149 FERC ¶ 61,208
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Chairman;
Philip D. Moeller, Tony Clark,
and Norman C. Bay.

Public Service Company of Colorado — Docket Nos. ER14-1969-000, ER14-1969-001, ER14-1969-002

ORDER CONDITIONALLY ACCEPTING AND SUSPENDING PROPOSED TARIFF REVISIONS, SUBJECT TO REFUND, AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued December 5, 2014)

1. On May 15, 2014, as amended on May 23, 2014, pursuant to section 205 of the Federal Power Act,[1] Public Service Company of Colorado (PSCo) submitted for filing: (1) revisions to Xcel Energy Operating Companies Joint Open Access Transmission Tariff (Xcel Energy OATT) Schedule 3 (Regulation and Frequency Response Service); (2) new Schedule 3A (Regulation and Frequency Response Service for Point-to-Point transmission customers serving load external to the PSCo balancing authority area); (3) new Schedule 6A (Flex Reserve Service, a supplemental category of reserves to address large reductions of on-line wind generation due to losses in wind speed); and (4) related ancillary services revisions. In this order, we conditionally accept PSCo's proposed tariff revisions for filing, suspend them for a nominal period, make them effective January 1, 2015, subject to refund,[2] and establish hearing and settlement judge procedures.

[1] 16 U.S.C. § 824d (2012).

[2] PSCo states that the proposed revisions do not modify or otherwise affect the Xcel Energy OATT provisions applicable to service over the facilities of the other Xcel Energy Operating Companies, which are Northern States Power Company-Minnesota, Northern States Power Company-Wisconsin, and Southwestern Public Service Company. May 15 Filing at n.2.

I. Background

2. PSCo is a vertically-integrated electric utility that provides electric service to retail and wholesale customers in Colorado. PSCo owns and operates approximately 4,000 miles of transmission facilities 115 kV and above in the Western Interconnection, and is the Transmission Provider for transmission and ancillary services under the Xcel Energy OATT. PSCo also operates a balancing authority area, and therefore is responsible for balancing generation resources and loads on the PSCo transmission system.[3]

3. PSCo explains that, over the years, it has become a leader in wind integration, and has one of the largest portfolios of wind resources among all public utilities relative to its size. PSCo states that its wind portfolio currently stands at 2,168 MW with approximately 450 MW of wind to be added in the near future. PSCo also states that there is approximately 80 MW of utility-scale solar generation on the PSCo system with an additional 170 MW planned for the near future. PSCo states that the PSCo balancing authority area actual peak load was 6,646 MW in 2013 and wind generation served 18.7 percent of PSCo load's annual energy requirements in 2013. PSCo notes that this integration has occurred on a system outside any regional day-ahead/real-time energy market.[4]

4. PSCo further explains that the need for flexible generation resources to balance wind and other variable energy resource (VER) generation together with load can be particularly acute on transmission systems that are not part of a large regional market, and that PSCo must balance the 2,251 MW of VERs on its system with approximately 5,000 MW of thermal generation.[5] PSCo states that in contrast, the Midcontinent Independent System Operator, Inc. can spread its VER integration burden over approximately 132,000 MW of generation, and the Southwest Power Pool, Inc. and the California Independent System Operator Corporation can do the same with approximately 71,000 MW and 56,000 MW of generation, respectively.[6]

5. On May 15, 2014, as amended on May 23, 2014, PSCo filed revisions to Schedule 3 (Regulation and Frequency Response Service for inside the PSCo balancing authority

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[3] *Id.* at 2.

[4] *Id*.

[5] *Id*. at 3 (citing Ex. PSCo-4 at 7-8).

[6] *Id*. at 3-4.

area) and new rate Schedules 3A (Regulation and Frequency Response Service for Point-to-Point transmission customers serving loads outside the PSCo balancing authority area) and 6A (Flex Reserve Service).[7] PSCo states that Schedule 6A is a supplemental category of reserves needed to address large reductions of on-line wind generation due to losses in wind speed. In addition, PSCo includes revisions to ancillary services-related provisions in sections 3, 36, 37, and 40 of the Xcel Energy OATT that are intended to reflect the addition of Flex Reserve Service and to clarify the obligation of Ancillary Services Customers under Part IV of the Xcel Energy OATT to obtain Flex Reserve Service.[8]

6. PSCo explains that, to date, it has not revised the Xcel Energy OATT ancillary services provisions to isolate the increased costs due to VER integration on its system and to recover those costs from the transmission customers that may be causing the costs to be incurred. PSCo states that, to the extent these costs are being recovered at all, they are currently borne only by native load customers, including PSCo's wholesale requirements customers through production rates.[9]

7. PSCo explains that, together, the proposed revisions are intended to permit it to better allocate costs and recover the increasing costs of VER integration on the PSCo system from transmission customers who purchase VER energy.[10] According to PSCo, the total increase in ancillary services revenue from Schedules 3, 3A, and 6A is approximately $727,000 annually,[11] and that by comparison the total 2014 annual transmission revenue requirement is $230 million.[12] PSCo states that the recovery of these generation-related ancillary services revenues will result in revenue credits to PSCo's production formula rate.

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[7] PSCo May 15, 2014 Filing, Docket No. ER14-1969-000 (filed May 15, 2014) (May 15 Filing); PSCo May 23, 2014 Amendment, Docket No. ER14-1969-001, at 2 (filed May 23, 2014) (May 23 Amendment).

[8] May 15 Filing at 19.

[9] *Id*. at 4.

[10] *Id*. at 1.

[11] *Id*. at 4 (citing Ex. PSCo-25 (Statements BG/BH)). The increased revenue requirement resulting from Schedules 3/3A is approximately $364,000, and the increased revenue requirement resulting from Schedule 6A is approximately $363,000.

[12] *Id*.

A. Schedules 3 and 3A, Regulation and Frequency Response Service

8. PSCo proposes revisions to the Xcel Energy OATT to allocate to transmission customers who use VER generation (including PSCo native load customers) their share of these VER integration costs. Specifically, PSCo proposes to modify the rates, terms, and conditions of Schedule 3 - Regulation and Frequency Response Service, in order to update the cost-of-service for this service and include differential rates that vary depending on whether the service is associated with load, VER generation (wind and solar), or non-VER generation. PSCo explains that Schedule 3 will continue to apply to Network Integration Transmission Service, Point-to-Point transmission service serving load within the PSCo balancing authority area, and Ancillary Service Customers under Part IV of the Xcel Energy OATT.[13]

9. PSCo states that it based its Schedules 3 and 3A - Regulation and Frequency Response Service rates in part on the models provided by *Westar Energy, Inc.* and *Puget Sound Energy, Inc.*, where the Commission approved differential rates for load, VER generation, and non-VER generation.[14] PSCo states that the testimony it submits explains that the variability of VER generation on PSCo's system justifies a differential rate for VER generation to mitigate subsidization of VER generation by load.[15] PSCo explains that its rates for Regulation and Frequency Response Service include a Fast-moving component for moment-to-moment fluctuations and a Following component for other changes that must be balanced to maintain reliability within a 15-minute scheduling interval. However, PSCo asserts that it did not include in its data additional margins for differences between forecasts or schedules and actual performance, which would have resulted in higher reserve requirements.[16] PSCo also states that it only used the dispersion of the inner 95 percent of its data to calculate the Regulation and Frequency Response Service reserve requirement. PSCo claims that using the inner 95 percent of values captures the vast majority of events while excluding the extreme outliers in the data.[17]

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[13] *Id*. at 4.

[14] *Id*. at 7 (citing *Westar Energy, Inc.*, 130 FERC ¶ 61,215 (2010), *on reh'g*, 137 FERC ¶ 61,142 (2011) (*Westar*); *Puget Sound Energy, Inc.*, 137 FERC ¶ 61,063 (2011) (*Puget Sound*)).

[15] *Id*. (citing Ex. PSCo-1 at 34-35; Ex. PSCo-7 at 7-13, 17-24).

[16] *Id.* at 13.

[17] *Id.*, Ex. PSCo-7 at 14-15.

10. Further, PSCo states that it performed a form of portfolio analysis in the Regulation and Frequency Response Service rate design to ensure that the reserve obligations for the different sources of the reserves requirements (VER generation, non-VER generation, and load) for the Schedule 3 and Schedule 3A services are allocated using a method that takes into account the relative contribution, or offsetting benefit, of each source. According to PSCo, the result is that VER generation, non-VER generation, and load are allocated individual Regulation and Frequency Response Service obligations that are lower than they otherwise would be.[18] PSCo also states that, in allocating capacity costs among the relevant ancillary services, it uses the "units most likely methodology" and an iterative *pro rata* allocation among the ancillary services and among the units, which eliminates any possibility of double recovery of capacity costs.[19]

11. PSCo explains that, under Schedule 3, Network and Point-to-Point transmission customers will pay a Regulation and Frequency Response Service charge based on the sum of the charges applicable to load, non-VERs, and VERs. The proposed rates for Schedule 3, based on 2012 cost data, are $0.18/kW/year for load, $0.23/kW/year for non-VER generation, and $1.92/kW/year for VER generation. PSCo states that the revised rates for Schedule 3 result in a 19.2 percent increase as compared to the existing rates for Schedule 3.

12. PSCo explains that new Schedule 3A will be applicable to Point-to-Point transmission service customers taking service in the PSCo balancing authority area and where the load or point of delivery is outside of the PSCo balancing authority area. PSCo states that customers taking service under Schedule 3A will pay the rate applicable to the resource for which the service is provided, and that, for non-VER generation, the charge would be $0.23/kW/year, and for VER generation, the charge would be $1.92/kW/year.[20] PSCo states that, with regard to Schedule 3A, no current customers take Point-to-Point transmission service to export generation, so there is no rate impact on current customers. PSCo further states that both Schedule 3 and Schedule 3A clearly provide that customers taking service under Schedule 3 will not be charged for Schedule 3A for the same transaction, and vice versa.[21] In addition, PSCo states that Schedule 3 and 3A rates will

[18] *Id.* at 8.

[19] *Id*. at 15 (citing Ex. PSCo-14 at 8-13).

[20] *Id*. at 9.

[21] *Id*. at 10.

be formula rates under the existing Attachment O-PSCo transmission formula rate template for ancillary services.[22]

13. PSCo also states that it considered each of the factors set forth in Order No. 764[23] in designing Regulation and Frequency Response Service charges that distinguish between VERs and other customers,[24] and also considered the requirements of other applicable Commission precedent.[25]

B. Schedule 6A, Flex Reserve Service

14. In addition to Regulation and Frequency Response Service, PSCo states that it needs additional reserves, which it calls "Flex Reserve Service," to address the existing and increasing penetration of wind resources in the PSCo balancing authority area. PSCo states that Flex Reserve Service is generation capacity needed to address sustained, declining wind ramps due to a loss of wind speed. According to PSCo, in these cases, the drop off of wind generation is not instantaneous, but occurs over tens of minutes or even a few hours. PSCo states that, while Flex Reserve Service is not currently a service offered under the *pro forma* open access transmission tariff (OATT), PSCo has carried Flex Reserves since 2008 to maintain system reliability. As with Schedules 3 and 3A, PSCo states that new Schedule 6A rates will be formula rates under the Attachment O-PSCo formula rate template of the Xcel Energy OATT.[26]

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[22] *Id*. at 4.

[23] *Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs. ¶ 31,331, *order on reh'g and clarification*, Order No. 764-A, 141 FERC ¶ 61,232 (2012), *order on clarification and reh'g*, Order No. 764-B, 144 FERC ¶ 61,222 (2013).

[24] May 15 Filing at 10-14.

[25] *Id*. at 14-15 (citing *Kentucky Utilities Co.*, 85 FERC ¶ 61,274 (1998) (*Kentucky Utilities*); *Westar*, 130 FERC ¶ 61,215 (2010); *PacifiCorp*, 144 FERC ¶ 61,135 (2013); *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 690, *order on reh'g*, Order No. 890-A, 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), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009)).

[26] *Id*. at 4.

15. PSCo explains that, as its total wind generation portfolio has grown in recent years, it has experienced an increasing frequency of large losses of on-line wind generation due to reductions in wind speed.[27] PSCo states that, when these "down ramps" begin to occur, PSCo must have available generation capacity to deploy to continue to balance load in light of the shortfall, and that it cannot satisfy the needed capacity through the use of contingency reserves (which are recovered under Schedules 5 and 6 of the Xcel Energy OATT). PSCo explains that contingency reserves are required to be held to respond to "Reportable Disturbances" in accordance with the North American Reliability Corporation's (NERC) Reliability Standards, and NERC's standards for such reserves do not allow for use of contingency reserves to address down ramps in wind generation levels. PSCo also states that using Schedule 3 Regulation and Frequency Response Service reserves to make up the shortfall is not a viable option because attempting to use Schedule 3 reserves to address large wind ramp events would quickly exhaust PSCo's supply of resources eligible to provide such reserves and compromise PSCo's ability to meet its moment-to-moment balancing obligations.[28]

16. PSCo states that the proposed Schedule 6A will recover the capacity costs of providing Flex Reserve Service from those transmission customers that create the need for the service, i.e., transmission customers that use wind resources, including PSCo's native load customers. To determine the capacity requirement for the rate design of Flex Reserve Service, PSCo states that it calculates the hourly averaged Flex Reserve Service reserve requirement for the study period and uses a confidence interval of 95 percent to determine the average amount of reserves necessary to meet the Flex Reserve Service reserve requirement 95 percent of the time. Similar to its rate design for Schedules 3 and 3A, PSCo states that its Flex Reserve Service formula accounts for actual variability of wind generation during the test year rather than the uncertainty associated with forecast error.[29] However, PSCo's Flex Reserve Service methodology is distinct from its Schedules 3 and 3A rate design in that it incorporates a 30-minute reserve guideline to determine what amount of Flex Reserves should be maintained at different wind generation levels on the PSCo system.[30] PSCo states that the resulting reserve requirement is 411 MW, which results in a reserve margin for PSCo customers using wind generation of 18.96 percent per MW of installed generation.

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[27] *Id*. at 15-16.

[28] *Id*. at 16.

[29] *Id.*, Ex. PSCo-7 at 34.

[30] *Id*. at 25-31.

17. In addition, PSCo explains that, under Schedule 6A, any transmission customer or ancillary service customer using wind generation to serve load in the PSCo balancing authority area or exporting the output of wind generation out of the PSCo balancing authority area must either purchase Flex Reserve Service or self-supply it.[31]

18. PSCo states that the Commission has not previously considered a rate schedule for Flex Reserve Service. However, PSCo points out that the Commission acknowledged the underlying issues related to managing extreme ramp events of VERs in the Notice of Proposed Rulemaking that led to the issuance of Order No. 764.[32]

C. Proposed Effective Date, Request for Suspension, and Request for Waivers

19. PSCo requests an effective date of August 1, 2014 for its proposed revisions; however, PSCo voluntarily consents to a five-month suspension so that the proposed rates may become effective after the suspension, on January 1, 2015. PSCo explains that the proposed rates are not "substantially excessive," and that permitting its proposed revisions to become effective as requested will enable PSCo to satisfy the requirements of its recently approved settlement agreement in Docket No. ER12-1589-000.[33] PSCo also states that, pursuant to this settlement agreement, it met with transmission customers and other interested parties and answered questions about the draft filing in the instant proceeding. PSCo states that several of the comments resulted in revisions or corrections to the filing.[34]

20. In addition, PSCo explains that the ancillary services rates calculated in its filing are derived using 2012 actual data because PSCo's currently effective Xcel Energy OATT formula ancillary services rates for 2014 were derived using 2012 actual data. PSCo states that if the Commission accepts the proposed revisions, PSCo anticipates updating the ancillary services rates, to be placed in effect January 1, 2015, using 2013

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[31] *Id.* at 19.

[32] *Id*. at 18 (citing *Integration of Variable Energy Resources*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,664, at P 100 (2010)).

[33] *See Public Service Company of Colorado*, 145 FERC ¶ 61,266 (2013) (approving a partial settlement agreement stating that any proposed modification to the Formula Rate run from January 1 to December 31 of the next Rate Year).

[34] May 15 Filing at 20.

Form 1 data, pursuant to the Formula Rate Implementation Procedures established in the partial settlement in Docket No. EL12-77-000.[35]

21. PSCo requests waiver of the Commission's cost-of-service regulations that require it to provide full Period I and Period II data, consistent with waivers granted by the Commission in other cases concerning formula rates, and requests waiver of any other requirements of the Commission's rules and regulations deemed necessary.[36]

22. In the May 23 Amendment, PSCo explains that it is replacing Exhibit No. PSCo-20 with a revised version that removes highly sensitive propriety information and that provides information about unit ramp rates that supports its proposed ancillary services rates.[37]

23. On July 30, 2014, a deficiency letter requesting further information regarding PSCo's filing was issued.[38] On August 26, 2014, PSCo submitted its response in two separate filings. The first filing included tariff revisions proposing to correct certain typographical errors and tariff provision omissions in the proposed Schedule 6A, Flex Reserve Service. The second filing (Deficiency Response) addressed the remaining questions set forth in the deficiency letter, as discussed below.

II. <u>Notice of Filings and Responsive Pleadings</u>

24. Notice of PSCo's filing was published in the *Federal Register*, 79 Fed. Reg. 29,757 (2014), with interventions and protests due on or before June 5, 2014. Notice of PSCo's May 23 Amendment was published in the *Federal Register*, 79 Fed. Reg. 32,267 (2014), with interventions and protests due on or before June 13, 2014. On June 6, 2014, Iberdrola Renewables, LLC (Iberdrola) filed a motion for extension of time to file

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[35] *Id.* at 20-21.

[36] *Id*. at 21 (citing *Commonwealth Edison Co*., 119 FERC ¶ 61,238, at P 94 (2007); *Trans-Allegheny Interstate Line Co*., 119 FERC ¶ 61,219, at P 57 (2007); *Duquesne Light Co.*, 118 FERC ¶ 61,087, at P 79 (2007); *PPL Elec. Utils. Corp.*, 125 FERC ¶ 61,121, at PP 40-41 (2008); *Pub. Serv. Elec. & Gas. Co*., 124 FERC ¶ 61,303, at P 23 (2008); *Oklahoma Gas & Elec. Co.*, 122 FERC ¶ 61,071 (2008); *Tampa Electric Co.*, 132 FERC ¶ 61,214 (2010)).

[37] May 23 Amendment at 2.

[38] On August 26, 2014, the Commission granted an extension of time to and including August 26, 2014 for PSCo to submit its response to the deficiency letter.

comments. On June 11, 2014, the Commission granted the extension of time to and including June 20, 2014. On June 13, 2014, the Colorado Independent Energy Association (CIEA) filed a motion to intervene and for extension of time for an additional seven days to June 27, 2014 to file comments. On June 19, 2014, the Commission denied CIEA's motion for extension of time, given that a one-week extension of time was already granted.

25. American Wind Energy Association (AWEA) filed a protest.[39] Iberdrola and Tri-State Generation and Transmission Association (Tri-State) filed motions to intervene and protests. Powerex Corp. (Powerex) filed a motion to intervene and comments. CIEA filed comments. Motions to intervene were filed by: Cedar Creek Wind Energy, LLC; Invenergy Wind Development LLC and Invenergy Solar Development LLC; and NRG Companies. NextEra Energy Resources, LLC (NextEra) and NorthWestern Corporation (Northwestern) submitted motions to intervene out-of-time. On July 7, 2014, Xcel Energy Services (Xcel), on behalf of PSCo, filed a motion for leave to answer and answer to the comments and protests. On July 18, 2014, AWEA and Tri-State filed motions for leave to answer and answers to PSCo's answer. On July 25, 2014, Xcel filed a motion for leave to answer and answer to the answer filed by AWEA and Tri-State.

26. On June 24, 2014, CIEA filed a motion to lodge, requesting that the Commission lodge information concerning PSCo's available pool of resources in this proceeding. CIEA states that a 569 MW combined cycle plant currently being constructed at Cherokee Generating Station and scheduled to be in service in 2015 should be included in the resource pool used to calculate PSCo's proposed Schedule 6A rates. CIEA argues that this information is directly relevant to the information provided by CIEA in its June 20 comments; the purpose of its motion to lodge is to assist the Commission in obtaining a complete and accurate record, and the scope of the motion is limited to the identity of this facility. Therefore, CIEA requests that the Commission grant its motion to lodge this information in this proceeding.

27. Notices of PSCo's responses to the deficiency letter were published in the *Federal Register*, 79 Fed. Reg. 52,645 (2014) and 79 Fed. Reg. 53,053 (2014), with interventions or protests due on or before September 16, 2014. On September 16, 2014, AWEA filed a protest and Tri-State filed an answer in response to PSCo's deficiency letter response. On October 1, 2014, Xcel filed, on behalf of PSCo, a motion for leave to answer and answer.

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[39] AWEA did not submit a motion to intervene in this proceeding.

A. **Comments and Protests**

28. Commenters generally agree with the underlying objective of PSCo's proposed rate schedules. Tri-State supports PSCo's efforts to ensure appropriate allocation and recovery of increasing costs of VER integration.[40] Iberdrola appreciates PSCo's support of renewable energy, and agrees that PSCo has been instrumental in recent discussions focused on the development of market mechanisms designed to more efficiently integrate variable resources.[41] Powerex fully supports PSCo's objectives of revising the Xcel Energy OATT to better address the integration of wind and other VERs on its system, and to develop rates that attempt to recover associated costs. Powerex also states that it supports PSCo's retention of existing self-supply options for Regulation and Frequency Response Service and its proposal to provide a self-supply option for Flex Reserve Service.[42] Although AWEA has serious concerns about PSCo's proposed rate design, AWEA notes that Xcel and PSCo have been national and global leaders in reliably, efficiently, and cost-effectively integrating renewable energy and applauds PSCo for working with stakeholders to develop its proposal. AWEA admits that PSCo's filing incorporates several significant improvements that resulted from stakeholder discussions and AWEA considers many aspects of the proposed methodology reasonable.[43]

29. However, some commenters challenge the appropriateness and consistency of the methodologies and assumptions underlying PSCo's rate design for Schedules 3 and 3A services. AWEA argues that a capacity factor is not an appropriate proxy for a generator's ability to provide operating reserves, and that PSCo should instead use an on-line hours calculation, which would change the allocation and therefore the cost of reserves under Schedules 3 and 3A, as the percent of hours in which a plant is grid-synchronized and producing power is typically much higher than a plant's capacity factor.[44] AWEA claims that the availability of the Cabin Creek pumped hydro plant to provide low-cost reserves is distorted downward in PSCo's analysis due to the inclusion of data from an anomalous outage that lasted for much of 2010.[45] AWEA asserts that

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[40] Tri-State Protest at 3.

[41] Iberdrola Protest at 2.

[42] Powerex Comments at 5-6.

[43] AWEA Protest at 2-3.

[44] *Id*. at 3-8.

[45] *Id*. at 8.

PSCo's assumption that the Cabin Creek pumped hydro plant is only minimally used to provide wind-related reserves is called into question by previous PSCo wind integration studies, which show that Cabin Creek has a major impact on wind integration costs.[46] CIEA argues that PSCo omitted facilities that produce relatively low-priced power from the "units most likely" approach, which may have resulted in an increase in the rates charged to transmission customers, and ultimately all customers, for wind generation.[47] Tri-State asserts that PSCo's proposal is internally inconsistent with regard to its description of the revenue credit mechanism, and requests that PSCo confirm Tri-State's understanding of the proposal or clarify its intent.[48] Powerex claims that PSCo fails to provide any explanation regarding why it is appropriate to recover capacity costs associated with generator variability under Schedule 3, when Schedule 3 is intended to address costs driven by fluctuations in load.[49]

30. Both Tri-State and AWEA raise concerns regarding the proper rate treatment of non-VER generators in PSCo's proposed Schedules 3 and 3A. Tri-State claims that the rates used in the calculation of Schedule 3 for non-VER generation are inconsistent throughout PSCo's filing and requests that PSCo submit corrected testimony to clarify how it derives rates under Schedule 3.[50] Tri-State also requests that PSCo clarify how it calculates the non-VER generation component based on the customer's installed capacity rather than the customer's load in the region.[51] According to AWEA, PSCo's proposal assumes that non-VER generators have no impact on the need for Following reserves, but AWEA asserts that non-VERs can impact Following reserves needs since non-VER generators frequently experience schedule deviations that persist for longer than 15 minutes.[52]

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[46] *Id*. at 8-11.

[47] *See* CIEA Comments at 4; CIEA Motion to Lodge at 1. CIEA identifies the Fountain Valley facility and the planned Cherokee Generating Station as two resources omitted from PSCo's methodology.

[48] Tri-State Protest at 7-8.

[49] Powerex Comments at 14.

[50] Tri-State Protest at 3-5.

[51] *Id.* at 5-6.

[52] AWEA Protest at 14.

31. AWEA argues that there are other inconsistencies in PSCo's filing regarding the proper allocation of reserves. AWEA maintains that, because PSCo's plants have far more than sufficient reserve capabilities to meet all operating reserve needs, PSCo's analysis should use only the lowest cost resources that are necessary to meet the total reserve needs and should exclude higher cost resources that are not needed to provide these reserves. AWEA states that PSCo's proposal for cost allocation under Schedules 3 and 3A treats Following reserves as being equivalent in cost to regulation reserves. AWEA argues that Following reserves should be allocated to the generators that provide them at the same time or just after regulation reserves are allocated, not after Supplemental Reserves and Spinning Reserves are allocated. AWEA also contends that PSCo's proposal does not account for the fact that PSCo is using wind generators to provide regulation and other fast-acting reserves in some hours, thereby reducing the need and cost for reserves.[53]

32. Tri-State also argues that there are other errors and inconsistencies associated with PSCo's proposed Schedule 3A rates. Tri-State contends that PSCo incorrectly asserts that the creation of Schedule 3A will have no effect on current customers. Tri-State claims that in 2013 it purchased Point-to-Point transmission service from PSCo to export generation it owns inside the PSCo balancing authority area, and Tri-State plans to continue this practice into the future. Under PSCo's proposed Schedule 3A charges, Tri-State believes it would incur charges to serve this load, and Tri-State requests that the Commission direct PSCo to review its data and provide a more accurate description of the effect of Schedule 3A on existing customers.[54]

33. Powerex contends that allocating capacity costs associated with the integration of VERs to load and exporters is inconsistent with the Commission's cost causation principles because costs are driven by the variability of generation, and must be imposed on generators. Powerex contends that PSCo's argument that certain classes of customers cause these costs to be incurred is flawed, as both the Commission and PSCo have recognized that the operational characteristics of VERs create the need to hold additional reserve capacity, not the variable need of the load or exporter.[55] Powerex argues that PSCo's reliance on *Westar* and *Puget Sound* is misplaced because in both cases the

[53] *Id*. at 11-14.

[54] Tri-State Protest at 8-9.

[55] Powerex Comments at 6-10.

Transmission Provider's proposal was tailored to ensure that costs were allocated to generators causing the need for the service.[56]

34. Several commenters oppose PSCo's Schedule 6A proposal on the grounds that it is inconsistent with the principles of Order No. 764. Iberdrola states that the Commission recognized the relationship between wind scheduling and wind variability in Order No. 764 when it implemented intra-hour scheduling to allow for more accurate VER scheduling.[57] Iberdrola claims that scheduling accuracy plays a key role in the level of variability that must be managed in a balancing authority area, and asserts that PSCo's claim that wind variability is separate from wind scheduling uncertainty is incorrect.[58] AWEA similarly opposes PSCo's proposal because it does not use wind energy forecasting to reduce the Schedule 6A charge.[59] CIEA also contends that the Flex Reserve Service fails to allow VER generators to adjust their schedules to hedge or mitigate against the imposition of Schedule 6A charges.[60] CIEA maintains that recent forecasts rather than historical analysis should serve as the basis for the reserve calculations, and that PSCo's rates are not based on up-to-date forecasts.[61]

35. Commenters also contend that PSCo's Schedule 6A rate does not properly take into account diversity benefits because it solely considers wind generation variability when wind down ramps should be analyzed in combination with the movement of load and non-VER resources as well.[62] Specifically, Iberdrola notes that PSCo excludes solar generation and conventional generation from its proposed Flex Reserve Service despite the clear contribution of these resources to flexible reserves requirements on PSCo's system.[63] AWEA claims that a large share of total system Schedule 6 integration costs

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[56] *Id*. at 11 (citing *Westar*, 130 FERC ¶ 61,215; *Puget Sound*, 137 FERC ¶ 61,063).

[57] Iberdrola Protest at 7 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at PP 22-24, 323).

[58] *Id.* at 6-7.

[59] AWEA Protest at 14-16.

[60] CIEA Comments at 7.

[61] *Id*. at 9-10.

[62] Iberdrola Protest at 9-10; AWEA Protest at 16; CIEA Comments at 6-7.

[63] Iberdrola Protest at 10-11.

are caused by conventional generators, but the costs of Supplemental Reserves for conventional generators' forced outages under Schedule 6 are currently allocated to load. AWEA states that allocating Schedule 6A costs to wind generators while similarly-situated conventional generators' Schedule 6 integration costs are broadly allocated to load would break with Commission precedent and cost-causation principles.[64] CIEA asserts that a more consistent approach with Order No. 764 is to offset the Schedule 6A rate with a portion of the contingency reserves and to charge customers who are using non-VERs accordingly.[65]

36. CIEA and Iberdrola both claim that the amount of Flex Reserves proposed by PSCo is excessive and will result in unnecessarily high costs for customers using wind generation. CIEA claims that the data presented shows that high levels of such reserves should not be required every hour of the year given the sufficiency of Operating Reserves and that Operating Reserves usually cover a large wind ramp-down event.[66] While procurement of incremental reserves is necessary in most hours, according to Iberdrola, there are numerous periods where little to no generation is in the forecast. Iberdrola maintains that PSCo's proposal to set aside a large amount of reserves beyond those required for regulation and contingency reserves on a long-term basis does not account for market efficiencies that could be leveraged through shorter-term transactions.[67]

37. Iberdrola contends that PSCo's proposed Flex Reserve Service provides no price signals to customers. According to Iberdrola, under the proposed rate structure of Schedule 6A, a customer exporting power from a generator that submits an accurate schedule and drives low levels of reserve deployment will pay the same amount as a customer exporting power from a generator that completely ignores the wind forecast. Instead of providing price signals to participants to incentivize desired behavior, Iberdrola claims that PSCo's rate design would result in increased scheduling error that

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[64] AWEA Protest at 17 (citing *Alabama Elec. Coop. v. FERC*, 684 F.2d 20, 21, 221 U.S. App. D.C. 246 (D.C. Cir. 1982) (stating that undue discrimination involves both the dissimilar treatment of similarly situated parties and the similar treatment of dissimilar parties); *Cal. Indep. Sys. Operator Corp*., 119 FERC ¶ 61,076, at P 369 (2007) (finding that "[i]n general, discrimination is 'undue' when there is a difference of rates, terms or conditions among similarly situated customers.")).

[65] CIEA Comments at 6-7.

[66] *Id*. at 10-11.

[67] Iberdrola Protest at 4-5.

places upward pressure on required balancing reserves, and increases costs for all customers on PSCo's system.[68]

38. Commenters raise other issues regarding PSCo's proposed Flex Reserve Service. Iberdrola states that PSCo's option for customers to self-supply Flex Reserves is not feasible. Iberdrola states that it has self-supplied its balancing reserves and lowered its integration costs within the Bonneville Power Administration's balancing authority area, but that conditions in that service territory have been conducive to such self-supply, whereas such conditions are lacking within PSCo's service territory.[69] Powerex asserts that PSCo does not provide justification for designating its Flex Reserve Service as Schedule 6A, and that its proposal suggests that this service is somehow related to Schedule 6, Operating Reserve-Supplemental Reserve Service. Powerex argues that it is not appropriate to classify reserves held to accommodate long-term down ramp events in the same class as contingency reserves.[70] Tri-State asserts that PSCo incorrectly allocates potential charges under Schedule 6A to Arkansas River Power Authority rather than to Tri-State in Exhibit No. PSCo-25.[71]

39. Commenters make general claims about the implications of PSCo's proposal as a whole. Powerex states that PSCo's proposal will have significant, unintended commercial implications for market participants who will need to differentiate between energy produced by VERs located in the PSCo Balancing Authority Area and energy produced by traditional generating resources.[72] CIEA states that the Western Area Colorado Missouri Balancing Authority Area serves thermal and hydroelectric resources that could enlarge the total pool of available resources to balance VER generation, however, PSCo does not mention these resources in its rate calculations.[73] According to CIEA, PSCo has had multiple opportunities to expand its transmission system in ways that maximize efficiency and integration, yet PSCo has not invested in expansion of interconnectivity or access to neighboring markets. Several commenters also agree that PSCo's filing is premature given the development of an energy imbalance market in the

[68] *Id*. at 8-9.

[69] *Id*. at 11.

[70] Powerex Comments at 14-15.

[71] Tri-State Protest at 6 (citing Ex. PSCo-25 at 3).

[72] Powerex Comments at 12-13.

[73] CIEA Comments at 3.

Western Interconnection, which could allow PSCo to integrate VERs efficiently without additional costs.[74]

40. Finally, commenters request different courses of action the Commission should take with respect to PSCo's filing. While Iberdrola does not oppose PSCo's proposed Schedules 3 and 3A rates, which it states appear to be consistent with Commission policy and represent legitimate costs, Iberdrola asserts that the rates should be reviewed periodically to ensure that proper updates occur to reflect changes in operations that may reduce reserve need and associated costs of providing this service.[75] However, Iberdrola requests that the Commission reject PSCo's Schedule 6A rate as unjust, unreasonable, unduly discriminatory or preferential, or suspend the proposed rates for the full five-month period and set the matter for hearing.[76] Tri-State requests that the Commission direct PSCo to make a compliance filing to address the concerns identified in Tri-State's protest.[77] While outlining general concerns with PSCo's methodologies, CIEA specifically requests that the Commission reject PSCo's proposed Schedule 6A rate as unduly discriminatory.[78] AWEA requests that the Commission direct PSCo to revise Schedules 3 and 3A in a compliance filing to be consistent with the recommendations AWEA makes, and that the Commission reject Schedule 6A as unjust and unreasonable, and inconsistent with Order No. 764.[79] If the Commission declines to do so, AWEA requests that the Commission suspend the proposed Schedules 3, 3A, and/or 6A rates subject to hearing and hold the hearing in abeyance to give the parties an opportunity to resolve the outstanding issues through settlement proceedings.[80] Powerex requests that the Commission reject PSCo's proposal without prejudice to PSCo filing a proposal to recover the costs associated with integration of VERs in a manner that addresses the concerns set out in Powerex's comments.[81]

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[74] *Id*. at 5; Iberdrola Protest at 11; AWEA Protest at 13.

[75] Iberdrola Protest at 2.

[76] *Id*. at 3, 13.

[77] Tri-State Protest at 3.

[78] CIEA Comments at 11.

[79] AWEA Protest at 1-2, 20.

[80] *Id*. at 1-2, 20.

[81] Powerex Comments at 15.

B. Answers

41. On July 7, 2014, PSCo filed an answer. First, PSCo states that it included in the resource pool used for the cost of service for the proposed ancillary services rates all generating plants it owns as well as plants available to PSCo through power purchase agreements. In response to CIEA's comments, PSCo states that its balancing authority area is independent and therefore does not use resources from neighboring balancing authority areas to provide Regulation and Frequency Response service or Flex Reserve Service to its customers. PSCo further asserts that CIEA's argument that PSCo's rates are too high because the rate calculations do not include all of the "units most likely" to provide the service for Schedules 3 and 3A appears to be based on a misunderstanding of the methodology. PSCo argues that, because the Fountain Valley power purchase agreement was not part of the PSCo resource portfolio during the test year covered by its filing, PSCo therefore has no test year data on Fountain Valley to determine whether it would have a measurable change on the proposed rates. PSCo maintains that the Cherokee Generating Station cannot be included in PSCo's cost-based rates because the unit has not yet been constructed and the rate impact is therefore unknown.[82]

42. PSCo also responds to multiple arguments advanced by AWEA on the specific allocation of reserve costs to PSCo's units. PSCo argues that AWEA has not explained how an on-line hours calculation is a reasonable proxy for the "units most likely" approach, and that the on-line hours calculation does not provide any information regarding the loading of the units.[83] PSCo maintains that the Commission has previously used capacity factors in measuring the usage of generation capacity,[84] and that a "units most likely" methodology has been sanctioned by the Commission in prior cases.[85] PSCo maintains that Cabin Creek can provide Spinning and Supplemental Reserves, but cannot provide Fast-moving reserves because the load is not variable. PSCo states that Cabin Creek's highest and best use is not as a dedicated Flex Reserve resource and

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[82] PSCo Answer at 4-6.

[83] *Id*. at 7-8.

[84] *Id*. at 8 (citing *City of Wichita, Kansas v. Western Resources, Inc*., 93 FERC ¶ 63,015, at 65,064-065 (2000), *aff'd*, 97 FERC ¶ 61,234 (2001)).

[85] *Id*. (citing *Consumers Energy Co*., 86 FERC ¶ 63,004, at 65,055 (1999), *aff'd*, 98 FERC ¶ 61,333 (2002)).

deploying it in the manner suggested by AWEA would impose higher system costs and ignore PSCo's merit dispatch.[86]

43. PSCo argues that AWEA's proposal to allocate only low cost reserves to Regulation and Frequency Response Service would directly contradict the "units most likely" methodology. According to PSCo, AWEA's adjustments result in arbitrary rates that do not reflect the actual operation of generation and increase the rates of other reserve ancillary services.[87] In response to AWEA's argument that wind generators' reserve allocation should be reduced to account for instances when wind generation is curtailed and provides regulating service to the balancing authority area, PSCo argues that any current contribution to the Regulation and Frequency Response Service reserve requirements from VER generation is insignificant or negligible. PSCo states that, since VER generators do not have a capacity charge, there is no credit to apply to wind resources for periods of time when these resources are curtailed.

44. PSCo also clarifies that its rates are not based on forecasted wind generation, but rather upon the actual performance of generation during the test period. PSCo states that, by basing proposed rates on actual load, VER, and non-VER performance, it excluded forecast error from its rate determination so that reserve requirements are based only upon test period data recording actual moment-to-moment fluctuations and deviations. PSCo argues that removing the uncertainty about forecasts from the rate determination and focusing only on the variability of actual wind generation results in more accurate rates.[88]

45. In response to multiple claims by commenters that PSCo's filing is premature given recent developments in the Western energy imbalance market, PSCo asserts that it is not currently a participant and has not yet made a decision about joining an energy imbalance market. PSCo argues that it is more appropriate to reevaluate the rates and services if and when it becomes a participant, and that it incurs considerable costs due to VER integration under current conditions.[89]

46. PSCo argues that, although certain parties allege that Flex Reserve Service is "excessive," PSCo notes that 98.9 percent of the Flex Reserve Service revenue

[86] *Id.* at 9-10.

[87] *Id*. at 9.

[88] *Id*. at 11-12.

[89] *Id*. at 12-13.

requirement will be borne by PSCo native load customers. PSCo states that the relatively small allocation to third party customers would end the current subsidy provided by PSCo native load wholesale production and retail customers.[90] PSCo further argues that Flex Reserves are not an overly-cautious deviation from industry practice, but are necessary on the PSCo system to maintain contingency reserves compliance. PSCo emphasizes that it must carry more reserves than would be carried in an organized market because the sheer volume of wind to be reliably integrated on its system must be spread over a smaller footprint than in most organized markets.[91]

47. In response to Iberdrola, PSCo clarifies that solar generation does not present the same reliability issues as wind generation given its relatively small size on the PSCo system. However, PSCo notes that solar generation would be subject to the same revised Schedules 3 and 3A charges as customers using VER generation. With regard to Iberdrola's comment that the Flex Reserve rate does not provide price signals to participants to incentivize desired behavior, PSCo maintains that the effect of Schedule 6A will be to mitigate the subsidization of customers using VER generation by other customers and to provide a more accurate price signal of the true costs of transmission service in the PSCo balancing authority area. PSCo also clarifies that nothing in its proposal will interfere with a customer's ability to submit accurate schedules for its VER resources and to mitigate imbalance penalties.[92]

48. In response to multiple comments that the Flex Reserve requirement is inconsistent with Order No. 764, PSCo asserts that the Commission declined to take action on the issue of whether a separate category of contingency reserves should be established to help manage "extreme ramp events" of VERs.[93] Although Order No. 764 required the calculation of diversity benefits among load, VERs, and non-VERs in Regulation and Frequency Response Service, PSCo argues that contingency and supplemental reserves have never been analyzed on a portfolio basis. PSCo explains that Flex Reserve Service is a type of supplemental reserves, and that precipitous declines in wind production must be managed as events occurring independently of other deviations on the system, such as aggregate Regulation and Frequency Response variations. PSCo asserts that Flex Reserves provide protection against the variability of wind generation

[90] *Id*. at 14.

[91] *Id*. at 14-16.

[92] *Id*. at 16-17.

[93] *Id*. at 18 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 96).

due to changes in wind speed, not protection against forecast errors, or the uncertainty of wind generation.[94]

49. With respect to various comments concerning the appropriate cost allocation for wind generators verses conventional generators, PSCo emphasizes that it is not proposing any revisions to Schedule 6 and is not proposing to charge wind plants Schedule 6 charges. PSCo clarifies that Flex Reserve Service has been designated as Schedule 6A because it is a type of supplemental reserves needed to respond to a particular contingency to which Schedule 6 does not apply.[95] PSCo emphasizes that its Schedule 6A rates are applicable to transmission customers using PSCo transmission service to deliver VER generation because that transmission service causes the VER integration costs to be incurred.[96] PSCo argues that it is not unduly discriminatory, as AWEA contends, to allocate the costs of providing Flex Reserve Service only to customers that use wind generation. PSCo asserts that, to constitute undue discrimination, there must be a difference in rates or services among similarly-situated customers that is not justified by some legitimate factor.[97] PSCo states that the Commission has found that VERs are not similarly situated to conventional generators.[98]

50. In response to Tri-State, PSCo confirms that customers taking short-term firm Point-to-Point transmission service will be subject to the Schedules 3, 3A, and 6A rates. PSCo disagrees with Tri-State that the proposal should be revised to include further clarification on the rate impact to short-term firm Point-to-Point customers because this service is generally unpredictable and occurs in small amounts on the PSCo system. PSCo states that rate increases for a service of a short duration and of a type for which the need and usage cannot be reasonably forecasted are subject to an abbreviated set of requirements that do not require a full cost-of-service study.[99]

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[94] *Id*. at 18-20.

[95] *Id*. at 21.

[96] *Id*. at 21-22.

[97] *Id*. at 22 (citing Order No. 436, FERC Stats. & Regs. ¶ 30,655 at 31,541 (1985)).

[98] *Id*. at 22 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 47).

[99] *Id.* at 24 (citing 18 C.F.R. § 35.13(a)(2)(F)(ii) (2014)).

51. PSCo argues that Tri-State incorrectly asserts that PSCo would over-collect if a customer had more installed capacity than load within the PSCo balancing authority area and elected to sell its excess capacity off-system. In response to Tri-State's concerns with the wholesale production credits, PSCo also clarifies that it will first credit revenues from Schedules 3, 3A, and 6A to its production customers based on their billing determinants, and will then credit remaining revenues to the overall production revenue requirement through the production formula rate template.[100]

52. In response to Powerex's claim that PSCo inappropriately included costs associated with generator variability in Schedule 3, PSCo provides four reasons why it disagrees. First, PSCo states that Powerex's reliance on *Northwestern Corporation* is misplaced because PSCo is not proposing any modifications to generator imbalance service as Northwestern proposed under Schedule 10 of its OATT, which PSCo notes was proposed as a form of generator regulation service that appeared to shift the burden to intermittent resources to account for their own regulation service.[101] Second, PSCo states that Schedule 3 is applicable to transmission customers serving load in the PSCo balancing authority area and not generators, as PSCo is only able to recover capacity costs from transmission customers. Third, PSCo asserts that delineating the VER and non-VER components in the Schedules 3 and 3A rates offers transparency and consistency between Schedules 3 and 3A. Fourth, PSCo maintains that, in order to be consistent with the mandate of Schedule 3 in the *pro forma* OATT and to provide continuous balancing of resources with load, PSCo must have capacity to balance both the changes in load as well as generation deviations.[102]

53. AWEA argues in its answer that PSCo portrays AWEA's protest against the use of a capacity factor proxy as pertaining to the calculation of a generating unit's Equivalent Availability Factor;[103] however, AWEA states that its concern was with the use of a capacity factor in a later step of the reserve allocation process: PSCo's use of a capacity factor as a proxy for the number of hours a plant is online and therefore capable of providing regulation, spinning, and Following reserves. AWEA argues that, after PSCo

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[100] *Id*. at 26-28.

[101] *Id.* at 30 (citing *NorthWestern Corp.*, 129 FERC ¶ 61,116, at PP 23, 25 (2009)).

[102] *Id*. at 30-32.

[103] PSCo defines a generating unit's Equivalent Availability Factor as equal to the unit's total service hours less the unit's planned derated hours, unplanned derated hours, and seasonal derated hours, divided by the hours in the period of the historical review. *See* Ex. PSCo-14 at 6.

has correctly used the capacity factor to calculate a unit's "available capacity," the capacity factor is then incorrectly used as a proxy for online hours to calculate the unit's ability to provide regulation, spinning, and Following reserves. According to AWEA, this use of the capacity factor skews the reserve allocation away from the plants that are actually the most likely to provide those reserves since most plants are partially-loaded in many operating hours.

54. In its answer to PSCo's answer, Tri-State asserts that PSCo's proposal to apply one pricing methodology to load within the PSCo balancing authority area and a different pricing methodology to non-VER generators in the PSCo balancing authority area is flawed because PSCo is calculating the non-VER generation component for which transmission customers will be assessed costs based on the transmission customer's installed capacity rather than the transmission customer's load in the region.[104]

55. In its July 25 answer, PSCo argues that the Commission should reject the answers of AWEA and Tri-State. PSCo also argues that it did not misunderstand AWEA's protest, but rather attempted to address AWEA's protest in its July 7 answer. PSCo also disagrees that Commission precedent on the use of capacity factors cited in its own answer is inappropriate.[105] PSCo contends that Tri-State misunderstands the purpose of PSCo's rate design for Schedules 3 and 3A. PSCo argues that a primary purpose of its filing is to establish Regulation and Frequency Response Service rates that are more consistent with cost causation principles.

III. <u>Deficiency Letter and Responses</u>

56. The July 30 deficiency letter requested that PSCo provide additional workpapers on the calculation of the Regulation and Frequency Response Service rates, clarify its implementation of power production forecasting and intra-hour scheduling in the context of the new and revised services, consider the impact of using 2-minute data instead of 1-minute data and alternative 30-minute data for Regulation and Frequency Response Service, reconcile certain tariff record errors and omissions, and provide additional data and documentation on Flex Reserves held since 2008, among other things.

57. In addition to providing the workpapers requested in the deficiency letter, PSCo's response generally clarifies that, rather than relying on a comparison of actual performance of VERs, non-VERs, and load with forecasts and/or schedules to provide an approximation of uncertainty, PSCo deliberately looked only to the minute-to-minute

[104] Tri-State July 18 Answer at 2-3.

[105] PSCo July 25 Answer at 3.

historical data of actual performance to identify variability. PSCo claims that the generators that provide Regulation and Frequency Response Service follow the instantaneous variability of net load, not advanced forecasts, and therefore, corresponding rates design should be based on a framework of actual variability rather than scheduling or forecasting error. PSCo explains that a rate design for Regulation and Frequency Response Service based solely on schedules would result in higher rates than its proposed rate design based on historical data.[106]

58. PSCo also clarifies its use of power production forecasting during the test period. PSCo states that wind generation forecasts were used by PSCo during the test year to optimize unit commitment on a day-ahead and real-time basis, and that PSCo's wind power production forecasting has not changed since the test year. PSCo notes that its day-ahead system commitment and dispatch plan is carried forward into the real-time system dispatch, and that the real-time dispatchers adjust the day-ahead system dispatch plan as events unfold. According to PSCo, real-time dispatchers consider the best available information, including up-to-date wind and load forecasts, and then make non-VER generation dispatch decisions to meet system reliability requirements.[107]

59. With regard to Flex Reserves, PSCo clarifies that, while its state-of-the-art weather forecasts are generally accurate in predicting large meteorological events, they are less effective at predicting smaller events that impact wind behavior, such as localized thunderstorms. PSCo claims that, even when its meteorological forecasts are accurate in predicting the size and direction of a large wind ramp, the forecasts are not sufficiently precise in predicting *when* the wind ramp will occur. PSCo notes that, on average, it has found that persistence forecasts[108] are more accurate for use in real-time dispatch to plan for wind ramping behavior.

60. PSCo also explains its use of one-minute data over a 15-minute scheduling interval rather than two-minute data over a 30-minute scheduling interval. PSCo explains that it uses one-minute data because that has a higher frequency sample rate and is consistent with NERC Control Performance Standard CPS1. PSCo justifies its use of a 15-minute interval for the Following reserves component of Regulation and Frequency Response Service as an effort to match the most discrete scheduling interval available to

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[106] Deficiency Response at 5.

[107] *Id*. at 6.

[108] PSCo describes persistence forecasting as continuing current wind generation volumes into the next block scheduling intervals. *Id.* at 7, n.8.

transmission customers pursuant to Order No. 764 and *PacifiCorp*.[109] PSCo claims that its choice of 15-minute intervals also results in a lower Fast-moving reserves requirement for all contributors (load, VERs, and non-VERs) than would be the case under a longer duration scheduling interval such as 30 minutes. PSCo concludes that, although customers do not currently provide PSCo with intra-hour transmission schedules, the 15-minute scheduling assumption produces lower rates, even for customers who continue to submit hourly schedules, because the potential variability of a resource tends to decrease when it is measured over shorter durations.[110]

61. PSCo asserts that pricing its Flex Reserve Service based upon nameplate capacity is consistent with cost causation. According to PSCo, nameplate capacity was used as a billing determinant in *Westar*, where Regulation and Frequency Response Service charges were applied to the nameplate capacity of generators exporting out of the Westar balancing authority area. PSCo further argues that the ratio of customer installed wind generation capacity to all wind generation capacity in the PSCo balancing authority area presents the best measure of relative use of Flex Reserve Service available, as it uses nameplate capacity as an approximation of the maximum wind generation demand the customer could achieve. PSCo also states that there are no feasible alternatives, given that any load-based measure of relative use, such as contract demand or peak pricing, would have no correlation to the wind ramps that Flex Reserves are used to address because wind ramps are driven by meteorological changes and do not follow typical time-of-day load patterns. PSCo also asserts that use of nameplate capacity as a means to allocate Flex Reserve costs results in lower rates for third-party customers because PSCo currently owns approximately 99 percent of wind generation in the PSCo balancing authority area.

62. On September 16, 2014, AWEA filed a renewed protest in response to PSCo's Deficiency Response reiterating its previous arguments that PSCo does not appropriately incorporate wind forecasting into its Schedule 6A charge, and that using wind forecasting can reduce the need for Flex Reserves. AWEA also reiterates its previous arguments regarding the ranking of the quality of reserves service in the "units most likely" approach. Also on September 16, 2014, Tri-State filed an answer to PSCo's Deficiency Response in which it reiterated its previous arguments regarding PSCo's treatment of

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[109] *PacifiCorp*, 144 FERC ¶ 61,135 at P 39.

[110] PSCo demonstrates how it reached this conclusion in its response to the deficiency letter by comparing data that took into account a longer time interval (30 minutes) with the original dataset interval (15 minutes). When a longer time interval was used, reserve requirements for both the Fast-moving component and the Following component increased, and corresponding rates also increased for each customer class.

non-VER generation under Schedules 3 and 3A. On October 1, 2014, PSCo filed an answer to AWEA's protest, stating that AWEA misunderstands Order No. 764, does not specifically challenge the data on the large wind ramps, and does not point to any precedent or evidence to support its contention on the ranking of reserves services.

IV. Discussion

A. Procedural Matters

63. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2014), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

64. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2014), the Commission will grant the late-filed motions to intervene of NextEra and Northwestern, given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

65. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2014), prohibits an answer to a protest or an answer unless otherwise ordered by the decisional authority. We will accept the answers because they have provided information that assisted us in our decision-making process. We will also grant CIEA's motion to lodge.

B. Substantive Matters

66. With the exception of the issues summarily decided below, PSCo's proposed Tariff revisions raise issues of material fact that cannot be resolved based on the record before us and are more appropriately addressed in the hearing and settlement judge procedures ordered below. Our preliminary analysis indicates that PSCo's proposed Tariff revisions have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Accordingly, we will conditionally accept Schedules 3, 3A, and 6A for filing, suspend them for a nominal period, to be effective January 1, 2015,[111] subject to refund, and set them for hearing and settlement judge procedures, as discussed below.

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[111] We note that the January 1, 2015 effective date included on PSCo's proposed tariff sheets is inconsistent with PSCo's request for an effective date 60 days from the date of its August 26, 2014 Deficiency Response. PSCo should ensure that the effective date requested and the effective date included on its proposed tariff sheets are consistent in its future filings submitted to the Commission. *See Electronic Tariff Filings*,

(continued ...)

67. We find that PSCo appropriately considered both moment-to-moment fluctuations and other on-going balancing of generation resources with load that might be required to maintain system reliability when designing Schedules 3 and 3A rates. In *Kentucky Utilities*,[112] the Commission disagreed with the notion that utilities are only required to provide, and therefore are only required to receive, compensation for a moment-to-moment balancing function through their Load Following service. The Commission recognized that there are also instantaneous differences between loads and corresponding schedules that occur during the hour.[113] We find that PSCo's rate design for Schedules 3 and 3A is consistent with *Kentucky Utilities*. PSCo addresses differences in net load and corresponding schedules by incorporating a Following-reserve component that incorporates a 15-minute centered moving average to represent the trend in net load data. PSCo addresses moment-to-moment fluctuations in net load by incorporating a Fast-moving reserve component that measures deviations in minute-to-minute load data from the 15-minute centered moving average.[114]

68. We disagree with commenters' assertions that PSCo's filing is premature given the possibility that PSCo could seek membership in an energy imbalance market. Based on its representations, PSCo is incurring increased costs now for providing Schedules 3, 3A and 6A services. As such, we find that it is appropriate for PSCo to seek cost recovery for reasonably incurred reserves costs.

69. With respect to Tri-State's argument that PSCo's filing is unclear as to whether the revenue credits will be provided to PSCo's wholesale production customers, PSCo explained in its July 7 Answer that Tri-State's understanding of the revenue credit mechanism is correct. PSCo will first credit revenues from Schedules 3, 3A, and 6A to

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130 FERC ¶ 61,047, at P 6 (2010) (stating "[a]s is current practice, the date established by the Tariff Record Proposed Effective Date, if that date is after the otherwise statutorily-established effective date, will establish the date on which, by statute, a tariff filing would go into effect by operation of law in the absence of Commission action" and "…statements in transmittal letters or other pleadings will <u>not</u> establish statutory action dates for tariff filings") (emphasis in original); *see also id.* n.9 (stating "…if the Tariff Record Proposed Effective Date is after the otherwise applicable statutorily-established effective date, the statutory period will be extended until the Tariff Record Proposed Effective Date").

[112] *Kentucky Utilities*, 85 FERC ¶ 61,274.

[113] *Id*. P 14.

[114] Ex. PSCo-7 at 11-17.

its production customers based on their billing determinants. Then, PSCo will credit remaining revenues to the overall production revenue requirement in the production formula rate, through Schedule H of the production formula rate template. We find PSCo's clarification in its July 7 Answer to be sufficient.

70. We also disagree with Tri-State's arguments that PSCo's Schedules 3 and 3A rates result in over-collection of revenues if a customer chooses to export excess capacity out of PSCo's balancing authority area. PSCo states that its tariff language is clear that PSCo may not assess transmission customers a charge under both Schedule 3 and Schedule 3A for the same transaction. We agree with PSCo's clarifying statements in its answers that a non-VER generator serving load in the PSCo balancing authority area would only be charged Schedule 3 rates for the generation capacity used to serve its internal load, while any excess capacity used to serve off-system load would be charged separately under Schedule 3A. Therefore, we find that PSCo's filed tariff language is sufficient to clearly indicate that customers will not be assessed full charges for the same transaction under both Schedules 3 and 3A. In response to Tri-State, we also note that basing both non-VER and VER generators' billing determinants on installed nameplate capacity, as PSCo has done, is consistent with *Westar*. Therefore, we find here that PSCo's use of nameplate capacity as a billing determinant for transmission customers using non-VER generation and VER generation in Schedules 3 and 3A is also just and reasonable.

71. We find Iberdrola's protest that the option for customers to self-supply Flex Reserves is not feasible on PSCo's system to be without merit. PSCo's proposed Schedule 6A clearly states that customers have the option to purchase or self-supply Flex Reserve Service, and PSCo's Schedule 6A proposal has no bearing on whether Iberdrola or other transmission customers have adequately positioned themselves within those areas to be able to effectively self-supply those reserves. We agree with PSCo's clarification and find that any customer within the PSCo balancing authority area subject to PSCo's Schedule 6A may self-supply some or all of its Flex Reserve Service obligation.[115]

72. We are also not persuaded by AWEA's argument that wind generators' reserve allocation should be reduced to account for periods when wind generators provide Fast-moving reserves. PSCo explains that non-VER generators similarly impact Fast-moving reserves through events such as unit starts and stops and unit trips, and that such events are captured in the non-VER regulating reserve calculation. Given that PSCo also captures the events when wind generation provided Fast-moving reserves in its regulating

[115] *See* PSCo July 7 Answer at 29-30.

reserve calculation, we find that PSCo equally considered the contribution of both VER and Non-VER generators to Fast-moving reserves.[116]

1. **Schedules 3 and 3A**

73. In Order No. 764, the Commission provided guidance on six principles that should be considered when designing Regulation and Frequency Response Service charges that distinguish between VERs and other customers.[117] PSCo states that it considered each of these factors in the redesign of its ancillary services rates. We discuss below whether the rates set forth in Schedules 3 and 3A are consistent with these principles.

74. Principle One provides that public utility transmission providers seeking to distinguish between customer classes for the purpose of requiring them to purchase or otherwise account for different quantities of generation regulating reserves should only do so to the extent such classes and distinctions among classes are reasonably related to operational similarities and differences among those resources.[118] PSCo has distinguished between VERs, non-VERs, and load, and demonstrates that these separate classes each involves a different Regulation and Frequency Response reserves burden.[119] Therefore, we find that, consistent with the consideration given to Principle One, PSCo has shown distinguishable differences among the three customer classes that justify proposing different rates for those classes of customers.

75. Principle Two provides that, to the extent a public utility transmission provider proposes to separate customers into specific groups based on operational characteristics, the public utility transmission provider should provide a detailed explanation as to why such classifications are appropriate if and when it proposes to allocate different generating regulation reserve obligations to different customer classes.[120] PSCo has identified the Regulation and Frequency Response burdens imposed by load, VERs, and non-VERs and provides a detailed analysis demonstrating that there is a distinct burden among the different classes that justifies separating transmission customers into specific

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[116] *Id*. at 10.

[117] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at PP 317-325.

[118] *Id*. P 318 (citing *Westar*, 137 FERC ¶ 61,142 at PP 27-28).

[119] Ex. PSCo-7 at 11-14.

[120] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 319.

groups based on the operational characteristics of the resources they use.[121] Thus, we find that PSCo effectively applies the guidance provided under Principle Two in developing rates for Schedules 3 and 3A.

76. Principle Three provides that, to the extent a public utility transmission provider proposes to differentiate among customers (or customer classes) in determining their relative regulating reserve responsibilities, the public utility transmission provider should demonstrate that the overall quantity of regulating reserves it requires from its transmission customers accounts for diversity benefits among all resources and loads, and the allocations to individual customers (or customer classes) of their proportionate share is based on the operational characteristics of such customers or customer classes.[122] PSCo used a form of portfolio analysis called the "fair allocation method," which allocates the costs of Regulation and Frequency Response Service to VERs, non-VERs, and load based upon their relative contributions to the need for service.

77. We agree with PSCo that use of the fair allocation method produces an obligation for VERs, non-VERs, and load that considers their offsetting deviations, resulting in a lower overall Regulation and Frequency Response reserves requirement than would otherwise be the case.[123] We also agree with PSCo that using a form of portfolio analysis is appropriate here; however, we find that the record is insufficient to determine whether the data impacting the inputs into the fair allocation method have been incorporated in such a way that diversity benefits are appropriately shared among VERs, non-VERs, and load, and that does not inappropriately allocate costs to any one customer. Therefore, we find that the data used in PSCo's fair allocation method raise issues of material fact that cannot be resolved based upon the record before us. For example, AWEA challenges PSCo's allocation of 0 MW for Following reserves to non-VER generators by claiming that detailed non-VER generator output data has not been provided in this case. We believe that the hearing and settlement judge procedures ordered below are the appropriate forums to explore the issues related to inputs into PSCo's fair allocation method.

78. Principle Four provides that weather events be considered, such as droughts that may affect the required quantity of generator regulating reserves that the public utility transmission provider must have in reserve more or less during one portion of the year versus another portion of the year. In such cases, these diversity events, though perhaps

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[121] *See* Ex. PSCo-1 at 34-36.

[122] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 320.

[123] *See* Ex. PSCo-1 at 36-37.

characterized as anomalies, should be included in the data set so that the quantity and costs of such reserves are more reflective of actual system operations.[124] PSCo used consecutive, 12-month Generation Availability Data System data and data from its Energy Management System, and did not exclude any weather events from the data set.[125] Therefore, we find that PSCo effectively applied the guidance provided under Principle Four in developing proposed rates for Schedules 3 and 3A.

79. Principle Five provides that, in designing any proposals for generator regulation service charges, a public utility transmission provider should consider the extent to which transmission customers are using intra-hour scheduling in evaluating whether to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves.[126] Although most of its load does not use intra-hour scheduling and intra-hour scheduling changes were not in place during the test period, PSCo incorporates a 15-minute centered moving average as the basis to measure Following and Fast-moving reserves in the rate design of the Regulation and Frequency Response Service proposal.[127] By employing the 15-minute centered-moving average, PSCo's proposal reflects the ability of transmission customers to submit schedules for each 15-minute interval and only considers the extent to which customers' deviations over 15-minute intervals creates the need for reserves. We find that PSCo has demonstrated that incorporating this metric within its rate design also lowers the reserve requirement and resulting rates for customers who continue to submit hourly schedules.[128] Given the unique circumstances surrounding PSCo's filing, use of a 15-minute centered moving average to reflect intra-hour scheduling is sufficient to account for the scheduling reforms adopted in Order No. 764. Therefore, we find that PSCo effectively applied the guidance provided under Principle Five in developing rates for Schedules 3 and 3A.

80. Principle Six considers the relationship between the use of power production forecasting and the allocation of generator regulation reserve quantities to a particular class of customers. In Order No. 764, the Commission found that power production forecasts can provide public utility transmission providers with advanced knowledge of

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[124] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 321.

[125] Ex. PSCo-7 at 13; Ex. PSCo-14 at 6-7.

[126] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 322.

[127] Ex. PSCo-7 at 15-16.

[128] Deficiency Response at 12-15.

system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than though the deployment of reserve services, such as regulation reserves.[129] The Commission stated that it expected the implementation of power production forecasting to be addressed in any proposal to require different transmission customers to purchase different quantities of generator regulation reserves.[130] The Commission explained that such a showing could involve demonstrating that the transmission provider used power production forecasts to manage system operating costs and/or to improve reliability by enabling the more efficient commitment and dispatch of resources.[131]

81. PSCo states that, since 2009, PSCo has utilized a "state-of-the-art" wind forecasting system in collaboration with the National Center for Atmospheric Research, which has provided highly accurate forecasts of wind production on the PSCo system.[132] Although PSCo's proposed rate design measures the variability of VERs, non-VERs, and load based on actual output data, and thus is intended to eliminate any forecasting error in its rate design, PSCo still considers Power Production Forecasting in its Schedules 3 and 3A. PSCo states that it used wind generation forecasts during the test year to optimize unit commitment on a day-ahead and real-time basis. PSCo's proposed rate design also relies on real-time dispatchers to consider up-to-date wind and load forecasts, and to make non-VER generation dispatch decisions to meet system reliability requirements.[133] Therefore, we find that PSCo effectively applies the guidance provided under Principle Six in developing rates for Schedules 3 and 3A.

82. With respect to Schedules 3 and 3A, the Commission has accepted utilities' proposals for separate regulation charges for generators exporting from the balancing authority area.[134] In addition, the Commission has accepted schedules for differentiated

[129] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 323.

[130] *Id*. P 325.

[131] *Id*.

[132] *See* Ex. PSCo-7 at 31.

[133] Deficiency Response at 5-6.

[134] *See Florida Power Corp.*, 89 FERC ¶ 61,263 (1999); *Entergy Services Inc.*, 120 FERC ¶ 61,042, at P 66 (2007).

rates as just and reasonable that are similar to PSCo's proposed Schedules 3 and 3A.[135] In *Westar*, the Commission accepted Westar's proposed Balancing Agreement and Schedule 3A, which allowed Westar to charge for generation regulation resulting from transactions involving exports of power out of the Westar balancing authority area, and where Westar proposed to charge different regulation charges for dispatchable and intermittent generation. In *Puget Sound*, the Commission accepted Puget Sound Energy Inc.'s (Puget Sound) proposed Schedule 13, which required transmission customers delivering energy outside of Puget Sound's balancing authority area from intermittent/non-dispatchable generators to purchase a different volume of generator regulation reserves than dispatchable generator resources.[136] We therefore disagree with Powerex's argument that PSCo's reliance on *Westar* and *Puget Sound* to support its proposal is misplaced. Although there are differences between the three proposals, those differences do not require us to reject PSCo's proposal. The Commission considers proposals to assess generator regulation charges on a case-by-case basis, and evaluates each case on its own merits to determine whether the proposal is just and reasonable.[137]

83. We find that the specific rates, terms, and conditions proposed in PSCo's proposed Schedules 3 and 3A that have not been expressly discussed in this section, have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Protesters raise issues of material fact that cannot be resolved based on the record before us and that are more appropriately addressed in hearing and settlement judge procedures ordered below. These issues include, but are not limited to, the assumptions and inputs into the "units most likely" methodology, the application of an iterative pro rata allocation to identify which units provide the relevant reserves, the impact of non-VER generators on Following reserves, and the impact of Schedule 3A's costs on current customers.

2. Schedule 6A

84. Proposed Schedule 6A service is an issue of first impression before the Commission. While discussing generator imbalance service in Order No. 764, the Commission stated that it would allow flexibility in developing capacity or reserve services that fit a transmission provider's system needs and continue a case-by-case

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[135] *See Puget Sound*, 137 FERC ¶ 61,063 at P 65; *Westar*, 130 FERC ¶ 61,215 at P 35; *see also* Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 277.

[136] *Puget Sound*, 137 FERC ¶ 61,063 at PP 62, 65.

[137] *Id.* P 63.

approach in evaluating such services.[138] The Commission also declined to establish an additional service related to extreme ramp events.[139]

85. While the six principles articulated in Order No. 764 addressed rate design for Regulation and Frequency Response Reserves, we find that these principles can be a useful evaluative tool in considering the justness and reasonableness of PSCo's proposed Schedule 6A. Here, the six principles serve as guidance to factors that the Commission may consider. We find a correlation between four of the six guiding principles and PSCo's proposed Schedule 6A service.

86. With regard to cost causation and treating wind generation as a separate class (Principles One and Two), PSCo demonstrates that wind generation creates a distinct need for holding additional reserves due to the increase of wind generation down ramp events that have shown a corresponding increase as the level of wind generation increases on PSCo's system.[140] Within the test year data, PSCo identified 119 wind generation down ramp events of more than 300 MW in 30 minutes on its system with an average installed wind generation capacity of 2,168 MW. We are persuaded by PSCo's arguments that these down ramps are distinctly attributable to wind generation resources, which PSCo has distinguished as an operationally unique resource on its system.

87. In response to protesters' assertions that PSCo did not incorporate diversity benefits (Principle Three) into its rate design for Flex Reserve Service, PSCo claims that Commission precedent in *Westar* and *Puget Sound* is relevant only to Regulation and Frequency Response reserves,[141] whereas the calculation of necessary volumes of Flex Reserves accounts for geographic diversity among wind resources because diversity exists between three primary Energy Resource Zones[142] in the PSCo balancing authority area at higher levels of wind generation. PSCo also claims that, because each Energy Resource Zone is concentrated in close proximity to the others along the

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[138] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at PP 268-269.

[139] *Id*. P 342.

[140] Ex. PSCo-7 at 26-27 tbl DB-1.

[141] PSCo July 7 Answer at 19-20.

[142] PSCo is required by Colorado law to designate Energy Resource Zones. An Energy Resource Zone is a geographic area in which transmission constraints hinder the delivery of electricity to Colorado consumers, the development of new electric generation facilities to serve Colorado consumers, or both.

Colorado/Wyoming border, there is minimal geographic diversity, especially at lower volumes of generation.[143] In evaluating PSCo's Schedule 6A proposal, it is unclear whether PSCo's inclusion of geographic diversity within its rate design is sufficient to reconcile the issue of diversity benefits. Due to distinctions in the methodologies used by PSCo, it is also unclear whether PSCo can account for the variability of wind with other resources, such as load, dispatchable generation, and other VERs, in its Schedule 6A rates in the same way it does under Schedules 3 and 3A. Therefore, we recommend that the issue of whether PSCo's inclusion of geographic diversity among wind resources alone sufficiently incorporates diversity benefits, consistent with relevant principles articulated in Order No. 764 and Commission precedent in *Westar* and *Puget Sound*, be considered and developed at the hearing and settlement judge procedures ordered below. As the record is more fully developed, we recommend that the possible relevance of diversity benefits among all resources in the final calculation of PSCo's Flex Reserve requirement in Schedule 6A be considered and developed at hearing and settlement judge procedures.

88. With regard to the inclusion of diversity events (Principle Four), we find that PSCo did not exclude any weather-related events from its data set. Therefore, the quantity and costs of Flex Reserves are reflective of PSCo's actual system operation during the test year.[144]

89. With respect to intra-hour scheduling (Principle Five), PSCo's methodology for calculating Flex Reserves incorporates historical data, and therefore, does not take into account deviations between a customer's schedules and its performance. The reliance on actual output variability rather than deviations to transmission schedules is consistent with PSCo's current circumstances, specifically that 98.9 percent of Flex Reserves are held for native load such that actual output variability is more relevant than deviations from transmission schedules. Further, PSCo presents evidence that state-of-the-art forecasting is currently not able to predict when a large wind ramp event will occur.[145] As a result, it seems likely that export transmission schedules will not be able to accurately reflect the type of wind ramp events that Flex Reserves will address. Therefore, due to the proportion of Flex Reserves allocated to native load and the current limitations of PSCo's forecasting technologies, we find that the intra-hour scheduling requirement is not applicable in this case because PSCo's rate design conforms to the unique circumstances surrounding the actual operating conditions on its system.

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[143] Ex. PSCo-7 at 29; Ex. PSCo-10 at 2.

[144] Ex. PSCo-1 at 43.

[145] Deficiency Response at 6-7.

90. Although PSCo notes the difficulty associated with using power production forecasting (Principle Six) to determine the precise timing of extreme wind ramping events, PSCo demonstrates that it has evaluated the efficacy of using persistence forecasting as an alternative to its meteorological forecasting, and that, on average, PSCo has found that persistence forecasts are more accurate in real-time dispatch to plan for wind ramping behavior.[146] As previously stated, PSCo's methodology for determining the amount of Flex Reserve capacity needed is based on actual output variability of wind generation during the test year, not on the accuracy of its forecasting techniques. However, this factor does not preclude the Commission from finding PSCo's proposal just and reasonable. The Commission stated in Order No. 764 that, although it expected the implementation of power production forecasting to be addressed, it would reserve judgment as to the appropriate power production forecasting requirements for a particular public utility transmission provider.[147]

91. PSCo states that its wind forecasts were used during the test year to optimize unit commitments on a day-ahead and real-time basis, and that real-time dispatchers considered the up-to-date wind forecasts in making dispatch decisions to meet system reliability requirements.[148] Commenters do not protest use of forecasting as it applies to PSCo's unit commitment and dispatch processes, but rather object to PSCo not using its forecasting to reduce the Schedule 6A charge, while offering no specific alternatives for how it could use its current forecasting technology to reduce its Flex Reserves requirement. Moreover, PSCo has demonstrated that, given the constraints of its current forecasting capabilities and its history of responding to Flex Reserve events, it has refined its methodology to reflect its actual system reliability conditions while still utilizing power production forecasting in the unit commitment and dispatch process, which reflects economic considerations as well. Therefore, we find that PSCo appropriately considered power production forecasting under Schedule 6A given PSCo's demonstration that power production forecasting and alternative, yet comparable, forecasting methods were considered and implemented during the test year. Specifically, PSCo demonstrated that the forecasting methods used provide advanced knowledge of system conditions to manage system operating costs and improve reliability by enabling the more efficient commitment and dispatch of resources.

92. We find that PSCo has demonstrated that it faces unique circumstances due to increasing wind integration on its system. For example, PSCo demonstrates that as the

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[146] *Id*.

[147] Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 327.

[148] Deficiency Response at 5-7.

level of wind generation increases on its system, there is a corresponding increase in the frequency and size of ramping events related to large losses of on-line wind generation due to decreases in wind output.[149] We are persuaded by PSCo's argument that, as more wind generation integrates on its system, which PSCo expects in the near future,[150] it will continue to need sufficient reserve capacity to address the large, sustaining losses of wind output. PSCo states that it has carried Flex Reserves to maintain reliability since 2008, and now seeks cost recovery to allocate the costs of maintaining those reserves in accordance with cost causation principles. We agree with PSCo that continuing to allow production customers to subsidize the costs of Flex Reserves would not be just and reasonable, and would be inconsistent with the Commission's cost causation principles.[151] PSCo further demonstrates that the 30-minute reserve guideline methodology it uses to produce the Flex Reserve requirement has been refined since 2008 to tailor the service to the unique circumstances PSCo faces in balancing its system. We find that the 30-minute reserve guideline appropriately incorporates factors that reflect PSCo's system conditions such as the historical, statistical relationship of wind production, the geographic dispersion of wind generation, and the potential size of the downward ramp on its system.[152] However, our finding here is not intended to preclude modification of PSCo's proposal to conform PSCo's methodology to be consistent with relevant Commission policy as the record is further developed at hearing or in settlement judge procedures.

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[149] Ex. PSCo-7 at 26-30; Ex. PSCo-9.

[150] Ex. PSCo-1 at 6-7.

[151] *See 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, FERC Stats. & Regs. ¶ 31,036, at 31,798 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *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 relevant 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 (2002); *Florida Power & Light Co*., 99 FERC ¶ 61,318 at P 77 (2002) (stating that "the party that causes costs to be incurred be responsible for such costs"); *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992) (stating that "all approved rates reflect to some degree the costs actually caused by the customer who must pay them").

[152] *See* Ex. PSCo-7 at 25-31; Ex. PSCo-10; Ex. PSCo-11; Ex. PSCo-12.

93. We are further persuaded by PSCo's arguments that there are no sufficient alternatives to providing Flex Reserve Service to address the large, sustained wind ramping events that occur on its system. First, we agree with PSCo that it must provide Flex Reserves as a service separate from Schedule 5 - Operating Reserves Spinning and Schedule 6 - Operating Reserves Supplemental. According to PSCo, the Rocky Mountain Reserve Sharing Group does not permit the use of contingency reserves to address declines in wind generation output due to loss of wind speed.[153] Despite AWEA's repeated assertions, PSCo is not proposing any modifications to its Schedule 6 service. Therefore, the issue of allocating Schedule 6 integration costs to conventional generators is not before us in this proceeding. Second, we find that precipitous declines in wind production, as defined and measured by PSCo in the instant filing, should be managed as events occurring independently from aggregate Regulation and Frequency Response variations on PSCo's system. PSCo demonstrates that, based on its calculation of the reserve margins for Schedules 3 and 3A, using Regulation and Frequency Response reserves to address these down-ramps would exhaust its supply of those reserves and compromise its ability to meet its balancing authority area obligations.[154] Therefore, we find that holding such reserves is just and reasonable under PSCo's current circumstances.

94. However, we require two modifications to the new Schedule 6A Flex Reserve Service. First, we find that PSCo's description of Flex Reserve Service, as proposed in the Schedule 6A tariff language,[155] is inconsistent with the Deficiency Response[156] submitted by PSCo regarding the calculation of a customer's Flex Reserve Service requirement and charge. Accordingly, notwithstanding any changes to the total Flex Reserve Service requirement or subsequent rates as a result of hearing and settlement procedures, the language in Schedule 6A under the subsection "Determination of Flex Reserve Requirement" should be modified to read as follows:

> A Transmission Customer or Ancillary Service Customer's Flex Reserve Service requirement shall be the total Flex Reserve Requirement of 411 MW for the PSCo Balancing Authority multiplied by the Customer's proportional share of wind generation in the PSCo Balancing

[153] Ex. PSCo-7 at 33.

[154] *Id*. at 33-34.

[155] *See* Ex. PSCo-2 at 32.

[156] *See* Deficiency Response at 15-16.

> Authority Area based on the nameplate capacity of installed wind generation in the PSCo Balancing Authority Area to which the customer has rights, as determined on a monthly basis by the Transmission Provider. As conditions change on the PSCo system, PSCo may make a single-issue Section 205 filing with the Commission to update the total Flex Reserve Requirement value.
>
> Flex Reserve Service Charge. The Transmission Customer or Ancillary Service Customer's charge for Flex Reserve Service shall be the Customer's Flex Reserve Service requirement, in kW, multiplied by $74.99/kW/Yr ~~times the nameplate capacity of installed wind generation in the PSCo Balancing Authority Area to which the customer has rights~~.

95. Second, we agree with Powerex that titling the new schedule as "Schedule 6A" may lead to confusion as to whether the Flex Reserve Service is a contingency-related product, or a sub-category of "Schedule 6 Operating Reserve - Supplemental Reserve Service." Therefore, we require PSCo to provide a schedule title with a different, currently unused, number of its choice to eliminate any confusion. We also direct PSCo to make conforming changes to its tariff sheets that reference what is currently titled "Schedule 6A" to reflect the revision to the title of the schedule.

96. We find that the specific rates, terms, and conditions proposed in PSCo's proposed Schedule 6A that have not been expressly discussed in this section, have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Protesters raise issues of material fact that cannot be resolved based on the record before us and that are more appropriately addressed in hearing and settlement judge procedures ordered below. These include, but are not limited to, the assumptions and inputs into the "units most likely" methodology, the application of an iterative pro rata allocation to identify which units provide the relevant reserves, assumptions, and inputs in PSCo's 30-minute reserve guideline methodology, the allocation of potential charges to Arkansas River Power, and the relevance of geographic diversity and diversity benefits.

97. Lastly, we grant PSCo's request for waiver of the applicable requirements of section 35.13 of the Commission's regulations, including the requirement to provide full Period 1 and Period 2 data, consistent with our prior approval of formula rates.[157]

[157] *Allegheny Power System Operating Cos.*, 111 FERC ¶ 61,308, at P 56 (2005), *order on reh'g*, 115 FERC ¶ 61,156 (2006); *Tampa Electric Co.*, 132 FERC ¶ 61,214, at P 51 (2010).

Nonetheless, to the extent that parties at the hearing procedures ordered below can show the relevance of additional information needed to evaluate PSCo's proposal, the presiding judge may provide for appropriate discovery of such information.

3. Hearing and Settlement Judge Procedures

98. With the exception of the issues discussed above, PSCo's proposed rates, terms, and conditions in Schedules 3, 3A, and 6A raise material issues of fact that cannot be resolved based on the record before us, and that are more appropriately addressed in the hearing and settlement judge procedures ordered below. With the exception of the issues discussed above, our preliminary analysis indicates that PSCo's proposed rates, terms, and conditions in Schedules 3, 3A, and 6A have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Therefore, we conditionally accept PSCo's proposed Schedules 3, 3A, and 6A for filing, suspend them for a nominal period, to become effective January 1, 2015, subject to refund, and set them for hearing and settlement judge procedures.

99. While we are setting these matters for a trial-type evidentiary hearing, we encourage the parties to make every effort to settle their dispute before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[158] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise, the Chief Judge will select a judge for this purpose.[159] The settlement judge shall report to the Chief Judge and the Commission within 30 days of the date of the appointment of the settlement judge, concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

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[158] 18 C.F.R. § 385.603 (2014).

[159] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five (5) days of this order. The Commission's website contains a list of Commission judges available for settlement proceedings and a summary of their background and experience (http://www.ferc.gov/legal/adr/avail-judge.asp).

The Commission orders:

(A) PSCo's proposed Schedules 3, 3A, and 6A are hereby conditionally accepted for filing and suspended for a nominal period, to become effective January 1, 2015, subject to refund, as discussed in the body of this order.

(B) PSCo is hereby directed to submit a compliance filing within thirty (30) days of the issuance of this order, to revise Schedule 6A, as discussed in the body of this order.

(C) PSCo's request for waiver of the requirements of section 35.13 to provide full Period I and Period II data is hereby granted, as discussed in the body of this order.

(D) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure, and the regulations under the Federal Power Act (18 C.F.R. Part I), a public hearing shall be held concerning PSCo's tariff revisions. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Ordering Paragraphs (E) and (F) below.

(E) Pursuant to Rule 603 of the Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2014), the Chief Administrative Law Judge is directed to appoint a settlement judge in this proceeding within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge within five (5) days of the date of this order.

(F) Within thirty (30) days of the appointment of the settlement judge, the settlement judge shall file a report with the Commission and with the Chief Judge on the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(G) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in these proceedings in a hearing room of the Commission, 888 First Street, NE, Washington, DC 20426. Such a conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.