



STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

DE 14-238
K

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

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

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

5

6 **Q. Please describe GSHA and your responsibilities.**

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

18

19 **Q. Please summarize your educational background.**

20 A. I received a Bachelor of Science degree in general science from the United States Naval
21 Academy in 1961. In 1970, I received a Master’s Degree in Business Administration from

1 the Harvard Graduate School of Business Administration. I also am a graduate of the
2 Navy's Nuclear Power School training program.

3
4 **Q. Please summarize your professional experience.**

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

20
21 My business experience includes familiarity with the operation of regulated and non-
22 regulated companies. I have participated in several dockets concerning avoided cost
23 determinations and have led or co-led the negotiation or renegotiation of a number of IPP

1 power purchase agreements with companies including New England Power Company,
2 Niagara Mohawk Power Corporation, Green Mountain Power Corporation, Pacific Power
3 and Light Company, Central Vermont Power Service Corporation, Public Service
4 Company of New Hampshire (“PSNH”) and the Vermont Electric Power Producers, Inc.

5
6 **Q. Have you testified previously before the New Hampshire Public Utilities Commission
7 or other regulatory bodies?**

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

15
16 **Q. What is the purpose of your testimony?**

17 A. The purpose of my testimony is to address issues arising from the manner in which the
18 2015 Public Service Company of New Hampshire Restructuring and Rate Stabilization
19 Agreement (the “2015 RRSA”) proposes to treat PSNH’s power purchases from QFs/IPPs.

20
21 **Q. How does the 2015 RRSA propose to treat PSNH’s purchases of IPP power?**

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

23 **Section III.C. Avoided Costs for IPPs:**

1 *“Unless otherwise found by the Commission or other appropriate*
2 *authority, PSNH’s responsibilities and avoided cost rates for*
3 *purchases of IPP power pursuant to PURPA and LEEPA shall be*
4 *equal to the market price for sales into the ISO-NE power*
5 *exchange, adjusted for line losses, wheeling costs, and*
6 *administrative costs. This agreement is not intended to impair*
7 *existing rate orders or contracts. Nothing in this Agreement shall*
8 *be construed as limiting the Commission’s authority with respect*
9 *to calculating avoided costs. ...”*
10

11 **Section VI. B. Purchases from Qualifying Facilities (“QFs”), Independent Power**
12 **Producers (“IPPs”) and Power Purchase Agreements:**

13 *“Unless otherwise found by the Commission or other appropriate*
14 *authority, for so long as PSNH purchases output from QFs, IPPs, or*
15 *pursuant to the PPAs, PSNH shall sell or bid such purchases into the pool*
16 *at the ISO-NE market clearing price, with the resulting costs or credits*
17 *recovered via Part 2 of the SCRC as a Non-Securitized Stranded Cost.”*
18

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

23
24 **Q. Please describe GSHA’s concerns about the above-referenced provisions of the 2015**
25 **RRSA.**

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

1 “Incremental cost of alternative electric energy” is defined as “the cost to the electric utility
2 of the electric energy which, but for the purchase from such ...small power producer, such
3 utility would **generate or purchase from another source.**” 16 U.S.C. §824a-3
4 (d)(emphasis added). Federal regulations implementing these statutory provisions
5 establish electric utilities’ obligations to purchase QF power. *See* 18 C.F.R. §292.303(a).
6 The regulations also indicate that payments for such purchases satisfy federal regulatory
7 rate requirements if they are equal to the purchasing utility’s avoided costs determined after
8 consideration of factors set forth in §292.304(e). *See* 18 C.F.R. §292.304(a)(2).
9

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

12 **A.** Section III.C. of the 2015 RRSA conflicts with the provisions of PURPA and the federal
13 regulations promulgated thereunder which require that utilities purchasing power from
14 QFs/IPPs must pay for that power at rates that are based upon the utility’s avoided costs
15 (i.e. costs that a utility like PSNH would incur to generate electricity itself or buy from
16 another source) – not market prices. In order to establish that market prices are, in fact,
17 equal to PSNH’s avoided costs, one must examine the costs PSNH incurs to generate and
18 make supplemental electricity purchases to serve its default service customers. The 2015
19 RRSA makes no provisions for doing that. In addition, using a single rate (i.e. the ISO-NE
20 market price) as PSNH’s avoided cost rate for all of PSNH’s purchases throughout the
21 duration of the 2015 RSSA is problematic because there are two different periods of
22 PSNH’s operations under the 2015 RRSA.
23

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

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

10
11 The second period addressed by the 2015 RRSA will begin following full divestiture of
12 PSNH's assets. The 2015 RRSA at Section III.B. specifies that, post-divestiture, PSNH
13 will acquire power to meet its default service load in a manner consistent with the process
14 determined by the Commission in its Docket IR-14-338, and like other utilities in this state,
15 will use periodic requests for proposals ("RFPs") or similar competitive bidding processes
16 to procure electricity from the market to meet default service needs. I refer to this post-
17 divestiture period as the *generic period*, because at that time, PSNH and other New
18 Hampshire electric utilities will all be purchasing default service power similarly, so their
19 avoided costs will be calculated in a similar or "generic" fashion.

20
21 **Q. Turning first to the hybrid period, please explain why Section III.C. of the 2015**
22 **RRSA (which defines PSNH's avoided costs in terms of ISO-NE's "market price") is**
23 **improper and therefore should not be approved.**

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

5
6 To conclude that the ISO-NE market price is an avoided cost rate for PSNH as is done in
7 the 2015 RRSA, one must first demonstrate that the ISO-NE market price is the cost (or
8 "rate" on a per unit basis) that PSNH would actually incur to generate that amount of power
9 or purchase it from another source if it did not buy QF power. In other words, the ISO-NE
10 market price must be equal to PSNH's marginal or incremental cost of generating or
11 procuring needed power if that market price is to apply to PSNH's purchases under
12 PURPA. This is the case because PURPA defines avoided cost as the "the incremental
13 cost to the electric utility of alternative electric energy" i.e., "the cost to the electric utility
14 of the electric energy which, but for the purchase of from...[the] small power producer,
15 such utility would **generate or purchase from another source.**" 16 U.S.C. §824a-3(b)
16 and (d)(emphasis added).

17
18 **Q. How does PSNH interpret "market price"?**

19 A. The term "market price" appears in both the 1999 Settlement Agreement and the 2015
20 RRSA. PSNH currently purchases IPP power pursuant to the 1999 Settlement Agreement
21 which contains "market price" language similar to Section III.C. of the 2105 RRSA.
22 However, the term "market price" is not defined in either the 1999 Settlement Agreement
23 or the 2015 RRSA. Despite the absence of a definition, PSNH interprets "market price" to

1 mean the ISO-NE hourly New Hampshire real time locational marginal energy price
2 (“LMP”) (“the RT price”). Using that interpretation, PSNH currently pays for QF/IPP
3 power purchases at the RT price pursuant to Section VI. B. of the 1999 Settlement
4 Agreement.

5
6 **Q. Please explain why GSHA believes that the Commission should not approve the use
7 of the RT price as PSNH’s avoided cost during the hybrid period.**

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

18
19 Furthermore, RT prices did not exist in 1999, so the parties to the 1999 Settlement
20 Agreement could not possibly have intended that RT prices be used to determine PSNH’s
21 payments to IPPs. At that time, ISO-NE administered the New England electricity market
22 using a *single* financial settlement procedure. IPPs selling energy in the short term energy

1 market were paid that single price. Thus, that single price was understood in 1999 to mean
2 the “market price” for energy.

3
4 Beginning in 2001, ISO-NE adopted and began to implement a Standard Market Design
5 (“SMD”) that included a multi-settlement procedure similar to that used in the PJM
6 electrical system. The SMD system dramatically changed the way electric energy is priced
7 within the ISO-NE system. The SMD system established two hourly prices: the Day
8 Ahead (“DA”) and RT prices. The ISO-NE SMD also established Locational Marginal
9 Pricing (“LMP”) under which hourly energy prices in the DA market vary depending upon
10 a generator’s location in New England. Due to the changes in market pricing that have
11 occurred at ISO-NE since 1999, I do not believe there currently exists a single, commonly
12 accepted definition of “market price.”

13
14 **Q. Are you aware of how PSNH uses its IPP power purchases?**

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

18
19 **Q. Is PSNH’s use of IPP power to serve default service load consistent with the 1999
20 Settlement Agreement?**

21 A. No. Section IX. B.2. of the 1999 Settlement Agreement states that “[f]or so long as PSNH
22 is required to purchase the output from IPPs under short term avoided cost rates, it shall be

1 deemed prudent for PSNH to sell or bid IPP power into the pool at the ISO New England
2 market clearing price.”

3
4 **Q. At those times when PSNH has surplus energy from its collective generating resources**
5 **do you know whether PSNH sells such surplus at the DA or RT market prices?**

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

12
13 **Q. Please explain the difference between the Day Ahead and Real Time markets.**

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

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

8
9 **Q. Are there any other differences between the Real Time and Day Ahead markets?**

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

17
18 There is also a difference in DA and RT market prices that results from changes in the way
19 ISO-NE operates its system. Primarily to address price volatility during winter months and
20 localized grid reliability problems, ISO-NE operates generating plants out of economic
21 order to maintain grid reliability, and pays subsidies to certain generators using oil and
22 liquefied natural gas (“LNG”). ISO-NE also has adopted negative pricing to address
23 transmission constraints during low demand periods. As a result of these changes, a

1 cumulative price difference now exists between the DA market price and the RT market
2 price. For example, for the period January 1, 2015 to September 1, 2015, cumulative RT
3 prices were 3.96% less than the cumulative DA prices.
4

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

6 A. Yes. Section VI. B. directs PSNH to sell or bid such purchases into the pool at the ISO-
7 NE market clearing price. GSHA believes, as explained in my testimony, that PSNH is not
8 bidding and selling IPP power into the pool. GSHA believes that PSNH uses IPP power
9 to meet its default service load obligations. In that regard, GSHA does not object to IPP
10 power being so used since such use reduces the amount of power needed to be purchased
11 from the pool thereby avoiding both distribution and transmission losses. However, GSHA
12 believes the value of IPP power so used should reflect PSNH's actual avoided costs.
13

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

16 A. GSHA believes that PSNH should pay IPPs based upon PSNH's avoided costs as required
17 by and defined in PURPA and the federal regulations cited previously. The proper avoided
18 cost rate PSNH should pay to IPPs until PSNH divests its generation assets is a rate that
19 reflects PSNH's cost of producing energy and any additional energy purchases to serve
20 PSNH's default service load. PSNH has not provided information regarding its cost of
21 producing energy and the cost of its additional energy purchases. Those costs would
22 determine PSNH's avoided cost and establish the price PSNH should pay for IPP power
23 purchases to meet its legal PURPA obligations during the hybrid period. In the absence of

1 that information there is no specific methodology that has been presented in this docket
2 that would meet the legal requirements of PURPA and that would correctly describe
3 PSNH's responsibilities and avoided cost rates for purchases of IPP power pursuant to
4 PURPA.

5
6 **Q. Turning now to the generic period covered by the 2015 RRSA, do you believe the 2015**
7 **RRSA conforms with PURPA and correctly describes PSNH's responsibilities and**
8 **avoided cost rates for purchases of IPP power pursuant to PURPA?**

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

17
18 For the post-divestiture period, Section III.B. of the 2015 RRSA states that "PSNH will
19 transition to a competitive procurement process for default service." Once the competitive
20 process begins, PSNH no longer will own any generating assets. PSNH will procure
21 default service power by competitive bids from suppliers or sources other than ISO-NE.
22 Therefore, the costs associated with PSNH's default service procurement will form the
23 basis for PSNH's avoided costs, not the ISO-NE market price (be it the DA price or the RT

1 price). In these circumstances, I believe Section III. C. is contrary to the legal requirements
2 of PURPA.

3
4 Additionally, the 2015 RRSA does not specify how PSNH will transition from the hybrid
5 period to a competitive procurement process. The generic period may consist of two parts,
6 Part A, a transition period that will begin when the first asset is sold and a Part B, once all
7 generating assets are sold and PSNH receives Commission approved default service rates
8 based upon PSNH's first competitive procurement process. There is no evidence in this
9 docket to show that the ISO-NE market price will be PSNHs avoided cost in either Part A
10 or Part B of PSNH's generic period. Once the competitive procurement process is fully
11 implemented and the Commission has approved PSNH default rates, it will be those rates,
12 not the ISO-NE market price existing at that time, that will form the basis for PSNH's
13 avoided costs.

14
15 **Q. Do you believe this proceeding is the proper forum in which to address questions**
16 **relating to the IPP price to be paid during the generic period?**

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

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

7
8 **Q. PSNH has filed a rulemaking request (docketed as DRM 15-340) to address the IPP**
9 **avoided cost issue and has argued that a rulemaking would be the most**
10 **administratively efficient and fair process to address the issue of establishing an**
11 **avoided cost methodology at this time. Do you agree?**

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

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

12
13 **Q. On page 3 of its Rulemaking Petition in DRM 15-340, PSNH states that the purpose**
14 **of including language in the 2015 RRSA similar to the avoided cost/market price**
15 **language contained in the 1999 Settlement Agreement is “to continue the status quo**
16 **until the Commission determines that some other methodology should be**
17 **implemented.” Do you agree that the “status quo” should be continued?**

18 A. No, I do not agree. It has been 15 years since the 1999 Settlement Agreement was signed.
19 In 1999, Section V. G. of the 1999 Settlement Agreement was of little importance to most
20 IPP generators because, at that time, most IPP power was sold under long term rate orders
21 or contracts that specified what rates PSNH would pay for the IPP power. In addition, to
22 the extent that the 1999 Agreement governed the rate paid for IPP purchases, in 1999 there
23 was only one “market price,” so there was little question as to how that term could be

1 interpreted. However, as explained above, in the intervening 15 years there have been
2 significant changes in the New England electricity markets – most notably that there are
3 now two “market prices.” Accordingly, I do not believe it is appropriate to continue using
4 the same problematic, unclear and outdated language from the 1999 Settlement Agreement
5 in the 2015 RRSA, or to continue to apply PSNH’s interpretation of it.
6

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

9 A. As I mentioned before, to the extent QF power purchases avoids PSNH generated power,
10 QFs should be paid a rate based upon PSNH’s generation costs. However, in the absence of
11 information to determine a precise avoided cost rate, and as a reasonable compromise to be
12 effective effect during the hybrid period only (i.e. until PSNH is fully divested of its
13 generation assets), GSHA suggests that PSNH avoided cost rates for purchases of IPP power
14 pursuant to PURPA should be the DA ISO-NE NH LMP prices.
15

16 With respect to the generic period, GSHA suggests that PSNH’s avoided cost rates be based
17 upon the Commission approved default service rates resulting from PSNH’s competitive
18 procurement process, as thereafter adjusted by subsequent Commission determination.
19

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

22 Unless otherwise found by the Commission or other appropriate authority, PSNH’s
23 responsibilities and avoided cost rates for purchases of IPP power pursuant to PURPA
24 and LEEPA shall be equal to the *Day Ahead ISO-NE New Hampshire Locational*

1 *Marginal Price for those purchases occurring from the effective date of this*
2 *Agreement until PSNH fully divests its generating assets and begins to purchase*
3 *default service pursuant to NH PUC Docket No. IR 14-338. Once PSNH begins to*
4 *procure default service in accordance with NH PUC Docket IR 14-338 (or any other*
5 *Commission order), PSNH's responsibilities and avoided costs for purchases of IPP*
6 *power pursuant to PURPA shall be based upon the lowest default service bid rate*
7 *accepted by PSNH for the period when the IPP purchases are made, as adjusted by*
8 *subsequent Commission orders. This Agreement is not intended to impair existing rate*
9 *orders or contracts. Nothing in this Agreement shall be construed as limiting the*
10 *Commission's authority with respect to calculating avoided costs. The Settling parties*
11 *agree not to oppose the opening of a generic docket or rulemaking upon petition by any*
12 *Settling Party, or any other party, to consider the proper calculation of Avoided Costs*
13 *under PURPA and LEEPA for all electric distribution companies in New Hampshire.*
14

15 **Q. Does this conclude your testimony?**

16 **A. Yes.**

17 1370902_1



Exhibit 1

RESUME OF RICHARD A. NORMAN

SUMMARY: Extensive experience in the startup and management of various energy companies.

EXPERIENCE:

ESSEX HYDRO ASSOCIATES, .L.L.C.

Boston, MA

2014 – Present Chairman

1983 – 2014 Founder - President

Developer and operator of hydroelectric projects regulated by the Federal Energy Regulatory Commission.

- * Directed the development, federal licensing, permitting, financing, construction and operation of 13 small scale hydroelectric projects encompassing \$75 million in assets and 35 MW of installed capacity. All regulated by the Federal Energy Regulatory Commission.
- * Negotiated and administered construction and long-term loan agreements, limited partnership equity arrangements, construction contracts, power contracts and property tax agreements.
- * Served as Chief Executive Officer
- * Member of the Unsecured Creditors Committee in the PSNH bankruptcy proceeding

1974 – Present

HONEOYE STORAGE CORPORATION

Honeoye, NY

Vice President, Secretary and Treasurer

Underground natural gas storage facility regulated by the Federal Energy Regulatory Commission. Wholly owned by Consolidated Energy Development Company

- * Directed the construction, financing and operation of this \$8 million underground natural gas storage company. This company is regulated by the Federal Energy Regulatory Commission and sells gas storage service to major northeastern gas marketing and distribution companies.

- * Manages the financial, administration, legal and regulatory affairs of the company.

1993 - 2005 ARC GLOBAL MARITIME, INC. Boston, MA

Director - Treasurer

Operator of contract small bulk carriers in Caribbean/US Gulf Coast commerce.

- * Managed the legal and financial affairs of the company.

1993-2002 INTERNATIONAL HUMAN RESOURCES DEVELOPMENT CORPORATION Boston, Mass.

Lecturer/Workshop coordinator

IHRDC presents seminars to international oil and gas industry. Lectured to junior executives of various international oil and gas companies specializing in Liquified Natural Gas, the Electrical Industry and Energy Project financing.

1989 - 1991 OXFORD ENERGY, INC. Boston, MA

Vice President Development - Eastern Region

- * Responsible for identification and development of Oxford's proposed 37 MW tire to energy project in Lackawanna, NY. Assisted in the development of a 30 MW tire to energy project in Connecticut.
- * Development tasks include site identification, site acquisition, power contract negotiations, acquisition of \$45 million New York State tax exempt bond authorization, development of tire supply strategy, government relations and local and state permit negotiations.

1982 - 1983 ESSEX COMPANY Lawrence, MA

President

- * Oversaw development of a 16 MW hydroelectric project in Lawrence, Massachusetts. First major U.S. redevelopment of a

small scale hydroelectric project. Regulated by the Federal Energy
Regulatory Commission.

1974 - 1983

J. MAKOWSKI ASSOCIATES, INC.

Boston, MA

Vice President and Executive Vice President

- * Consultant for various clients regarding underground natural gas storage and liquefied natural gas projects (1974-1977).
- * Managed construction, operation, long-term financing of Honeoye Storage Corporation, a FERC regulated underground storage company (1974-present).
- * Directed firms small scale hydroelectric development program (1978-1983) (subsequently acquired by Essex Hydro Associates in 1983).

1972 - 1974

U.S. DEPARTMENT OF COMMERCE

Washington, DC

Special Assistant - Assistant Secretary of Commerce for Maritime Affairs

- * Acted as special advisor to Maritime Administrator concerning U.S. program to construct liquefied natural gas tankers.
- * Participated in negotiations with various U.S. ship yards, ship owners and financing companies including review of LNG vessel designs and estimates of capital and operating costs.

1970 - 1972

CABOT CORPORATION

Boston, MA

Assistant to President - Distrigas Corporation

- * Project Manager for the design, construction and operating plan of the USS Massachusetts, a 5,000m³ liquefied natural gas (LNG) barge.
- * Worked with the naval engineering design firm, negotiated the ship construction contract and also the towing agreement for the project.

1962 - 1968

UNITED STATES NAVY

- * Various engineering, weapons and operational billets - USS Seawolf (SSN575) and USS Daniel Boone (SSBN629).
- * Qualified officer of the deck and engineering watch officer

EDUCATION: HARVARD GRADUATE SCHOOL OF
BUSINESSADMINISTRATION

1970 - Master in Business Administration, with Distinction

U.S. NAVAL ACADEMY
1961 - Bachelor of Science

NAVAL NUCLEAR POWER TRAINING PROGRAM
1961 - 1962 Vallejo, California - Idaho Falls, Idaho

U.S. NAVY SUBMARINE SCHOOL
1962 - New London, CT

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