import of the *New Orleans* case are unpersuasive. First, the record in this case does not establish that GSHA's QFs are "as available" sellers. Second, even if that were the case, FERC made no pronouncement as to the proper avoided cost payments to these QFs. Simply put, the *New Orleans* decision is a red herring and does not undermine the validity and relevance of the *Exelon Wind* decision.

In view of the foregoing, GSHA urges the Commission to issue an order directing PSNH to pay QFs day ahead market prices for so long as the 1999 Settlement Agreement is in effect. GSHA further urges the Commission to reject the wording of Section III.C. of the 2015 Settlement Agreement and either order the Settling Parties to modify the language of the settlement agreement as Mr. Norman has suggested in his supplemental prefiled testimony, or condition approval of the Settlement Agreement on including Mr. Norman's suggested language.

Respectfully submitted,

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By its Attorneys
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Certificate of Service

I hereby certify that on this 8th day of February, 2016 a copy of the foregoing Memorandum of Law was sent by electronic mail to the Service List in this docket.

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Susan S. Geiger