DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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| IN THE MATTER OF NorthWestern Energy's Application for Interim and Final Approval of Revised Tariff No. QF-1, Qualifying Facility Power Purchase | REGULATORY DIVISION<br><br>Docket No. D2016.5.39 |

**PRE-FILED DIRECT TESTIMONY OF R. THOMAS BEACH ON BEHALF OF VOTE SOLAR AND MONTANA ENVIRONMENTAL INFORMATION CENTER**

Department of Public Service Regulation
Montana Public Service Commission
Docket No. D2016.5.39
Avoided Cost Rate Filing – Schedule QF-1
NorthWestern Energy

**PRE-FILED DIRECT TESTIMONY OF**

**R. THOMAS BEACH**

**ON BEHALF OF VOTE SOLAR AND MONTANA ENVIRONMENTAL INFORMATION CENTER**

**TABLE OF CONTENTS**


page

Executive Summary……. ii

I. Introduction……..1

II. Background……..2

III. Applicable PURPA Policies…… 4

IV. Analysis of NWE's Current Avoided Costs…….8

A. NWE's Current Need for Resources…….8

B. Blended Market + Combined Cycle Method……..11

C. Issues with NWE's Avoided Costs Using the "Peaker Method"……17

1. Methodology……17

2. Avoided Energy Costs……..18

3. Avoided Capacity Costs: Solar Capacity Value……...21

V. Other Benefits and Costs of Incremental Solar Generation...……..28

A. Hedging Benefits……..29

B. Market Price Mitigation……32

C. Avoided Transmission Costs……34

D. Local Economic Benefits……..37

E. Integration Costs……...37

VI. "Gold Rush" Concerns.……39

**EXHIBITS**

| | |
|---|---|
| RTB-1 | CV of R. Thomas Beach |
| RTB-2 | Vote Solar's Proposed Avoided Costs: Blended Market + Combined Cycle |
| RTB-3 | Certain discovery responses from NWE |

## Executive Summary

This testimony presents the position of Vote Solar and Montana Environmental Information Center (collectively, "Vote Solar") on the proposal of NorthWestern Energy ("NWE") to revise its Schedule QF-1 avoided cost rate applicable to solar QFs who seek to provide new renewable generation to NWE. The utility asserts that its present QF-1(a) avoided cost rate is now outdated, such that the rate exceeds its current avoided costs. NWE claims that it may be forced to execute numerous 25-year contracts with solar QFs up to 3 MW in size, resulting in long-term overpayments from its ratepayers.

Vote Solar has carefully evaluated NWE's current long-term avoided costs, using two different methodologies, to see if the current QF-1(a) rate exceeds the utility's avoided costs. The first methodology is the blended market + combined cycle approach, as adopted in Orders No. 7199e and 7108e. This is the method that the Commission used to set NWE's present QF-1 rates. Vote Solar calculates NWE's current avoided costs using this methodology, with an updated natural gas forecast and assuming that the utility's avoided resource is the internal combustion engine (ICE) units that NWE plans to install in 2019. These ICE units are the next resource planned in NWE's *2015 Integrated Resource Plan*, and should be the avoided resource in recognition of the FERC's requirement to consider the short lead times and small capacity increments available from QFs. Our calculation also makes a small change to represent more accurately the wholesale market costs avoided by solar resources, and adds to all years the value of the renewable attributes that would be conveyed to the utility in the "with carbon" prices. With these updates, Vote Solar calculates new 25-year QF-1(a) avoided cost rates for solar resources on NWE's system that are essentially the same as the existing QF-1(a) rates, indicating that no change in avoided cost rates is necessary at this time.

The second avoided cost methodology that Vote Solar examines is NWE's proposal in this case to use a new approach – the peaker method – for calculating its avoided costs. The Commission should consider whether this methodology is a reasonable approach for NWE, given that the peaker method assumes that the utility system is in equilibrium with a least-cost peaker as the only capacity need, a questionable assumption given NWE's very significant capacity deficit. If the Commission wishes to use this approach, Vote Solar recommends a number of changes to the utility's calculations of its avoided costs for both energy and capacity. First, NWE's production cost modeling incorrectly assumes that its avoided energy costs are zero in certain hours

when its marginal costs exceed market prices. In reality, in these hours, market prices are the utility's avoided costs, because the utility has the opportunity to substitute lower-cost market power (or QF power priced at market) for its more expensive marginal system resource. Second, a revised and updated gas forecast should be used to calculate avoided energy costs. Third, and most important, NWE has significantly understated the capacity value of utility-scale solar facilities in Montana. The utility's valuation of solar capacity applies an unreasonably stringent "85% exceedance" standard to solar resources, a standard that is not used by any other control area operator in the U.S. The result is a solar capacity value of just 9.6% of the solar nameplate capacity, which is three to five times lower than the solar capacity values of other Northwest utilities. Vote Solar examines several other, more reasonable approaches to calculating the capacity value of solar on NWE's system. These approaches measure the capacity factor of solar resources over several different sets of the top load hours in NWE's on-peak period, including two summer and three winter months. These approaches are versions of the capacity factor methods used widely by other utilities and control area operators. They result in capacity values for utility-scale solar on NWE's system that range from 38% to 51% of the solar nameplate. Vote Solar recommends that the Commission adopt a solar capacity value equal to 38% of nameplate, at the low end of this range, which is the value that results from the structure of the current QF-1(a) rate and which would be similar to the solar capacity values used by neighboring utilities in the West. Our calculations also improve upon NWE's approach by using a full ten years of data and employing actual solar insolation data to more accurately simulate solar output. With these modifications to the peaker method, Vote Solar's re-calculation of NWE's avoided costs using this method also produces QF-1(a) avoided cost rates that are similar to today's rates.

These two independent analyses both show that no change is needed in NWE's current avoided cost rates for solar QFs.

This testimony also discusses several other benefits and costs of utility-scale solar QF generation for ratepayers that can be quantified but that have not been included traditionally in the Schedule QF-1 rates. These benefits include the following:

- **Hedging** against volatility in fossil fuel prices
- **Reductions in prices** in the wholesale markets in the West
- **Avoided transmission capacity** costs
- **Local economic benefits** from developing Montana's solar resources

These benefits significantly exceed the modest costs that NWE may incur to integrate

these new solar resources into its system.

Vote Solar is not recommending that these additional net benefits should be included in the Schedule QF-1(a) rate at this time. However, the Commission should consider these added net benefits in its deliberations, and should find that they result in ratepayers receiving a good deal if NWE contracts for new solar generation at either (1) existing QF-1(a) prices or (2) the similar updated prices that Vote Solar has presented above.

Finally, Vote Solar disagrees with NWE's assertion that it is facing an imminent "gold rush" of small solar QFs in its service territory that would be harmful to its ratepayers. First, and most important, for the reasons presented above, today's QF-1(a) rates accurately reflect NWE's current avoided costs, so there would be no ratepayer harm if NWE were to continue to sign contracts with 3 MW solar QFs at these rates. Second, NWE needs the capacity that these solar contracts will provide, given its severe capacity deficit. Third, this new solar capacity will add diversity to NWE's existing renewable resources, complementing its wind and hydro assets, and will help the utility meet its renewable portfolio standard ("RPS") requirements. Fourth, these projects will provide other quantifiable net benefits to NWE ratepayers that are not included in the QF-1(a) rates. Finally, the amount of solar capacity that can be added at the QF-1(a) rate is limited by the maximum 3 MW size of these projects, and by the inherent difficulties in siting and developing successful QF projects. Based on the existing pace of successful contracting under the existing QF-1(a) rate, as well as the experience in other neighboring states that have experienced significant solar QF development in the last several years, NWE has substantially over-estimated the likely success of small solar QF projects in its service territory. The most recent NWE interconnection queue, provided to Vote Solar in discovery, shows that the utility has just 19 active solar projects that would qualify for the QF-1(a) tariff in its queue, representing 52 MW of capacity. Assuming that only a fraction of this capacity will be developed successfully, as has been the case under NWE's existing QF-1 rates, there is hardly a "gold rush" of solar QFs in NWE's service territory.

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## I. INTRODUCTION

**Q: Please state your name, address, and business affiliation.**

A: My name is R. Thomas Beach. I am principal consultant of the consulting firm Crossborder Energy. My business address is 2560 Ninth Street, Suite 213A, Berkeley, California 94710.

**Q: Please describe your experience and qualifications.**

A: I have 35 years of experience in utility analysis, resource planning, and rate design. I began my career at the California Public Utilities Commission ("CPUC"), working from 1981-1984 on the initial implementation in California of the Public Utilities Regulatory Policies Act ("PURPA") of 1978. I also served for five years as a policy advisor to three CPUC commissioners. Since entering private practice as a consultant in 1989, I have served as an expert witness in a wide range of utility proceedings before many state utility commissions. This includes sponsoring testimony on PURPA-related issues, including the calculation of avoided cost prices, in state regulatory proceedings in California, Idaho, Oregon, Nevada, North Carolina, Utah, and Vermont. I also have extensive experience on public policy issues related to the development and deployment of solar generation, both photovoltaic ("PV") and solar thermal. This includes assessing the costs and benefits of both small, distributed solar and large, utility-scale systems. Prior to this professional experience, I earned degrees in English and Physics from Dartmouth College and a Masters in Mechanical Engineering from the University of California at Berkeley. My CV is included as Exhibit RTB-1.

**Q: On whose behalf are you testifying in this proceeding?**

A: I am appearing on behalf of Vote Solar and the Montana Environmental Information Center (collectively, "Vote Solar"). Vote Solar is a non-profit grassroots organization working to foster economic opportunity, promote energy independence, and fight climate change by making solar a mainstream energy

resource across the United States. Since 2002, Vote Solar has engaged in state, local, and federal advocacy campaigns to remove regulatory barriers and implement key policies needed to bring solar to scale. Vote Solar is not a trade group and does not have corporate members. Vote Solar has more than 70,000 members throughout the United States, including members and supporters in NorthWestern Energy's Montana service territory.

Montana Environmental Information Center ("MEIC") is a non-profit environmental advocate founded in 1973 by Montanans concerned with protecting and restoring Montana's natural environment. MEIC plays an active role in promoting Montana clean energy projects and policies, including advocating for the expansion of responsible, renewable energy and energy efficiency; and supporting policies that insulate energy consumers from fuel price risk. At the state level, MEIC leads the effort to pass policies that help expand clean, affordable, reliable and efficient energy solutions for Montana. MEIC represents approximately 5,000 members, including roughly 3,500 members in Montana.

**Q: Have you previously testified or appeared as a witness before the Montana Public Service Commission?**

A: No, I have not.

**Q: Do you have any exhibits?**

A: Yes. Exhibit RTB-1 is my CV. Exhibit RTB-2 is my calculation of NWE's avoided costs using the blended market + combined cycle method. Exhibit RTB-3 includes certain discovery responses from NWE.

## II. BACKGROUND

**Q: Please describe NWE's proposal in this case.**

A: NWE proposes to revise its QF-1 avoided cost rate applicable to solar qualifying facilities (QFs) who seek to provide new renewable generation to NWE. The utility asserts that its present QF-1(a) avoided cost rate is now outdated, because the rate exceeds its current avoided costs. NWE claims that it may be forced to execute numerous 25-year contracts with solar QFs up to 3 MW in size, resulting in long-term overpayments from its ratepayers.[1]

**Q: What does the utility cite as evidence that there could be a "gold rush" of solar QFs seeking to obtain contracts?**

A: NWE's primary evidence of the alleged "gold rush" of solar QFs in its service territory is the number of possible solar projects in its current interconnection queue.[2]

**Q: What remedy does the utility propose?**

A: NWE asks the Commission to revise its QF-1(a) rate based on a new calculation of its long-term avoided energy and capacity costs. These revised avoided costs use a production cost analysis of NWE's avoided energy costs, plus a small adder for avoided capacity costs.[3] NWE's capacity adder assumes that solar generation would contribute capacity to NWE's system equal to just 9.6% of a utility-scale solar facility's nameplate capacity.[4] **Table 1** below shows NWE's current and proposed QF-1(a) rates for solar QFs.[5] The utility's proposed QF-1(a) rates represent decreases of 31% (with carbon) and 46% (without carbon) from the utility's presently-effective QF-1(a) rates.

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[1] NWE Testimony (Hines), at pp. JDH-3 to JDH-8.
[2] *Ibid*., at pp. JDH-7 to JDH-8.
[3] NWE Testimony (Hansen) for avoided energy costs, and NWE Testimony (Bushnell) for avoided capacity costs.
[4] NWE Testimony (Bushnell), at pp. JBB-5 to JBB-6 and JBB-10 to JBB-11. Mr. Bushnell's original testimony has a solar capacity contribution of 7.8% of nameplate, subsequently corrected in discovery to 9.6% of nameplate.
[5] From NWE Testimony (Bushnell), at Exh. JBB-2, pp. 8 and 9 of 10, with corrected solar capacity contribution of 9.6% instead of 7.8%.

**Table 1:** *Current and Proposed QF-1(a) Tariff Rates*

| 25-year levelized prices | Current QF-1(a) Tariff | NWE Proposed QF-1 Tariff | |
|---|---|---|---|
| Carbon included? | No | No | Yes |
| On-peak price ($/kWh) | 0.09273 | 0.03027 | 0.03988 |
| Off-peak price ($/kWh) | 0.05314 | 0.03027 | 0.03988 |
| Capacity price ($ per kW-yr) | n/a | $13.55 | |
| Solar average price ($/kWh) | 0.06609 | 0.03597 | 0.04558 |
| Change from Current QF-1(a) | | -46% | -31% |

## III. APPLICABLE PURPA POLICIES

**Q: Mr. Beach, as an expert with 35 years of experience in PURPA-related issues, please provide your perspective on the economic intent and regulatory innovations of PURPA.**

A: Congress enacted PURPA to encourage a new, free market for the independent development of generation from resources that would reduce our nation's dependence on fossil fuels, with the goal of increasing the energy security and independence of the United States. PURPA required public utilities, who enjoyed a state-sponsored monopoly in the generation market, to purchase power from cogeneration and small renewable power producers, collectively called "qualifying facilities" or QFs, at prices that could not exceed the utilities' "avoided cost." In the words of the statute, avoided costs are "the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."[6]

Congress intended PURPA's must-take requirement at an avoided cost price as the means to offset the monopsony power[7] of the utility as the sole buyer of

[6] Section 210(d) of PURPA (92 Stat. 3117, 16 U.S.C. § 2601).

[7] A monopsony market is similar to a monopoly except that a large buyer, not a large seller, controls a large proportion of the market and drives the prices down. A monopsony is sometimes

generation in its service territory. Congress limited the purchase price to the utility's avoided cost in order to achieve a balance between the interests of ratepayers and PURPA generators, so that the price would be both "just and reasonable to the electric consumers of the electric utility and in the public interest" and "not discriminate against qualifying cogenerators or qualifying small power producers" in comparison to the utility's other supply options.[8] The FERC and the courts have found that a price set at 100% of the utility's avoided cost satisfies this dual standard and the intent of PURPA to encourage QF development.[9]

In essence, the economic design of PURPA was to simulate the outcome of a free and open market that would encourage QF development, if QFs could offer generation at a competitive cost equal to or less than the incremental cost to the utility of building its own generation or procuring power from other sources. PURPA generation purchased at the avoided cost price would be reasonable for the consumer because it would be no more expensive than if the monopoly utility had generated the power itself or purchased it from another source.

**Q: Who establishes the avoided cost prices paid to QFs?**

A: State regulatory authorities, such as this Commission, adopt avoided cost prices for the regulated utilities under their jurisdiction, following the guidelines set forth in the FERC's rules implementing PURPA.[10]

**Q: PURPA was enacted almost four decades ago. Have Congress and the FERC enacted significant changes to PURPA since then?**

A: Yes. PURPA was the key first step in the development of independent power generation in the U.S. The success of this new industry in many states under the

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also referred to as the buyer's monopoly.

[8] Section 210(b) of PURPA, 16 U.S.C. § 824a-3(b).

[9] 18 C.F.R. § 292.304(b)(2); *American Paper Inst., Inc. v. American Elec. Power Serv. Corp.*, 103 S. Ct. 1921 (1983).

[10] 18 C.F.R. § 292.304.

PURPA framework enabled the creation, in the 1990s and early 2000s, of viable and less-regulated markets for electric generation in many regions of the U.S. Over time, these markets have expanded to include, in some states, competition in generation at both retail and wholesale levels, as well as non-discriminatory access to electric transmission through regional transmission organizations ("RTOs") with independent system operators of the transmission grid. In addition, many states have enacted renewable portfolio standard ("RPS") programs, based on the states' traditional authority over utility procurement, designed to provide long-term markets for the new renewable generation that previously had been developed principally through PURPA. Responding to these developments, Congress enacted the Energy Policy Act of 2005 ("EPAct"), which implemented a new Section 210(m) of PURPA. This section allowed a utility to petition the FERC for relief from the "must purchase" requirement of PURPA if FERC found that QFs in that utility's territory have access to sufficiently competitive wholesale markets for long-term sales of capacity and electric energy.

**Q: Have utilities in other states and regions successfully petitioned the FERC under Section 210(m) to end the PURPA must-purchase obligation?**

A: Yes. However, this has occurred in states that have opened their generation market to substantial competition at the wholesale level. For example, when the major California investor-owned utilities ("IOUs") successfully petitioned the FERC in 2011 for relief from the PURPA must-purchase obligation for QFs larger than 20 MW, they were able to show the FERC that California had taken the following steps to provide viable long-term wholesale markets for QF generation:

- A CPUC-approved program for the IOUs to conduct competitive solicitations for long-term contracts with existing or new cogeneration QFs;

- A state-enacted RPS that required the California IOUs to purchase a specified percentage of their generation from RPS-eligible renewable generators by a date certain, implemented through regular competitive solicitations to procure RPS generation under long-term contracts of up to 25 years;

- A resource adequacy program requiring the IOUs to purchase capacity from QFs and merchant generators to meet near-term resource adequacy requirements; and

- Non-discriminatory access to the transmission system and to an auction-based, day-ahead wholesale energy market operated by a FERC-regulated RTO, the California Independent System Operator ("CAISO").[11]

It is important to note that the PURPA must-purchase obligation remains in place in California (and in most other RTO/ISO footprints) for QFs up to 20 MW in size, and that the must-purchase obligation can be re-instated if the FERC finds that long-term wholesale markets are no longer available to QFs. The fact that the U.S. Congress and the FERC have found that a state must create long-term wholesale markets for energy and capacity from QFs in order to end PURPA's must-purchase obligation indicates clearly that the fundamental purpose of the PURPA program continues to be to provide such a long-term market for QF generation.[12]

**Q: Do you agree that the 25-year contracts available to QFs in Montana provide a long-term market for QF generation in the state?**

A: Yes. As noted by NWE witness Mr. Hines, Montana state law expresses a preference for long-term QF contracts.[13] In my experience, given the significant capital investment required to develop new QF projects, developers need

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[11] See *Order Granting Application to Terminate Purchase Obligation* (issued June 16, 2011) in FERC Docket No. QM11-2-000, 135 FERC ¶ 61,234.

[12] It has been asserted that the RTOs in which the PURPA must-purchase obligation has ended do not provide markets for wholesale sales longer than three years. The flaw in this argument is that the key feature necessary to end the PURPA must-purchase obligation is that renewable and cogeneration resources must have access to long-term power purchase agreements. These new long-term markets are based on procurement programs, principally RPS programs, sponsored by the states under their authority over utility procurement, not through the RTOs. Again, the California RPS program noted above is an example of such a state-sponsored RPS program that provides long-term contracting opportunities for renewable QFs in California. 29 states have RPS programs, including Montana, and an additional 8 states have less stringent renewable portfolio goals; the states whose utilities operate within RTOs and have deregulated wholesale markets are generally included within these 37 states. See http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2014/11/Renewable-Portfolio-Standards.pdf.

[13] NWE Testimony (Hines), at p. JDH-10.

contracts of this length in order to develop QF projects successfully.

**Q: What types of renewable QF generation have been developed historically in NWE's service territory?**

A: Renewable QF development in NWE's service territory to date has been principally wind and small hydro QFs. For example, the QF wind projects developed recently under Schedule QF-1 have obtained long-term, 25-year contracts with NWE.[14] NWE does not presently purchase power from solar QFs on its system, although it has signed nine long-term contracts for 26 MW of solar QFs that are still under development.[15]

## IV. ANALYSIS OF NWE'S CURRENT AVOIDED COSTS

### A. NWE's Current Need for Generation Resources

**Q: What is NWE's current need for generation resources?**

A: Based on NWE's *2015 Integrated Resource Plan (2015 IRP)*, NWE today has a substantial deficit in committed capacity; its present reserve margin is -28%.[16] By any standard measure of resource adequacy in the utility industry, NWE needs to add generation capacity in order to provide adequate resources to meet its customers' long-term needs. The utility's *2015 IRP* acknowledges this need, and presents a ten-year plan of capacity additions to remedy this resource deficit. In the past, NWE has relied on surpluses in the regional market to serve its capacity needs, but, as the *2015 IRP* recognizes, these surpluses may be ending due to the

[14] See NWE's *2015 Integrated Resource Plan (2015 IRP)*, at Volume 1, Table 8-6 for future QF wind resources under Schedule QF-1; for existing wind projects, see *2015 IRP*, Volume 2, page 35 of 2652 (titled "NWE Existing Energy Supply Resources as of February 11, 2015").

[15] NWE Testimony (Hines), at pp. JDH-7 and JDH-12, supplemented by NWE response to PSC Data Request PSC-002, PSC-005, and NWE's current interconnection queue (for the project capacities).

[16] *2015 IRP*, at Figures 1-3 and 7-3.

closure of aging coal-fired plants.[17]

**Q: Can solar QFs provide a significant source of capacity to the NWE system?**

A: Yes. As I will discuss in more detail below, NWE has substantially underestimated the capacity contribution that solar PV generation could make to NWE's system. Recent integrated resource plans or solar capacity studies from other utilities in the West, including several utilities that neighbor NWE, value solar PV capacity at 30% to 50% of its nameplate capacity, far above the 9.6% capacity credit that NWE proposes. The solar capacity values used by these other western utilities are summarized in **Table 2**.

**Table 2:** *Solar PV Capacity Values for Other Western Utilities*

| Utility | Solar Capacity Value (as a % of nameplate) | *Source* |
|---|---|---|
| Idaho Power | 28% to 51% | *2015 Idaho Power IRP*, at Table 5.1, pp. 50-51. |
| PacifiCorp – East | 34% to 39% | *2015 PacifiCorp IRP*, Vol. 2, at Appendix N, Table N-1. |
| Public Service of Colorado | 40% | Utility-scale solar in Xcel Energy's *2013 Distributed Solar Generation* study. |
| Avista | 37% to 45% | Summer only. Assumes 50 MW of solar. *2015 Electric IRP*, at Table 9.3. |

**Q: Haven't some studies of the capacity value of solar shown that its capacity value decreases as more solar is added?**

A: Yes, but such studies show that this effect does not become significant until substantial amounts of solar capacity have been added, on the order of a 10% penetration of solar in terms of energy (kWh) generated.[18] The small amount (5

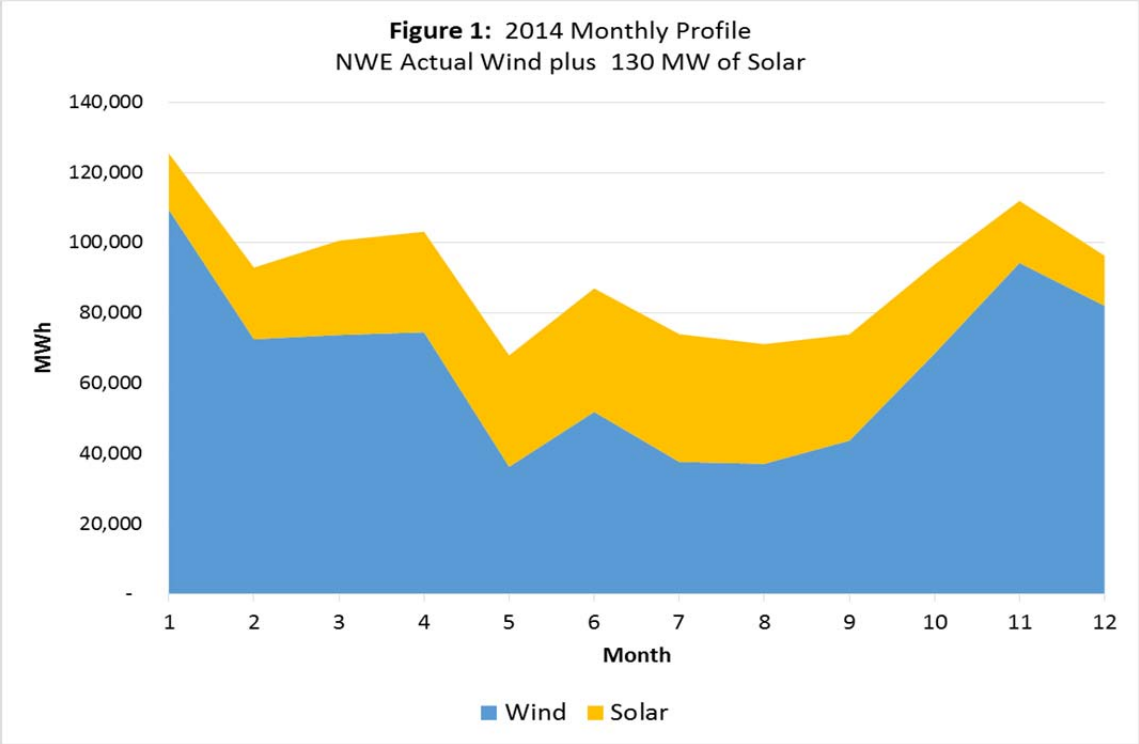
[17] *Ibid.*, at pp.1-10 to 1-11, 7-3 to 7-5.

[18] Lawrence Berkeley National Laboratory's (LBNL) June 2012 study *Changes in the Economic Value of Variable Generation at High Penetration Levels: Pilot Case Study of California* showed that solar photovoltaics (PV), solar thermal, and wind resources have similar value on the California grid at 10% penetrations of each in 2030, and only begin to diverge in value at

MW) of solar capacity on NWE's system today is distributed, rooftop solar generation, and amounts to just 0.4% of NWE's peak demand, and an even lower percentage of the utility's energy requirements.[19]

**Q: As a capacity resource, does solar provide other benefits to utilities?**

A: Yes. Solar projects are completely scalable in size, and the lead time to develop solar projects on the scale of 3 MW is short, in comparison to other types of generation. Solar QFs can be constructed on a wide variety of sites in open space or in the built environment. They have no air emissions, no noise impacts, no avian or aircraft impacts, and minimal water use for panel cleaning. The construction time for a 3 MW solar facility can be as short as 2 to 3 months. Solar provides a significant summer peaking resource, with an output profile that complements local wind resources. **Figure 1** below shows that NWE's wind resources have their lowest output in the summer months when solar output peaks.




penetrations above 15%, as illustrated in Figure ES-1 from the study. The LBNL study is available at http://emp.lbl.gov/sites/all/files/lbnl-5445e.pdf.

[19] *2015 IRP*, at pp. 8-21 to 8-22.

**Q: Do the FERC rules implementing PURPA specify that the calculation of avoided costs should consider the smaller capacity increments and shorter lead times available with additions of capacity from solar QFs?**

A: Yes, that is exactly what the FERC rules specify.[20] I will comment further below on how the calculation of NWE's avoided costs should incorporate this factor.

### B. Blended Market + Combined Cycle Method

**Q: Please describe the methodology the Commission has used in the past to calculate NWE's avoided costs.**

A: The Commission used the blended market + combined cycle approach, as adopted in Orders No. 7199e and 7108e, to set NWE's present QF-1 rates. This approach is often referred to as the "proxy method." It assumes that the QF allows the utility to delay its next planned generating unit, usually the next generating unit identified in the utility's current IRP. The proxy method estimates avoided costs based on the projected capacity and energy costs of that next planned unit. In some states, including Montana, the costs of short-term market purchases (or system-wide marginal energy costs plus short-term capacity purchases) are used in the years before the year in which the proxy unit is expected to enter service. The proxy method is generally regarded as the simplest of the avoided cost methods because it relies on utility plant-specific data for the proxy resource and avoids the need for long-term modeling of system-wide marginal energy costs. Other states in the Pacific Northwest (Oregon, Idaho, and Utah) also have used the proxy method, and it has been used in California to establish the rates for purchases of energy and capacity from high-efficiency combined heat and power ("CHP") units.

**Q: Have you undertaken an independent analysis of NWE's current long-term avoided costs, using the "blended market + combined cycle" methodology that the Commission adopted in Orders No. 7199e and 7108e?**

[20] See 18 C.F.R. § 292.304(e)(vii).

A: Yes, I have. This methodology is based principally on the long-run, all-in costs of the utility's next resource addition, with market prices used in the years prior to the year in which that resource is added. NWE's *2015 IRP* selects three gas-fired internal combustion engines (ICE) to be installed in 2019 as the utility's next resource addition.[21] The utility appears to agree that these ICE resources are its avoidable source of capacity, as the utility uses their capacity cost as its measure of avoided capacity costs in its application in this case.[22] NWE's ICE units have the following key cost and operating parameters, with the costs in 2015 dollars.[23]

**Table 3:** *Key ICE Parameters*

| Parameter | Value |
|---|---|
| Heat Rate | 8,314 Btu/kWh |
| Variable O&M | $5.14 per MWh |
| Capital cost | $1,280 per kW |
| Fixed O&M | $10.50 per kW-year |

**Q: What other changes to the "blended market + combined cycle" method have you made?**

A: I have made a number of changes:

- **Updated natural gas price forecast.** I have updated the natural gas forecast from the *2015 IRP*, using the approach adopted in Order No. 7199e. This approach relies on the two years of available forward market prices for the AECO hub (as of September 1, 2016), escalated to future years based on the current Energy Information Administration (EIA) *2016 Annual Energy Outlook* forecast. To the AECO price I add the tariffed cost of transportation in Alberta and Montana to move gas to power plants on NWE's system. The utility's testimony cites lower natural gas prices as a key reason why the current QF-1 rates, which were set in 2012, are now outdated. However, current gas prices are modestly higher than those in the *2015 IRP*. This updated gas forecast is 3% higher than the *2015*

[21] See *2015 IRP*, at pp. 1-4 to 1-5, Table 1-2, Table 12-3 and Figure 12-2.
[22] NWE Testimony (Bushnell), at pp. JBB-9.
[23] See *2015 IRP*, at Table 9-1.

*IRP* gas forecast.[24]

- **Solar avoids 107% of the ATC market price.** In the initial years when solar QFs will avoid market power, they will avoid high-load-hour (HLH) power prices six days of the week (Monday-Saturday, except holidays), and low-load-hour (LLH) power prices only on Sunday and holidays.[25] As a result, the average market price avoided by solar will be higher than the around-the-clock (ATC) average market price. Based on recent Mid-Columbia (Mid-C) HLH and LLH prices, a solar QF will avoid 107% of the ATC market price at Mid-C (before adjustment for the basis to Montana). I have adjusted the avoided market prices in 2017-2018 to reflect the higher average market prices avoided by predominantly HLH solar generation.

- **REC value in years prior to 2022.** NWE's *2015 IRP* does not start adding a value for reductions in carbon emissions until 2022. However, this does not mean that the environmental attributes of new renewable generation have zero value prior to 2022, if they are conveyed to NWE as renewable energy credits (RECs). First, there is a market for RECs in the Western Electricity Coordinating Council (WECC) region from utilities that must comply with state RPS requirements. Second, the well-documented growing demand for green power from major corporate customers and the U.S. military will make the RECs from renewable resources increasingly valuable to utilities.[26] As a result, NWE could sell excess RECs in order to reduce the cost of renewable generation for its customers. Recent REC market prices have been relatively low, on the

[24] Based on 25-year levelized gas costs at a 7.02% discount rate (NWE's weighted average cost of capital).

[25] NWE's high load hours (16 hours per day, 7 a.m. to 11 p.m. weekdays and Saturdays) generally include all of the daylight hours when solar will produce significant amounts of power. See current Schedule No. QF-1 (defining "Heavy Load Hours").

[26] See GreenBiz, "Apple, Google, and the evolving economics of energy" (February 11, 2015), at http://www.greenbiz.com/article/google-inc-apple-inc-wind-solar-fossil-fuels-renewable-energy-economics.

order of $5 per MWh,[27] but may increase as states raise their RPS requirements, as California and Oregon have done recently.[28] For the "with carbon" QF-1 rates, I assume a REC price of $5 per MWh in 2017, increasing with inflation through 2021 until NWE's assumed carbon adder takes effect in 2022.

- **The updated calculation of Schedule QF-1 avoided cost prices starts in 2017**, as that would be the earliest start year for the QFs impacted by the proposed change in avoided cost prices. Given the Commission's suspension of the existing QF-1 prices and the adopted schedule for this proceeding, there appears to be no chance that a new QF entering service in 2016 could qualify for the current, but suspended, QF-1 prices. Thus, the relevant 25-year time frame for new avoided cost prices is 2017-2041.

I calculate the 25-year (2017-2041) levelized avoided cost price for the QF-1 tariff under the Commission's current blended market + combined cycle method.[29] This analysis uses the operating parameters for the ICEs selected in the *2015 IRP* (see Table 2), plus the updated gas forecast and the other changes discussed above. These calculations are presented in **Exhibit RTB-2**. For

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[27] Public data on PacifiCorp's sales of RECs over the last five years shows that RECs were worth more than $30 per MWh in 2010-2011, but that value has dropped to about $5 per MWh in 2013-2014. See *Prepared Direct Testimony of R. Thomas Beach on behalf of the Sierra Club* in Utah Public Service Commission Docket No. 15-035-53 (filed September 16, 2015), at p. 27 (Table 1). NV Energy conducted a reverse RFP to sell RECs in 2014, but decided not to sell any even though it had bids as high as $4 per MWh, indicating that the Company believes the future value of RECs to be higher. *See* NV Energy, *2014 RPS Compliance Report*, at pp. 27-28.

[28] In California, SB 350 (signed October 7, 2015) raised California's RPS goal to 50% by 2030. Oregon's SB 1547 (enacted in March 2016) raised that state's RPS goal to 50% by 2040. See, generally, http://ncsolarcen-prod.s3.amazonaws.com/wp-content/uploads/2014/11/Renewable-Portfolio-Standards.pdf.

[29] I calculate a 25-year levelized avoided cost price because that is the maximum QF contract term. A 25-year levelization period is appropriate for 25-year QF contracts. Order No. 7199d, at p. 14, calculated a 24-year levelized price, without explanation. In contrast, Order No. 7108e, at pp. 23-24, calculated a 25-year levelized price for 2011-2035, with the Commission finding that the 25-year calculation is appropriate in order "to capture the full 25 year contract period available under Option 1." For a 25-year contract term, a 25-year levelized price is appropriate in order to reflect full avoided cost.

NWE's representative 3 MW solar QF, **Table 4** below compares Vote Solar's updated QF-1 price to both the current QF-1 tariff and the price that NWE has proposed. The results indicate that there is not a significant difference between the current QF-1 tariff prices and an updated estimate of NWE's long-run avoided costs based on today's natural gas prices and the future resources identified in the utility's *2015 IRP*.

**Table 4:** *Comparison of Results – Blended Market + Combined-cycle Method*

| **25-year levelized prices** | **Current QF-1 Tariff** | **Vote Solar Updated QF-1 Tariff** | | **NWE Proposed QF-1 Tariff** | |
|---|---|---|---|---|---|
| Carbon included? | No | No | Yes | No | Yes |
| On-peak price ($/kWh) | 0.09273 | 0.10039 | 0.10988 | 0.03027 | 0.03988 |
| Off-peak price ($/kWh) | 0.05314 | 0.04180 | 0.05129 | 0.03027 | 0.03988 |
| Capacity price ($ per kW-yr) | n/a | n/a | n/a | $13.55 | |
| Solar average price ($/kWh) | 0.06609 | 0.06097 | 0.07046 | 0.03597 | 0.04558 |
| **Change from Current QF-1** | | **-8%** | **+7%** | **-46%** | **-31%** |

**Q: Order 7500, as well as Commissioner Kavulla's dissent, discusses versions of the current blended market + combined cycle method which assume that the first resource that QFs can avoid is a combined-cycle gas turbine (CCGT) built in either 2022 or 2025. Please critique this assumption.**

A: Although this CCGT is in NWE's resource plan, it is not the first capacity that the utility is planning to add – the ICE units in 2019 are. An assumption that the avoided resource is a CCGT to be built in 2025 would ignore the utility's preferred ICE units, assumes that NWE will continue to rely on market purchases for up to eight more years, and will not begin to remedy its serious capacity deficit until as late as 2025. As noted above, the current method is an example of a "proxy method" for calculating avoided costs, where the full energy and capacity costs of the utility's next planned resource are used as the proxy for long-run avoided costs. This approach should be based on whatever the next planned resource is in the utility's IRP. Prior iterations of this approach in Montana have used other resources (such as coal plant costs) as the proxy resource, not just a

CCCT.[30]

Further, the FERC regulations explicitly state that avoided cost rates for purchases from QFs must take into account "the smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities." QF capacity obviously is available in smaller increments, given that long-term contracts under the QF-1 tariff are limited to projects no larger than 3 MW. Capacity from solar QFs can be installed with shorter lead times and much more quickly than traditional utility capacity, with construction requiring as little as two months once permitting is complete. In contrast, typical utility additions of capacity are in increments of at least 50 MW, and often more, as shown by NWE's current resource plan. These larger central station units require significantly longer time to develop, permit, and build. If a utility is short on capacity, as NWE is, the long lead times and the large, "lumpy" nature of utility capacity additions extend the time required for the utility to become resource adequate.[31] Because QF capacity can be built in smaller increments and with shorter lead times, QF development can match more closely the utility's future load growth and future capacity needs, with fewer shortages or surpluses of capacity. This benefit should be recognized in the calculation of NWE's avoided costs by not ignoring the smaller increment of ICE capacity that the utility would add as early as 2019. It would underpay QFs, in violation of FERC requirements, if QF capacity rates assume that new, small-scale, short-lead-time QF capacity has zero capacity value until the year when the next large combined-cycle unit would be installed.

**Q: Does the design of the on- and off-peak rates under the QF-1 tariff assume that QFs can provide capacity immediately?**

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[30] See Order No. 6973d.

[31] Conversely, if the utility is long on capacity today, but expects to need capacity in the future, utility-owned plants must be sized to provide much more than the amount of capacity which the utility needs in the year in which the new plant enters service. The result is that ratepayers may have to pay for years of excess capacity until demand "catches up" to the last major addition.

A: Yes. The difference between the on- and off-peak rates under the QF-1 tariff, in all years, is set at 100% of the capacity-related costs of a simple-cycle combustion turbine (SCCT). This implicitly assumes that a QF resource which produces at a 100% capacity factor in all on-peak hours will avoid the full costs of a capacity resource in all years.

### C. Issues with NWE's Proposed Avoided Costs Using the "Peaker Method"

#### 1. Methodology

**Q: Does NWE's application propose a fundamentally new method of calculating avoided costs?**

A: Yes. NWE's application abandons the "blended market + combined cycle" methodology previously used by the Commission and proposes a calculation of avoided costs using what is known as the "peaker method." The peaker method assumes that a QF allows the utility to reduce the marginal generation on its system and to avoid building a peaking unit, rather than displacing or delaying the need for a particular new generating unit. According to the theory underlying the peaker method, if the utility's generating system is operating in equilibrium, at the optimal point, the cost of a peaker (often a SCCT) will be the least-cost source of new capacity, and new generation will have to be less expensive than a peaker plus the system marginal cost. Thus, the peaker method involves a dual calculation: the avoided energy costs are determined by the projected, system-wide marginal cost of energy (often calculated through production cost modeling), and the avoided capacity costs are established by determining the capacity-related costs of an inexpensive source of capacity, such as a SCCT. In this case, NWE is proposing to use a calculation of its system marginal energy costs from production cost modeling, plus the capacity-related costs of its planned ICE units as the avoided cost of capacity.[32]

[32] NWE Testimony (Hansen) for avoided energy costs, and NWE Testimony (Bushnell) for avoided capacity costs.

**Q: What are the drawbacks of the peaker method?**

A: The peaker method depends on the assumption that the utility's system is operating at an optimal point, such that there is no resource other than a low-cost peaker that would reduce overall system costs. For example, the method assumes that the utility has no need for energy as well as capacity, such that it might be worthwhile to build a resource such as an ICE or combined cycle that provides both capacity and lower-cost energy. However, as indicated in their IRPs, utilities often plan to add resources other than SCCTs, indicating that the utility's system may not always be operating at the "optimal" point of equilibrium, or that the utility must respond to other constraints such as air emission restrictions or RPS requirements. Therefore, if a utility is planning to add a resource other than a SCCT, the proxy method may be the more appropriate method to establish the utility's full avoided cost. With respect to NWE, the utility clearly is not operating at an optimal point given its significant deficiency in both capacity and energy, and the utility's preferred IRP scenario adds ICE units first, and then a combined cycle, to move closer to resource adequacy.[33] This argues for retaining the current proxy method instead of moving to NWE's proposed peaker method.

In addition, the peaker method requires modeling of the utility's system-wide marginal costs in each hour, which then are used to produce avoided energy prices. Such modeling is complex, uses many assumptions (some of which may be confidential and whose impact on the results may not be transparent), and requires resources and capabilities which may not be available to any party except the utility.

### 2. Avoided Energy Costs

**Q: Do you have concerns with NWE's modeling of its system marginal costs?**

A: Yes, I have several concerns.

[33] NWE at least partially remedies these problems with the peaker method by assuming that its avoided capacity cost is the cost of the 2019 ICE units, rather than a lower-cost SCCT.

**Zero avoided costs in some hours.** NWE's modeling of its avoided energy costs makes the erroneous assumption that its avoided costs are zero in hours in which the utility is long on resources and "the market price is lower than the variable cost of the avoidable resource."[34] The utility wrongly asserts that "there is no avoidable resource" in such hours. This is not correct, as NWE clearly states that, in these "LONG-2" hours there is a dispatchable resource with higher-than-market costs that can be avoided by QF generation. In other words, the utility has an opportunity in such hours to turn down its own generation and to replace it with lower-cost market power (or with additional QF power priced at market). In response to a staff data request, NWE re-ran its modeling to change the treatment of this "LONG-2" condition, in order to recognize that the utility's opportunity cost in such hours is the market price. This re-run raised the utility's avoided energy costs for solar by 14%.[35]

**Natural gas costs are understated.** The utility appears to use only the cost of natural gas transportation to the U.S. Canadian border in its production cost modeling.[36] The full cost of transportation to the burnertip in Montana should be used in these long-run avoided cost calculations. In addition, as discussed above, updating the *2015 IRP* natural gas costs to today's prices also results in a small increase in the long-term gas forecast. **Figure 2** compares Vote Solar's updated burnertip gas cost forecast to the burnertip gas forecast that NWE appears to be using in its ProSimm runs, from the workpapers for Mr. Hansen's testimony. The combined effects of these gas forecast issues is that long-run avoided energy costs should be increased by about 12%.

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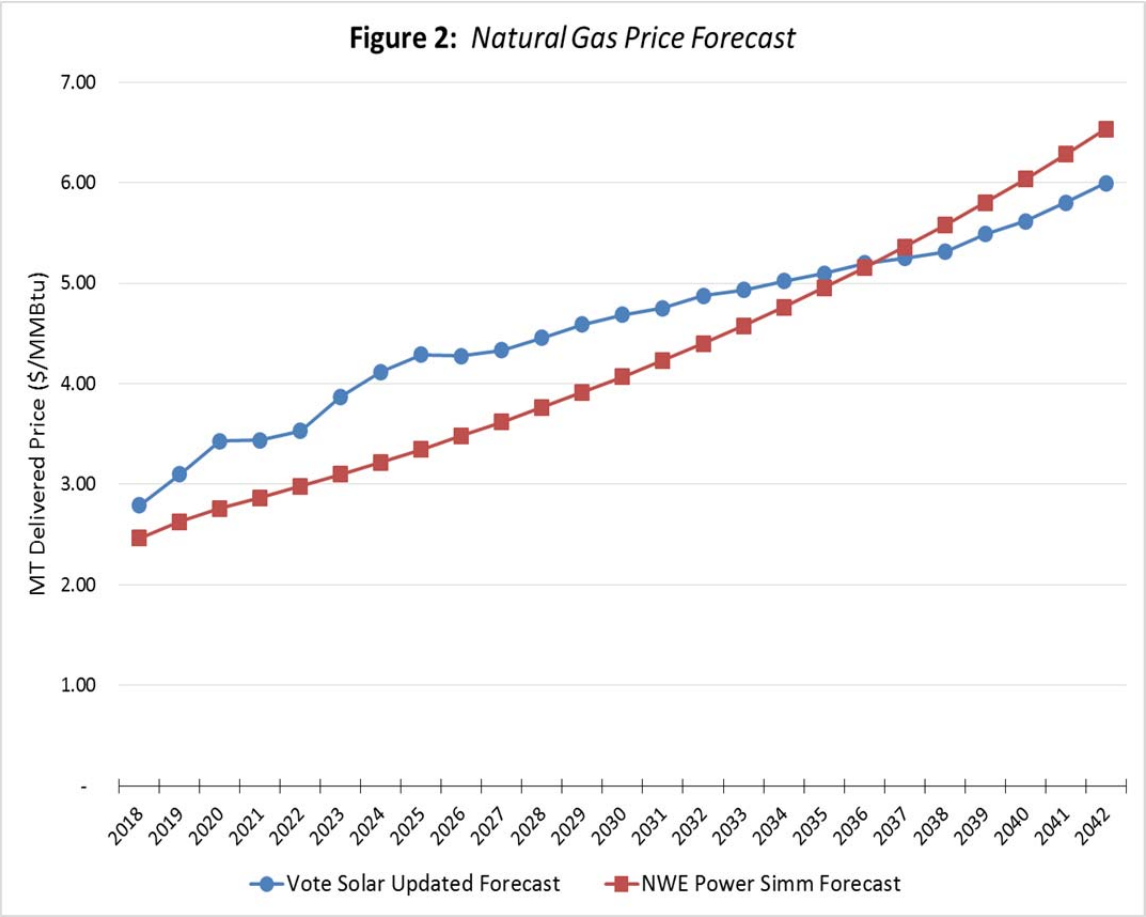
[34] NWE Testimony (Hansen), at p. LPH-6.

[35] NWE response to PSC Data Request PSC-013, included in Exhibit RTB-3. 14% is the average increase in avoided energy costs both with and without the transfer of RECs, as shown below in Table 5.

[36] NWE response to Vote Solar Data Request VS-014(b), included in Exhibit RTB-3.




**Q: What are NWE's avoided energy costs when these changes are applied to NWE's production cost modeling results?**

A: The changes in NWE's avoided energy costs discussed above are summarized in **Table 5**.

**Table 5:** *Revised NWE Avoided Energy Costs – Peaker Method*

| Issue | Avoided Energy Costs *($/kWh)* | | | |
|---|---|---|---|---|
| | Without Carbon | | With Carbon | |
| | Costs | Change | Costs | Change |
| NWE Application | $0.03027 | | $0.03988 | |
| LONG-2 Condition | $0.03510 | +16% | $0.04502 | +13% |
| Revised Gas Forecast | $0.03945 | +30% | $0.05060 | +27% |
| Revised Avoided Energy Costs | $0.03945 | +30% | $0.05060 | +27% |

With these changes, NWE's revised avoided energy costs using the utility's

proposed "peaker" methodology are, on average, about 28% higher than NWE has proposed, or $0.039 per kWh without carbon and $0.051 per kWh with carbon, for a 25-year contract. This includes the impacts of both the re-run of NWE's avoided cost for the LONG-2 condition, as well as the higher long-term natural gas forecast. The higher gas forecast impacts both the cost of NWE's own marginal gas-fired generation as well as the market cost of regional wholesale purchases that are likely to be produced by other gas-fired generation during the daylight hours when solar plants operate.

### 3. Avoided Capacity Costs: Solar Capacity Value

**Q: What capacity value do solar QFs receive under the present structure for the QF-1(a) rate?**

A: The structure of the present QF-1(a) rate sets the difference between the on- and off-peak rates using on the full fixed costs of a SCCT. Thus, a QF resource that operates at its full nameplate capacity in all on-peak hours will earn 100% of the capacity value of a SCCT. As a result, a solar QF under this rate will earn capacity value based on its capacity factor during the 2,038 hours of the on-peak period.[37] Based on the exemplary solar projects that NWE has modeled, as extended by my analysis to include more years of data, the average capacity factor for a solar QF over the utility's on-peak hours is 38%.[38] Thus, the present QF-1(a) rate structure assumes that a solar QF has a capacity value equal to 38% of its nameplate capacity.

**Q: NWE would assign a capacity value to solar resources equal to just 9.6% of solar nameplate. Please critique this assumption.**

A: NWE is substantially undervaluing solar capacity in Montana. As shown in

[37] NWE's on-peak period is a 6x16 block of hours over three winter months (December – February) and two summer months (July – August), about 2,038 hours per year. See current Schedule No. QF-1 (defining "Heavy Load Hours" and "On-Peak Hours").

[38] See the discussion below of my extension of the solar output data in Mr. Bushnell's workpapers to include a full ten years (2006-2015) of solar output data.

**Table 2** above, NWE's assumption that solar's capacity value is just 9.6% of its nameplate capacity is far lower than the capacity value assigned to solar by other utilities in the western U.S. In contrast, Table 2 shows that the QF-1(a) rate's assumed 38% capacity value is within the range of capacity values used by other neighboring utilities. NWE effectively treats solar resources as though they are baseload fossil-fueled generators, giving them capacity credit only for the output which they can exceed in 85% of the top 10% of on-peak load hours. This is far more conservative than how the capacity value of solar is assessed by most control areas and balancing authorities in the U.S.

**Q: How do other control area operators assess the capacity value of solar resources?**

A: As the North American Electric Reliability Council (NERC) has noted in a special report on this topic,[39] many control area operators assess the capacity contribution of solar resources based on their average capacity factor over a designated set of on-peak hours. As noted above, this is also the approach that is implicit in the present structure of the QF-1(a) rate. Applying this general approach to NWE, the average capacity factor of solar resources in Montana over NWE's broad on-peak period is 38%. To use a more focused set of peak hours – the top 10% of NWE's on-peak hours, about 200 hours per year -- the average solar capacity factor over these critical hours is even higher, 51% of nameplate. These are more standard and representative measures of solar capacity value in Montana than the highly conservative metric that NWE has proposed. **Table 6** shows these results, which I will explain in more detail below and contrast with NWE's calculations.

[39] *See* the report of NERC's Integration of Variable Generation Task Force, *Accommodating High Levels of Variable Generation* (April 2009), available at http://www.nerc.com/files/IVGTF_Report_041609.pdf. See esp. Figure 3.3 on page 40.

**Table 6:** *Solar Capacity Values (% of nameplate)*

| Method | Season(s) | Solar Capacity Value (% of nameplate) |
|---|---|---|
| Capacity factor over 100% of On-peak hours | Summer and Winter | 38% |
| Capacity Factor over Top 10% of On-peak hours | Summer and Winter | 51% |
| | Summer only | 84% |
| | Winter only | 20% |
| 60% exceedance over Top 10% of On-peak hours (SPP Method) | Summer and Winter | 39% |
| 85% exceedance over Top 10% of On-peak hours (NWE Method) | Summer and Winter | 5.1%[40] |

**Q: Could NWE cite any other utility that uses such a restrictive approach to determining solar's capacity value?**

A: No, it could not.[41]

**Q: Are you aware of any other utility or control area operator in the U.S. that calculates solar capacity value by applying an exceedance factor to solar output over a set of peak hours?**

A: Yes, but the exceedance percentages are much lower than NWE's 85%, and the exceedance is calculated over a far broader set of hours than the 200 hours per year that NWE uses. For example, California's resource adequacy program calculates monthly capacity values of wind and solar using a 70% exceedance over 1,825 peak hours per year.[42] Using this approach, solar capacity values in California in the peak months typically exceed 50%. The Southwest Power Pool (SPP) also uses an exceedance approach, but measured over 10% of all hours (i.e. 876 hours), not just over the top 10% of on-peak hours. SPP also uses ten years of data, and recently reduced its exceedance percentage for determining wind

[40] This calculation uses NWE's methodology with a full ten years of data (2006-2015). NWE's proposed 9.6% uses just four years of data (2006-2009).

[41] NWE response to Vote Solar Data Request VS-005, included in Exhibit RTB-3.

[42] See CPUC, *Qualifying Capacity Methodology Manual*, at pp. 11-16. Available at http://www.cpuc.ca.gov/General.aspx?id=6311.

capacity values from 85% to 60%.[43] As shown in Table 6 above, even using SPP's 60% exceedance over NWE's top 10% of on-peak hours (with ten years of data) results in a solar capacity value of 39%.

**Q: Do you have any other concerns with the utility's calculations of the 9.6% solar capacity value.**

A: Yes. First, the utility's analysis uses just four years of load and solar output data, from 2006 through 2009, data which is 7 to 10 years old at this point.[44] In my analysis, I have added load and solar output data from 2010 through 2015, for a full ten years (2006-2015) of data including the most recent available data. As discussed below, including more recent load data is important because in recent years the on-peak hours with the highest 10% of loads have been shifting to the summer months of July and August when solar output is high.

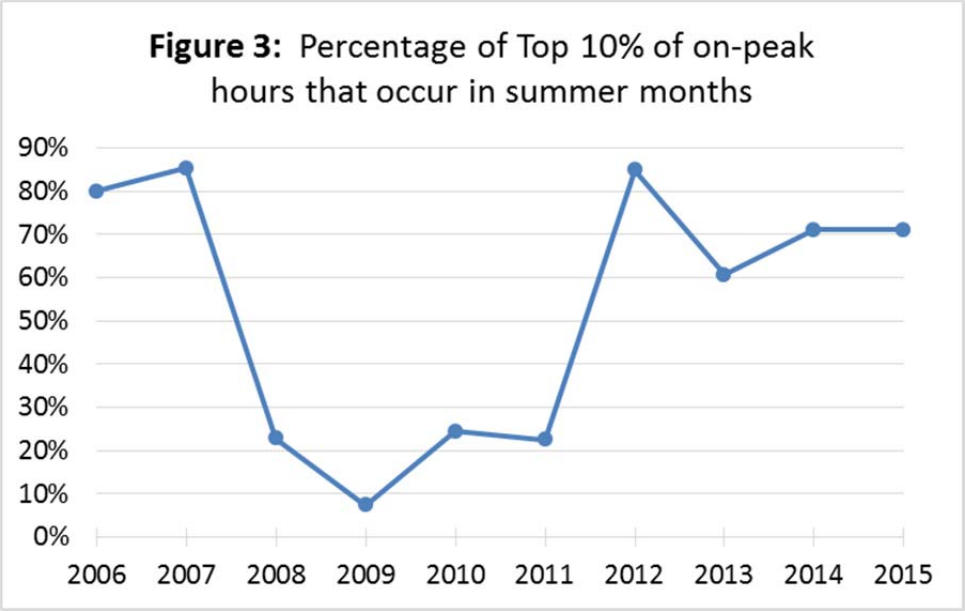
Vote Solar's analysis uses actual solar insolation data from 2006 through 2013 to simulate the output of a representative 3 MW solar project in Montana, plus solar output data based on typical meteorological conditions for 2014 and 2015. This should capture for at least eight of the 10 years the correlation between actual solar output and electric loads. It would be even better to use actual solar output data from operating solar plants in Montana, but such historical data obviously is not yet available.

**Q: Isn't NWE a winter-peaking utility?**

A: In fact, NWE is dual-peaking; the utility's winter and summer peak-hour demands are similar. The utility's peak-hour retail customer demand is higher in the winter, but its peak-hour transmission system demand in its balancing area is higher in the summer.[45] Moreover, it is important to look not just at a resource's performance in the single hour with the highest load, but also at performance in a

[43] NWE response to Vote Solar Data Request VS-005, included in Exhibit RTB-3.
[44] Workpapers for NWE Testimony (Bushnell), see file "Solar_Exceedance - Top 10 percent QF Peak period – 20160808.xls."
[45] NWE response to Vote Solar Data Request VS-011(d), included in Exhibit RTB-3.

broader set of high-demand hours that are close to the peak. For NWE, these include both summer and winter on-peak hours. Looking at the top 10% of on-peak hours, which include hours in three winter months (December-February) and two summer months (July-August), over the last six years (2010-2015) the trend is toward an increasing percentage of summer (July-August) hours in the top 10%, as shown in **Figure 3** below. NWE's analysis does not include these more recent years, and thus fails to capture this recent trend. As a result, the capacity value of solar should be calculated considering the resource's capacity value over the top load hours in both the summer and winter on-peak hours.




**Q: Doesn't solar have a low capacity factor during peak winter hours?**

A: Solar's capacity factor over the top 10% of on-peak load hours from December to February is lower than in the summer months, but it is not zero. As shown in Table 6, the capacity factor for solar in these winter peak hours is 20%.

**Q: Considering the results presented in Table 6, what is your recommendation for the capacity value of solar on NWE's system?**

A: I recommend that the Commission continue to use the current method for designing the QF-1(a) rate that assigns the capacity value of a SCCT to the on-peak rate. This effectively provides solar with a capacity value equal to its

capacity factor over these on-peak hours, which is 38% of nameplate based on the 10 years of data used in our analysis. This capacity value is similar to the capacity value attributed to utility-scale solar facilities by other western utilities, as shown in Table 2. It is a more conservative value than solar's capacity value over the more limited top 10% of NWE's on-peak hours (51% of nameplate), and is very close to the 60% exceedance value over the top 10% of on-peak hours (39% of nameplate, using the SPP method).

**Q: Should the Commission consider using an effective load-carrying capacity (ELCC) analysis to establish the capacity value of solar?**

A: It is my understanding that parties to past avoided cost dockets in Montana have suggested using an ELCC analysis to establish the capacity value of wind resources.[46] Although some consider ELCC analyses to be the most rigorous method for establishing the capacity value of intermittent renewables, there are a number of practical problems with using an ELCC approach in Montana at this time. First, the process of performing an ELCC study is generally as follows: an ELCC analysis uses a reliability model of the utility system that includes the candidate resource (e.g. 50 MW of solar plants) and that achieves the utility's reliability standard (e.g. 1 day of outages in 10 years). Then the candidate solar plants are removed, and capacity from a standard resource (e.g. a SCCT) is added until the reliability standard is again achieved. If 20 MW of SCCT capacity must be added to restore the original reliability level, then the ELCC of the 50 MW of solar resources is 40% (20 MW / 50 MW). The NWE system is so far from a standard reliability level that substantial generic resources would need to be added to reach this level. This could make an ELCC analysis for NWE highly artificial. Second, the literature on using the ELCC method emphasizes the importance of using actual, correlated data for both (1) loads and (2) wind or solar output.[47]

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[46] See Order 7199d, at pp. 15-17.

[47] See the NERC report *Accommodating High Levels of Variable Generation* referenced in Footnote 39. The report includes a section on Resource Adequacy Planning, which addresses the methods that utilities and control area operators should use to assess the capacity value of intermittent wind and solar resources. In discussing the data to be used in ELCC analyses, the NERC special report notes that "[c]are should be taken to account for the correlation between

Using actual load and solar output data from the same time period is particularly important for solar ELCC studies, due to the fact, noted above, that it is often sunny on hot summer days when electric loads are high. Obviously, actual solar output data from utility-scale solar generators is not yet available on NWE's system. Third, ELCC analyses use reliability models that are complex and costly to run. The ability to run these analyses is not available to a wide range of stakeholders. It is difficult to audit the results or to understand how the results are affected by different assumptions such as maintenance schedules, the profile of intermittent resources, or resource availability. These are important reasons why many utilities and control area operators have opted for simpler, more transparent capacity factor approaches.

**Q: Do you think that the use of a capacity factor methodology, such as the one you have proposed, can be as accurate as ELCC approaches?**

A: Yes. A 2012 study from NREL found that such methods can accurately approximate the results of more complex, but also more opaque and difficult-to-replicate, methods such as ELCC models.[48]

**Q: What is the result of your proposed revisions to NWE's avoided cost calculations?**

A: Combining the changes that I propose to the calculations for the avoided costs of both energy and capacity using NWE's peaker method, the utility's 25-year solar avoided costs are $0.062 to $0.073 per kWh, i.e. essentially the same as the current QF-1 tariff. These revised avoided costs using NWE's peaker method are shown in **Table 7**, which compares Vote Solar's revised avoided costs to the current QF-1(a) tariff and to NWE's proposed rates.

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hourly variable generation and the hourly demand series. To perform this analysis, a significant amount of time-synchronized 8,760 hourly wind generation and demand data is required and this data is needed for variable generation plants in the specific geographic regions being studied."

[48] See Seyed Hossein Madaeni, Ramteen Sioshansi, and Paul Denholm, *Comparison of Capacity Value Methods for Photovoltaics in the Western United States* (NREL, July 2012), available at http://www.nrel.gov/docs/fy12osti/54704.pdf.

**Table 7:** *Current and Proposed QF-1(a)Rates using the Peaker Method*

| 25-year levelized prices | Current QF-1(a) Tariff | Vote Solar QF-1(a) Tariff (Revised Peaker) | | NWE Proposed QF-1(a) Tariff | |
|---|---|---|---|---|---|
| Carbon included? | No | No | Yes | No | Yes |
| On-peak price ($/kWh) | 0.09273 | 0.03945 | 0.05060 | 0.03027 | 0.03988 |
| Off-peak price ($/kWh) | 0.05314 | 0.03945 | 0.05060 | 0.03027 | 0.03988 |
| Avoided capacity cost ($ per kW-year) | n/a | $141.18 | | $141.18 | |
| Solar capacity value (%) | n/a | 38% | | 9.6% | |
| Capacity price ($ per kW-yr) | n/a | $53.65 | | $13.55 | |
| Solar average price ($/kWh) | 0.06609 | 0.06202 | 0.07317 | 0.03597 | 0.04558 |
| Change from Current QF-1(a) | | -6% | +11% | -46% | -31% |

Thus, whether using the "blended market + combined cycle" method or NWE's proposed "peaker method" for calculating avoided costs, the appropriate QF-1(a) tariff rates, as recalculated using corrected assumptions, are similar to the current QF-1(a) tariff rates.

## V. OTHER BENEFITS AND COSTS OF INCREMENTAL SOLAR GENERATION

**Q: Are there other direct, quantifiable benefits of incremental solar generation for ratepayers that are not included in the avoided cost rates in the QF-1 Tariff?**

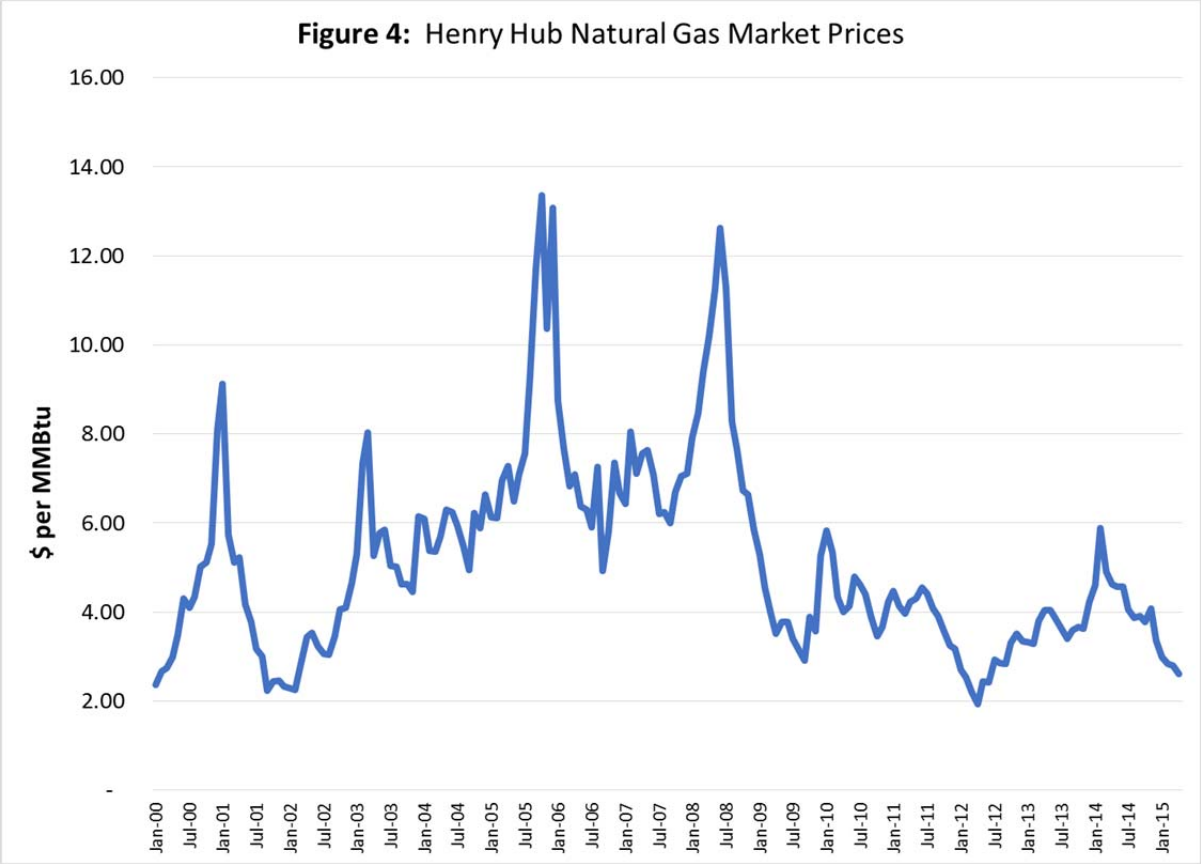
A: Yes. Incremental solar QF generation will result in other benefits for NWE ratepayers. Several these benefits can be quantified in terms of direct avoided costs for NWE that will benefit its customers, and these additional avoided costs could be included in the QF-1 tariff price. However, these are ratepayer benefits that have not been included traditionally in avoided cost prices, and it is <u>not</u> my

recommendation that they be included at this time. Nonetheless, the Commission should consider these benefits in its deliberations, and should find that these benefits mean that ratepayers are receiving a good deal if NWE contracts for new solar generation at either existing QF-1(a) prices or at the updated prices that Vote Solar has presented above. Finally, the Commission should conclude that these additional benefits exceed the costs that NWE may incur to integrate additional solar resources, such as the cost of incremental regulation capacity.

### A. Hedging Benefits

**Q: Do fixed-price contracts for renewable generation provide a benefit to consumers as a hedge against future uncertainty and volatility in energy and fossil fuel markets?**

A: Yes, they do. As shown in NWE's *2015 IRP*, the alternative to the QF contracts is reliance on marginal utility fossil generation (mostly natural gas-fired) and/or market purchases, whose prices also are influenced heavily by natural gas prices. Spikes in natural gas prices have occurred regularly over the last several decades, as shown in the plot of historical benchmark Henry Hub gas prices in **Figure 4** below. Hedging against these extreme events can be very beneficial for ratepayers. Fixed prices also hedge against market dislocations or generation scarcity such as was experienced throughout the West during the California energy crisis of 2000-2001 or as occurred recently with the extreme drought in California from 2013-2015 and the long-term, drier-than-normal conditions elsewhere in the West. Obviously, there is a risk that consumers may not benefit if future prices turn out to be lower than anticipated, but, if that happens, consumers will enjoy the low prices for the portion of their needs that is not hedged.




The value for ratepayers of hedging this exposure is simple: fixed-price generation protects against periodic costly spikes in natural gas prices.

**Q: Has this benefit been quantified?**

A: Yes. A number of studies have quantified these hedging benefits. In the West, Public Service of Colorado estimated in 2013 that the long-term (20-year) hedging benefits of distributed solar resources on its system are $6.60 per MWh.[49] We assume that small, utility-scale solar projects on NWE's system would provide a similar value in reducing the utility's exposure to volatile natural gas prices.

**Q: Utilities sometimes argue that long-term QF contracts are too risky for**

[49] Xcel Energy Services, *Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System: Study Report in Response to Colorado Public Utilities Commission Decision No. C09-1223* (May 2013), at pp. 6 and 43, and Table 1. This study used the cost of options contracts in the gas futures market to calculate the hedging benefit.

**ratepayers. NWE implicitly makes this argument in stating that "the effects [of QF contracts] are both irrevocable and long" and asserting that "even a modest overstatement of avoided costs can generate a significant ratepayer liability over the life of a 25-year contract."[50] Is it too risky for consumers to commit to long-term fixed-price contracts?**

A: No. With any fixed-price power purchase contract – and with any significant capital investment by the utility in generation or transmission – there is always a risk that the alternatives will prove to be less expensive over the long-term. This is a risk that consumers bear with PURPA contracts, with other purchases in wholesale markets, and with the alternative of utility-owned fossil-fuel plants whose capital costs are largely fixed once they are approved for cost recovery through rate base and whose fuel costs are subject to significant market risk. NWE complains that the prices or terms of QF contracts are "irrevocable" and cannot be modified once they are signed, yet it is also difficult to modify the costs for utility-owned generation included in the rate base once they have been authorized. And ratepayers become exposed to the market risk associated with the fuel costs for the utility-owned units. This can result in exposure to very high prices during times of scarcity or to stranded assets if plants become uneconomic in the market, as has happened recently with many coal units in the U.S. Utility-owned fossil generation, and in particular coal units, also face the risk that long-term capital costs for rate-based units could increase over time because additional capital expenditures may be necessary to continue to operate the units in compliance with more protective laws and regulations. Such expenses would either increase the overall costs of the utility-owned power plant, or force the utility to deal with stranded assets. Both scenarios (higher fuel cost or stranded assets) increase costs to customers in the long-term, which will not happen under a fixed-price QF contract.

If it is too uncertain and too risky to forecast avoided cost prices for 25 years, then by the same argument it would also be too risky to evaluate the merits of the

[50] NWE Testimony (Hines), at pp. JDH-9 and JDH-10.

alternatives to QF power (such as a new utility-owned resource or retrofitting an existing fossil fuel plant with expensive pollution controls), or even to make decisions based on the long-term projections in an IRP. The North Carolina commission recognized this fact in a recent decision that reviewed avoided cost policies in that state, concluding that the uncertainties in future energy markets will impact ratepayers regardless of whether the utility contracts with QFs at long-term avoided costs or builds its own resources which are the basis for those avoided costs:

> Failure to calculate accurately a utility's avoided cost means ratepayers will pay for the additional energy and capacity whether the utility builds the plant and places it in rate base or the utility pays QFs avoided cost rates. The Commission concludes that establishing avoided cost rates based upon the best information available at the time and making such rates available in long-term fixed contracts, as required by Section 201 of PURPA should leave the utilities' ratepayers financially indifferent between purchases of QF power versus the construction and rate basing of utility-built resources.[51]

### B. Market Price Mitigation

**Q: What is the impact of adding renewable solar QF resources, which have zero variable costs, on market prices for both electricity and natural gas?**

A: New solar generation will increase the electricity supplies available to NWE. Because this generation is must-take (and has zero variable costs), it will displace the most expensive fossil-fired or market resources that the utility would otherwise have generated or purchased. The addition of this local generation will reduce the demand which the utility places on the regional markets for electricity and natural gas. With this reduction in demand, there is a corresponding reduction in the price in these markets, which benefits the company when it does buy power or natural gas in these markets. As discussed in NWE's 2015 IRP, the Company has a significant short position in these markets today, and will have a similar

[51] North Carolina Utilities Commission, *Order Setting Avoided Cost Input Parameters* (Docket No. E-100 Sub-140, issued December 31, 2014), at p. 21.

position for many years into the future.[52] This "market price mitigation" benefit of renewable generation is widely acknowledged, has been quantified in market with visible hourly prices such as New England and California, and has become highly visible in markets that now have significant penetrations of wind and solar resources.

**Q: Are you aware of any modeling of this benefit in the West?**

A: Yes. The National Renewable Energy Laboratory (NREL) and GE Consulting have undertaken the Western Wind and Solar Integration Study (WWSIS), a major, multi-phase modeling effort to analyze much higher penetrations of wind and solar resources in the western U.S.[53] This modeling included analysis of the impact of increasing solar penetration on market prices in the West; the results for spot prices in Arizona are shown in **Figure 5** below. The high penetration solar cases (10% to 25% penetration) in the WECC result in 10% to 20% reductions in spot market prices, with much of the price reductions occurring from the initial 10% solar penetration. A 15% reduction in a current forecast of the 20-year levelized Mid-C market price provides a benefit of $5.20 per MWh to NWE's ratepayers.[54]

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[52] NWE *2015 IRP*, at pp. 1-2 to 1-3, 1-12, 1-15, and Figures 12-1 and 12-2.

[53] The high penetration solar results from the WWSIS are reported in *Impact of High Solar Penetration in the Western Interconnection* (NREL and GE Consulting, December 2010), at p. 8 and Figure 19. Note that this report assumes 100 MW of solar in Montana in the 3% solar penetration case and 500 MW of Montana solar in the 15% penetration scenario. This report, as well as all reports from the WWSIS, are available on the NREL website at http://www.nrel.gov/electricity/transmission/western_wind.html.

[54] These benefits assume equal volumes of solar and market purchases. The benefits per MWh of solar will be higher if the volume of NWE's market purchases exceeds the volume of its solar purchases.

**Figure 5:** *Impact of Increasing Solar Penetration on Spot Market Price*

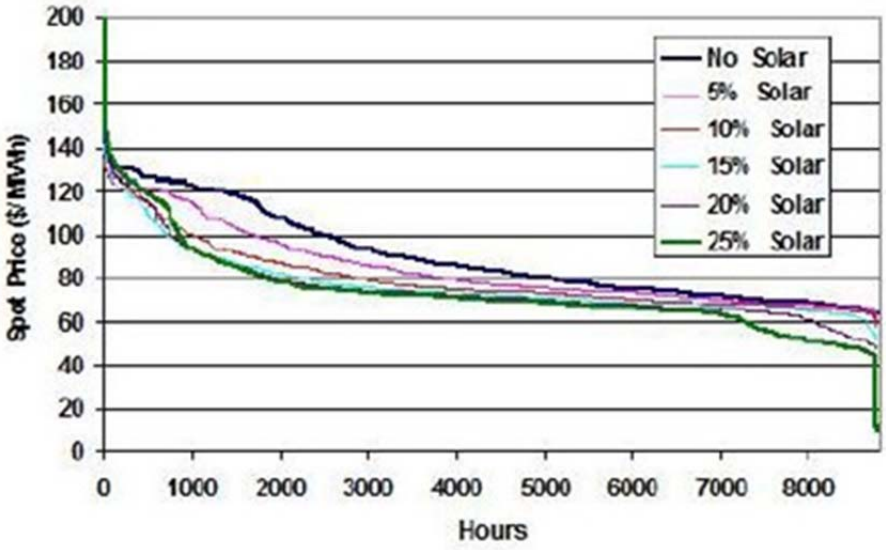


Figure 19 – Arizona Spot Price Duration Curves.

### C. Avoided Transmission Costs

**Q: Are there potential transmission benefits from relatively small, 3 MW solar QFs located on the NWE system?**

A: Yes. Solar QF developers bear the costs to interconnect their projects to the NWE system. Solar projects with a maximum size of 3 MW typically will interconnect to the distribution system at primary distribution voltages, and the power produced generally will serve loads on the distribution system. As a result, small, widely distributed solar projects internal to the NWE system and interconnected to the distribution system may reduce peak loads at the transmission substations to which they interconnect. This can make transmission capacity available for load growth, for other transmission customers, or for greater access to regional markets. Assessing the extent to which small solar projects avoid transmission capacity costs presents a particular challenge, because transmission substations and lines show greater variations in when they peak than does the system as a whole. To address this issue, we followed an approach developed by Energy and Environmental Economics (E3) to calculate avoided

sub-transmission and distribution capacity costs in its cost-benefit studies of distributed solar generation and net energy metering in California. We obtained the available hourly load data for 2015 for 100 of NWE's transmission substations. For each substation we developed an hourly allocation that measures, in each hour, how close that substation is to its annual peak. The allocation calculates a "peak capacity allocation factor" (PCAF) for each hour in which the substation load is within 10% of the annual peak. Thus, all hours where the substation load is below 90% of the annual peak receive a PCAF of zero. The formula for the PCAF allocation factor is as follows:

$$PCAF_s(h) = \frac{(Load_s(h) - Threshold_s)}{\sum_{k=1}^{8760} Max[0, (Load_s(k) - Threshold_s)]}$$

Where:

$PCAF_s(h)$ = peak capacity allocation factor for substation s in hour h
$Load_s(h)$ = the load for substation s in hour h
$Threshold_s$ = 90% of the substation s annual peak load

The summation in the denominator includes all hourly load increments above the threshold.

**Figure 6** shows the resulting average PCAF allocation for each hour of the day across all of the transmission substations, weighted by the annual peak demand at each substation. Most of the peak loads at NWE's substations occur between the hours of 10 a.m. to 9 p.m. The figure also shows a typical PV output profile for Montana. Clearly, there is significant PV output during many of the peak load hours at NWE's transmission substations.

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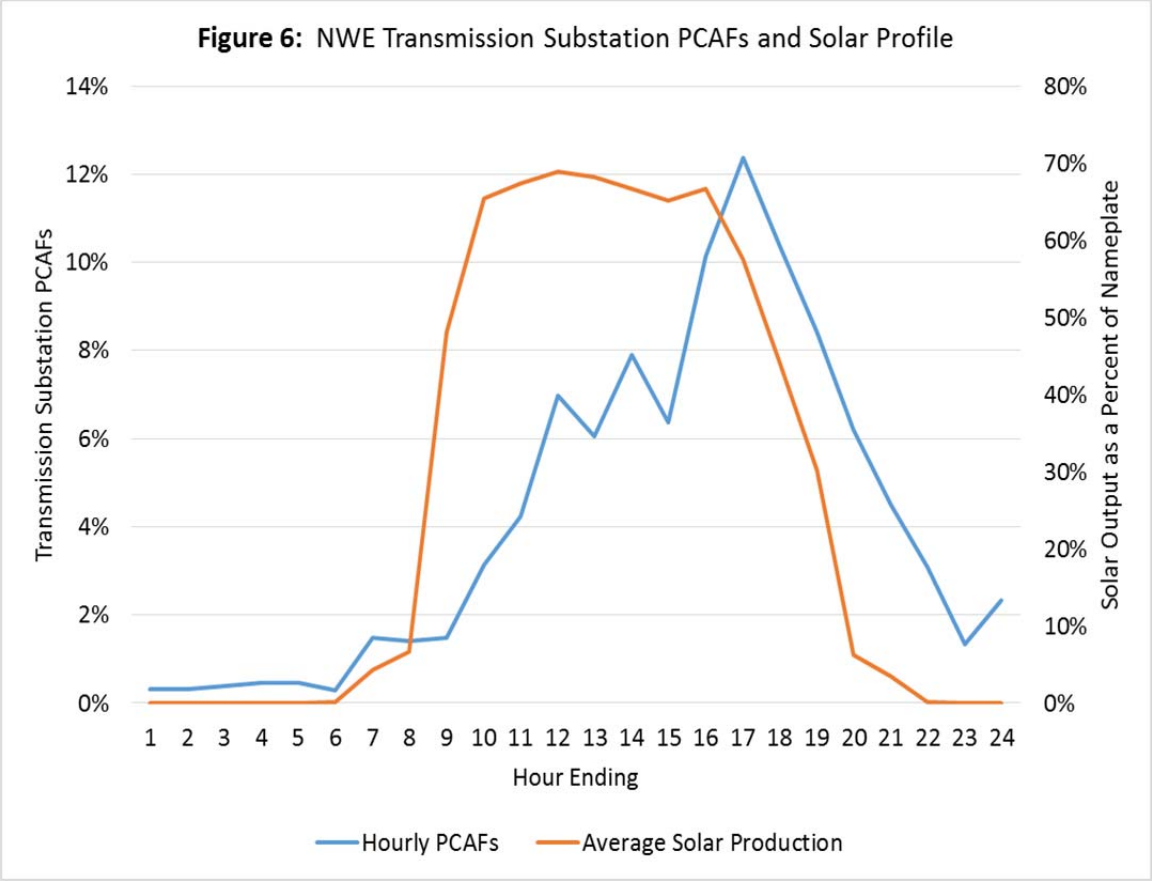


As the figure shows, the substation peaks tend to occur slightly later in the day than solar output. Nonetheless, solar output clearly can make a significant contribution to reducing peak loads at transmission substations. We apply the PCAF allocation of transmission loads shown in Figure 6 to the typical hourly PV output profile for Montana to determine the portion of transmission capacity costs that small, distributed solar QFs can avoid. The result is that solar QFs can avoid transmission capacity costs equal to 49% of their nameplate. For transmission capacity costs, we use NWE's current FERC-authorized firm transmission rate of $3.16 per kW-month.[55] As shown in **Table 8** below, the result is that solar QFs will avoid transmission capacity costs of $8.30 per MWh.

[55] Although this FERC rate is an embedded, not a marginal, cost number, it does represent NWE's opportunity cost to use or to sell firm transmission capacity which is made available by reduced transmission system loads resulting from small, distributed solar resources.

**Table 8:** *NWE Avoided Transmission Costs*

| Component | Cost or Metric | *Notes* |
|---|---|---|
| Transmission Capacity Costs ($/kW-yr) | $37.92 | *$3.16 per kW-month x 12* |
| x Solar Capacity as % of Nameplate | 52% | |
| = Transmission Capacity Costs Avoided | $19.72 | |
| ÷ Annual PV Output kWh per kW-AC | 2,377 | *from exemplary solar projects* |
| = Avoided Transmission Capacity Cost ($/MWh) | $8.30 | |

### D. Local Economic Benefits

**Q: Will there be local economic benefits from the development of solar QFs in NWE's Montana service territory?**

A: Yes. The construction of each additional 100 MW of solar generation in Montana would represent an investment of $300 million in the state, assuming a capital cost of $3,000 per kW. Not all of this money will be spent in Montana, of course, but there would be significant short-term employment benefits during construction as well as permanent employment operating and maintaining these facilities, as well as lease payments to landowners and property taxes to local communities. Significantly, because these facilities will be located in Montana, the economic benefits are more likely to accrue locally than if these were out-of-state power plants, power purchases from regional markets, or gas-fired generation whose fuel is procured out of state.

### E. Integration Costs

**Q: Are you concerned that NWE would have difficulty integrating additional intermittent solar generation into its system?**

A: No. The integration of higher levels of wind and solar resources presents a challenge to utilities and grid operators across the U.S., not just in the West. For example, in the West the NREL/GE WWSIS showed the ability to integrate levels of wind and solar penetration far in excess of today's levels, provided these

variable resources could be balanced on a sub-hourly basis over a large geographic footprint, with more accurate forecasts of variable resource output.[56]

Most notably, many western utilities have now joined with the CAISO to create a successful new energy imbalance market (EIM) that, among other benefits, implements the key findings of the WWSIS – balancing wind and solar resources more efficiently on a sub-hourly basis over a larger geographic footprint. For example, the cost of regulation on the CAISO system is significantly lower than what NWE spends today for regulation.[57] NWE's *2015 IRP* also shows lower costs for integrating an additional 100 to 200 MW of solar onto its system than for adding a similar amount of wind.[58] The *2015 IRP* shows incremental regulation costs of $2.02 per MWh of solar output for 50 MW of additional solar and $4.35 per MWh for 100 MW.[59] These added integration costs are significantly less than the additional quantifiable benefits of solar resources, discussed above and summarized in **Table 9**, that are not included in avoided cost prices.

**Table 9:** *Additional Benefits and Costs of Solar Resources*

| **Category** | **Benefits or (Costs)** *$ per MWh* |
|---|---|
| Fuel Hedging | 6.60 |
| Market Price Mitigation | 5.20 |
| Avoided Transmission Costs | 8.30 |
| Integration Costs for 100 MW | (4.35) |
| Net Benefit | 15.75 |

[56] The high penetration solar results from the WWSIS are reported in *Impact of High Solar Penetration in the Western Interconnection* (NREL and GE Consulting, December 2010), at p. 8 and Figure 19. This report, as well as all reports from the WWSIS, are available on the NREL website at http://www.nrel.gov/electricity/transmission/western_wind.html.

[57] At the CAISO's 2014-2015 market prices for regulation, NWE's current 33 MW regulation requirement would cost about $1.4 million, versus NWE's stated annual costs of $7.2 million using the combination of the Dave Gates Generating Station and NWE's hydro system. See CAISO, *2015 Annual Report on Market Issues and Performance*, at p. 135 (Figure 6.5, showing regulation costs of about $5 per MWh of regulation capacity). Available at http://www.caiso.com/Documents/May12_2016_2015AnnualReport_MarketIssues_Performance_ZZ16-4.pdf. Also see NWE's *2015 IRP*, at Figure 11-10.

[58] *2015 IRP*, at pp. 11-2 to 11-5.

[59] Based on the incremental regulation requirements shown in Figure 11-6, assumed regulation costs of $7.2 million per year for the base 34 MW of regulation, and solar output of 2,400 MWh per MW.

## VI. "GOLD RUSH" CONCERNS

**Q: NWE's testimony states that it may be forced to execute PPAs for as much as 130 MW of solar QFs, if the current QF-1 rates remain in place. Do you agree with this assessment?**

A: No. There has been a relatively low rate of successful QF development on the NWE system, even with the current QF-1 tariff. NWE's testimony, supplemented in discovery responses to staff, shows that NWE has executed only 14 interconnection agreements and 9 power purchase agreements (PPAs) with 2 - 3 MW solar QFs over the three-and-a-half years that the existing QF-1 rates have been available.[60] This does not support the idea that there is a "Gold Rush" of solar QFs trying to develop projects on NWE's system. Nine PPAs out of 89 interconnection requests over the last 17 months is a success rate of just 10%. The utility fears that it could be required to add another 130 MW of solar. This assumes a 100% success rate, which is not realistic given the historical track record. Developers face significant hurdles in securing buildable sites with reasonable, economic access to the transmission system, even when a PPA with acceptable prices is available from the utility. Further, a signed PPA is no guarantee of success. Not all projects that obtain an interconnection agreement and PPA are successfully financed and built, for a variety of reasons that can include failure to maintain site control, local or state permitting difficulties, and an inability to secure financing. In a recent proceeding before the Utah commission, PacifiCorp conceded in discovery that, since 2007, only 75% of QF projects in its service territory that have executed PPAs have been successfully developed.[61] As another data point, in 2014 Idaho Power signed 461 MW of solar QF contracts. By mid-2015, 141 MW (31%) of these contracts had been terminated, without the projects being built.[62]

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[60] NWE response to Data Requests PSC-002, PSC-005, and VS-010 (NWE's current interconnection queue).

[61] Utah Docket No. 15-035-53, PacifiCorp (dba Rocky Mountain Power) response to Sierra Club Data Request 1.4.

[62] Idaho Power Company, *2015 Integrated Resource Plan*, at p. 9.

**Q: Have you looked at the current status of solar QF projects requesting to interconnect with NWE?**

A: Yes. The most recent NWE interconnection queue, provided to Vote Solar in discovery,[63] shows that the utility has just 19 active solar projects that would qualify for the QF-1(a) tariff in its queue, representing 52 MW of capacity. Given the likelihood that only a fraction of this capacity will be developed successfully, there is hardly a "Gold Rush" of solar QFs in NWE's service territory.

**Q: Even if a significant number of additional 3 MW solar QF projects are successfully developed in NWE's service territory – for example, if a total of 25 projects totaling 75 MW are built – will NWE's ratepayers be harmed?**

A: Not at all. In fact, ratepayers will benefit. As presented in this testimony, the current QF-1(a) rates accurately reflect NWE's current avoided costs, so there would be no ratepayer harm if NWE were to continue to sign contracts with 3 MW solar QFs at these rates. Second, NWE needs the capacity that these solar contracts will provide, given its severe capacity deficit. Third, this new solar capacity will add diversity to NWE's existing renewable resources, complementing its wind and hydro assets, and will help the utility meet its renewable portfolio standard (RPS) requirements. Fourth, these projects will provide other quantifiable net benefits to NWE ratepayers that are not included in the QF-1(a) rates.

**Q: Does this complete your direct testimony?**

A; Yes, it does.

[63] See NWE response to Vote Solar Data Request VS-010.

**Exhibit RTB-1**

*Curriculum Vitae of*
*R. Thomas Beach*

Mr. Beach is principal consultant with the consulting firm Crossborder Energy. Crossborder Energy provides economic consulting services and strategic advice on market and regulatory issues concerning the natural gas and electric industries. The firm is based in Berkeley, California, and its practice focuses on the energy markets in California, the western U.S., Canada, and Mexico.

Since 1989, Mr. Beach has had an active consulting practice on policy, economic, and ratemaking issues concerning renewable energy development, the restructuring of the gas and electric industries, the addition of new natural gas pipeline and storage capacity, and a wide range of issues concerning independent power generation. From 1981 through 1989 he served at the California Public Utilities Commission, including five years as an advisor to three CPUC commissioners. While at the CPUC, he was a key advisor on the CPUC's restructuring of the natural gas industry in California, and worked extensively on the state's implementation of the Public Utilities Regulatory Policies Act of 1978.

## AREAS OF EXPERTISE

- *Renewable Energy Issues:* extensive experience assisting clients with issues concerning Renewable Portfolio Standard programs, including program structure and rate impacts. He has also worked for the solar industry on rate design and net energy metering issues, on the creation of the California Solar Initiative, as well as on a wide range of solar issues in many other states.

- *Restructuring the Natural Gas and Electric Industries:* consulting and expert testimony on numerous issues involving the restructuring of the electric industry, including the 2000 - 2001 Western energy crisis.

- *Energy Markets:* studies and consultation on the dynamics of natural gas and electric markets, including the impacts of new pipeline capacity on natural gas prices and of electric restructuring on wholesale electric prices.

- *Qualifying Facility Issues:* consulting with QF clients on a broad range of issues involving independent power facilities in the Western U.S. He is one of the leading experts in California on the calculation of avoided cost prices. Other QF issues on which he has worked include complex QF contract restructurings, standby rates, greenhouse gas emission regulations, and natural gas rates for cogenerators. Crossborder Energy's QF clients include the full range of QF technologies, both fossil-fueled and renewable.

- *Pricing Policy in Regulated Industries:* consulting and expert testimony on natural gas pipeline rates and on marginal cost-based rates for natural gas and electric utilities.

## EDUCATION

Mr. Beach holds a B.A. in English and physics from Dartmouth College, and an M.E. in mechanical engineering from the University of California at Berkeley.

## ACADEMIC HONORS

Graduated from Dartmouth with high honors in physics and honors in English.
Chevron Fellowship, U.C. Berkeley, 1978-79

## PROFESSIONAL ACCREDITATION

Registered professional engineer in the state of California.

## EXPERT WITNESS TESTIMONY BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION

1. Prepared Direct Testimony on Behalf of **Pacific Gas & Electric Company/Pacific Gas Transmission** (I. 88-12-027 — July 15, 1989)

   - *Competitive and environmental benefits of new natural gas pipeline capacity to California.*

2. a. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 10, 1989)
   b. Prepared Rebuttal Testimony on Behalf of the **Canadian Producer Group** (A. 89-08-024 — November 30, 1989)

   - *Natural gas procurement policy; gas cost forecasting.*

3. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (R. 88-08-018 — December 7, 1989)

   - *Brokering of interstate pipeline capacity.*

4. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029 — November 1, 1990)

   - *Natural gas procurement policy; gas cost forecasting; brokerage fees.*

5. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission and the Canadian Producer Group** (I. 86-06-005 — December 21, 1990)

   - *Firm and interruptible rates for noncore natural gas users*

6. a. Prepared Direct Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — January 25, 1991)
   b. Prepared Responsive Testimony on Behalf of the **Alberta Petroleum Marketing Commission** (R. 88-08-018 — March 29, 1991)

   - *Brokering of interstate pipeline capacity; intrastate transportation policies.*

7. Prepared Direct Testimony on Behalf of the **Canadian Producer Group** (A. 90-08-029/Phase II — April 17, 1991)

   - *Natural gas brokerage and transport fees.*

8. Prepared Direct Testimony on Behalf of **LUZ Partnership Management** (A. 91-01-027 — July 15, 1991)

   - *Natural gas parity rates for cogenerators and solar thermal power plants.*

9. Prepared Joint Testimony of R. Thomas Beach and Dr. Robert B. Weisenmiller on Behalf of the **California Cogeneration Council** (I. 89-07-004 — July 15, 1991)

   - *Avoided cost pricing; use of published natural gas price indices to set avoided cost prices for qualifying facilities.*

10. a. Prepared Direct Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-033 — October 28, 1991)
    b. Prepared Rebuttal Testimony on Behalf of the **Indicated Expansion Shippers** (A. 89-04-0033 — November 26,1991)

    - *Natural gas pipeline rate design; cost/benefit analysis of rolled-in rates.*

11. Prepared Direct Testimony on Behalf of the **Independent Petroleum Association of Canada** (A. 91-04-003 — January 17, 1992)

    - *Natural gas procurement policy; prudence of past gas purchases.*

12. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (I.86-06-005/Phase II — June 18, 1992)
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council** (I. 86-06-005/Phase II — July 2, 1992)

    - *Long-Run Marginal Cost (LRMC) rate design for natural gas utilities.*

13. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 92-10-017 — February 19, 1993)

    - *Performance-based ratemaking for electric utilities.*

14. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-02-014/A. 93-03-053 — May 21, 1993)

    - *Natural gas transportation service for wholesale customers.*

15 a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — June 28, 1993)
   b. Prepared Rebuttal Testimony of Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038 — July 8, 1993)

    - *Natural gas pipeline rate design issues.*

16. a. Prepared Direct Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — November 10, 1993)
    b. Prepared Rebuttal Testimony on Behalf of the **SEGS Projects** (C. 93-05-023 — January 10, 1994)

    - *Utility overcharges for natural gas service; cogeneration parity issues.*

17. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 93-09-006/A. 93-08-022/A. 93-09-048 — June 17, 1994)

    - *Natural gas rate design for wholesale customers; retail competition issues.*

18. Prepared Direct Testimony of R. Thomas Beach on Behalf of the **SEGS Projects** (A. 94-01-021 — August 5, 1994)

    - *Natural gas rate design issues; rate parity for solar thermal power plants.*

19. Prepared Direct Testimony on Transition Cost Issues on Behalf of **Watson Cogeneration Company** (R. 94-04-031/I. 94-04-032 — December 5, 1994)

    - *Policy issues concerning the calculation, allocation, and recovery of transition costs associated with electric industry restructuring.*

20. Prepared Direct Testimony on Nuclear Cost Recovery Issues on Behalf of the **California Cogeneration Council** (A. 93-12-025/I. 94-02-002 — February 14, 1995)

    - *Recovery of above-market nuclear plant costs under electric restructuring.*

21. Prepared Direct Testimony on Behalf of the **Sacramento Municipal Utility District** (A. 94-11-015 — June 16, 1995)

    - *Natural gas rate design; unbundled mainline transportation rates.*

22. Prepared Direct Testimony on Behalf of **Watson Cogeneration Company** (A. 95-05-049 — September 11, 1995)

    - *Incremental Energy Rates; air quality compliance costs.*

23. a. Prepared Direct Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — January 30, 1996)
    b. Prepared Rebuttal Testimony on Behalf of the **Canadian Association of Petroleum Producers** (A. 92-12-043/A. 93-03-038/A. 94-05-035/A. 94-06-034/A. 94-09-056/A. 94-06-044 — February 28, 1996)

    - *Natural gas market dynamics; gas pipeline rate design.*

24. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 96-03-031 — July 12, 1996)

    - *Natural gas rate design: parity rates for cogenerators.*

25. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 96-10-038 — August 6, 1997)

    - *Impacts of a major utility merger on competition in natural gas and electric markets.*

26. a. Prepared Direct Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — December 18, 1997)
    b. Prepared Rebuttal Testimony on Behalf of the **Electricity Generation Coalition** (A. 97-03-002 — January 9, 1998)

    - *Natural gas rate design for gas-fired electric generators.*

27. Prepared Direct Testimony on Behalf of the **City of Vernon** (A. 97-03-015 — January 16, 1998)

    - *Natural gas service to Baja, California, Mexico.*

28. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (A. 98-10-012/A. 98-10-031/A. 98-07-005 — March 4, 1999).
    b. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — March 15, 1999).
    c. Prepared Direct Testimony on Behalf of the **California Cogeneration Council** (A. 98-10-012/A. 98-01-031/A. 98-07-005 — June 25, 1999).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

29. a. Prepared Direct Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — February 11, 2000).
    b. Prepared Rebuttal Testimony on Behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — March 6, 2000).
    c. Prepared Direct Testimony on Line Loss Issues of behalf of the **California Cogeneration Council** (R. 99-11-022 — April 28, 2000).
    d. Supplemental Direct Testimony in Response to ALJ Cooke's Request on behalf of the **California Cogeneration Council and Watson Cogeneration Company** (R. 99-11-022 — April 28, 2000).
    e. Prepared Rebuttal Testimony on Line Loss Issues on behalf of the **California Cogeneration Council** (R. 99-11-022 — May 8, 2000).

    - *Market-based, avoided cost pricing for the electric output of gas-fired cogeneration facilities in the California market; electric line losses.*

30. a. Direct Testimony on behalf of the **Indicated Electric Generators** in Support of the Comprehensive Gas OII Settlement Agreement for Southern California Gas Company and San Diego Gas & Electric Company (I. 99-07-003 — May 5, 2000).
    b. Rebuttal Testimony in Support of the Comprehensive Settlement Agreement on behalf of the **Indicated Electric Generators** (I. 99-07-003 — May 19, 2000).

    - *Testimony in support of a comprehensive restructuring of natural gas rates and services on the Southern California Gas Company system. Natural gas cost allocation and rate design for gas-fired electric generators.*

31. a. Prepared Direct Testimony on the Cogeneration Gas Allowance on behalf of the **California Cogeneration Council** (A. 00-04-002 — September 1, 2000).
    b. Prepared Direct Testimony on behalf of **Southern Energy California** (A. 00-04-002 — September 1, 2000).

    - *Natural gas cost allocation and rate design for gas-fired electric generators.*

32. a. Prepared Direct Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — September 18, 2000).
    b. Prepared Rebuttal Testimony on behalf of **Watson Cogeneration Company** (A. 00-06-032 — October 6, 2000).

    - *Rate design for a natural gas "peaking service."*

33. a. Prepared Direct Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—April 25, 2001).
    b. Prepared Rebuttal Testimony on behalf of **PG&E National Energy Group & Calpine Corporation** (I. 00-11-002—May 15, 2001).

    - *Terms and conditions of natural gas service to electric generators; gas curtailment policies.*

34. a. Prepared Direct Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 7, 2001).
    b. Prepared Rebuttal Testimony on behalf of the **California Cogeneration Council** (R. 99-11-022—May 30, 2001).

    - *Avoided cost pricing for alternative energy producers in California.*

35. a. Prepared Direct Testimony of R. Thomas Beach in Support of the Application of **Wild Goose Storage Inc.** (A. 01-06-029—June 18, 2001).
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Wild Goose Storage** (A. 01-06-029—November 2, 2001)

    - *Consumer benefits from expanded natural gas storage capacity in California.*

36. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (I. 01-06-047—December 14, 2001)

    - *Reasonableness review of a natural gas utility's procurement practices and storage operations.*

37. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024—May 31, 2002)

    - *Electric procurement policies for California's electric utilities in the aftermath of the California energy crisis.*

38. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association** (R. 02-01-011—June 6, 2002)

    - *"Exit fees" for direct access customers in California.*

39. Prepared Direct Testimony of R. Thomas Beach on behalf of the **County of San Bernardino** (A. 02-02-012 — August 5, 2002)

    - *General rate case issues for a natural gas utility; reasonableness review of a natural gas utility's procurement practices.*

40. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association** (A. 98-07-003 — February 7, 2003)

    - *Recovery of past utility procurement costs from direct access customers.*

41. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — February 28, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council, the California Manufacturers & Technology Association, Calpine Corporation, and Mirant Americas, Inc.** (A 01-10-011 — March 24, 2003)

    - *Rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord II).*

42. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — March 21, 2003)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers & Technology Association; Calpine Corporation; Duke Energy North America; Mirant Americas, Inc.; Watson Cogeneration Company; and West Coast Power, Inc.** (R. 02-06-041 — April 4, 2003)

    - *Cost allocation of above-market interstate pipeline costs for the California natural gas utilities.*

43. Prepared Direct Testimony of R. Thomas Beach and Nancy Rader on behalf of the **California Wind Energy Association** (R. 01-10-024 — April 1, 2003)

    - *Design and implementation of a Renewable Portfolio Standard in California.*

44. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 23, 2003)
    b. Prepared Supplemental Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 01-10-024 — June 29, 2003)

    - *Power procurement policies for electric utilities in California.*

45. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Indicated Commercial Parties** (02-05-004 — August 29, 2003)

    - *Electric revenue allocation and rate design for commercial customers in southern California.*

46. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 16, 2004)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation and the California Cogeneration Council** (A. 04-03-021 — July 26, 2004)

    - *Policy and rate design issues for Pacific Gas & Electric's gas transmission system (Gas Accord III).*

47. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 04-04-003 — August 6, 2004)

    - *Policy and contract issues concerning cogeneration QFs in California.*

48. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 11, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council and the California Manufacturers and Technology Association** (A. 04-07-044 — January 28, 2005)

    - *Natural gas cost allocation and rate design for large transportation customers in northern California.*

49. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — March 7, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 04-06-024 — April 26, 2005)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

50. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Solar Energy Industries Association** (R. 04-03-017 — April 28, 2005)

    - *Cost-effectiveness of the Million Solar Roofs Program.*

51. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration Company, the Indicated Producers, and the California Manufacturing and Technology Association** (A. 04-12-004 — July 29, 2005)

    - *Natural gas rate design policy; integration of gas utility systems.*

52. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — August 31, 2005)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 04-04-003/R. 04-04-025 — October 28, 2005)

    - *Avoided cost rates and contracting policies for QFs in California*

53. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — January 20, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 05-05-023 — February 24, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in southern California.*

54. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Producers** ( R. 04-08-018 – January 30, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **California Producers** ( R. 04-08-018 – February 21, 2006)

    - *Transportation and balancing issues concerning California gas production.*

55. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Manufacturers and Technology Association and the Indicated Commercial Parties** (A. 06-03-005 — October 27, 2006)

    - *Electric marginal costs, revenue allocation, and rate design for commercial and industrial electric customers in northern California.*

56. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 05-12-030 — March 29, 2006)

    - *Review and approval of a new contract with a gas-fired cogeneration project.*

57. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 14, 2006)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Watson Cogeneration, Indicated Producers, the California Cogeneration Council, and the California Manufacturers and Technology Association** (A. 04-12-004 — July 31, 2006)

    - *Restructuring of the natural gas system in southern California to include firm capacity rights; unbundling of natural gas services; risk/reward issues for natural gas utilities.*

58. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 06-02-013 — March 2, 2007)

    - *Utility procurement policies concerning gas-fired cogeneration facilities.*

59. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — August 10, 2007)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 07-01-047 — September 24, 2007)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems.*

60. a. Prepared Direct Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — May 15, 2008)
    b. Prepared Rebuttal Testimony of R,. Thomas Beach on Behalf of **Gas Transmission Northwest Corporation** (A. 07-12-021 — June 13, 2008)

    - *Utility subscription to new natural gas pipeline capacity serving California.*

61. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — September 12, 2008)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-015 — October 3, 2008)

    - *Issues concerning the design of a utility-sponsored program to install 500 MW of utility- and independently-owned solar photovoltaic systems.*

62. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 08-03-002 — October 31, 2008)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems*.

63. a. Phase II Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — December 23, 2008)
    b. Phase II Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers, the California Cogeneration Council, California Manufacturers and Technology Association, and Watson Cogeneration Company** (A. 08-02-001 — January 27, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

64. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (A. 09-05-026 — November 4, 2009)

    - *Natural gas cost allocation and rate design issues for large customers.*

65. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 5, 2010)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Indicated Producers and Watson Cogeneration Company** (A. 10-03-028 — October 26, 2010)

    - *Revisions to a program of firm backbone capacity rights on natural gas pipelines.*

66. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014 — October 6, 2010)

    - *Electric rate design issues that impact customers installing solar photovoltaic systems*.

67. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Indicated Settling Parties** (A. 09-09-013 — October 11, 2010)

    - *Testimony on proposed modifications to a broad-based settlement of rate-related issues on the Pacific Gas & Electric natural gas pipeline system.*

68. a. Supplemental Prepared Direct Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 6, 2010)
    b. Supplemental Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 13, 2010)
    c. Supplemental Prepared Reply Testimony of R. Thomas Beach on behalf of **Sacramento Natural Gas Storage, LLC** (A. 07-04-013 — December 20, 2010)

    - *Local reliability benefits of a new natural gas storage facility.*

69. Prepared Direct Testimony of R. Thomas Beach on behalf of **The Vote Solar Initiative** (A. 10-11-015—June 1, 2011)

    - *Distributed generation policies; utility distribution planning.*

70. Prepared Reply Testimony of R. Thomas Beach on behalf of the **Solar Alliance** (A. 10-03-014—August 5, 2011)

    - *Electric rate design for commercial & industrial solar customers.*

71. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-06-007—February 6, 2012)

    - *Electric rate design for solar customers; marginal costs.*

72. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R.11-02-019—January 31, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Northern California Indicated Producers** (R. 11-02-019—February 28, 2012)

    - *Natural gas pipeline safety policies and costs*

73. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 11-10-002—June 12, 2012)

    - *Electric rate design for solar customers; marginal costs.*

74. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002—June 19, 2012)

    - *Natural gas pipeline safety policies and costs*

75. a. Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—June 25, 2012)
    b. Reply Testimony of R. Thomas Beach on behalf of the **California Cogeneration Council** (R. 12-03-014—July 23, 2012)

    - *Ability of combined heat and power resources to serve local reliability needs in southern California.*

76. a. Prepared Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—November 16, 2012)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Southern California Indicated Producers** and **Watson Cogeneration Company** (A. 11-11-002, Phase 2—December 14, 2012)

    - *Allocation and recovery of natural gas pipeline safety costs.*

77. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 12-12-002—May 10, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

78. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-04-012—December 13, 2013)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

79. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 13-12-015—June 30, 2014)

    - *Electric rate design for commercial & industrial solar customers; residential time-of-use rate design issues.*

80. a. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation** and the **Indicated Shippers** (A. 13-12-012—August 11, 2014)
    b. Prepared Direct Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—August 11, 2014)
    c. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation** (A. 13-12-012—September 15, 2014)
    d. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of **Calpine Corporation, the Canadian Association of Petroleum Producers, Gas Transmission Northwest,** and **the City of Palo Alto** (A. 13-12-012—September 15, 2014)

    - *Rate design, cost allocation, and revenue requirement issues for the gas transmission system of a major natural gas utility.*

81. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (R. 12-06-013—September 15, 2014)

    - *Comprehensive review of policies for rate design for residential electric customers in California.*

82. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-06-014—March 13, 2015)

    - *Electric rate design for commercial & industrial solar customers; marginal costs.*

83. a. Prepared Direct Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A.14-11-014—May 1, 2015)
    b. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Solar Energy Industries Association** (A. 14-11-014—May 26, 2015)

    - *Time-of-use periods for residential TOU rates.*

84. Prepared Rebuttal Testimony of R. Thomas Beach on behalf of the **Joint Solar Parties** (R. 14-07-002—September 30, 2015)

    - *Electric rate design issues concerning proposals for the net energy metering successor tariff in California.*

**EXPERT WITNESS TESTIMONY BEFORE THE COLORADO PUBLIC UTILITIES COMMISSION**

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Colorado Solar Energy Industries Association and the Solar Alliance, (Docket No. 09AL-299E – October 2, 2009).

   - *Electric rate design policies to encourage the use of distributed solar generation.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the Vote Solar Initiative and the Interstate Renewable Energy Council, (Docket No. 11A-418E – September 21, 2011).

   - *Development of a community solar program for Xcel Energy.*

**EXPERT WITNESS TESTIMONY BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION**

1. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League** (Case No. IPC-E-12-27—May 10, 2013)

   - *Costs and benefits of net energy metering in Idaho.*

2. a. Direct Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — April 23, 2015)
   b. Rebuttal Testimony of R. Thomas Beach on behalf of the **Idaho Conservation League and the Sierra Club** (Case Nos. IPC-E-15-01/AVU-4-15-01/PAC-E-15-03 — May 14, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

**EXPERT WITNESS TESTIMONY BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION**

1. Direct and Rebuttal Testimony of R. Thomas Beach on Behalf of Geronimo Energy, LLC. (In the Matter of the Petition of Northern States Power Company to Initiate a Competitive Resource Acquisition Process [OAH Docket No. 8-2500-30760, MPUC Docket No. E002/CN-12-1240, September 27 and October 18, 2013])

   - *Testimony in support of a competitive bid from a distributed solar project in an all-source solicitation for generating capacity.*

**EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA**

1. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 97-2001—May 28, 1997)

   - *Avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

2. Pre-filed Direct Testimony on Behalf of **Nevada Sun-Peak Limited Partnership** (Docket No. 97-6008—September 5, 1997)

   - *QF pricing issues in Nevada.*

3. Pre-filed Direct Testimony on Behalf of the **Nevada Geothermal Industry Council** (Docket No. 98-2002 — June 18, 1998)

   - *Market-based, avoided cost pricing for the electric output of geothermal generation facilities in Nevada.*

**EXPERT WITNESS TESTIMONY BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION**

1. Direct Testimony of R. Thomas Beach on Behalf of the **Interstate Renewable Energy Council** (Case No. 10-00086-UT—February 28, 2011)

   - *Testimony on proposed standby rates for new distributed generation projects; cost-effectiveness of DG in New Mexico.*

2. Direct Testimony and Exhibits of R. Thomas Beach on behalf of the **New Mexico Independent Power Producers** (Case No. 11-00265-UT, October 3, 2011)

   - *Cost cap for the Renewable Portfolio Standard program in New Mexico*

**EXPERT WITNESS TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION**

1. Direct, Response, and Rebuttal Testimony of R. Thomas Beach on Behalf of the North Carolina Sustainable Energy Association. (In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2014; Docket E-100 Sub 140; April 25, May 30, and June 20, 2014)

   - *Testimony on avoided cost issues related to solar and renewable qualifying facilities in North Carolina.*

**EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC UTILITIES COMMISSION OF OREGON**

1. a. Direct Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — August 3, 2004)
   b. Surrebuttal Testimony of Behalf of **Weyerhaeuser Company** (UM 1129 — October 14, 2004)

2. a. Direct Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — February 27, 2006)
   b. Rebuttal Testimony of Behalf of **Weyerhaeuser Company and the Industrial Customers of Northwest Utilities** (UM 1129 / Phase II — April 7, 2006)

   - *Policies to promote the development of cogeneration and other qualifying facilities in Oregon.*

**EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA**

1. Direct Testimony and Exhibits of R. Thomas Beach on behalf of **The Alliance for Solar Choice** (Docket No. 2014-246-E – December 11, 2014)

   - *Methodology for evaluating the cost-effectiveness of net energy metering*

**EXPERT WITNESS TESTIMONY BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH**

1. Direct Testimony of R. Thomas Beach on behalf of the **Sierra Club** (Docket No. 15-035-53—September 15, 2015)

   - *Issues concerning the term of PURPA contracts in Idaho.*

**EXPERT WITNESS TESTIMONY BEFORE THE VERMONT PUBLIC SERVICE BOARD**

1. Pre-filed Testimony of R. Thomas Beach and Patrick McGuire on Behalf of **Allco Renewable Energy Limited** (Docket No. 8010 — September 26, 2014)

   - *Avoided cost pricing issues in Vermont*

**EXPERT WITNESS TESTIMONY BEFORE THE VIRGINIA CORPORATION COMMISSION**

1. Direct Testimony and Exhibits of R. Thomas Beach on Behalf of the Maryland – District of Columbia – Virginia Solar Energy Industries Association, (Case No. PUE-2011-00088, October 11, 2011)

   - *Cost-effectiveness of, and standby rates for, net-metered solar customers.*

## LITIGATION EXPERIENCE

Mr. Beach has been retained as an expert in a variety of civil litigation matters. His work has included the preparation of reports on the following topics:

- The calculation of damages in disputes over the pricing terms of natural gas sales contracts (2 separate cases).
- The valuation of a contract for the purchase of power produced from wind generators.
- The compliance of cogeneration facilities with the policies and regulations applicable to Qualifying Facilities (QFs) under PURPA in California.
- Audit reports on the obligations of buyers and sellers under direct access electric contracts in the California market (2 separate cases).
- The valuation of interstate pipeline capacity contracts (3 separate cases).

In several of these matters, Mr. Beach was deposed by opposing counsel. Mr. Beach has also testified at trial in the bankruptcy of a major U.S. energy company, and has been retained as a consultant in anti-trust litigation concerning the California natural gas market in the period prior to and during the 2000-2001 California energy crisis.

# Exhibit 2

## Vote Solar's Blended Market – Combined-cycle Avoided Costs

**Blended Market-Combined Cycle Plant Approach**
**Approved in Docket No. D2012.1.3**

**Revised MT Gas Forecast**

| Year | Annual Capital | Fixed O&M 2.0% | Total fixed | Variable O&M 2.0% | Natural Gas Cost Forecast | Fuel Cost 8.314 | Market Price for Solar | Total Cost | REC/CO2 Cost | Total Cost w/CO2 |
|---|---|---|---|---|---|---|---|---|---|---|
| | *($/kW-yr)* | *($/kW-yr)* | *($/kW-yr)* | *($/kWh)* | *($/MMBtu)* | *($/kWh)* | *($/kWh)* | *($/kWh)* | *($/kWh)* | *($/kWh)* |
| 2017 | | | | | | | 0.02303 | 0.02303 | 0.00510 | 0.02813 |
| 2018 | | | | | | | 0.02337 | 0.02337 | 0.00531 | 0.02867 |
| 2019 | 139.99 | 11.37 | 151.36 | 0.00545 | 3.10 | 0.02576 | | 0.05041 | 0.00563 | 0.05604 |
| 2020 | 139.99 | 11.59 | 151.58 | 0.00556 | 3.43 | 0.02852 | | 0.05331 | 0.00609 | 0.05941 |
| 2021 | 139.99 | 11.82 | 151.81 | 0.00567 | 3.44 | 0.02860 | | 0.05353 | 0.00673 | 0.06026 |
| 2022 | 139.99 | 12.06 | 152.05 | 0.00579 | 3.53 | 0.02935 | | 0.05443 | 0.00992 | 0.06435 |
| 2023 | 139.99 | 12.30 | 152.29 | 0.00590 | 3.87 | 0.03216 | | 0.05738 | 0.01012 | 0.06750 |
| 2024 | 139.99 | 12.55 | 152.54 | 0.00602 | 4.12 | 0.03424 | | 0.05961 | 0.01032 | 0.06993 |
| 2025 | 139.99 | 12.80 | 152.79 | 0.00614 | 4.29 | 0.03565 | | 0.06117 | 0.01053 | 0.07170 |
| 2026 | 139.99 | 13.06 | 153.05 | 0.00627 | 4.27 | 0.03553 | | 0.06121 | 0.01074 | 0.07195 |
| 2027 | 139.99 | 13.32 | 153.31 | 0.00639 | 4.33 | 0.03603 | | 0.06187 | 0.01095 | 0.07282 |
| 2028 | 139.99 | 13.58 | 153.57 | 0.00652 | 4.46 | 0.03706 | | 0.06306 | 0.01117 | 0.07423 |
| 2029 | 139.99 | 13.85 | 153.84 | 0.00665 | 4.59 | 0.03814 | | 0.06430 | 0.01140 | 0.07570 |
| 2030 | 139.99 | 14.13 | 154.12 | 0.00678 | 4.69 | 0.03896 | | 0.06529 | 0.01163 | 0.07691 |
| 2031 | 139.99 | 14.41 | 154.40 | 0.00692 | 4.75 | 0.03949 | | 0.06600 | 0.01186 | 0.07785 |
| 2032 | 139.99 | 14.70 | 154.69 | 0.00706 | 4.87 | 0.04052 | | 0.06720 | 0.01209 | 0.07929 |
| 2033 | 139.99 | 15.00 | 154.99 | 0.00720 | 4.93 | 0.04100 | | 0.06786 | 0.01234 | 0.08019 |
| 2034 | 139.99 | 15.30 | 155.29 | 0.00734 | 5.02 | 0.04175 | | 0.06879 | 0.01258 | 0.08137 |
| 2035 | 139.99 | 15.60 | 155.59 | 0.00749 | 5.10 | 0.04237 | | 0.06960 | 0.01284 | 0.08243 |
| 2036 | 139.99 | 15.91 | 155.90 | 0.00764 | 5.20 | 0.04320 | | 0.07061 | 0.01309 | 0.08370 |
| 2037 | 139.99 | 16.23 | 156.22 | 0.00779 | 5.25 | 0.04365 | | 0.07126 | 0.01335 | 0.08461 |
| 2038 | 139.99 | 16.56 | 156.55 | 0.00795 | 5.31 | 0.04414 | | 0.07194 | 0.01362 | 0.08557 |
| 2039 | 139.99 | 16.89 | 156.88 | 0.00811 | 5.49 | 0.04563 | | 0.07364 | 0.01389 | 0.08753 |
| 2040 | 139.99 | 17.23 | 157.22 | 0.00827 | 5.61 | 0.04668 | | 0.07489 | 0.01417 | 0.08906 |
| 2041 | 139.99 | 17.57 | 157.56 | 0.00843 | 5.80 | 0.04823 | | 0.07665 | 0.01445 | 0.09111 |
| | | | | | 2017-2041 25-year levelized cost: | | | 0.05543 | | 0.06492 |

| | | |
|---|---|---|
| Inflation: | | 2.0% |
| Discount Rate: | | 7.03% |
| On-Peak hours/year: | | 2038 |
| 2017 REC Value ($/kWh) | | 0.005 |
| Representative Solar MWh | | |
| | Off-Peak: | 4,798,515 |
| | On Peak: | 2,332,951 |
| | Total: | 7,131,466 |

| QF-1 Tariff Solar Rates | | | | Revised MT Gas | | | |
|---|---|---|---|---|---|---|---|
| | Rate ($/kWh) | Current | Vote Solar 7199d Method | | NWE Proposal | |
| No Carbon | Off-Peak: | $0.05314 | $0.04180 | *-21%* | $0.03027 | *-43%* |
| | On Peak: | $0.09273 | $0.10039 | *8%* | $0.03027 | *-67%* |
| | Solar Rate: | $0.06609 | $0.06097 | *-8%* | $0.03597 | *-46%* |
| With Carbon | Off-Peak: | | $0.05129 | *-3%* | $0.03988 | *-25%* |
| | On Peak: | | $0.10988 | *18%* | $0.03988 | *-57%* |
| | Solar Rate: | | $0.07046 | *7%* | $0.04558 | *-31%* |

**Exhibit RTB-3**

*Certain Discovery Responses*
*from NorthWestern Energy*

PSC-013

Regarding: Avoided Cost Calculation
Witness: Hansen

For the wind, solar, and hydro/other resources, please calculate avoided costs using market sale price as the value of production under all long conditions, and market purchase price when short. Please calculate with and without a carbon adder.

RESPONSE:

| RESOURCE | ENERGY RATE WITHOUT CARBON ($/MWh) | ENERGY RATE WITH CARBON ($/MWh) |
|---|---|---|
| HYDRO | $ 33.84 | $ 43.77 |
| SOLAR | $ 35.10 | $ 45.02 |
| WIND | $ 35.69 | $ 45.62 |

**NorthWestern Energy**
**Docket No. D2016.5.39**
**Application for Approval of Avoided Cost Tariff Schedule QF-1**

**Vote Solar/Montana Environmental Information Center**
**Set 1 (001-012)**

Data Requests received July 14, 2016

VS-005 Subject: Capacity Contribution of Wind and Solar (Bushnell Testimony)

Concerning the proposed method to calculate the capacity contribution of wind and solar resources (Bushnell testimony, at p. JBB-10):

a. Please provide references to any other jurisdiction that uses an 85% exceedance value in the highest 10% of load hours in the on-peak period to set the capacity value of solar or wind resources.

b. Please provide references to all documents, sources, or reports that Mr. Bushnell reviewed or consulted in deciding to choose this method for establishing the capacity contribution of wind and solar resources.

c. Mr. Bushnell states that "Opinions differ as to the capacity contribution of intermittent QF resources" (p. JBB-13). Please provide his understanding of what those differences of opinion are.

d. Was Mr. Bushnell's testimony in Docket No. D2012.1.3 concerning the use of 85% exceedance to determine capacity contribution (as referenced on page JBB-11) adopted by the Commission?

RESPONSE:

a. The On-Peak period in the QF-1 Tariff is defined to be the heavy load hours for January, February, July, August, and December. This definition, to Mr. Bushnell's knowledge, is unique to Montana QF-1 Tariffs. Mr. Bushnell knows of no other jurisdiction that uses an 85% exceedance value in the highest 10% of load hours in the on-peak period to set the capacity value of solar or wind resources, or hydroelectric resources.

b. The proposal to measure and pay for measured capacity is based upon the witness's past experience in QF proceedings before the MPSC, but the proposed method most closely resembles the SPP method as outlined by NREL Conference Paper NREL/CP-500-43433, June 2008. The major differences are:
   - SPP calculates capacity contribution monthly instead of annually;
   - SPP uses 10% of all hours instead of 10% of On-Peak hours, and
   - SPP averages up to ten years instead of five years.

   SPP recently changed its methodology, reducing the exceedance from 85% to 60%.

VS-005 cont'd

c. The statement is a generalization of Mr. Bushnell's experience, including the record in Docket No. D2012.2.3.

d. No. However, the proposals contained in this filing are not the same as the proposals contained in Docket No. D2012.1.3. In Docket No. D2012.1.3, NorthWestern's proposal was to set the capacity contribution using an 85% exceedance method. In this proceeding, NorthWestern's proposal is to use an 85% exceedance method to measure capacity contribution and pay each QF for their contribution (a five-year average).

**NorthWestern Energy**
**Docket No. D2016.5.39**
**Application for Approval of Avoided Cost Tariff Schedule QF-1**

**Vote Solar/Montana Environmental Information Center**
**Set 1 (001-012)**

Data Requests received July 14, 2016

VS-010 Subject: Interconnection Requests (Exhibit AMM-1)

Concerning the interconnection requests received by NWE, as discussed by Mr. Hines (p. JDH-7) and Ms. Mueller (p. AMM-5), please provide an Excel version of Exh. AMM-1.

RESPONSE:

The interconnection requests received by NorthWestern are posted on the Company's Open Access Same-Time Information System (OASIS) website. Exhibit__(AMM-1) was downloaded from that website on April 28, 2016, and an updated version from June 7, 2016 was provided as Exhibit NWE-2 at the June 9 hearing. View the most current interconnection queue (an Excel document) at the following link:

http://www.oatioasis.com/NWMT/NWMTdocs/GenConnect7.html

**NorthWestern Energy**
**Docket No. D2016.5.39**
**Application for Approval of Avoided Cost Tariff Schedule QF-1**

**Vote Solar/Montana Environmental Information Center**
**Set 1 (001-012)**

Data Requests received July 14, 2016

VS-011 Subject: NWE's Avoided Transmission and Distribution Costs

For use in calculating NWE's avoided transmission and distribution costs, please provide:

a. The voltage level at which each of the still-active solar projects in NWE's current interconnection queue would interconnect. Please indicate whether this is a distribution or transmission voltage on the NWE system.

b. For the most recent calendar year for which such data is available, please provide the following data:

   i. The hourly loads (i.e. the 8,760 hourly loads over the year) for each distribution substation on the company's system. Generic (e.g. numbered) substation labels may be used if the company prefers, for security reasons or to preserve customer confidentiality. Please indicate for what percentage of such substations the company has such hourly data. If hourly load data is only available for those distribution substations with SCADA, please provide that data for the substations with SCADA.
   ii. Alternatively, if hourly load data is not available for some distribution substations, please provide the magnitude of the annual peak load (in MW) at each such distribution substation that does not have hourly load data, and the time and date of such peak load, if available.
   iii. The maximum kW capacity of each distribution substation.

c. For the most recent calendar year for which such data is available, please provide the following data:

   i. The hourly loads (i.e. the 8,760 hourly loads over the year) for each transmission substation on the company's system. Generic (e.g. numbered) substation labels may be used if the company prefers, for security reasons or to preserve customer confidentiality. Please indicate for what percentage of such substations the company has such hourly data. If hourly load data is only available for those transmission substations with SCADA, please provide that data for the substations with SCADA.
   ii. Alternatively, if hourly load data is not available for some transmission substations, please provide the magnitude of the annual peak load (in MW) at each such transmission substation that does not have hourly load data, and the time and date of such peak load, if available.

VS-011 cont'd

iii. The maximum kW capacity of each transmission substation.

d. Please provide the company's current investment plan for its transmission and distribution facilities, preferably over the next five years, but for at least the next three years. This should include:

i. The annual transmission and distribution plant additions and retirements in each year, by FERC account if available.
ii. The forecasted annual peak demands, in MW, on the company's transmission and distribution systems.

e. Please provide data, by FERC account, on the company's historical investments for its transmission and distribution facilities for the last ten years (2006-2015).

RESPONSE:

a. See Attachment.

b. The requested information is being extracted from multiple data sources, and will be provided shortly.

c. The requested information is being extracted from multiple data sources, and will be provided shortly.

d. i. See Attachment.

ii. Below is the NorthWestern Transmission group's load forecast for NorthWestern's Balancing Authority Area.

VS-011 cont'd

| Balancing Authority Area Load Forecast with DSM | | |
|---|---|---|
| Peak MW | | |
| Year | Summer | Winter |
| 2016 | 1801 | 1729 |
| 2017 | 1821 | 1744 |
| 2018 | 1841 | 1759 |
| 2019 | 1861 | 1773 |
| 2020 | 1881 | 1778 |

Below is the NorthWestern Supply group's load forecast for the distribution system. It was taken from the 2015 Electricity Supply Resource Procurement Plan.

| | 1 in 2 Peak Demand Forecast Excluding DSM (MW) | | |
|---|---|---|---|
| | Year | Winter | Summer |
| Forecast | 2016 | 1224 | 1154 |
| | 2017 | 1244 | 1177 |
| | 2018 | 1264 | 1200 |
| | 2019 | 1285 | 1222 |
| | 2020 | 1305 | 1245 |

| | Peak Demand DSM Savings Forecast (MW) | | |
|---|---|---|---|
| | Year | Winter | Summer |
| Forecast | 2016 | 40 | 38 |
| | 2017 | 50 | 48 |
| | 2018 | 60 | 58 |
| | 2019 | 69 | 66 |
| | 2020 | 79 | 76 |

| | 1 in 2 Peak Demand Forecast Including DSM (MW) | | |
|---|---|---|---|
| | Year | Winter | Summer |
| Forecast | 2016 | 1184 | 1116 |
| | 2017 | 1195 | 1129 |
| | 2018 | 1205 | 1143 |
| | 2019 | 1216 | 1156 |
| | 2020 | 1226 | 1169 |

e. See Attachment.

**NorthWestern Energy**
**Docket No. D2016.5.39**
**Application for Approval of Avoided Cost Tariff Schedule QF-1**

**Vote Solar/Montana Environmental Information Center**
**Set 2 (013-023)**

Data Requests received September 6, 2016

VS-014 Subject: Natural Gas Transportation Cost Assumptions

In the workpapers for Mr. Hansen's testimony, there are files with the outputs of his runs – Hydro Worksheet.xls, Solar spreadsheet.xls, and Wind Worksheet.xls. Each of these spreadsheets have a tab with "Iteration Prices." Row 38 of this tab appears to show that NWE has added just a flat $0.15 per Dth to the AECO gas price as the "transport" cost in all years from 2018 through 2042.

a. Is this the assumed gas transportation cost from AECO to NWE's gas-fired power plants in all years in NWE's PowerSimm modeling in this case?

b. Please justify the reasonableness of this cost, and show how it was derived from current tariffed rates on the NWE gas system and the TransCanada system in Canada.

c. If this $0.15 per Dth transport cost is just the variable cost of transportation, please explain why new renewable generation resources on NWE's system that displace long-term gas-fired resources do not also avoid firm transportation reservation costs on the NWE and TransCanada gas pipeline systems.

d. Why does this rate not escalate over time as natural gas prices escalate?

RESPONSE:

a. No. NorthWestern has determined that the rate needs to be updated and will provide an updated avoided cost calculation when it submits its rebuttal testimony.

b. The transportation rate of $0.15 is the cost that it would require to transport natural gas from AECO to NorthWestern's natural gas system. The rate of $0.15 was taken from the TransCanada tariff, converted into United States dollars, and escalated to 2018. The rate calculation (performed for the 2015 Electricity Supply Resource Procurement Plan) is shown below:

VS-014 cont'd

| | | |
|---|---|---|
| FT-D Demand Rate | $ 5.08 | $/GJ/month |
| 5+ year term discount | 10% | |
| FT-D Demand Rate after discount | $ 4.57 | $/GJ/month |
| Abandonment Surcharge | $ 0.32 | $/GJ/month |
| total transportation | $ 4.89 | $/GJ/month |
| daily rate per GJ | $ 0.163 | $/GJ/day |
| GJ to MMBtu conversion | 0.9478 | |
| daily rate per MMBtu (Cdn) | $ 0.155 | Cdn/MMBtu |
| Canadian exchange rate | 0.89 | |
| Transportation per MMBtu in USD (2015 $) | $ 0.137 | U.S.$/MMBtu |
| Transportation per MMBtu in USD (2016 $) | $ 0.140 | U.S.$/MMBtu |
| Transportation per MMBtu in USD (2017 $) | $ 0.142 | U.S.$/MMBtu |
| Transportation per MMBtu in USD (2018 $) | $ 0.145 | U.S.$/MMBtu |

c. The $0.15 charge includes the TransCanada NGTL demand and abandonment charges. An updated avoided cost will include the demand rate and abandonment charges on the TransCanada NGTL pipeline and the interruptible commodity tariff rate on NorthWestern's pipeline.

d. The rate should escalate over time. See also the response to part a, above.

**CERTIFICATE OF SERVICE**

I hereby certify that on the 14th day of October, 2016, I served the foregoing by first-class mail, postage prepaid, and electronic mail on the following:

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