BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the	**Docket No. UE-100849**
Inquiry on Regulatory Treatment for Renewable Energy Resources	**Exhibit A to Joint Comments of Renewable Northwest Project, NW Energy Coalition, Climate Solutions, Cascade Chapter of the Sierra Club, and the Washington Environmental Council**

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Puget Sound Energy, Inc.	)	**Docket No. ER10-1436-000**

PROTEST OF THE AMERICAN WIND ENERGY ASSOCIATION, THE RENEWABLE NORTHWEST PROJECT AND THE CENTER FOR ENERGY EFFICIENCY AND RENEWABLE TECHNOLOGIES

Pursuant to Rule 211 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("Commission"), 18 C.F.R. § 85.211 (2009), the American Wind Energy Association ("AWEA"), the Renewable Northwest Project Protest ("RNP"), and the Center for Energy Efficiency and Renewable Technologies ("CEERT")[1] hereby respectfully file this protest in the above-captioned proceeding initiated by Puget Sound Energy, Inc. ("Puget"), requesting Commission approval of its new Schedule 12, Wind Integration Within-Hour Generation Following Service ("Following Capacity"), to its Open Access Transmission Tariff ("OATT"). In particular, Puget proposes a $2.70/kW-month rate for the Following Capacity charge.

For the reasons discussed below, AWEA, RNP and CEERT submit that Puget's filing has not been shown to be just and reasonable and request that the Commission reject the filing or, in the alternative, suspend the proposed rate for the maximum statutory period and order a full paper hearing on the matter.

[1] AWEA, RNP and CEERT have reviewed a draft of the protest filed by Invenergy Wind North America LLC and generally support the positions taken therein.

I. Background

Puget seeks to modify Schedule 12 of its OATT by adding a Following Capacity charge and to require that all wind generation resources located within Puget's Balancing Authority Area ("BAA") to purchase Following Capacity from Puget. Puget states that it currently recovers most of its energy cost component, but not the capacity cost component, of following wind generation under Schedule 9 of its OATT.

According to Puget, it bases its proposed monthly charge of $2.70/kW for the Following Capacity on: (1) the percentage of a wind generator's installed capacity that must be backed up with following capacity, determined on the basis of actual operating data from the most recent calendar year, referred to as the Following Capacity Allocation Factor ("FCAF"); and (2) the incremental monthly cost of reserving one kilowatt of fast start natural gas-fired generation capacity, referred to as the Following Capacity Fixed Charge ("FCFC").

Puget maintains that the 18.1 percent FCAF would ensure that wind generators pay only for the generating capacity that Puget needs to balance the incremental within-hour variability of the wind generation on its system. Puget further maintains that it is appropriate to base the FCFC on the incremental cost to Puget of a peaking unit rather than the average or embedded cost of capacity on Puget's system. While its existing stored hydroelectric capacity may be operationally suitable to provide the needed Following Capacity, Puget argues that its hydroelectric capacity should not serve this role because it was acquired for the purpose of providing a least cost resource to serve Puget's native load and has been paid for by Puget's native load. Puget also claims that it is inappropriate to use its embedded fossil fuel generation to determine the FCFC, because the rapid ramps of a wind generator require Following Capacity that can be quickly and substantially ramped both up and down.

II. Executive Summary

To develop the charge for Following Capacity, Puget proposes a formulary rate equal to the product of: (1) the FCAF (initially set at 18.1 percent); and (2) the FCFC of \$14.91/kW/month. The initial charge of \$2.70/kW/month would be applied to each wind generator's nameplate capacity, *e.g.*, if a wind generator's nameplate capacity were 100 MW, the generator would pay \$3.2 million per year under Schedule 12. The FCAF will be revised annually, effective April 1 of each year, to reflect the most recent 12 months of actual calendar year load and wind variability data ("Annual Update"), and Puget proposes procedures to allow parties to challenge the revised rate ("Annual Review Procedures").

While Puget describes the proposed rate as a "modest" charge,[2] that claim is incorrect. Puget's current charge for transmission service is \$2.76/kW/year, or \$0.23/kW/month,[3] by contrast, its proposed charge for wind integration regulation service is \$2.70/kW/month—clearly not modest. In addition to the Following Capacity charge, Puget proposes to continue to apply other charges for regulation capacity to all customers, including wind generators. For example, under Schedules 3 and 13 of its OATT, Puget assesses charges for Regulation and Frequency Response Service for deliveries within and outside its control area. Also, under Schedules 4 and 9, Puget assesses charges for Energy Imbalance Service and Generator Imbalance Service. As such, Puget is attempting to

[2] Puget Filing, Exhibit Puget-100, Prepared Testimony of Charles J. Cicchetti ("Cicchetti Testimony") at 34.
[3] Puget OATT, Schedule 7.

receive revenue under Schedule 12 for Following Capacity even though it already receives revenue under other schedules to compensate it for regulation capacity.

The proposed Following Capacity charge clearly is excessive, insofar as it would collect considerably more than the actual costs Puget incurs in providing regulating capacity, and therefore, is unjust and unreasonable. In addition, since Puget proposes to make these excessive charges apply only to wind generation, it is also discriminatory and would provide preferential treatment to other resources. Should a transmission provider claim that wind integration is ever warranted, this likely would arise from the transmission provider's failure to adopt cost-effective operating procedures that would eliminate the need for such a service. As such, it would be unjust and unreasonable for Puget to seek to recover from wind generators costs that it incurs on account of operating procedures so poorly suited for accommodating wind. Since Puget acknowledges that it is currently pursuing reforms to its operating procedures, it should be required to update the Following Capacity charge at the time any such reforms are adopted that would change that rate.

In short, as Puget's proposed rate for Following Capacity has not been shown to be just and reasonable, the Commission should either reject the filing or order it set for a formal hearing.

III. Protest

A. The Filing Should be Rejected, or in the Alternative, Suspended for 5 Months, and Set for Hearing and Settlement Procedures

For the reasons discussed below, AWEA, RNP and CEERT request that the Commission should find that Puget's proposed rate for Following Capacity has not been shown to be just and reasonable, and either reject the filing or order that a formal hearing be established subject to a Track Three Schedule. If the Commission accepts the filing, it should suspend collection of the proposed rates for the maximum statutory period of five months.[4]

B. Schedule 12 Does Not Involve a New Service

Puget is also incorrect in its claim that the Within Hour Generation Following Service is a new service.[5] Regulation and Frequency Response Service is already an established service under Schedules 3 and 13 of the Puget OATT, which both require Puget to "follow the moment-by-moment" changes in output or load.[6] As the Commission has recognized, all transmission providers provide regulation service in connection with generator imbalance services and, as such, may propose charges to recover the capacity costs related to generation imbalance services under the OATT.[7] The only thing "new" about Puget's Schedule 12 is that it proposes to single out wind generators for a second, and much more costly, regulation service charge than is already applied under its OATT. Currently, the rate for moment-to-moment regulation is $5.50/kW/month applied to 2 percent of the customer's network load responsibility or reserved capacity, *i.e.*, $0.11/kW/month for each kW of transmission service provided.[8] When Schedule 12 is

[4] In *West Texas Utilities Company*, the Commission explained that when preliminary analysis indicates that a proposed rate may be unjust and unreasonable, and may be substantially excessive (more than 10 percent of the rate is preliminarily found to be excessive.), the Commission will generally impose a five-month suspension. 18 FERC ¶ 61,189 (1982) (*West Texas*). AWEA asserts that the rates proposed by Puget meet the definition of substantially excessive set forth in *West Texas*.
[5] Puget Filing at 16, Cicchetti Testimony at 23.
[6] Puget OATT, Schedules 3 (Regulation and Frequency Response Service) and 13 (Regulation and Frequency Response Service for Generation Selling Outside of Control Area).
[7] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 at P 689 n.401 (2007) ("Order No. 890"), *order on reh'g*, Order No. 890-A, 73 Fed. Reg. 2984 (Jan. 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009). Puget itself acknowledges that it is implementing the option that FERC has authorized to allow transmission providers to recover the capacity costs of providing imbalance service to generators under the OATT. Puget Filing at 9-10.
[8] The product of $5.50/kW/month and 2percent is $0.11/kW/month.

combined with the Schedule 3 or 13, wind generators would pay $2.81/kW/month for regulation service, an increase of $2.70/kW/month—***an astounding increase of 2,454 percent***.

When Puget filed Schedule 13—Regulation and Frequency Response Service for Generators Selling Outside the Control Area—it explained that it was implementing the Commission's determination in Order No. 890 that allows it to propose a method for recovery of regulation service associated with generator imbalances.[9] In the instant filing, Puget similarly contends that it is following the Commission's Order No. 890 determination.[10] Thus, Puget cannot now claim that this is a "new" service and that it does not currently charge for such service.[11]

C. The Proposed Following Capacity Charge Is Not Just and Reasonable

i. It is Unjust and Unreasonable to Charge Wind Generators for Costs that are a Product of Outdated Power System Operating Procedures

AWEA, RNP and CEERT contend that it would be unjust and unreasonable for Puget to seek to recover from wind generators costs that Puget incurs on account of operating procedures so poorly suited for accommodating wind. Indeed, a number of studies demonstrate that balancing area consolidation or coordination greatly reduces the perceived costs of integrating variable generators into the power system.[12] In addition,

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[9] Puget Sound Energy, Inc., Open Access Transmission Tariff Changes Filing, Docket No. ER10-723-000 at 4 n.15 (Feb. 4, 2010).
[10] Puget Filing at 4 and 9-10.
[11] Puget Filing at 3.
[12] *See, e.g.,* Presentation of M. Milligan and B. Kirby at WindPower 2008 Houston, Texas, *Analysis of Sub-Hourly Ramping Impacts of Wind Energy and Balancing Area Size* at 2 (June 1-4, 2008), *available at* http://www.nrel.gov/wind/systemsintegration/pdfs/2008/milligan_wind_ramping_impacts.pdf; NERC, *Accommodating High Levels of Variable Generation* at 8 (April 2009), *available at* http://www.nerc.com/docs/pc/ivgtf/IVGTF_Report_041609.pdf.

analysis has shown that balancing area consolidation or coordination is a cost-effective means of reducing the cost of operating the power system even in the absence of variable generators.[13] Other studies have identified various operating procedures reforms that could be inexpensively implemented that would greatly reduce the cost of integrating variable generation. These procedures include the use of dynamic scheduling on transmission ties to neighboring balancing areas, faster generator dispatch intervals, and more comprehensive energy and ancillary services markets.[14] Unmentioned in Puget's filing is the potential for providing balancing services through load control mechanisms that likely cost significantly less than adding a thermal generator, absolutely calling into question their use of a generating unit as a proxy for integration costs.

In short, the extra costs attributable to Puget's decision not to have implemented any of these or other operating procedures should not be borne by wind generators, as they are not responsible for whatever incompatibility exists between Puget's current operating procedures and its ability to appropriately integrate variable generation.[15]

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[13]Informational Filing of Midwest Independent Transmission System Operator, Inc. Docket No. EL06-000 (April 3, 2006).

[14] Jennifer DeCesaro and Kevin Porter, NREL Technical Report: Wind Energy and Power System Operations: A Review of Wind Integration Studies to Date at 7-10 (Dec. 2009), *available at* http://www.nrel.gov/wind/systemsintegration/pdfs/2009/milligan_electric_structure_impact.pdf.; M. Milligan, B. Kirby, R. Gramlich, and M. Goggin, NREL Technical Report: Impact of Electric Industry Structure on High Wind Penetration Potential, at 15 (July 2009), *available at* http://www.uwig.org/EWEC07paper.pdf.

[15] We note that many of these reforms that are necessary for transmission providers to address the integration of new types of resources are currently under consideration by the Commission. *See Notice of Inquiry, Integration of Variable Energy Resources*, 130 FERC ¶ 61,053 (2010). While we hope that proceeding will address the need for operating procedure reforms on a generic basis, we nevertheless are concerned that until such time as these reforms are implemented, if Puget's proposed rate is permitted to take effect wind generators would be unfairly required to bear costs that could have been mitigated through cost-effective steps that should have been adopted years ago.

ii. The Incremental Reserve Needs Identified By Puget Are Unrelated to the Need for Incremental Generating Capacity, Invalidating the Proffered Methodology for Determining Costs

Notwithstanding specific substantive issues raised below with respect to how the level of balancing reserves is calculated, Puget's filing assumes that the calculated quantity is indicative of an incremental amount of generation capacity that must be added to their system mix in order to maintain load and generation balance—an assumption that is not correct. In the extreme hypothetical case where wind begins an operating hour at maximum capability and unexpectedly falls to zero output,[16] the needed generation to maintain system reliability is the same capacity that Puget is required have available to meet system load absent the wind—there is no incremental generating capacity (defined as nameplate generating capability) that must be acquired. It is illogical to associate the cost of purchasing a new generation facility with the need to increase output from existing generation, albeit potentially at a more rapid rate than would otherwise be the case.

Conceptually, it might be possible that a system resource displaced by wind generation might be unavailable to increase generation rapidly enough (ramp) to make up for rapidly declining wind generation, though this case is not specifically made. Puget argues that existing resources may not have sufficient ramping capability for needs absent wind.[17] Certainly acquiring a new LMS 100 would provide additional flexibility for both existing load and for wind, but it is unclear why the full cost of that capacity would then be ascribed to the wind, and equally unclear whether the resulting incremental ramping capability in terms of MW/minute is sufficient to the task. It may be more economic and

[16] Of course, as indicated by the data submitted by Puget, the actual declines in wind output are never this extreme.
[17] Reed page 7, 4-15.

practicable to increase ramp rates in existing resources (or loads). It is telling that Puget asserts a need for increased capacity to accommodate wind at the same time it is planning to voluntarily move a wind project from BPA's balancing area (which has a relatively low integration charge) into its own balancing area[18] prior to any efforts to increase generating capacity.[19]

Puget's discussion of "flexible capacity" provides no information on its current ramping capability (maximum rate of change of generation in time). Neither is information provided regarding the ability to retrofit existing equipment to better provide ramping capability (e.g., by adding AGC controls, etc.). The incremental ramping capability of its proxy resource, the LMS 100, is not discussed. Puget has not shown that the LMS 100 generating plant is either a necessary (i.e., its capacity is required for the task at hand), nor potentially sufficient (i.e., that the incremental ramping capability of an LMS 100 provides needed ramping capability).

Despite Puget's protestations that its existing infrastructure is otherwise committed, and incapable of providing the needed balancing services, it is indeed those facilities that provide the balancing services today. Whether those facilities are sufficient to the task has been proven out in recent history. The charts in Appendix A compellingly illustrate that the increased variability associated with adding wind to Puget's system is incredibly small when compared to the variability of load alone.

Puget's concern over expiring hydro contracts provides a perfect opportunity to acquire replacement generation that has the flexibility it needs to meet load. If there are

[18] Reed page 22 at 1-4
[19] *Id.* at page 26 at 1-3.

incremental direct or opportunity costs associated with providing such flexibility, Puget should be required to demonstrate actual costs of providing balancing services and not merely equate incremental balancing requirements with the cost of acquiring a fictional resource somehow dedicated to system balancing separate from any other benefits such as meeting load.

We strongly disagree that wind on Puget's system causes an incremental capacity requirement. However, if there were an incremental capacity requirement, that requirement would not be met most cost effectively by building a new resource. The regional Northwest Power and Conservation Council's (NPCC) most recent 6th Power Plan (pp 3-18 to 3-19) shows the region to be capacity surplus through 2026 or 2028. Idle generating capability exists on existing infrastructure owned by independent power producers in the Northwest, depressing the market value of capacity significantly below that provided by new generation. In addition, the region possesses significant unutilized demand response resources that could provide this capacity at a far lower cost, as evidenced by the significant quantity of such demand response resources that have been procured at low cost in capacity markets such as PJM's.[20]

iii. The Proposed FCFC Produces a Charge that Greatly Exceeds the Actual Costs of the Resources Puget Uses to Provide Regulating Capacity and Should Be Rejected

Puget is constrained, under FERC policy and precedent and the just and reasonable standard under Section 205 of the Federal Power Act ("FPA"),[21] to base its charges on the

[20] http://pjm.com/~/media/about-pjm/newsroom/2010-releases/20100514-rpm-auction-results-2013-2014.ashx
[21] 16 U.S.C. § 824d.

costs of the facilities it uses to provide the service.[22] This is particularly true with respect to ancillary services, such as regulation service, where FERC requires the transmission provider to offer the service under cost based rates.[23]

Puget concedes that regulation capacity currently is provided by its hydroelectric (or "hydro") resources, supplemented by purchases from third-party suppliers.[24] However, it proposes to base its rates on the cost of a hypothetical generation unit that Puget has no plans to acquire, and the hypothetical costs from this nonexistent plant exceeds the actual costs of the generation resources Puget uses to provide regulation service. The "phantom" generation facility that Puget has selected for pricing purposes would involve two new 100 MW General Electric LMS100 generating units that it has no present intention to construct or acquire. Indeed, Puget indicates that, should it construct or acquire new generation capacity, the decision on facility size and type will be driven by the overall system needs

[22] *California Independent System Operator Corp, et al.*, 103 FERC ¶ 61,114 at P 26 (2003) ("Properly designed rates should produce revenues from each class of customers which match, as closely as practicable, the costs to serve each class of individual customer.") (quoting *Alabama Elec. Coop., Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982)); *KN Energy v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) ("[I]t has been traditionally required that all approved rates reflect to some degree the costs actually caused by the customer who must pay them.") (quoting *Alabama Elec. Coop., Inc. v. FERC*, 684 F.2d at 27).

[23] *Order 888: Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, 61 Fed. Reg. 21540 (May 10, 1996), FERC Stats. & Regs. [Regs. Preambles Jan. 1991-Jul.1996] ¶ 31,036, 31,720-21 (1996) ("Order No. 888"), *order on reh'g*, Order No. 888-A, 62 Fed. Reg. 12274 (March 14, 1997), FERC Stats. & Regs. [Regs. Preambles Jul. 1996-Dec. 2000] ¶ 31,048 ("Order No. 888-A"), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g,* Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1, 122 S. Ct. 1012 (2002) ("[i]n the absence of a demonstration that the seller does not have market power in such services, rates for ancillary services should be cost-based and established as price caps . . ."); Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,237-38.

[24] Puget indicates at points in its filing that it uses gas-fired resources as well (Puget Filing at 9 and 12), but elsewhere clarifies that none of its fossil units have Automatic Generation Control ("AGC") capability (Cicchetti Testimony at 31).

and that, even then, it would continue to base rates for wind integration regulation service on the basis of the hypothetical peaking unit.[25]

Puget argues that its proposed pricing based on hypothetical costs of the hypothetical generator would be less than the actual costs it would incur were it to provide wind integration regulation service using its Mint Farm combined cycle generating unit.[26] While this unit is, at least, not fictional, it also is not the generating unit used by Puget to provide regulation service and, therefore, does not satisfy the Commission's cost-of-service requirements.[27]

Puget further argues that, even though its hydro resources may be used to provide the service, the cost of those units should not be used to price wind integration regulation service because those units were constructed for the purpose of serving native load and native load has paid for those resources in their prior rates.[28] Puget's arguments again run counter to well-established principles of cost based rates for FERC-jurisdictional services. The Commission has consistently held that customers pay for service, not for assets, *i.e.*, by

[25] Puget Filing, Exhibit Puget-200, Prepared Direct Testimony of Lloyd C. Reed ("Reed Testimony") at 26 ("[T]he provision of Following Capacity for wind facilities located within the [Puget] BAA is only one of the many factors that [Puget] considers when choosing what new generating units, if any, to add to its resource portfolio. Therefore, while [Puget] might acquire the incremental generating unit chosen to establish the Schedule 12 Following Capacity rate, [Puget] may ultimately choose to acquire some other generating unit[s], consistent with its [Integrated Resource Planning] criteria."); Cicchetti Testimony at 40 ("The type of generation that [Puget] ultimately builds will be a decision [Puget] makes based on the totality of the circumstances.").
[26] Puget Filing at 6; Cicchetti Testimony at 44-46.
[27] Moreover, as discussed, even if the Mint Farm generating unit were the appropriate foundation for developing capacity charges for wind integration regulation service, Puget's cost calculation grossly overstates the cost of this unit by applying the total cost of the unit to only its variable capacity and, if these errors are corrected, a rate based on the cost of the Mint Farm generation would be reduced to a level that is roughly 50 percent below the proposed Schedule 12 charge.
[28] Puget Filing at 5; Cicchetti Testimony at 32.

paying rates based on the cost of specific assets, customers do not obtain ownership-like rights in those facilities.[29]

Next, contrary to Puget's claim,[30] the fact that Puget's existing fossil generation is ill-suited to providing the service is simply irrelevant. Puget must base its charges on the cost of the resources that it does, in fact, use to provide such services. Finally, Puget's attempt to buttress its extraordinarily high charge by pointing to rates charged by Florida Power Corporation ("FPC") and Bonneville Power Administration ("BPA") also fails. Puget first points to an alleged $4.70/W/month charge imposed by FPC for regulation services under Schedule 3 of the FPC OATT.[31] However, unlike the $5.50/kW/month charge included in Puget's Schedules 3 and 13, the FPC charge is not applied to nameplate capacity or total transmission reservation capacity. Instead, the FPC charge is applied only to 1.5 percent of the transmission reservation or load, equating to a charge of $0.071/kW/month when applied to total transmission reservation or load.[32] In other words, the FPC rate, which Puget points to as supporting its charge, actually contradicts its position because the applicable charge is less than 3 percent of the rate level proposed by Puget for Schedule 12. Similarly, the BPA charge for wind integration (which is not subject to review and approval by the Commission under the FPA) is very much lower than Puget's

[29] *See*, *e.g.*, *Southern Company Services, Inc.*, 69 FERC ¶ 61,437, 62,560 (1994) ("It is well-settled that customers pay only for service; they do not obtain, by their payments, an entitlement in a utility's assets.") (citing *Board of Public Utility Commissioners v. New York Telephone Co.*, 271 U.S. 23, 32 (1926) ("Customers pay for service, not for the property used to render it. . . . By paying bills for service they do not acquire any interest, legal or equitable, in the property used for their convenience or in the funds of the company."); and *Duke Power Company*, Opinion No. 641, 48 F.P.C. 1384, 1394-95 (1972), *reh'g denied*, Opinion No. 641-A, 49 F.P.C. 406 (1973)).

[30] Reed Testimony at 5-6.

[31] Cicchetti Testimony at 42, Table 2. The reference points provided by Puget in Table 2 respecting transmission providers other than FPC and BPA do not represent rates that have been authorized for regulation service. Rather, they reflect Puget's assessment of a rate that other transmission providers might propose if they decided to use the same hypothetical cost method proposed by Puget. *Id.*, Table 2, n.3 and n.4.

[32] The product of $4.70/kW/month and 1.5percent is $0.071. *See* Florida Power Corporation, Amendments to Open Access Transmission Tariff at proposed Schedule 3A, Docket No. ER00-113-000 (Oct. 13, 1999).

proposed rate.[33] Puget also is incorrect in suggesting that the proposed cost per kW of Following Capacity ($14.91/kW/month) compares favorably with the cost used by BPA to develop its wind integration charges.[34] In fact, BPA's initial rate proposal was based on an embedded cost of $7.01/kW/month.[35]

Because none of Puget's arguments justify its assessing charges in excess of the actual costs of the resources used for regulation services provided under its OATT, it has not met its burden to demonstrate that the Following Capacity charge is just and reasonable. Therefore, Commission should reject Puget's filing.

iv. Due to an Error in Puget's Calculations, Puget's Claimed Integration Costs Have Been at Least Doubled

Puget's integration cost number is at least double what it should be due to one error alone. Puget took the maximum wind output upswing and maximum wind output downswing in a year, and essentially applied four times the standard deviation by taking two times the standard deviation of each. Puget calculated the required following reserve based on the differences between the ten minute actual net-load and the hour-ahead forecasts for load, wind, and net-load. In order to meet a 90 percent CPS2 requirement they require reserves that are sufficient to cover 95 percent of the following deviations. Puget calculates a full year of 10 minute up and down deviations and sets a constant following requirement based on four standard deviations. Four standard deviations are presumably used to cover 95 percent of the variability (1.96 standard deviations for a normal distribution) in both the up and down direction. As noted in the testimony of Mr.

[33] Cicchetti Testimony at 42, Table 2. The currently effective rate is $1.29/kW/month.
[34] Puget Filing at 15.
[35] Testimony of Janet Ross Klippstein, *et al.*, Embedded Cost Pricing Methodology For Regulating Reserve and Wind Balancing Reserve, WP-10-E-BPA-24 at 11.

Reed, "using the standard deviation, [Reed] established the 95% confidence interval across the entire range of both the positive and negative generation deviations."[36]

Puget's logic is flawed. In the case of load, there is no need to carry down following reserves during the morning ramp up or up reserves during the evening ramp down. Similarly with wind, there is no need for carrying up reserves on conventional generation when the wind is at zero and no need to carry conventional generation down reserves when the wind is at full output. The maximum change in either direction is similarly limited in both directions in the middle of wind's output curve. Thus, Puget has over-estimated the required following reserves by a factor of two. In reality one would only need two standard deviations since at any point on wind's output curve the output can only change by a limited amount before it hits either zero output or maximum output.

The effect of Puget's logic is to charge wind generation the cost of acquiring additional generating capability on both the need to increase generation, and for decreasing generation. While it is conceivable that incremental reserves might be necessary to cover rapid reductions in wind output, acquiring generating capability to cover sudden increases in wind generation defies logic.

FERC precedent has established that the amount of regulation capacity assumed to be reserved for pricing regulation service should be based on the total variation divided by two. The divide by 2 rule is a well-established precedent, based on ancillary services proceedings for Entergy, Otter Tail, Consumers, Allegheny Power, Kentucky Utilities, and AEP. In the Otter Tail case, the Commission summarily ruled on this matter and did not allow Otter Tail to litigate it in the hearing the Commission established, noting that "the

[36] Reed Testimony at 18, 20.

charge for the entire amount of the load variation within an hour instead of only half of that variation is inconsistent with Commission precedent."[37] Citing the Kentucky Utilities and Allegheny Power cases, the Commission "concluded that since a company would only be required to provide, on average, adequate generating capacity to cover the portion of the hour when a customer's load is above the amount of generating capacity it has block scheduled, then the company is required to divide the regulation obligation figure that it derived by two."[38]

This error and failure to follow Commission precedent alone causes Puget to overstate its purported integration cost by a factor of two, which makes their proposal unjust and unreasonable since it would charge for costs in excess of actual costs.

v. Interconnection Agreements Already Keep Wind Plants from Ramping More Than 5 Percent

[redacted]

[37] Otter Tail, Docket Nos. ER02-912-000
and ER02-912-001, April 5, 2002, at 15
[38] Otter Tail at 17
[39] *See* Appendix C to Wild Horse LGIA at § 6(a) ("The production ramp-up limit, determined as a one-minute average value, must not at any time exceed five percent per minute of the maximum power of the Transmission Customer's Generating Facility.")

[redacted]

vi. Theories of Marginal Cost Do Not Rehabilitate Puget's Proposed Excessive Charges

Puget mistakenly relies on marginal cost pricing principles to claim a right to assess rates in excess of the cost of the resources that are, in fact, used to provide the service.[40] However, even where marginal cost rate designs are appropriately employed and properly developed (neither of which is demonstrated here), rates may not recover more than the actual cost to provide the relevant service. For example, in considering marginal cost pricing concepts, in part, to approve an on-peak/off-peak energy rate design for full requirements services, the Commission relied on the fact that total charges to customers would not exceed actual costs:

[40] The filing presents two concepts underlying its marginal cost pricing proposal. In some instances, it claims that Schedule 12 customers will pay no more than the actual cost incurred to provide the service. *See*, *e.g.*, Cicchetti Testimony at 14 (the charge, based on the cost of General Electric's LMS100 units, "would be expected to offset the marginal costs that Puget would incur"). However, the filing makes clear at other points that Puget has no present intention to acquire these facilities. *See* Reed Testimony at 26 (("[T]he provision of Following Capacity for wind facilities located within the [Puget] BAA is only one of many factors that [Puget] considers when choosing what new generating units, if any, to add to its resource portfolio. Therefore, while [Puget] might acquire the incremental generating unit chosen to establish the Schedule 12 Following Capacity rate, [Puget] may ultimately choose to acquire some other generating unit[s], consistent with its [Integrated Resource Planning] criteria.") and Cicchetti Testimony at 40 ("The type of generation that [Puget] ultimately builds will be a decision [Puget] makes based on the totality of the circumstances."). Accordingly, any aspects of the filing and supporting testimony that suggest Puget will incur costs associated with the GE LMS100 units are misleading.

> [P]ure marginal costs would exceed the aggregate cost of service, computed by traditional ratemaking methods. The parties are agreed that a utility's aggregate revenue guaranteed by tariff is limited to the traditionally formulated cost of service. This is consistent with economic theory. Accordingly, translation of pure marginal cost pricing to WEPCO's regulated wholesale rates requires that some way be found to reconcile revenues under pure marginal cost pricing to the constraints of the traditional revenue requirement.[41]

Here, as Puget concedes, it currently provides the service using its hydro capacity, supplemented by occasional purchases of third-party capacity. Accordingly, it is these actual costs that serve as a revenue constraint on any properly developed marginal cost pricing rate design. Because Puget has failed to limit its revenues to its actual costs, its marginal cost proposal should be rejected by the Commission.[42]

Moreover, apart from the fatal flaw of not developing an appropriate revenue constraint based on actual costs, Puget has also failed to establish either that marginal cost rate designs are appropriate for this service or that its proposal reflects a reasonable marginal cost rate design. Puget's justification for marginal cost rates reflects the opinions and conclusory assertions of its witness, Mr. Cicchetti, as the sole justification for adopting marginal cost pricing in the first instance. Thus, Puget describes general principles underlying marginal cost pricing, such as the objective of sending economically efficient price signals, but provides no supporting data or analysis to demonstrate that the Schedule 12 proposal would, in fact, send economically efficient price signals. Nor does Puget

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[41] *See Wisconsin Electric Power Company*, Opinion No. 186, 25 FERC ¶ 61,229, 61,624 (1983) (footnotes omitted) ("*WEPCO*"). As discussed *infra*, in *Electricity Consumers Resource Council v. FERC*, 747 F. 2d 1511 (D.C. Cir. 1984) ("*ELCON*"), the court affirmed the Commission's decision to authorize WEPCO to use time of use energy prices, but reversed the Commission's approval of the proposed marginal cost pricing proposal.

[42] As discussed, Puget's suggestion that rates based on the hypothetical unit are less than the actual costs of its Mint Farm combined cycle generation unit (Cicchetti Testimony at 43-46) does not mitigate the lack of an appropriate revenue constraint based on actual costs because the Mint Farm unit is not used to provide regulation service and, when correctly calculated, its costs are much lower than the proposed rate.

examine any other options, such as installing AGC equipment on Puget's fossil generation, obtaining demand response, or implementing a curtailment policy, to determine if such alternatives would be superior from an economic efficiency standpoint. Similarly, Puget provides no analysis, evaluations, studies or data to compare the impacts on operations, transmission customers, markets and consumers under the proposed pricing method. Indeed, given that Puget explains, as discussed above, that it and the Northwest power community are working diligently to develop initiatives to more efficiently address wind integration, such as intra-hour scheduling,[43] and Puget has no present plans to acquire new generation to provide regulation services, it would appear that the least costly option to increase capacity available for regulation is to add AGC equipment to Puget's fossil units.

Importantly, Puget points to no Commission precedent that supports marginal cost pricing for capacity charges for regulation service or other relevant services, let alone any precedent that justifies the use of hypothetical costs as a form of marginal cost pricing for regulation services provided by a transmission provider under its OATT. Rather, Puget points very generally to the use of peaking unit data to develop time of use ("TOU") rates employed by some state commissions designed to incent retail customers to shift their energy usage from on-peak (when energy costs are higher) to off-peak (when energy costs are lower) and the use of avoided cost rates for qualifying facilities ("QFs") under the Public Utility Regulatory Policy Act.[44] While it may be true that TOU and QF regulatory policies considered "measuring something akin to the economic concept of marginal

[43] Puget Filing at 2.
[44] Cicchetti Testimony at 25-30.

cost,"[45] and it may be true that peaking units were selected to benchmark some TOU and QF rates, Puget does not otherwise explain how these precedents provide a sufficient basis to conclude that the appropriate marginal cost rate design for regulation service provided to wind generators is the cost of a hypothetical peaking generating unit.

As the D.C. Circuit explained in *ELCON*, reversing a Commission decision to approve a marginal cost rate, "[t]he Commission relied exclusively on economic theory" and based its approval on reasons that "are almost wholly conclusory, largely short-sighted and patently unpersuasive."[46] Puget's arguments in support of the use of marginal cost pricing methods and in support of its proposed implementation of a marginal cost price suffer from these same defects and, thus, fail for these reasons.

vii. Even If the Commission Were To Entertain A Marginal Cost Rate Design Based On Hypothetical Costs, the Proposal Is Flawed

As noted, Puget has failed to justify why the acquisition of a new peaking unit is the appropriate benchmark for the costs Puget would incur to obtain regulation capacity beyond the capacity it currently uses to provide these services. While one of the benefits of quick start generation capacity is that it can respond quickly and provide relatively larger amounts of ramping capacity than other resources, Puget has apparently failed to examine other options that might be more cost-effective. Prudence dictates that Puget determine the lowest cost option, even when considering marginal, rather than actual, costs. Indeed, Order No. 890 made clear that, in demonstrating whether traditional cost-based rates for

[45] *Id.* at 26.
[46] *ELCON* at 1514-15.

ancillary services are just and reasonable, the Commission would consider whether the transmission provider had considered less expensive options for procuring the service.[47]

Puget also has not provided any data or support to corroborate the reasonableness of its estimates of the costs for the unit chosen and those rejected. Mr. Reed's testimony simply adopts the assumption that combustion turbines provide an appropriate benchmark based on Mr. Cicchetti's statement that they "have typically been utilized to establish rates under the incremental unit approach."[48] He then simply identifies the units he considered and puts forth, without any supporting documentation, the all-in costs of capacity and operation and maintenance, without any further data or analysis. And while Mr. Reed says that he investigated the capital costs and operating parameters for five generating units, he provides no information as to these data or his evaluations.[49] Similarly, Mr. Reed's cost support for the installed cost is based on a single sentence saying that Puget gave him the information. There is no supporting data or analysis as to these cost projections.[50] There also is no support for the stated cost of capital other than to state it is Puget's "current pre-tax cost of capital" and reflects an amortization provided by Puget "staff," and no support for the operation and maintenance costs other than to state that they reflect "recent price quotes obtained by [Puget] personnel."[51] Puget is obliged to provide comprehensive cost support to justify a proposed rate, particularly one where it intends to assess a regulation service charge that is about twelve times as high as the rate for full transmission cost. Having failed to do so, its proposed rate design must be rejected out of hand.

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[47] Order No. 890 at P 893, n.545.
[48] Reed Testimony at 26.
[49] *Id.* at 27-28.
[50] *Id.* at 29.
[51] *Id*. at 30.

Puget also has grossly overstated the cost allocable to regulation service by spreading the claimed total cost of the 200.4 MW proxy peaking unit it has selected as the hypothetical generating unit over only 164.8 MW of capacity (based on its determination that only 164.8 MW of capacity is sufficiently flexible to provide regulation service). This inflates the cost per MW of the unit by 22 percent based on the unreasonable assumption that if Puget were to acquire this unit, it would be dedicated only to wind integration service, *i.e.*, simply by spreading total costs over the full capacity, the proposed rate would be reduced from $2.70/kW/month to $2.11/kW/month. This is an unreasonable assumption because such a unit would be available for other purposes, *e.g.*, to provide capacity and energy to Puget's customers and to the market and to provide other ancillary services.

Moreover, Puget appears to have made this same error when considering the capacity capabilities of existing generating units. An existing unit might have been found to be the cheapest capacity option if that unit's capability had been calculated correctly, undermining all of Puget's analysis. Of course, using a capacity calculation at all is still fundamentally flawed for the reasons outlined above and below.

Puget has failed to identify any FERC precedent for allocating the total cost of a generating unit over less than the full capacity value based on the fact that only a portion of the unit's capacity is available for regulation service. This is not surprising because for regulation service charges proposed by other transmission providers, and approved by the Commission, there has been no such "de-rating" of the actual capacity of generation units used to provide regulation service.[52] This is the only reasonable approach given that the

[52] *See, e.g.,* Entergy Services, Inc. Revisions to Generator Imbalance Agreement, Prepared Direct Testimony of Phillip B. Gilliam at 8, Docket No. ER04-901-000 (June 1, 2004) (explaining that the daily rate for generator regulation

remaining capacity has not evaporated or become unavailable—the entire capacity of the generating unit is available to the transmission provider to meet a variety of needs.[53] Put simply, should Puget ever acquire two LMS100 generating units, it will have the benefit of the full 200 MW of generation capacity for its use. Yet, by assessing the total cost of the generating resource to its regulation service customers, Puget would have the use of the full capacity at no cost to itself. This is clearly unjust and unreasonable and unduly discriminatory.

viii. The Commission Must Ensure That Any Rate Adopted Here Is Reconciled With the Revenues Puget Already Receives Which Compensate It for Regulation Capacity

If the Commission allows Puget to establish a separate capacity-based charge for regulation services provided to wind generators, the Commission must require Puget to reconcile the revenues received under Schedule 12 with the revenues that Puget already receives to compensate it for regulation capacity. Puget currently recovers a contribution to its capacity costs through its energy imbalance charges under Schedules 4 and 9. While the Commission requires that energy imbalance charges be based on actual incremental energy costs, Puget uses the Dow Jones Mid-Columbia Firm Energy index as a proxy for its incremental cost (the "Mid-C index"). However, it is very likely that prices based on the

service was developed by dividing the annual revenue requirement of system-wide AGC units by 365 times "the sum of the capacity of those generating units"); Otter Tail Power Company, Revisions to Control Area Services and Operations Tariff, Attachment C at 2, Docket No. ER02-912-000 (Jan. 31, 2002) (explaining that the total fixed costs per kW for load following were calculated by dividing fix cost by the plant's capacity rating).

[53] As noted earlier, to the extent that a cost based revenue constraint were to be based on the cost of the Mint Farm generating unit (which it should not), Puget has overstated the cost of regulation capacity based on the same flawed logic that total costs of the Mint Farm unit should somehow be allocated totally to the smaller amount of ramping capacity available from the Mint Farm unit, i.e., Puget allocated total costs of the Mint unit over the unit capacity of 279 MW, Puget allocates these costs over only 115 MW, inflating the charge by 242 percent. Cicchetti Testimony at 46. Adjusting the Mint Farm unit cost estimate to correct this one error would reduce the Mint Farm generating unit charge from Puget's claimed cost of $3.17/kW/month to $1.23/kW/month, assuming that all other elements of the cost of service were found reasonable. However, this reduction does not yet include the further adjustments that would be required when the FCAC is reduced below 18.1percent as discussed above.

Mid-C Index result in a charge in excess of Puget's actual incremental energy costs for providing imbalance energy and, thus, the inframarginal revenues provide a contribution towards the fixed costs of providing imbalance services, *i.e*., a contribution towards the fixed costs of regulation capacity. It is also worth noting that no other customer pays an additional capacity cost for Mid-Columbia Firm Energy. The potential for over recovery, due to the combination of energy charges above actual energy costs under Schedules 4 and 9 together with revenues received under Schedules 3, 12 and 13 requires that the Commission ensure that all revenues received that provide contributions to fixed costs be reconciled into a just and reasonable rate.

C. The Proposed Following Capacity Charge is Unduly Discriminatory

i. Because Puget Proposes These Excessive Rates Only For Wind Generation Facilities, Its Proposal Is Unduly Discriminatory

Puget is asking that it be allowed to give preferential rates under its OATT, *i.e*., rates based on the cost of hydro resources, to its native load only. Such a result would clearly violate the FPA's prohibition on undue discrimination and preferential treatment. While Puget attempts to veil this preference by ostensibly charging its native load the same wind integration charge as non-Puget wind generation resources, the math simply does not work. As Puget explains, "charges" to native load will be a paper transaction by which native load pays itself the charges under Schedule 12 but would see no actual rate increase:

> For wind generation used to supply Puget's native load, [Puget] believes that this schedule will have a net zero impact on native customer rates as regulated by the Washington Utilities and Transportation Commission ("WUTC"). This occurs because payments from Puget's merchant business associated with its wind generation or wind power purchase agreements to the transmission business for Following Capacity under Schedule 12 will be offset by

> payments to the transmission business from the merchant business' flexible capacity for supplying this service.[54]

Accordingly, these "charges" to native load are equally as fictional as the costs that Puget seeks to use for the purpose of charging others. Native load customers will essentially write themselves a check for fictional costs—a meaningless exercise.[55] Indeed, it is most likely that the WUTC will actually require Puget to reduce native load rates to reflect revenue credits associated with wind integration regulation charges to third parties. In other words, since Schedule 12 charges exceed the actual costs that Puget incurs in providing the service to non-Puget wind generators, revenue credits provided by such Schedule 12 customers will, in effect, subsidize the actual costs otherwise allocated to native load for their regulation services.

Second, Puget's suggestion that the Commission should abandon cost-based prices because the beneficiaries of this service are not likely to be existing customers is troubling.56 At its core, Puget is claiming that plainly discriminatory pricing is appropriate because it is more "fair" to Puget's existing customers.[57] The Commission should not countenance rate discrimination based on the type of customer that is being favored, and Puget's attempt to introduce a "vintage-based" discrimination should be rejected.

ii. Since All Resources on the Power System Have Integration Costs, Charging a Wind-Only Integration Charge is Discriminatory

[54] Puget Filing at 3 n.4. *See* also Cicchetti Testimony at 13-14 (payments by native load for Schedule 12 charges are "offset" by revenue credits of the same amounts).
[55] When dealing with the allocation of actual costs, nondiscriminatory treatment is ensured by allocating the appropriate share of costs to the FERC-jurisdictional service, leaving the transmission provider to recover the remainder of its actual costs from other customers. However, here there is no allocation of actual costs, *i.e.*, Puget will not incur \$2.70/kW/month to provide Schedule 12 services and, thus, no costs related to the fictional unit are "allocated" to native load in the first instance.
[56] Puget Filing at 5.
[57] Cicchetti Testimony at 12.

There are significant costs associated with integrating non-wind generators onto the power system, many of them caused by the variability and uncertainty in the output of these non-wind generators, as well as their inflexibility. Those costs are not typically allocated to the generators that cause those costs. Nevertheless, Puget proposes to single out wind generators for paying integration costs while other generators do not have to pay such costs. Assuming for the sake of argument that wind generators bear some of these costs, FERC's cost causation and ratemaking principles require that generators be required to pay no more than the amount of such costs as they caused to be incurred.[58] As the Commission has explained: "the well-established principle of cost causation requires that costs should be allocated . . . to customers based on . . . cost incurrence."[59] In other words, costs must be fairly allocated among participants, "including those who cause them to be incurred."[60] Therefore, Puget's proposal to charge only wind generators for its perceived integration costs when competing non-wind generators do not have to pay any share of such costs is clearly discriminatory and unjust and unreasonable.[61]

The cost of accommodating the variability and uncertainty in the output of non-wind generators is often large. It is true that wind generators and conventional generators are not similarly situated in all respects. In particular, the timing and nature of the variability and

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[58] "Properly designed rates should produce revenues from each class of customers which match, as closely as practicable, the cost to serve each class or individual customer." *Ala. Elec. Coop., Inc. v. FERC*, 221 U.S. App. D.C. 246, 684 F.2d 20, 26 (D.C. Cir. 1982); *see also, Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004) (*quoting KN Energy, Inc. v. FERC*, 968 F.2d 1294, 1300 (D.C. Cir. 1992)); *Entergy Servs., Inc. v. FERC*, 319 F.3d 536, 543 (D.C. Cir. 2003); *Western Massachusetts Elec. Co. v. FERC*, 165 F.3d 922, 927 (D.C. Cir. 1999); Federal Power Act, 16 U.S.C. § 824d.
[59] *Cal. Power Exch. Corp.*, 106 FERC ¶ 61,196, at P 17 (2004).
[60] *See* Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241, at P 559 (2007); *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007)*, order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008).
[61] *See, e.g., Ameren Servs. Co. v. Midwest Indep. Transmission Sys. Operator, Inc*. 125 FERC ¶ 61,161 at P 141 (2008), *order on reh'g*, 127 FERC ¶ 61,121 (2009) (finding current tariff exempting certain market participants that cause Revenue Sufficiency Guarantee costs from sharing in the responsibility for those costs was unduly discriminatory)

uncertainty of conventional generators and wind generators are in some ways. Nevertheless, both types of generators have significant variability and their actual output often is uncertain. (We discuss below several types of costs associated with integrating non-wind generators onto the power system.) Of course, while wind generators might be differently situated in relation to conventional generators with respect to the levels of their variability and uncertainty, they are similarly situated insofar as, while their respective contribution may differ, they both contribute to incurrence of integration costs. Therefore, it is not just and reasonable to single out only wind plants for integration costs when competing conventional generators do not have to pay their integration costs. Moreover such preferential treatment plainly would have an anti-competitive effect on the development of wind energy in general.

Some might argue that assigning integration costs to wind generators but not to other generators is economically efficient, based on the purported claim that a wind plant can reduce the variability and uncertainty associated with its output, while a conventional generator cannot. In fact, there is a far more persuasive case to be made for the opposite conclusion, insofar as conventional generators have a large number of options at their disposal for decreasing forced outages and reducing their integration costs. As the Commission has acknowledged, variable generation resources should not be penalized for the inherent uncertainty and variability in their output.[62]

[62] *See, e.g., Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. P 31,241 at P 664-665 (applying a reduced penalty amount to intermittent resources' imbalances that would otherwise be subject to the highest-tier generation imbalance penalties).

It is important to note that Puget's proposed wind integration charge differs from Westar's proposed wind integration charge recently before the Commission.[63] While AWEA objected to Westar's proposed charge for a number of reasons, that proposal at least acknowledged that there are significant costs associated with integrating non-wind generators and assigned such costs in part to those generators.[64] Indeed, we briefly discuss several types of costs associated with integrating non-wind generators onto the power system.

a. Costs for Maintaining Contingency Reserves

There is a significant cost for maintaining the contingency reserves needed to accommodate the variability and uncertainty in the output of large conventional generators caused by forced outages; yet Puget is not proposing to charge these generators based on their role in causing these costs to be incurred. Contingency reserves are fast-acting, and thus expensive, reserves needed in all hours of the year to maintain power system frequency in the event that the largest generator currently online experiences a forced outage. The sudden and unexpected loss of generation caused by a forced outage is clearly a case of variability and uncertainty in the output of a generator. All generators experience forced outages from time to time, although the need for maintaining these reserves is driven by the largest generators on the system since smaller generators, because they are not the largest single contingencies on the power system, do not increase the total amount of reserves needed to maintain reliability.

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[63] *Westar Energy, Inc.,* 130 FERC ¶ 61,215 (2010) (Westar proposed to apply a Regulation Percentage of 7.8 percent to intermittent generators purchasing regulating capacity under Schedule 3A and of 1.35 percent to dispatchable generators purchasing such service).
[64] Westar Filing, Testimony of Paul Dietz, at pages 6-8

Kirby and Hirst catalogued the costs of maintaining these contingency reserves in their paper titled, "Allocating Costs of Ancillary Services: Contingency Reserves and Regulation," attached to this filing as Appendix A. This paper disclosed that, for a real but unidentified 10 GW power system in the Western U.S., the total contingency reserve costs for a year equaled $113 million, equivalent to $2/MWh of all generation. For the study period for that power system, in 98 percent of hours the cost of maintaining these reserves were relatively evenly spread to all generators based on the WECC rule that contingency reserves be provided equal to 5 percent of the load being served by hydroelectric resources plus 7 percent of the load being served by thermal resources. However, the cause of these costs being incurred is far from uniformly distributed among the generators.

Kirby and Hirst explored two potential methods for allocating the costs of contingency reserves to the generators responsible for causing those reserves to be needed, rather than the more uniform method currently employed. One method assigned the cost of these reserves based on the MWs of outages caused by each generator over the study period, while the other assigned them based on the number of hours that each generator was the largest contingency on the power system. Under the first methodology, 3 of the 24 generators would be responsible for causing over 40 percent of the contingency reserve needs for the power system, while under the second methodology those same three generators would be responsible for over 23 percent of the total reserve need. Thus, the current method of allocating contingency reserve costs subsidizes the true cost of accommodating the variability and uncertainty of those three generators by a factor of around 50 percent to 175 percent.

Importantly, small generators (those with less than 150 MW of capacity) would pay nothing under either of these alternative allocation methods, as they played no role in causing contingency reserves to be needed. Thus, under the current, mostly uniform methodology of allocating these costs, small generators on the studied power system are paying around $25 million per year or $2/MWh to subsidize the operation of larger generators.

It is important to emphasize that nearly all wind plants would fall into this category of generators that are too small to impose a contingency reserve need on the power system. Even extremely large wind plants are unlikely to ever be the single largest contingency on the power system, since these wind plants tend to be spread over very large geographic areas with redundancies built into their wiring, often including multiple points of interconnection to the grid, and they are composed of many smaller generators that are not prone to common mode failure.

Charging wind plants an integration cost thus represents a “double-whammy” and puts wind plants at a disadvantage to other generators, since wind plants are already paying a great deal for contingency reserves that they do not use so that competing large generators can use those reserves at a greatly subsidized rate. As demonstrated by Kirby and Hirst, the cost of maintaining contingency reserves to accommodate the variability and uncertainty exhibited by non-wind generators is significant. These costs are not assigned to the generators that cause them, even though such an allocation could be easily implemented through methodologies like those suggested by Kirby and Hirst.

b. Costs of Conventional Generators' Failures to Meet Scheduled Output Levels

Similarly, non-wind generators impose significant integration costs on the power system when they fail to produce electricity at the scheduled output level for reasons other than a complete forced outage. These reasons include generators failing to ramp as quickly as expected, generator output fluctuating due to unexpected mechanical or fuel quality issues, and others. While some of the cost of accommodating this variability and uncertainty of non-wind generators is recovered through imbalance penalties just as such charges recover some of the costs of wind variability, the costs imposed by some deviations are not fully or proportionally recovered from the generators that cause them.

c. Cost Due to Inflexibility of Natural Gas Generators

Many natural gas generators impose a significant integration cost on the power system due to inflexibility introduced through the natural gas purchasing process. The fuel used by natural gas generators is typically purchased a day or more in advance based on an estimate of what output will be required from that generator, based on load forecasts and other factors. However, there is significant uncertainty in those forecasts. Because many natural gas fuel purchase contracts contain "take-or-pay" provisions, the natural gas generator will typically use all of the purchased fuel even in situations when it becomes apparent after the purchase of the fuel that it was not economically efficient for the gas plant to operate. As a result of the inflexibility in these natural gas purchase contracts, the natural gas plant transfers the uncertainty in the day-ahead load forecast through to the real-time operation of the power system, imposing costs on other users of the system. These costs imposed on other generators and on the power system as a whole are typically not assigned to the natural gas plant that caused them.

d. Costs from Integrating Baseload Plants

There is also a cost associated with integrating many baseload coal and nuclear power plants onto the grid, since these plants' limited ability to change their level of output poses an additional burden on other generators. Nuclear plants typically do not change their level of output, while most coal plants have limited ability to change their level of output. However, electricity demand is highly variable, with significant changes over the course of a day and from season to season, with many of these changes depending on weather conditions that cannot be perfectly forecast.

Adding a baseload generator to a power system, particularly one that already has a large number of inflexible baseload generators, will thus impose a greater ramping burden and thus significant costs on the more flexible generators on that power system. In addition, the new baseload plant may make it necessary for other baseload plants to cycle off during periods of low electric demand, imposing significant costs on that generator and the power system. These costs are not currently allocated to the generators that cause them.

D. Puget Should be Encouraged to Pursue Reforms that Will Lower the Following Capacity Rate

Puget states that it is "actively involved with regional efforts to address the challenges associated with integrating wind generation into the transmission grid."[65] Puget states that these initiatives include: (1) a movement toward intra-hour scheduling and development of common regional protocols and business practices to allow wind resources

[65] *Id.* at 2.

to revise schedules within the hour based on up-to-date forecast data; (2) efforts to develop a market for flexible capacity and reserve products available for appropriate intra-hour use by transmission providers and wind generation to address the inevitable ramping of variable resources, accompanied by widespread deployment of ITAPi and Dynamic Scheduling Systems; and (3) preliminary discussions regarding ways to increase balancing authority coordination, or possibly even consolidation of BAAs, up to and including the formation of an independent entity to perform wide area optimization to reduce overall balancing requirements and facilitate economic dispatch of the intra-hour market.

AWEA, RNP and CEERT agree with Puget that these initiatives, if implemented, could significantly reduce, or even likely eliminate the need for, the proposed Following Capacity rate.[66] However, we also think that Puget could take major steps in the interim towards achieving these goals. For instance, Puget could embrace faster sub-hourly scheduling of generators, which has become the norm across much of the country with many regions now scheduling generators to operate for 5-minute intervals. Grid operators that have made the transition have experienced significant benefits and no significant adverse consequences. In addition, markets for ancillary services have been deployed across large regions of the country with positive results, and we think Puget could make major strides in this respect. Finally, to help fulfill the goal of increased cooperation among balancing areas, Puget could easily and almost immediately join the Area Control Error Diversity Interchange pilot program that has been operating across a large part of the Western U.S. for several years.

[66] *Id.* (stating that "Puget believes that these efforts now underway in the Pacific Northwest could one day lead to a regional solution to the challenges associated with integrating variable resources").

We would also note that if the Commission grants Puget its proposed wind integration charge, it would likely greatly reduce its incentive to implement many of these operating reforms, as it would have effectively passed a large share of any costs resulting from the obsolescence of its operating practices onto wind generators.[67] Moreover, since Puget's proposed Following Capacity charge is far in excess of its actual costs, it would seem to have little incentive to embrace reforms that would reduce the charge so that it would be reflective of its true costs of providing regulation services under its OATT. As these reforms can and should be implemented in the near future, AWEA, RNP and CEERT request that the Commission encourage Puget to pursue these reforms and request a commitment from Puget to pursue the implementation of such reforms with all deliberate speed possible. To that end, the Commission should ensure that Puget will include in its Annual Update any reductions to the Following Capacity charge from such reforms that are implemented.[68]

IV. Conclusion

WHEREFORE, for the foregoing reasons, AWEA, RNP and CEERT request that the Commission should find that Puget's proposed rate for Following Capacity has not been shown to be just and reasonable, and either reject the filing or order that a formal hearing be established. If the Commission accepts the filing, it should suspend collection of the proposed rates for the maximum statutory period of five months.

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[67] In this respect, the operational reforms discussed in this section have been discussed for years, with commitments by Puget to implement them dating back to the March 2007 Northwest Wind Integration Action Plan and before, yet little progress has been made towards making them a reality. The Northwest Wind Integration Action Plan, for which Puget served on the Steering Committee and the Technical Working Group, is available at http://www.nwcouncil.org/energy/wind/library/2007-1.pdf .

[68] We would also encourage the Commission to consider requiring Puget to make a section 205 filing, rather than an informational filing, to help ensure that Puget's Following Capacity charge is just and reasonable and that it is taking all efforts possible to ensure the prompt implementation of the initiatives it states that it is pursuing with respect to integrating variable resources onto its system.

Respectfully submitted,

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Dated: July 13, 2010

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that this protest of AWEA, RNP and CEERT has been served in accordance with 18 C.F.R. § 385.2010 upon each person designated on the official service list compiled by the Secretary in this proceeding.

________/s/ Gene Grace_______
Gene Grace

Dated at Washington, DC, this July 13, 2010.

APPENDIX A

Ramping Analysis

[redacted]