

141 FERC ¶ 61,232
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris, and
Cheryl A. LaFleur.

Integration of Variable Energy Resources

Docket No. RM10-11-001

ORDER NO. 764-A

ORDER ON REHEARING AND CLARIFICATION AND GRANTING MOTION FOR
EXTENSION OF TIME

(Issued December 20, 2012)

1. On June 22, 2012, the Commission issued the *Integration of Variable Energy Resources* Final Rule, requiring each public utility transmission provider to: (1) offer intra-hourly transmission scheduling at 15-minute intervals; and, (2) incorporate provisions into the *pro forma* Large Generator Interconnection Agreement (LGIA) requiring interconnection customers whose generating facilities are variable energy resources (VER) to provide meteorological and forced outage data to the public utility transmission provider for the purpose of power production forecasting.¹ The Commission also provided guidance regarding the development and evaluation of proposals related to recovering the costs of regulation reserves associated with VER integration. Order No. 764 defined a VER as a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by

¹ *Integration of Variable Energy Resources*, Order No. 764, 77 FR 41482 (July 13, 2012) FERC Stats. & Regs. ¶ 31,331 (2012) (Order No. 764). Order No. 764 resulted from the *Integration of Variable Energy Resources*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,664 (2010) (Proposed Rule) and the *Integration of Variable Energy Resources*, Notice of Inquiry, FERC Stats. & Regs. ¶ 35,563 (2010) (Notice of Inquiry).

the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.²

2. Requests for rehearing and clarification were submitted regarding certain aspects of: (1) the intra-hour scheduling and forecasting reforms adopted in Order No. 764; (2) statements addressing public utility transmission provider's obligation to offer generator regulation service; and (3) the estimated burden on small entities to comply with the Final Rule. Additionally, Edison Electric Institute (EEI) filed a motion to extend the period for compliance filings from September 11, 2013, to November 12, 2013. In this order, the Commission affirms its basic determinations in Order No. 764, provides clarification, and grants EEI's request to extend the period for compliance filings.

I. Background

3. In Order No. 764, the Commission adopted reforms designed to remove barriers to the integration of VERs and to ensure that the rates, terms, and conditions for Commission-jurisdictional services provided by public utility transmission providers are just and reasonable and not unduly discriminatory or preferential.³ Noting the increasing number of VERs being brought online, the Commission concluded that reforms were needed to ensure that transmission customers are not exposed to excessive or unduly discriminatory charges, and that public utility transmission providers have the information needed to efficiently manage reserve-related costs.

4. Specifically, the Commission amended the *pro forma* Open Access Transmission Tariff (OATT) to provide all transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals.⁴ The Commission found transmission customers' inability to adjust their transmission schedules within the hour to reflect changes in generation output can cause charges for Schedule 9 generator imbalance service to be unjust and unreasonable or unduly discriminatory. The intra-hour scheduling amendment was designed to correct this deficiency. It was also designed to allow public utility transmission providers, over time, to use fewer reserves to maintain overall system balance.⁵

² Order No. 764, 1FERC Stats. & Regs. ¶ 31,331 at P 1.

³ *Id.* P 1.

⁴ *Id.* P 2.

⁵ *Id.* P 95.

5. The Commission also amended the *pro forma* LGIA to require new interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data to the public utility transmission provider with which the customer is interconnected.⁶ Such data would only be required where it is necessary for that public utility transmission provider to develop and deploy power production forecasting. This reform was designed to facilitate public utility transmission providers' use of power production forecasts, which the Commission found can provide public utility transmission providers with advanced knowledge of system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than through the deployment of more costly reserve service, such as regulation reserves.

6. Finally, the Commission declined to modify the *pro forma* OATT to include a new Schedule 10 governing generator regulation service.⁷ The Commission explained that the Schedule 10 proposal was intended to provide clarity to public utility transmission providers and transmission customers alike by setting forth a generic approach to the provision of generator regulation service. In light of the numerous comments stressing the importance of flexibility in the design of capacity services needed to efficiently integrate VERs into the transmission system, the Commission decided to maintain its existing case-by-case approach to evaluating proposals related to recovering the costs of regulation reserves associated with VER integration. However, the Commission provided guidance in response to the comments submitted to assist public utility transmission providers and their customers in the development and evaluation of such proposals.

II. Motion for Extension of Compliance Period

7. On October 19, 2012, EEI filed a motion to extend the compliance deadline from September 11, 2013, to November 12, 2013.⁸ EEI expresses concern that the existing compliance deadline of September 11, 2013, would require public utility transmission providers to implement the modifications associated with Order No. 764's intra-hour scheduling reform during the summer peak season. EEI states that such modifications to industry practices may result in unforeseen issues, which could be exacerbated during

⁶ *Id.* P 3.

⁷ *Id.* P 4.

⁸ EEI notes that American Public Power Association (APPA) and National Rural Electric Cooperative Association (NRECA) have authorized EEI to state that they do not oppose the motion.

strained situations, such as summer peak conditions. Therefore, EEI requests that the Commission extend the deadline for compliance by 62 days in order to provide public utility transmission providers with flexibility in addressing operational challenges that may arise during the transition to intra-hourly scheduling without jeopardizing reliability.

8. We grant EEI's request for an extension of time for compliance with Order No. 764. The Commission finds good cause to extend the compliance deadline in order to allow public utility transmission providers to implement reforms set forth in Order No. 764 outside of the summer peak season. The Commission therefore extends the compliance period, with compliance filings now due by November 12, 2013.

III. Requests for Clarification and Rehearing

9. The following parties sought clarification and/or rehearing of various portions of Order No. 764: APPA, Florida Municipal Power Agency, and Public Power Council (collectively, Public Power); American Wind Energy Association (AWEA); Bonneville Power Administration (Bonneville); Iberdrola Renewables, LLC (Iberdrola); NRECA; Powerex Corporation (Powerex); and Public Interest Organizations (PIOs).⁹

A. Intra-hour Scheduling Reform

10. In Order No. 764, the Commission amended the *pro forma* OATT to provide all transmission customers the option of using more frequent transmission scheduling intervals within each operating hour, at 15-minute intervals.¹⁰ This reform was designed to allow transmission customers the flexibility to adjust their transmission schedules, in advance of real-time, to reflect the variability of output in generation, more accurate power production forecasts, and other changes in load profiles and system conditions.¹¹ The Commission implemented this reform to ensure that charges for generator imbalance service under Schedule 9 of the *pro forma* OATT and for other ancillary services through

⁹ Public Interest Organizations are: Alliance for Clean Energy New York; Citizens Utility Board of Wisconsin; Climate and Energy Project; Conservation Law Foundation; Energy Conservation Council of Pennsylvania; Environment Northeast; Environmental Defense Fund; Great Plains Institute; Natural Resources Defense Council; Pace Energy and Climate Center; Sustainable FERC Project; Sierra Club; Union of Concerned Scientists; The Wilderness Society; Western Grid Group; Western Resource Advocates; and Wind on the Wires.

¹⁰ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 91.

¹¹ *Id.* P 92.

which reserve-related costs are recovered are just and reasonable and are not unduly discriminatory. The Commission received requests for rehearing and clarification of several discrete aspects of this requirement.

1. **Applicability of Intra-hour Scheduling**

a. **Order No. 764**

11. In the Final Rule, the Commission stated that it expects that many types of entities, not only VERs, may benefit from the availability of intra-hour scheduling. The Commission further explained:

Every transmission customer will have the ability to adjust its schedule at 15-minute intervals to reflect changing conditions. This includes, for example, transmission customers that experience a within-hour forced outage or transmission customers taking delivery from energy constrained resources (such as flow-limited hydro-electric generators, emission-limited thermal generators, and energy storage resources), even if using point-to-point transmission internal to the system.... [T]he Commission finds that intra-hour scheduling will provide a range of transmission customers with a necessary tool to mitigate exposure to Schedule 9 generator imbalance charges in light of changing conditions.¹²

b. **Requests for Rehearing/Clarification**

12. Several commenters request that the Commission clarify the applicability of the intra-hour scheduling reform adopted in Order No. 764. Public Power requests the Commission clarify that 15-minute scheduling is available: (1) to Network Integration Transmission Service (NITS) customers to the extent they are subject to scheduling requirements for their network resources; and (2) for scheduling secondary network service under Part III of the *pro forma* OATT. Public Power states that the intra-hour scheduling reform requires amendments to sections 13.8 and 14.6 of the *pro forma* OATT, which are provisions in Part II of the OATT that relate to point-to-point transmission service. Public Power observes that no changes are required under Part III of the tariff specifically addressing NITS, yet there are statements made in Order No. 764

¹² *Id.* P 94.

that indicate that the intra-hour scheduling reform would be available for all customers.¹³ Public Power contends that while the Commission did not specifically address the applicability of the intra-hour scheduling reform to NITS, it did indicate a strong intent to reach all transmission customers; only in doing so would Order No. 764 achieve its goals of ensuring just, reasonable and not unduly discriminatory service.

13. Moreover, Public Power argues that a customer using secondary network service and a customer using point-to-point transmission service are subject to the same generator imbalance charges.¹⁴ Therefore, Public Power contends that if NITS customers are unable to utilize intra-hour scheduling, they would be exposed to excessive imbalance charges. Public Power also argues that consistent scheduling practices across transmission systems are necessary to ensure that intra-hour scheduling is available for VERs that rely on both point-to-point and network service to deliver energy across multiple systems.

14. AWEA and Iberdrola seek clarification that the Commission intends for all point-to-point transmission customers, including those using point-to-point transmission service to schedule to loads, to have the option to use intra-hour scheduling.¹⁵ AWEA requests that the Commission clarify that load-serving entities that use point-to-point transmission service to deliver energy from adjacent transmission service providers to load are eligible to use intra-hour scheduling.

c. Commission Determination

15. The Commission clarifies that the intra-hour scheduling reform adopted in the Order No. 764 applies to *all* transmission customers that schedule transmission service under the OATT. This includes load serving entities, entities using point-to-point transmission service to schedule to loads, and transmission customers using network service. Order No. 764 should not be read to limit the scope of transmission customers eligible to use the intra-hour scheduling reform, but instead should be read as allowing any customer that schedules transmission service to adjust those schedules on a 15-minute basis. The Commission believes this clarification to be consistent with the scope of Order No. 764 and does not require any further changes to the *pro forma* OATT to

¹³ Public Power at 3 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at PP 2, 94,151).

¹⁴ *Id.* at 4-5.

¹⁵ Iberdrola at 3-4; AWEA at 3-4.

allow all transmission customers taking service under the *pro forma* OATT to adjust transmission schedules on a 15-minute basis.

2. Calculation of Imbalance Charges

a. Order No. 764

16. In Order No. 764, the Commission explained that the intra-hour scheduling requirement applies only to scheduling practices, and that transmission providers may continue to calculate imbalance charges on an hourly basis.¹⁶ The Commission explained, however, that the metric against which generator imbalances are measured will be more granular than under current hourly scheduling protocols.

17. The Commission rejected requests to reform the imbalance settlement time period, recognizing the costs associated with such changes. However, the Commission explained that if a public utility transmission provider believes that aligning the imbalance settlement interval with the intra-hour scheduling interval or implementing sub-hourly dispatch will lead to more efficient operations, provide appropriate price signals to customers, or address other potential issues, it may seek the necessary authorizations to do so from the Commission under section 205 of the Federal Power Act (FPA).¹⁷

b. Requests for Rehearing/Clarification

18. Iberdrola and AWEA argue that in the absence of sub-hourly settlement and dispatch requirements, the Commission should clarify how intra-hour scheduling information will factor into the calculation of Schedule 9 charges. Iberdrola states that while the Commission asserted that “the metric against which generator imbalances are measured will be more granular than under current hourly scheduling protocols,” it did not provide specifics regarding the manner in which generation imbalance should be measured and/or calculated as a result of the new requirement.¹⁸ Accordingly, Iberdrola and AWEA request that the Commission clarify that public utility transmission providers are required to average a transmission customer’s intra-hour schedules to determine the hourly imbalance charged, or credited, over a given hour.¹⁹ Iberdrola and AWEA

¹⁶ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 104.

¹⁷ *Id.* P 105.

¹⁸ Iberdrola at 2-3 (quoting Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 105).

¹⁹ Iberdrola at 2-3; AWEA at 2-3.

contend that this clarification will ensure that the intra-hour schedules are properly factored into the hourly scheduled amount, thereby minimizing the overall hourly schedule deviation and any associated imbalance penalty charge.

c. Commission Determination

19. The Commission agrees with Iberdrola and AWEA that, in the absence of sub-hourly settlement and dispatch, a public utility transmission provider must account for intra-hour imbalances in order to ensure that they are properly factored into the calculation of hourly imbalance charges. As Iberdrola notes, the Commission in Order No. 764 intended that the use of 15-minute scheduling will cause the metric against which generator imbalances are measured to be more granular when compared to the use of hourly scheduling. To the extent a transmission customer using 15-minute scheduling is taking service from a public utility transmission provider with hourly imbalance charges, the public utility transmission provider would calculate the hourly imbalance volume by averaging the imbalances during each 15-minute scheduling interval over the hour, which is equivalent to what Iberdrola and AWEA described in their requests for clarification.²⁰

3. Curtailment Priority

a. Order No. 764

20. In Order No. 764, the Commission did not propose any changes to curtailment priorities or the available transmission capacity (ATC) calculation to accommodate intra-hour transmission schedules.²¹ The Commission recognized that when a public utility

²⁰ The calculation of average hourly imbalances is the same whether one uses (a) the average of the four separate 15-minute imbalances within the hour, or (b) the difference between the average of the scheduled amounts over the four 15-minute intervals and the average of the actual generation during the same period. Consider the following example: there are four 15-minute schedules of 10MW, 11MW, 9MW, and 10MW, with four 15-minute actual usages of 10MW, 12MW, 10MW, and 9MW. The difference between these schedules and actual usages results in four 15-minute imbalances of 0MW, -1MW, -1MW, and +1MW. The average of the four 15-minute imbalances is $(0-1-1+1)/4 = -0.25\text{MW}$. This is identical to taking the difference of the average hourly scheduled amounts $((10+11+9+10)/4 = 10\text{MW})$ and the average hourly actual usage $((10+12+10+9)/4 = 10.25\text{MW})$. This difference is $(10\text{MW} - 10.25\text{MW}) = -0.25\text{MW}$.

²¹ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 136.

transmission provider makes unscheduled transmission service available after firm schedules have been received, the application of curtailment rules and the ATC calculation may become more complicated. However, the Commission indicated that this is already the case under hourly scheduling, and it reiterated that transmission schedules for firm service will continue to have curtailment priority over schedules for non-firm service.²²

21. In response to comments on whether a review of standards or business practices is necessary to implement 15-minute scheduling, the Commission found no North American Electric Reliability Corporation (NERC) standards or NAESB business practices that would prevent industry from implementing intra-hour scheduling.²³ The Commission stated that to the extent industry believes it is beneficial to refine one or more standards or business practices to reflect intra-hour scheduling, industry can use existing processes to pursue such refinements.

b. Requests for Rehearing/Clarification

22. Powerex asks the Commission to clarify what it meant in saying that, “all transmission schedules for firm service will continue to have curtailment priority over all schedules for non-firm service.”²⁴ Powerex urges the Commission to clarify whether the submission of firm intra-hour schedules will displace non-firm hourly schedules on constrained paths. Powerex also requests that the Commission require the North American Energy Standards Board (NAESB) to adopt business practice standards that establish the priority of firm intra-hour schedules over non-firm hourly schedules.

c. Commission Determination

23. The Commission confirms that schedules for firm transmission service will continue to have curtailment priority over schedules for non-firm transmission service.²⁵

²² *Id.* P 136 & n.173 (noting that section 14.5 of the *pro forma* OATT clearly states that “[p]arties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff”).

²³ *Id.* P 146.

²⁴ Powerex at 10 (quoting Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 136).

²⁵ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 136.

Powerex provides no reason why a non-firm hourly schedule should have priority over a firm schedule submitted within the hour. We reiterate that a firm transmission schedule should be treated as firm and retain curtailment priority over a non-firm transmission schedule. Thus, firm transmission schedules have priority over non-firm transmission schedules for 15-minute intervals, just as they currently have for hourly intervals. To the extent Powerex believes that refinements to standards or business practices are needed to account for intra-hour schedule changes, it should work through the relevant standards body to develop standards or business practices related to transmission schedule curtailment priorities.

4. Customer Benefits of Intra-hour Scheduling

a. Order No. 764

24. In Order No. 764, the Commission indicated that over time, the implementation of intra-hour scheduling should allow public utility transmission providers to rely more on planned scheduling and dispatch procedures, and less on reserves, to maintain overall system balance. The Commission further explained that:

By moving from hourly to 15-minute scheduling intervals, the amount of imbalance energy for which the source balancing authority is potentially responsible can be reduced.... This can lead to a corresponding reduction in the amount of capacity held to provide that energy and, in turn, lower reserve-related costs for the source balancing authority, *and* ultimately consumers. Therefore, the Commission also finds that implementation of intra-hour schedules is necessary in order to ensure that charges for ancillary services through which reserve-related costs are recovered are just and reasonable and not unduly discriminatory.²⁶

b. Requests for Rehearing/Clarification

25. Iberdrola contends that the intra-hour scheduling reform focuses not only on the beneficial impacts intra-hour scheduling can have on a VER generators' exposure to generation imbalance charges, but also recognizes the benefits that all point-to-point transmission customers would receive from this capability. Specifically, Iberdrola points to the Commission's expectation that Order No. 764 would ensure that "other ancillary services through which reserve related costs are recovered are just and reasonable and not

²⁶ *Id.* P 96.

unduly discriminatory.”²⁷ Iberdrola seeks clarification that, to the extent 15-minute scheduling reduces the reserve requirements for other ancillary services (specifically Schedules 3 and 4), customers will benefit from reduced reserve-related costs and reduced exposure to regulation and imbalance charges.

c. Commission Determination

26. As indicated by the above-quoted passage from Order No. 764, use of intra-hour scheduling can reduce the amount of imbalance energy for which a balancing authority is potentially responsible and, in turn, lower reserve-related costs. Such benefits could manifest themselves in the form of reduced regulation charges under Schedule 3 of the *pro forma* OATT as well as any other ancillary service schedule through which a public utility transmission provider recovers the costs of capacity needed to provide generator imbalance service. Moreover, to the extent a transmission customer uses intra-hour scheduling to reduce the total imbalance charges it may incur under Schedule 4 of the *pro forma* OATT, that customer would directly benefit from the proposed reform.

B. Data and Forecasting Reform

27. In Order No. 764, the Commission required public utility transmission providers to modify their *pro forma* LGIAs to require new interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data to the public utility transmission provider where necessary for that public utility transmission provider to develop and deploy power production forecasting. In requiring this change to the *pro forma* LGIA, the Commission decided not to modify existing LGIAs, in part because doing so would be administratively burdensome.²⁸ The Commission received one request for rehearing of this requirement.

1. Order No. 764

28. In Order No. 764, the Commission required each public utility transmission provider to incorporate provisions into the *pro forma* LGIA requiring interconnection customers whose generating facilities are VERs to provide meteorological and forced outage data to the public utility transmission provider for the purpose of power production forecasting. Specifically, the Commission required public utility transmission providers to revise article 8.4 of the LGIA to provide that reporting requirements for

²⁷ Iberdrola at 4 (quoting Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 91).

²⁸ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 195.

meteorological and forced outage data would be set forth in Appendix C, Interconnection Details, of an LGIA.²⁹

29. In requiring this change to the *pro forma* LGIA, the Commission decided not to modify existing LGIAs, in part because doing so would be administratively burdensome. The Commission noted that nothing in the *pro forma* LGIA precludes the parties to an LGIA from mutually agreeing to revise the requirements set forth in Appendix C to reflect the reporting of meteorological and forced outage data.³⁰ To the extent that the parties are unable to agree to modifications of Appendix C, the Commission acknowledged that article 30.11 of the *pro forma* LGIA gives the transmission provider the right to make a unilateral filing to the Commission proposing to modify an existing LGIA under section 205 of the FPA.³¹

2. Request for Rehearing/Clarification

30. Bonneville requests that the Commission clarify that transmission providers have the unilateral right to amend Appendix C of the LGIA to include data reporting requirements. Bonneville cites a Commission order in which the Commission found that Bonneville's proposal to clarify that the transmission provider has the unilateral right to modify Appendix C as control area requirements change was unnecessary because Article 9.3 already gives the transmission provider the right to unilaterally amend Appendix C for operational requirements.³² Bonneville cites the following passage from the Safe Harbor Order:

While the Interconnection Customer does have the right to agree to modifications to the agreement, the LGIA should be read as granting the Transmission Provider the right to determine the applicable reliability criteria. Moreover, under LGIA article 9.3 (Transmission Provider Obligations), the *Transmission Provider has the responsibility for establishing*

²⁹ *Id.* P 193.

³⁰ *Id.* P 195 (noting that article 9.4 of the *pro forma* LGIA recognizes that Appendix C will be modified to reflect changes to the interconnection customer's requirements as they may change from time to time).

³¹ *Id.*

³² Bonneville at 10 (citing *Bonneville Power Admin.*, 112 FERC ¶ 61,195 (2005) (Safe Harbor Order)).

the Interconnection Customer's operating instructions and operating protocols and procedures. Because these instructions, protocols, and procedures will include reliability requirements, *article 9.3 already gives the Transmission Provider responsibility for modifications to Appendix C.* The same provision gives the Interconnection Customer the right to propose changes for the Transmission Provider to consider, but not the right to make unilateral changes. In light of this provision, *we conclude that BPA's proposed change is unnecessary.* . . .³³

In light of the Safe Harbor Order, Bonneville urges the Commission to clarify Order No. 764 to state specifically that transmission providers have the unilateral right to amend Appendix C of the LGIA to include data reporting requirements.

31. Alternatively, Bonneville urges the Commission to clarify that the requirement of mutual agreement or a filing under section 205 of the FPA does not apply to non-jurisdictional transmission providers because section 205 does not apply to non-jurisdictional transmission providers such as Bonneville. Bonneville argues that the ability to unilaterally amend Appendix C is essential for non-jurisdictional transmission providers. Bonneville states that if the Safe Harbor Order had not granted Bonneville the right to unilaterally amend Appendix C for operational requirements, Bonneville might not have sought reciprocity safe harbor status with the Commission. Bonneville further states that without the ability to make unilateral changes to Appendix C of the LGIA for operational requirements, Bonneville may not be able to implement the rule's data reporting requirements and continuously obtain the data required from VERs.³⁴

32. To the extent that the Commission does not grant either of these clarifications, Bonneville seeks rehearing. Bonneville states that it relied on the Safe Harbor Order in seeking safe harbor status and entering into interconnection contracts with multiple generators. Bonneville argues that the Commission failed to explain its departure from the Safe Harbor Order, which Bonneville contends results in an arbitrary and capricious

³³ Safe Harbor Order, 112 FERC ¶ 61,195 at P 20 (emphasis added by Bonneville).

³⁴ Bonneville at 11-12 (noting that Bonneville has more than 4,900 MW of existing VER generation on its system).

order, especially where there are “serious reliance interests that must be taken into account.”³⁵

3. Commission Determination

33. We deny Bonneville’s requests for clarification or rehearing. The data provision requirements established in Order No. 764 require interconnection customers to provide public utility transmission providers with a specific set of data (i.e., meteorological and forced outage data) to be set forth in Appendix C of the LGIA. The Commission directed that these data provision requirements apply only to new interconnection agreements. Recognizing that there may be instances where transmission providers wish to incorporate these provisions into existing LGIAs, the Commission explained that such changes could be accomplished in one of two ways: (1) through mutual agreement with the interconnection customer, or (2) through a unilateral filing with the Commission under section 205 of the FPA, as contemplated by article 30.11 of the LGIA.³⁶

34. In its request for rehearing, Bonneville urges the Commission to clarify, notwithstanding the Commission’s determination in Order No. 764, that transmission

³⁵ *Id.* at 12 (citing *FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009)).

³⁶ Article 30.11 of the *pro forma* LGIA states:

Transmission Provider shall have the right to make a unilateral filing with FERC to modify this LGIA with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

providers have the unilateral right to amend Appendix C of the LGIA to include Order No. 764's data reporting requirements. Bonneville's argument is based on the Safe Harbor Order's holding, quoted at length above, that interpreted article 9.3 of the LGIA to give transmission providers the responsibility for modifying Appendix C of the LGIA to establish the interconnection customer's operating instructions, protocols, and procedures, which include reliability requirements.³⁷

35. In Order No. 764, the Commission recognized that power production forecasts could yield significant benefits if incorporated into scheduling and unit commitment processes.³⁸ The Commission noted, however, that such forecasts are only as good as the data upon which they rely. The Commission also concluded that the current lack of meteorological and forced outage data reporting requirements in the *pro forma* LGIA may limit the efforts of transmission providers to manage operating costs more efficiently.³⁹ Therefore, in Order No. 764 the Commission revised the *pro forma* LGIA for new interconnection customers to require inclusion of certain data in those LGIAs. The Commission concluded that such information will enable transmission providers to commit resources providing reserves more accurately, thereby ensuring that reserve-related charges remain just, reasonable, and not unduly discriminatory.⁴⁰

36. The Commission then specified how the data should be added to existing and new LGIAs, finding that it would be administratively burdensome on public utility transmission providers and interconnection customers, especially where the public utility transmission provider is not engaged in power production forecasting, to apply Order No. 764 retroactively to existing agreements.⁴¹ The Commission found in Order No. 764

³⁷ Safe Harbor Order, 112 FERC ¶ 61,195 at P 20.

³⁸ Order No. 764, FERC Stats, & Regs. ¶ 31,331 at P 172 (referencing National Renewable Energy Laboratory, *Western Wind and Solar Integration Study* ES-18 (2010), available at <http://www.nrel.gov/wind/systemsintegration/wwsis.html>). In addition, NERC has recommended that forecasting techniques be incorporated into day-to-day operational planning and real-time operations routines/practices including unit commitment and dispatch. North Am. Elec. Reliability Corp., *Accommodating High Levels of Variable Generation* 54 (2009), available at http://www.nerc.com/files/IVGTF_Report_041609.pdf).

³⁹ *Id.* at P 173.

⁴⁰ *Id.*

⁴¹ *Id.* P 195.

that the provision of the specified data for the performance of meaningful forecasting and the process by which it should be included in LGIAs will assure just and reasonable rates and avoid undue discrimination. Therefore, the Commission concludes that Order No. 764 limits the unilateral right that Bonneville asserts flows from the Safe Harbor Order's interpretation of article 9.3 with regard to the issues addressed in Order No. 764—i.e., with regard to meteorological and forced outage data provision requirements and the procedures for including them in LGIAs as addressed in Order No. 764. Allowing transmission providers unilateral rights to act in a manner inconsistent with the findings in Order No. 764 could result in the provision of services in an unduly discriminatory manner and at rates that are unjust and unreasonable.

37. The reason for requiring revisions to Appendix C of existing LGIAs that incorporate the specific set of data described in Order No. 764 to be made either through the mutual agreement of the parties or through a filing with the Commission is so that the Commission can ensure that any such changes are made in a just, reasonable, and not unduly discriminatory manner. In Order No. 764, the Commission established a flexible approach regarding the specific data that would be required from individual customers, in which public utility transmission providers and interconnection customers are expected to negotiate in the first instance.⁴² Moreover, the Commission recognized the potential that certain data reporting requirements could result in increased costs to the interconnection customer.⁴³

38. While new interconnection customers will be in a position to work out the details of the meteorological and forced outage data prior to developing their projects, existing interconnection customers are not in the same position. It would be unfair to allow public utility transmission providers to unilaterally impose unexpected costs associated with data reporting provisions on existing interconnection customers without being required to make at least some showing that specific data sought by the transmission provider (and the associated costs) are just and reasonable.

39. We also deny Bonneville's alternative request for clarification or rehearing, which urges the Commission to clarify that the requirement of mutual agreement or a section 205 filing for inclusion of the data reporting requirements addressed above in existing LGIAs does not apply to non-jurisdictional transmission providers. Order No. 764 does not apply to non-jurisdictional entities such as Bonneville unless such entities seek to qualify for, or maintain safe harbor status.⁴⁴ To the extent Bonneville

⁴² *Id.* PP 175-76.

⁴³ *Id.* n.207.

⁴⁴ *Id.* P 377.

seeks to qualify for, or maintain safe harbor status, and wants to include the data reporting requirements addressed above in its existing LGIAs and Bonneville's customers disagree with the inclusion, Bonneville may seek to incorporate these data reporting requirements into existing LGIAs through a petition for declaratory order. In such case, Bonneville would need to demonstrate that its proposal substantially conforms or is superior to the Commission's *pro forma* LGIA. In such a filing, the Commission would be in a position to consider facts and circumstances unique to Bonneville (such as the high penetration of VER interconnection customers) in the context of Bonneville's tariff as a whole.

C. Generator Regulation Service

40. In Order No. 764, the Commission declined to adopt the proposed Schedule 10 component of the Proposed Rule.⁴⁵ Instead, the Commission indicated that it would continue its current policy of evaluating proposals to recover capacity costs incurred to provide Schedule 9 generator imbalance service on a case-by-case basis. However, in light of the disparate views on the generator regulation service in comments on the Proposed Rule, the Commission provided guidance on the proper design of a generator regulation service charge.⁴⁶ The Commission received requests for rehearing or clarification regarding several aspects of the guidance provided in Order No. 764.

1. Case-by-Case Approach to Generator Regulation Service Proposals

a. Order No. 764

41. In response to the Proposed Rule, the Commission received numerous comments urging flexibility in the design of capacity services needed to integrate VERs into transmission systems. In response to these comments, Order No. 764 maintained the Commission's existing approach of evaluating individual proposals to recover the capacity costs incurred to provide generator imbalance service on a case-by-case basis.⁴⁷ The Commission explained that this result allowed public utility transmission providers to retain the flexibility needed to propose capacity services that best respond to the needs of their customers; it also avoided requiring them to expend resources to adopt the one-

⁴⁵ *Id.* P 268.

⁴⁶ *Id.* PP 315-335.

⁴⁷ *Id.* PP 268-269. The Commission specifically withheld comment on whether additional reforms to contingency reserves were necessary. *Id.* P 342.

size-fits-all generator regulation service discussed in the Proposed Rule. The Commission set forth guiding principles that public utility transmission providers should take note of in calculating the relative impact of individual customers or customer classes on a public utility transmission provider's overall generation regulating reserve needs and allocating those costs accordingly.⁴⁸

b. Requests for Rehearing/Clarification

42. PIOs argue that the end result of Order No. 764 is to permit the imposition of unjust and unreasonable rates by allowing public utility transmission providers to charge VERs directly for integration costs while allowing other generation integration costs to be spread system-wide, resulting in unlawful discrimination. PIOs argue that by permitting public utility transmission providers "to impose Schedule 10-type of service charges," Order No. 764 reflects unsound regulatory policy.⁴⁹ PIOs argue that the guidance set forth in Order No. 764 on how such generator regulation charges should be developed is unworkable, and that the service itself is too expensive, complex, and may not be necessary in light of the other reforms adopted in Order No. 764. PIOs contend that, at a minimum, the Commission should prohibit public utility transmission providers from implementing such a service for at least two years after the effective date of Order No. 764 in order to provide sufficient time for the other reforms to be implemented and their effects studied.

43. PIOs suggest that Order No. 764 allows public utility transmission providers to charge VERs for their contribution to system variability while allocating the costs of the variability of conventional generators across all system customers, which PIOs believe to unduly discriminatory and in contravention of section 205 of the FPA. PIOs contend that both VERs and conventional generators share attributes of uncertainty and variability, asserting that thermal generators routinely fail to start, trip offline, and vary from their schedules. PIOs further contend that "dispatchability" is not a consistent distinction between the two categories of generators, as some VERs can be dispatchable.⁵⁰ PIOs disagree with the Commission's conclusion in Order No. 764 that VERs are not similarly situated to conventional, dispatchable generation for purposes of evaluating the need to implement the reforms adopted therein.⁵¹ PIOs assert that the only support given by the

⁴⁸ *Id.* P 317.

⁴⁹ PIOs at 8.

⁵⁰ *Id.* at 5-6 (citing instances where public utility transmission providers require generators, including VERs, to be dispatchable).

⁵¹ *Id.* at 5-6 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 47).

Commission when recognizing that VERs are not similarly situated to conventional generators was the Commission's definition of VERs set forth in Order No. 764.⁵² PIOs argue that the Commission cannot support its conclusion using only this definition of VERs. PIOs argue that the Commission erred to the extent that it intended the general assertion that VERs are not similarly situated to conventional generation to be determinative as to the specific issue of both uncertainty and variability. PIOs argue that the Commission provided no factual or economic support for this assertion, nor does the Commission tie the statement to the discussion of Schedule 10-type regulation service. PIOs contend that all generators impose integration costs on a transmission system, and that the Commission should allocate all such costs to all customers in a service territory, rather than allowing public utility transmission providers to allocate different generator regulation charges to different sets of customers.⁵³ PIOs argue that the Commission should amend Order No. 764 to prohibit public utility transmission providers from charging different volumetric reserve requirements to different customers.

44. PIOs state that if the Commission does not grant rehearing on these points, it should, at a minimum, condition any Schedule 10-type service on the public utility transmission provider utilizing a design that reflects the following two options.⁵⁴ First, PIOs argue that the Commission could require public utility transmission providers to implement a slower reserve service (akin to load-following or spinning reserves). Second, PIOs argue that the Commission could require that the regulation service be designed to compensate only for the moment-to-moment balancing associated with generation variability, and not for VER variability that affects the system beyond the balancing timeframe. Expanding on this point, PIOs argue that the Commission's use of the term "regulation" is imprecise and could include both seconds-to-minutes, and minutes-to-hours. PIOs argue that Schedule 10 rates for all schedule variations within an hourly period is likely to be unjust and unreasonable, and therefore PIOs urge the Commission to oppose it here.

45. PIOs also argue that Order No. 764 failed to expressly address how the six principles applicable to any Schedule 10-type filing will ensure that the proposal is not unduly discriminatory toward VERs.⁵⁵ PIOs believe that the Commission should establish a technical conference to address the operational issues associated with the

⁵² *Id.* at 6 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at n.1).

⁵³ *Id.* at 10-12 (citing AWEA, Comments on Proposed Rule at 28-32).

⁵⁴ *Id.* at 13-14.

⁵⁵ *Id.* at 13.

implementation of a Schedule 10-type service as well as the six principles discussed in Order No. 764. PIOs allege that the Commission ignored requests for a technical conference in Order No. 764.

c. Commission Determination

46. The Commission finds that PIOs' concerns have been thoroughly considered and addressed in this proceeding and that PIOs' request for a finding that VERs are no different from other generators is misplaced at this time. As a general matter, all transmission customers are required to account for ancillary services in a similar manner. To the extent that a public utility transmission provider proposes to allocate to VERs their share of system variability, it must also allocate to all other generation resources as transmission customers their corresponding share of system variability.⁵⁶

47. Where appropriate, the Commission has recognized how the unique characteristics of VERs can inform regulatory policies.⁵⁷ Within the context of this proceeding, we continue to believe that the fact-intensive nature of public utility transmission provider proposals to implement a generator regulation charge with a differentiated rate justifies a case-by-case review of such proposals. At that time, the Commission would be in a position to determine the ways in which a public utility seeks to apply different generator regulating reserves to different customers (or customer classes), and whether such rates accurately reflect the customers' proportionate share of the public utility transmission provider's overall regulation needs.⁵⁸ Moreover, such individual cases are the appropriate place to evaluate the extent to which different customers may impose such a degree of variability or uncertainty on a transmission system that they merit different generator regulating rates.

⁵⁶ Order No. 764, 139 FERC ¶ 61,246 at P 320.

⁵⁷ See, e.g., *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at PP 663-666, *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). (recognizing the limited ability of intermittent generators to precisely forecast or control generation levels); *Interconnection for Wind Energy*, Order No. 661, FERC Stats. & Regs. ¶ 31,186, *order on reh'g*, Order No. 661-A, FERC Stats. & Regs. ¶ 31,198 (2005) (adopting a package of interconnection standards applicable to large wind generators).

⁵⁸ Order No. 764, FERC Stats & Regs. ¶ 31,331 at P 320.

48. Order No. 764 implemented a *minimum* set of requirements applicable to *all* public utility transmission providers that would build on existing regional efforts to address VER integration.⁵⁹ Within individual cases, a public utility transmission provider seeking to allocate the cost of generator regulation service to customers based on their responsibility for those costs must show that the rates for any such service are just and reasonable. In making this showing, the public utility transmission provider may propose additional operational reforms or other complementary services, such as following or spinning reserve services, as warranted for its particular circumstances. At the same time, transmission customers may advocate that additional reforms should be implemented. Based on the record in an individual proceeding, the Commission will determine whether such additional operational reforms or complementary services are necessary to ensure that the public utility transmission provider's rates remain just and reasonable and not unduly discriminatory. The public utility transmission provider will be expected to reduce the costs of generator regulation service to the extent practicable⁶⁰ and allocate such costs based on transmission customers' proportionate share of responsibility.⁶¹

49. While we acknowledge that the Commission did not explicitly repeat in Order No. 764 each of PIOs' arguments in response to the Proposed Rule, we did consider and respond to the substance of their arguments by: (1) not adopting the proposed reform to which PIOs objected; (2) allowing for flexibility in how any capacity service would be designed and thereby not prescribing that all public utility transmission providers must provide the regulation-type service to which PIOs object; and (3) setting forth guidelines that will ensure that future proposals to implement generator regulation charges with differentiated rates are just, reasonable, and not unduly discriminatory.

50. For these reasons, we will not make the determinations sought by PIOs on rehearing because the record in this proceeding leads us to believe that generator regulation services are best addressed on a case-by-case basis, where the specific facts and circumstances of a public utility transmission provider's system and its proposed generator regulation service can be explored.⁶² Nor will we adopt the additional

⁵⁹ *Id.* P 24 (*emphasis added*).

⁶⁰ *Id.* PP 321-23.

⁶¹ *Id.* P 320.

⁶² *See Westar Energy Inc.*, 130 FERC ¶ 61,215, at P 36 (2010), *order on reh'g*, 137 FERC ¶ 61,142 (2011) (*Westar*) (accepting a proposal by a public utility transmission provider to assess intermittent generators higher regulation costs in a manner consistent with cost causation principles); *PacifiCorp*, 136 FERC ¶ 61,092

(continued...)

conditions and two-year waiting period advanced by PIOs. The Commission was mindful of these suggestions when developing Order No. 764. Indeed, the Commission found in Order No. 764 that the requirement for public utility transmission providers to offer shorter, 15-minute scheduling would tend to reduce the amount of capacity that source balancing authorities would need to maintain.⁶³ However, upon evaluating the competing interests of different industry participants, including those raised by PIOs here,⁶⁴ the Commission concluded that its existing case-by-case approach provided the necessary flexibility for capacity services to be tailored to the particular needs of a transmission system.

51. Likewise, rather than establishing time periods before allowing public utility transmission providers to implement a generator regulation service, the Commission sought to achieve a balanced approach that emphasizes public utility transmission providers' obligation to take the intra-hour scheduling and forecasting reforms into account in supporting any such proposal.⁶⁵ The Commission stated that "[i]n reviewing any future proposal to allocate a greater quantity of capacity costs to a particular set of transmission customers, it would be reasonable for the Commission to consider whether the public utility transmission provider has taken steps to mitigate such costs."⁶⁶ Thus, while the Commission will consider the extent to which additional reforms might mitigate a public utility transmission provider's reserve costs, there is no need for a two-year wait-and-see period. Public utility transmission providers are entitled to an effective opportunity to recover the costs of providing service,⁶⁷ and we will not foreclose their option to seek such cost-recovery for reasonably incurred reserve costs. However, in light of the potential for the reforms in Order No. 764 to result in additional cost savings over time,⁶⁸ the Commission will be open to considering whether a public utility

(2011) (setting a proposed generator regulation service rate schedule, among other things, for hearing and settlement procedures); *Puget Sound Energy, Inc.*, 137 FERC ¶ 61,063 (2011) (setting a proposed generator regulation service rate schedule that charges different rates for different customers for hearing and settlement procedures).

⁶³ Order No. 764, 139 FERC ¶ 61,246 at PP 95-96.

⁶⁴ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at PP 248-50.

⁶⁵ *Id.* PP 322-325.

⁶⁶ *Id.* P 334.

⁶⁷ *Id.* P 324.

⁶⁸ *See, e.g., id.* PP 95-96.

transmission provider should be required to update its rates to reflect the impact of these reforms over time to ensure that rates remain just and reasonable and not unduly discriminatory.

2. **Load and Conventional Generation Anomalies and Cost Allocation**

a. **Order No. 764**

52. In Order No. 764, the Commission recognized that calculating the relative impact of individual customers or customer classes on a public utility transmission provider's overall generator regulation reserve needs and allocating those costs accordingly could be difficult and complex.⁶⁹ Accordingly, Order No. 764 set forth specific guidance as to how the Commission expects proposals to implement a generator regulation service to be developed and supported. Among other things, the Commission explained:

[T]o 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 must demonstrate that the overall quantity of regulating reserve it requires of 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).⁷⁰

53. The Commission further explained that “diversity events, though perhaps 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.”⁷¹ The Commission described weather events, such as droughts that may affect the required quantity of generator regulation reserves more or less during different parts of the year as an example of such “diversity events.”

⁶⁹ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 317.

⁷⁰ *Id.* P 320.

⁷¹ *Id.* P 321.

b. Request for Rehearing/Clarification

54. AWEA seeks clarification of the guidance in Order No. 764 that proposals to implement generator regulation service should account for “diversity events” and data anomalies in the calculation of the quantity and allocation of generator regulation reserves.⁷² AWEA asks the Commission to affirm that this includes the anomalous behavior of conventional generators and loads. AWEA states that a transmission service provider might argue that it should exempt a conventional generator’s deviations from scheduled output during periods in which the conventional generator is ramping from one output level to another, or that a load schedule deviation caused by the behavior of a non-conforming industrial load is anomalous and should be excluded from the dataset. According to AWEA, such deviations can account for a sizeable share of the regulation burden of the power system. AWEA contends that excluding such deviations could bias the allocation of reserve costs away from conventional generators and loads, thereby imposing excessive and discriminatory costs on entities such as VERs.

c. Commission Determination

55. The Commission believes that Order No. 764 already addresses AWEA’s concern. As the Commission explained in Order No. 764, once the overall quantity of regulation reserves is calculated for transmission customers, it should be allocated to individual customers (or customer classes) based on their “proportionate share,” as determined by the operating characteristics of those customers (or customer classes).⁷³ However, we agree with AWEA that public utility transmission providers proposing a generator regulation charge must calculate their total regulating reserve need with respect to all operational causes that drive the need for regulating reserves. In the absence of system specific data, it would be difficult to determine whether certain behavior (such as the ramps and schedule deviations described by AWEA) is “anomalous.” Thus, while we decline to make a *per se* finding here that any one customer (or customer class) or any one type of behavior is “anomalous,” we emphasize that the public utility transmission provider must explain how the variations of all resources and loads are accounted for in its section 205 filing. To the extent AWEA believes that a public utility transmission provider has not justified how it accounts for all variations in a section 205 filing, AWEA may raise that issue in that proceeding.

⁷² AWEA at 4 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 224).

⁷³ Order No. 764, FERC Stats. & Regs. ¶ at P 320.

3. Transmission Provider's Discretion & Deployment of Resources

a. Order No. 764

56. In Order No. 764, the Commission acknowledged comments seeking guidance on the extent to which power production forecasting would affect a differentiated rate structure under the proposed Schedule 10 generator regulation service. One commenter (Puget Sound Energy, Inc. (Puget)) sought clarification of the proposed Schedule 10 as to whether a transmission customer delivering from a VER would be required to schedule according to the public utility transmission provider's centralized power production forecast.⁷⁴

57. The Commission responded to this comment by explaining that a transmission customer is responsible for the accuracy of transmission schedules and the public utility transmission provider is responsible for the reliability of its system.⁷⁵ The Commission also explained that power production forecasting is intended to inform the transmission provider regarding aggregate system variability that results from having VERs on its system, but it is not intended to replace transmission schedules from transmission customers delivering from VERs. The Commission further clarified that public utility transmission providers that use power production forecasts should use them to manage uncertainty in the same manner they use other forecasts of uncertainty for the transmission system.

58. Accordingly, the Commission declined to require transmission customers delivering from VERs to submit transmission schedules according to the public utility transmission provider's forecast. The Commission further stated:

[T]he public utility transmission provider's obligation should be to deploy its resources according to its own forecast in order to maintain the reliability of the system. The public utility transmission provider retains the risk and responsibility

⁷⁴ *Id.* P 302 (describing a comment stating that if the public utility transmission provider's forecast sets the schedule, then there could be a perverse incentive for public utility transmission providers to generate inaccurate forecasts and collect larger generator imbalance charges under Schedule 9; however, if the VER is permitted to set its own schedule that differs from the public utility transmission provider's forecast, it remains unclear how the public utility transmission provider is supposed to manage and deploy its resources—according to its own forecast or to the VER's schedule).

⁷⁵ *Id.* P 328.

for inaccurate procurement of reserve requirements while the transmission customer retains the financial risk and responsibility for inaccurate schedules.⁷⁶

b. Request for Rehearing/Clarification

59. Bonneville requests clarification that each transmission provider may determine how to use its forecasts to plan and deploy its resources. Bonneville explains that it is concerned with the statement in Order No. 764 that a transmission provider is obligated “to deploy its resources according to its own forecast in order to maintain the reliability of its system.”⁷⁷ Bonneville indicates that VER power production forecasts have several uses, such as: (1) establishing an agreed-upon approach to scheduling; and (2) helping to ensure that reserve costs are minimized by identifying the likely range of reserves to be deployed and the direction of the reserve deployment. However, Bonneville believes that the transmission provider must deploy reserves in response to actual variability on its system, and it needs to consider factors beyond just the power production forecast.

60. For these reasons, Bonneville urges the Commission to clarify that, while power production forecasts may inform planning decisions, each transmission provider may determine how to use its forecasts to plan and deploy its resources. Alternatively, Bonneville contends that if the Commission intends to require a transmission provider to plan to deploy resources only according to its power production forecast, then the Commission should clarify that the transmission provider may limit the provision of generator imbalance service to the amount that it can supply from the resources it deployed in accordance with the forecast.⁷⁸

c. Commission Determination

61. As the context for the statement highlighted by Bonneville indicates, the Commission did not require public utility transmission providers to deploy their reserves solely based on centralized forecasts, without regard to actual system conditions and circumstances. Rather, Order No. 764 pointed to centralized forecasts as a tool available to public utility transmission providers to manage system variability and the associated costs. The statement highlighted by Bonneville was made in order to differentiate the responsibilities and risks of transmission customers and public utility transmission

⁷⁶ *Id.* P 331.

⁷⁷ Bonneville at 25 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 331).

⁷⁸ *Id.* at 26.

providers regarding the manner in which they use forecasts. It was not intended to be a prescriptive statement that would limit the public utility transmission provider to deploying reserves based solely upon the forecast, without regard to other facts and system conditions.

62. Public utility transmission providers have a significant amount of flexibility in how they choose to incorporate centralized forecasts into their system operations. Consistent with Order No. 764, public utility transmission providers remain free to propose capacity services that best respond to the needs of their customers with the expectation that the implementation of power production forecasting will be addressed in any proposal to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves.⁷⁹

4. **Financial Risk of Reserve Capacity Procurement**

a. **Order No. 764**

63. In Order No. 764, the Commission recognized that there was disagreement on exactly how power production forecasting should be factored into public utility transmission providers' allocation of regulation reserves. Therefore, the Commission reserved judgment as to the appropriate power production forecasting requirements for a particular public utility transmission provider. At the same time, the Commission expressed its expectation that the implementation of power production forecasting will be addressed in any proposal to require different transmission customers to purchase or otherwise account for different quantities of generator regulation reserves.⁸⁰ The Commission set forth the following policy guidance in order to assist public utility transmission providers in crafting any such proposals:

[T]he transmission customer is responsible for the accuracy of transmission schedules and the public utility transmission provider is responsible for the reliability of its system. Therefore, the public utility transmission provider would utilize the power production forecast to identify the necessary amount of reserves and to use those reserves to maintain reliability of the transmission system. The obligation of the transmission customer is to submit schedules for deliveries. Power production forecasting is intended to inform the

⁷⁹ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 325.

⁸⁰ *Id.*

transmission provider regarding aggregate system variability that results from having VERs on its system, not to replace transmission schedules from transmission customers delivering from VERs. Public utility transmission providers using power production forecasts should do so to manage uncertainty in the same manner they use other forecasts of uncertainty for the transmission system. For example, despite service agreements to serve load, public utility transmission providers develop and use load forecasts to assure load can be met reliably and efficiently. Similarly, despite transmission schedules to deliver from a VER, public utility transmission providers should use power production forecasts to assure energy can be provided to load in a reliable and efficient manner.⁸¹

64. The Commission further described the appropriate division of responsibilities among public utility transmission providers and transmission customers, stating that “the public utility transmission provider’s obligation should be to deploy its resources according to its own forecast in order to maintain the reliability of the system.”⁸² The Commission explained that “the public utility transmission provider retains the risk and responsibility for inaccurate procurement of reserve requirements while the transmission customer retains the financial risk and responsibility for inaccurate schedules.”⁸³

b. Request for Rehearing/Clarification

65. Bonneville contends that the Commission should clarify that while the transmission provider retains the responsibility for the reliable operation of its system, VER customers bear the risk of inaccurate reserve capacity procurement. Bonneville argues that this clarification is necessary because Order No. 764 places the risk and responsibility for the inaccurate procurement of reserve requirements on public utility transmission providers,⁸⁴ while at the same time requiring public utility transmission providers to use power production forecasts to identify the necessary amount of

⁸¹ *Id.* P 328.

⁸² *Id.* P 331.

⁸³ *Id.*

⁸⁴ Bonneville at 6 (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 331).

reserves.⁸⁵ Bonneville contends that because these forecasts are based on data supplied by VER customers, they will only be as good as the data used to generate them. Bonneville argues that if the data are wrong, the forecasts will be wrong, causing the transmission provider to procure an incorrect amount of reserves. Bonneville further points out that even if the data are correct and generate an accurate forecast, the amount of reserves procured based on the forecast may not align with the amount actually needed for balancing VER customers.

66. Accordingly, Bonneville contends that VER customers should bear the costs of (1) excess reserves when the transmission provider acquires too many reserves based on a power production forecast; and (2) potentially expensive, short-term purchases when the transmission provider acquires too few reserves based on similar forecasting methods. Bonneville asserts that, alternatively, the transmission provider may have to resort to transmission curtailments to preserve system reliability and alleviate excess or inadequate energy flows.

67. To the extent that the Commission does not make this clarification, Bonneville seeks rehearing. Bonneville states that the Commission's conclusion that the transmission provider retains the risk and responsibility for inaccurate procurement of reserves creates an inequitable cost shift to other transmission customers.⁸⁶ Bonneville also contends that the Commission did not address its comments on this point in Order No. 764. In response to the Proposed Rule, Bonneville stated:

Since the centralized forecast is based on the information provided from the VERs, is developed for the benefit of the VERs, and since the plant-specific components of the centralized forecast would ideally be used to establish VER schedules, VERs should bear the residual risk and costs associated with forecast error, which will not be completely eliminated, even through the deployment of state-of-the-art centralized forecasting systems. For example, the risks and costs associated with centralized forecast error would include generation imbalance charges that result from the difference between scheduled generation and actual generation. These costs reflect the nature of generation imbalances and should continue to be recovered from VER generation customers. In addition, *VERs should accept reasonable risks or costs*

⁸⁵ *Id.* (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 328).

⁸⁶ *Id.* at 8-9.

*associated with balancing reserve capacity shortfalls that may result from centralized forecast error, such as VER generation limitations or curtailments from the transmission provider or emergency balancing reserve capacity purchases. Allocation of such risks and costs to other transmission customers and rate payers would be inequitable and inconsistent with the principle of cost causation.*⁸⁷

68. Bonneville urges the Commission to respond to these comments by granting rehearing and by holding that, if the transmission provider procures an incorrect amount of reserve capacity, either because the VER power production forecast is developed with inaccurate VER data or because VER scheduling practices do not correspond to predictions generated with VER data, VER customers assume the risk of those inaccuracies—both the economic risk associated with the costs of procurement and the risk of curtailments when needed to preserve reliability.

c. Commission Determination

69. As the Commission explained in Order No. 764, the public utility transmission provider must procure an amount of regulating reserves sufficient to manage the aggregate variability caused by the loads and resources on its system, taking into account offsetting deviations or “diversity benefits” among loads and resources.⁸⁸ In turn, the public utility transmission provider is entitled to recover the just and reasonable costs associated with providing these capacity reserves to its transmission customers. The obligation to procure generator regulation reserves did not change in Order No. 764.⁸⁹ Moreover, Order No. 764 affirmed the Commission’s existing policy of allowing public utility transmission providers to allocate the costs of generator regulation service to customers based on their responsibility for those costs,⁹⁰ while at the same time requiring public utility transmission providers to reduce those costs to the extent practicable⁹¹ and

⁸⁷ *Id.* at 8 (citing Bonneville Comments on Proposed Rule at 50-51 (emphasis added)).

⁸⁸ Order No. 764, FERC Stats. & Regs. ¶ 21,331 at P 319.

⁸⁹ *Id.* P 270.

⁹⁰ *Id.* PP 269, 317-323.

⁹¹ *Id.* PP 321-323.

allocating them based on transmission customers' "proportionate share" of the responsibility.⁹²

70. Order No. 764 pointedly determined that public utility transmission providers should remain free to propose capacity services that best respond to the needs of their customers,⁹³ and it clearly articulated the Commission's expectation that power production forecasting will be addressed in any proposal to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves.⁹⁴ We believe this leaves adequate room for a public utility transmission provider to demonstrate that inaccurate data are leading to increased reserve costs and the public utility transmission provider should be able to recover such costs from customers causing them. Thus, we will not determine on a generic basis here that VER customers should bear the costs of excess reserves procured as a result of power production forecasting based upon poor quality data; nor will we find generically that VER customers should bear the costs of expensive, short-term purchases made because the transmission provider acquired too few reserves based on similarly poor data. The interplay between forecasting data quality and reserve cost allocation is more appropriately addressed in individual section 205 filings raising the issue.

5. Intra-Hour Scheduling Flexibility & Rate Design

a. Order No. 764

71. Order No. 764 allows public utility transmission providers to propose to recover and allocate generator regulation costs by way of a proposal under section 205 of the FPA.⁹⁵ The Commission provided guidance as to its expectations for such proposals, expressly stating that 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 (or groups of customers) to purchase or otherwise account for different quantities of generator regulating reserves.

⁹² *Id.* P 320.

⁹³ *Id.* P 268.

⁹⁴ *Id.* P 325.

⁹⁵ *Id.* P 333.

b. Request for Clarification/Rehearing

72. Bonneville contends that the Commission should clarify that transmission providers may establish reserve requirements and commensurate rates based on historical *hourly* scheduling for VER customers that choose to switch between hourly and intra-hour scheduling instead of committing to intra-hour scheduling.⁹⁶ Bonneville contends that this clarification is important because transmission providers will be unable to make reductions in the amount of reserve capacity needed to meet the balancing needs of all VER customers if transmission providers have no certainty that VER customers will correct their scheduling error on an intra-hour basis.

73. Bonneville contends that the voluntary intra-hour scheduling requirement of Order No. 764 will not provide enough certainty for transmission providers to reduce operating reserves. Bonneville further contends that generator imbalance service charges do not provide sufficient incentives for VER customers to participate in voluntary 15-minute scheduling.⁹⁷ Bonneville therefore argues that mandatory intra-hour scheduling is the best way to ensure system-wide reductions in reserve capacity and cost savings for VER customers. Accordingly, Bonneville urges the Commission to acknowledge that there may not be cost savings if VER customers do not utilize intra-hour scheduling to correct their schedule error in every scheduling interval, and to clarify that transmission providers may establish options for VER customers to commit to schedule on an intra-hour basis.

74. Bonneville requests that the Commission ratify Bonneville's model through which VER customers may commit to make intra-hour schedule adjustments and to meet a level of scheduling accuracy that is predetermined and measurable, such as scheduling to an agreed-upon forecast or basing schedules on persistence scheduling assumptions. Under this approach, VER customers would be able to choose to commit to utilize intra-hour scheduling to correct their schedule error for every interval, or to choose to schedule on an hourly basis or mix of hourly and intra-hour scheduling. Bonneville explains that the consequence of choosing the option to switch between hourly and intra-hour scheduling, however, is that the VER customer will pay higher rates because the transmission

⁹⁶ Bonneville at 13.

⁹⁷ *Id.* at 15 (citing its own experience that despite generator imbalance service penalty charges, VER customers have not consistently utilized intra-hour scheduling to correct schedule error).

provider will have to ensure sufficient reserve capacity is available at all times to balance a potential scheduling error based on historical *hourly* scheduling of VER customers.⁹⁸

75. Bonneville contends that this approach is necessary to ensure that sufficient reserve capacity is available to meet system reliability needs and the potential scheduling errors of VER customers, while providing system operators with the flexibility to manage their systems efficiently. Bonneville further states that its requested clarification will ensure that the users of reserve capacity are allocated the costs associated with that capacity, consistent with the principle of cost causation.

c. Commission Determination

76. While we will not address the specifics of Bonneville's model here, we find as a general matter that whether a transmission customer commits to scheduling at every intra-hour interval can be a relevant consideration as to the quantity of reserves properly allocated to that customer. As indicated above, Order No. 764 explicitly envisions that public utility transmission providers should consider the extent to which customers use intra-hour scheduling in determining whether to require different transmission customers (or groups of customers) to purchase or otherwise account for different quantities of generator regulation reserves. Therefore, it follows that if a public utility transmission provider can show that transmission customers that schedule at every intra-hour interval impose less of a regulating burden than those customers that do not schedule as frequently, a different reserve requirement may be reasonable. However, because any such proposal would be necessarily fact-intensive and system specific, we will not address the specifics of Bonneville's proposal here. Instead, such proposals will be addressed on a case-by-case basis, as described in Order No. 764.⁹⁹

77. Finally, we note that the Commission set forth a potential remedy for the problem described by Bonneville, i.e., that despite existing generator imbalance service penalty charges, VER customers do not use intra-hour scheduling to correct scheduling errors. Order No. 764 explained that if a public utility transmission provider believes it is necessary to address customers that intentionally deviate from their schedules, the public utility transmission provider may propose revisions to Schedule 9 generator imbalance service pursuant to section 205 of the FPA.¹⁰⁰ We affirm that decision here and further

⁹⁸ *Id.* at 16.

⁹⁹ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 269.

¹⁰⁰ *Id.* P 108 (noting that such proposals would need to demonstrate that VERs are not adjusting their transmission schedules despite their reasonable ability to foresee that output will deviate significantly from existing transmission schedules).

note that even where deviations are not “intentional,” public utility transmission providers may propose revisions to Schedule 9 generator imbalance service to address the effect of those deviations on reserve requirements.

6. Lack of Data & Higher Reserve Costs

a. Order No. 764

78. In Order No. 764, the Commission recognized the relationship between the use of power production forecasting and the allocation of generator regulation reserve quantities to a particular class of customers. The Commission found that: (1) the quantity of reserves used to provide generator regulation service can be managed most efficiently with the implementation of power production forecasting (as well as intra-hour scheduling) by public utility transmission providers; (2) power production forecasts can provide public utility transmission providers with advanced knowledge of system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than through the deployment of reserve services; and (3) without the increased situational awareness of projected variability provided by power production forecasts, the public utility transmission provider’s ability to efficiently commit or de-commit resources providing regulation reserves can be constrained, potentially resulting in rates for generator regulation service that are unjust and unreasonable or unduly discriminatory.¹⁰¹

b. Request for Rehearing/Clarification

79. Bonneville urges the Commission to clarify that it is not unduly discriminatory for transmission providers to impose higher generator regulation charges and larger reserve capacity requirements on VER customers that do not provide the data necessary to construct a forecast.¹⁰² Bonneville argues that power production forecasts depend on information received from VER customers, and that the absence of data prevents transmission providers from producing a power production forecast. Bonneville states that Order No. 764 recognizes both the benefits of power production forecasting and the potential harm from not using forecasts. Noting that Order No. 764 limits the ability of transmission providers to collect data from existing customers, Bonneville argues that this lack of data requires the transmission provider to hold more reserve capacity.

¹⁰¹ *Id.* P 323.

¹⁰² Bonneville at 26-27.

c. Commission Determination

80. Order No. 764 recognized the contentious nature of proposals by public utility transmission providers to implement power production forecasting requirements and to allocate different reserve requirements to different transmission customers.¹⁰³ For this reason, the Commission reserved judgment as to the appropriate power production forecasting requirements for particular public utility transmission providers, with the expectation that such matters would be addressed in individual proposals to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves. Given the flexibility afforded by Order No. 764, public utility transmission providers are not precluded from attempting to demonstrate, for example, that the lack of data from some group of customers has a direct effect on the quality of their forecasts and the quantity of reserves they must retain, and thereby justifying a higher rate for that group of customers. Because such a proposal would require a fact-intensive inquiry unique to the public utility transmission provider's system, we decline to address it in the abstract here.

7. Curtailement & e-Tagging

a. Order No. 764

81. In Order No. 764, the Commission explained that its decision not to adopt a generic generator regulation rate schedule does not relieve public utility transmission providers of their obligation to maintain sufficient capacity to provide Schedule 9 generator imbalance service.¹⁰⁴ The Commission then reiterated the scope of a public utility transmission provider's obligation to provide Schedule 9 generator imbalance service that it established in the Order No. 890 proceeding. Specifically, the Commission explained that:

[I]f it is not physically feasible for a transmission provider to offer generator imbalance service using its own resources, either because they do not exist or they are fully subscribed, the public utility transmission provider must attempt to procure alternatives to provide the service, taking appropriate steps to offer an option that customers can use to satisfy their

¹⁰³ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 324.

¹⁰⁴ *Id.* P 270 (citing *NorthWestern Corp.*, 129 FERC ¶ 61,116, at P 24 (2009), *order denying reh'g*, 131 FERC ¶ 61,202, at PP 17-18 (2010)).

obligation to acquire generator imbalance service as a condition of taking transmission service.¹⁰⁵

82. The Commission explained that a public utility transmission provider can establish the amount of generator imbalance service and generator regulation service that it is capable of providing by either stating the maximum amount on its OASIS or by performing system impact studies on a case-by-case basis.¹⁰⁶ The Commission also reiterated when there are no additional resources available, the public utility transmission provider must accept the use of dynamic scheduling with a neighboring control area.¹⁰⁷ Moreover, the Commission explained its existing requirement for public utility transmission providers to allow customers to self-supply ancillary services.¹⁰⁸

b. Requests for Rehearing/Clarification

83. Bonneville contends that the Commission should clarify that the transmission provider may limit the output of VER customers that are over-generating to their schedules, or curtail the schedules of VER customers that are under-generating to their actual output if it is not physically feasible for the transmission provider to provide additional reserve capacity from its resources or from third parties or to allow dynamic scheduling.¹⁰⁹

84. Bonneville states that it is possible that a transmission provider may not be able to provide generator imbalance service where factors such as fuel or environmental constraints, maintenance, or other outages result in insufficient capacity to do so.¹¹⁰ Bonneville further states that when a transmission provider is out of balancing reserve capacity (from its own resources as well as those in the marketplace), it is no longer able to absorb the difference between scheduled and actual output, and it must take other steps to keep its transmission system balanced, or else risk violating reliability standards or other legal requirements. Bonneville asserts that it would be inequitable for transmission

¹⁰⁵ *Id.* (citing Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at PP 289-290).

¹⁰⁶ *Id.* PP 270-271 (noting that Order No. 764 does not place an obligation to build generation on public utility transmission providers).

¹⁰⁷ *Id.* n.277 (citing Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 290).

¹⁰⁸ *Id.* PP 273-274.

¹⁰⁹ Bonneville at 20.

¹¹⁰ *Id.* at 20-21.

customers that are not the source of these errors to bear the resulting cost. Bonneville concludes that when a transmission provider no longer has available balancing resources (of its own or from a third-party), it is appropriate to adjust the schedules or output of generating facilities whose scheduling errors have depleted the available balancing resources.

85. Bonneville explains that in the event of schedule curtailments, the sink balancing authority area or purchasing entity would need to deploy its own reserve capacity resources or resources available to it to maintain load and resource balance. Bonneville further explains that in order to maintain system reliability, the source and sink balancing areas need to exchange information about the likelihood of such events.¹¹¹

86. Bonneville argues that these issues are not limited to Bonneville or the Pacific Northwest, asserting that they are ripe for a rulemaking because weather, system maintenance, market liquidity, and environmental obligations may affect transmission providers' ability to provide reserve capacity for generator imbalance service. Bonneville further contends that the likelihood for reserve capacity constraints increases as VER integration increases across the country.

87. To the extent that the Commission does not grant clarification, Bonneville requests that the Commission grant rehearing on this point.¹¹² Bonneville asserts that while the Commission acknowledged the possibility of reserve capacity limitations, it did not discuss how transmission providers should manage system reliability when they had no more reserve capacity and dynamic scheduling was not feasible.

88. Powerex urges the Commission to clarify that a transmission customer's discretion to submit schedules for transmission service does not override the transmission provider's right and responsibility to ensure that firm transmission schedules originating on its system are supported by sufficient reserves. Powerex expresses concern that Order No. 764 could be interpreted as providing transmission customers with unfettered rights to submit firm transmission schedules, regardless of their forecasted power production and/or the transmission system's available reserves.¹¹³ Powerex argues that, by not requiring customers to schedule transmission service according to the transmission

¹¹¹ *Id.* at 22 (noting that it provides customers information about the probabilities of curtailments given their preferred level of service, and has developed tools to provide real-time information regarding Bonneville's reserve capacity deployment).

¹¹² *Id.* at 22-23.

¹¹³ Powerex at 5.

provider's centralized forecast, while at the same time placing the transmission provider at risk for inaccurate procurement of reserves, Order No. 764 could be interpreted to mean that the customer's scheduling rights are unlimited, even where there is a demonstrable mismatch between a resource's expected production and its firm transmission schedules.

89. For these reasons, Powerex, urges the Commission to allow public utility transmission providers to deny transmission customers' firm schedules based on available reserves in a transparent and non-discriminatory fashion by: (1) advising customers in advance regarding the amount of balancing reserves the public utility transmission provider will provide; (2) specifying the portion of a VER's output that will be allowed to be firm, with any remaining amount being classified as non-firm; and (3) allowing customers to self-supply additional reserves in order to fully schedule all of their VER output.¹¹⁴ Powerex argues that if the public utility transmission provider exhausts its established level of reserves, it should be permitted to deny firm e-Tags¹¹⁵ in order to maintain reliability. Powerex further argues that the Commission should clarify that transmission customers' transactions must be properly e-Tagged (i.e., as to whether they are firm or non-firm) to ensure that sink balancing authorities are fully aware of the firmness of energy that they are receiving and whether they should procure additional reserves to back particular schedules.¹¹⁶ To the extent the Commission is unwilling to make these clarifications, Powerex urges the Commission to make clear that customers that overstate firm schedules may be subject to substantial fines or penalties, including any fines or penalties that result from reliability events.

90. Powerex argues that these clarifications are critical because, in Powerex's experience, imbalance penalties and charges are not robust enough to deter deliberate generation imbalances in every single hour, as deliberate imbalances can be profitable in given market conditions. Powerex states that during periods when prices in an organized market such as California Independent System Operator Corporation (CAISO) are high, wind generators in the Pacific Northwest have a substantial economic incentive to submit schedules for their full output, even if they do not expect to fulfill those schedules.¹¹⁷

¹¹⁴ *Id.* at 5-6.

¹¹⁵ E-Tags, also known as Requests for Interchange, are used by NERC and/or Regional Entities to schedule interchange transactions in wholesale markets.

¹¹⁶ Powerex at 6.

¹¹⁷ *Id.* at 7 (explaining that energy prices in CAISO can climb high enough that when the wind generators' firm schedules flow, the generator imbalance penalties

(continued...)

Powerex posits that in this scenario, CAISO could unknowingly receive a large volume of energy that is e-Tagged as firm energy, relying on such energy to meet firm load in the CAISO balancing authority area, when in actuality the energy is not fully backed by sufficient VER output and reserves at the source balancing authority area. Powerex therefore argues that if the transmission provider expects that it may exhaust its established level of balancing reserves, the transmission provider should be able to deny firm e-Tags in order to maintain reliability, allowing customers to submit non-firm schedules instead.¹¹⁸

c. Commission Determination

91. The requests for clarification made by Bonneville and Powerex¹¹⁹ both go to the extent of a public utility transmission provider's obligation to maintain sufficient reserves to provide generator imbalance service to transmission customers. The Commission has previously denied a proposal by a public utility transmission provider to disclaim its responsibility to offer generator regulation service for intermittent renewable generator export transactions.¹²⁰ Order No. 764 kept in place the Commission's policy of requiring public utility transmission providers to maintain sufficient reserves to provide generator imbalance service under Schedule 9 of the *pro forma* OATT.¹²¹

92. Both Bonneville and Powerex urge the Commission to limit a public utility transmission provider's obligation to provide this service to some pre-determined amount of reserves. We decline to make that determination in this proceeding, in which the Commission did not propose to modify and is not modifying the obligation previously set forth.

combined with the cost of generator regulation service are still less than the price the wind generators will receive for such schedules).

¹¹⁸ *Id.* at 6.

¹¹⁹ Powerex filed an answer to Bonneville's request for clarification or rehearing. Rule 713(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(d) (2012), provides that the Commission will not permit answers to requests for rehearing. Accordingly, we will reject Powerex's answer.

¹²⁰ *NorthWestern Corp.*, 129 FERC ¶ 61,116, *order denying reh'g*, 131 FERC ¶ 61,202.

¹²¹ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 270.

93. Nevertheless, consistent with Powerex's request, we affirm our determination in Order No. 890-A, reiterated in Order No. 764, that a public utility transmission provider may, when it has exhausted all other options, establish the amount of generator imbalance service and generator regulation service that it is physically capable of providing by either stating the maximum amount on its OASIS or by performing system impact studies on a case-by-case basis.¹²² To the extent that a public utility transmission provider seeks to curtail a transmission customer's transmission service due to a lack of balancing reserves, then it would have to show that it made the efforts specified by the Commission in Order No. 890-A, i.e., that it attempted to procure alternative balancing resources,¹²³ and where such resources are unavailable, it accepted the use of dynamic scheduling with a neighboring control area or allowed customers to self-supply the service.

94. We also note that Bonneville requests that it be allowed to curtail only VERs but makes no mention of curtailing other transmission customers. Under the *pro forma* OATT, curtailments are required to be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint and to network customers and transmission customers taking firm point-to-point transmission service on a basis comparable to the curtailment of service to the transmission provider's native load customers.¹²⁴ While Order No. 764 allows public utility transmission providers to require different customers to purchase or otherwise account for different amounts of regulating reserves, such distinctions must be reasonable and well-supported. Of course, the Commission would require similar evidentiary showings by a public utility transmission provider seeking to limit the reserves it would provide to any customer or class of customers.

95. We also decline to address the specifics of Powerex's concern regarding the scope of a transmission customer's discretion to submit schedules for transmission service at this time. Order No. 764 did not make any changes in the transmission customer's discretion to schedule transmission service that it has already reserved. Powerex describes a situation in which customers intentionally deviate from their schedules when it is economically beneficial for them to do so, even in light of the imbalance penalties

¹²² *Id.* PP 270-271.

¹²³ Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 290 (“If it is not physically feasible for the transmission provider to offer generator imbalance service using its own resources, either because they do not exist or they are fully subscribed, the transmission provider must attempt to procure alternatives to provide the service....”).

¹²⁴ Section 13.6 of the *pro forma* Open Access Transmission Tariff, available at <http://www.ferc.gov/whats-new/comm-meet/2008/061908/E-1.pdf>.

they would incur. However, as discussed in other sections above Order No. 764 addressed this situation stating that if a public utility transmission provider believes it is necessary to address intentional deviations, it may propose revisions to Schedule 9 generator imbalance service pursuant to section 205 of the FPA.¹²⁵ Accordingly, rather than impose a novel and generic restriction on transmission customers' discretion to schedule transmission service here, without the benefit of broad industry comment, we will allow the mechanisms discussed in Order No. 764 to work and revisit them when and if necessary.

96. Finally, we find Powerex's concerns about e-Tagging to be beyond the scope of this proceeding. Powerex's concern appears to be specific to power being exported from Bonneville's system and the extent to which Bonneville's curtailment practices pursuant to as Dispatcher Standing Order 216 (DSO 216) render certain transactions sufficiently "firm." Ultimately, however, Powerex's concern is more of a commercial matter between the buyer and the seller of power being exported from Bonneville's system. To the extent power is being exported from Bonneville's system, customers and neighboring balancing authorities are aware that Bonneville has implemented DSO 216 and that export transactions are subject to curtailment. It is up to these customers to decide for themselves whether such transactions can be marketed as "firm" or as something else.

97. Moreover, Powerex's concern appears to be based primarily on the firmness of the energy that is scheduled by the e-Tag and not on the firmness of the transmission service. E-Tags only reflect the firmness of transmission service priorities that transmission customers reserved prior to scheduling; they do not reflect the firmness of energy. While certain events (e.g., a forced outage or a curtailment pursuant to DSO 216) could interrupt the flow of energy scheduled by an e-Tag, that does not change the underlying nature of transmission service. Because the Commission's focus here is on the reserves necessary to support transmission service, we decline to require generic revisions to e-Tags here to address the unrelated issue of whether changes to e-Tags are necessary to reflect the potential that energy scheduled by an e-Tag as firm may ultimately not flow. In terms of reliability, transmission providers still have the authority to alleviate capacity and energy emergencies according to applicable reliability standards.¹²⁶

¹²⁵ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 108.

¹²⁶ See, e.g., EOP-002-3.1 Capacity and Energy Emergencies (authorizing balancing authorities and reliability coordinator to take whatever actions are needed to ensure the reliability of their respective areas and to alleviate capacity and energy emergencies).

D. Regulatory Flexibility Act Analysis**1. Order No. 764**

98. In Order No. 764, the Commission recognized that “the cost of moving from hourly to 15-minute transmission scheduling could be substantial.”¹²⁷ The Commission further stated that:

Several transmission providers state that costs will depend heavily on the extent to which intra-hour scheduling is actually used by transmission customers, estimating staffing costs to be in the range of \$1-2 million per year if widely used. While these costs are not insignificant, greater use of intra-hour schedules means that more transmission customers are mitigating exposure to Schedule 9 generator imbalance charges and providing greater opportunities for public utility transmission providers to lower reserve-related costs.¹²⁸

99. The Commission noted that many of the costs cited by commenters as being specific to 15-minute scheduling are really related to the automation of systems used to process transmission schedules and verify cross-balancing authority aggregate schedules, which the Commission did not mandate.¹²⁹ Furthermore, the Commission acknowledged that some commenters raised concerns about costs associated with sub-hourly settlement of imbalance charges and sub-hourly dispatch of resources, neither of which the Commission required in Order No. 764.¹³⁰

100. The Commission also conducted an analysis under the RFA.¹³¹ The Commission explained that Order No. 764 applies to public utilities that own, control or operate interstate transmission facilities (that have not received waiver of the obligation to comply with Order Nos. 888, 889, and 890) and to variable energy resources. The

¹²⁷ Order No. 764, FERC Stats. & Regs, ¶ 31,331 at P 102.

¹²⁸ *Id.* (internal footnote omitted).

¹²⁹ *Id.* P 103.

¹³⁰ *Id.* P 104.

¹³¹ *Id.* P 384.

Commission estimated that ten small public utility transmission providers¹³² would be affected equally by Order No. 764, at an average cost of \$13,500 per year. The Commission found that this was not a significant economic impact, noting that in any event, each of these entities may seek waiver of these requirements.¹³³ (The Commission also found that Order No. 764 would not have a significant economic impact on VERs, which NRECA does not challenge in its rehearing request.) Accordingly, the Commission certified that Order No. 764 would not have a significant economic impact on a substantial number of small entities.

2. Request for Rehearing

101. NRECA argues that the Commission erred in concluding that Order No. 764 will not have a significant impact on a substantial number of small entities and that, therefore, no final regulatory flexibility analysis is required under the Regulatory Flexibility Act (RFA).¹³⁴ Specifically, NRECA objects to the Commission's determination that Order No. 764 will "impact all the applicable transmission providers equally at an annual cost of \$13,500 per year."¹³⁵

102. NRECA argues that in response to the Proposed Rule, it provided estimates of the cost impacts of the Commission's intra-hour scheduling reform, explaining that the changes needed to implement the reform will depend on a number of factors, including the size of the transmission provider, whether the transmission provider is an RTO, and the number of customers that take advantage of 15-minute scheduling.¹³⁶ On rehearing,

¹³² A "small entity" as referenced in the RFA refers to the definition provided in section 3 of the Small Business Act where a firm is "small" if, including its affiliates, it is primarily engaged in the generation, transmission, and/or distribution of electric energy for sale and its total electric output for the preceding fiscal year did not exceed 4 million megawatt hours.

¹³³ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 384 & n.365 ("The criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888, 889, and 890.").

¹³⁴ NRECA at 2 (citing Regulatory Flexibility Act of 1980, 5 U.S.C. §§ 601-612 (2006)).

¹³⁵ *Id.* (referencing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 384).

¹³⁶ *Id.* at 3 (citing NRECA, Comments on Proposed Rule at 10-15).

NRECA quotes the Commission's description of its cost estimates in response to the Proposed Rule:

Assuming hourly schedules at a 15-minute interval used only by VERs, NRECA anticipates the need for software modifications in the range of \$50,000 per company, but notes that some of its members have incurred expenses in the range of \$250,000 annually for software licensing and maintenance related to scheduling and energy accounting software upgrades. If hourly schedules at a 15-minute interval are widely used by transmission customers, NRECA estimates a minimum of one additional 24x7 shift, resulting in approximately \$1.0 million of staffing costs, and potentially two 24x7 positions depending on the size of the transmission provider.¹³⁷

103. NRECA emphasizes that the Commission noted that such costs were “not insignificant” and that the Commission did not question or criticize NRECA's cost estimates.¹³⁸ NRECA contrasts these findings with the Commission's RFA analysis, in which the Commission found that Order No. 764 would affect all applicable small transmission providers equally at an average cost of \$13,500 per year, and that it will not have a significant economic impact on a substantial number of small entities.¹³⁹

104. NRECA argues that the Commission did not provide any evidence to support the assumption that the average cost impact of Order No. 764 on small transmission providers will be \$13,500. Further, NRECA states that the estimates the Commission did cite, and characterized as “not insignificant” and potentially “substantial,” are in the range of \$1-2 million per year if intra-hour scheduling is widely used. NRECA contends that even if intra-hour scheduling were limited to VERs, NRECA estimated a cost impact of \$50,000, which does not take into account \$250,000 in annual additional software-related costs that some NRECA members have incurred.¹⁴⁰ NRECA notes that this \$50,000 estimate is “nearly quadruple” the Commission estimate of \$13,500 per year. For these reasons, NRECA contends that the Commission has not articulated a

¹³⁷ *Id.* at 4 (quoting Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 82).

¹³⁸ *Id.* (citing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 102).

¹³⁹ *Id.* at 4-5 (referencing Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 384).

¹⁴⁰ *Id.* at 5.

satisfactory explanation for concluding that Order No. 764 will not have a substantial economic impact on a substantial number of small entities.

3. Commission Determination

105. As an initial matter, we note that NRECA challenges only one portion of the Commission's RFA certification—the Commission's finding that the average cost impact on small public utility transmission providers would be \$13,500 per year, which the Commission determined was not a significant economic impact.¹⁴¹ NRECA does not challenge the Commission's finding that Order No. 764 will only affect ten small public utility transmission providers, nor does it challenge the Commission's estimates or its finding that Order No. 764 would not have a significant economic impact on the 160 VERs that the Commission found to be small entities.¹⁴² Moreover, NRECA does not challenge, let alone address, Order No. 764's express acknowledgment that small public utility transmission providers may seek waiver of the Commission's intra-hour scheduling requirement.¹⁴³

106. NRECA's key argument focuses on the Commission's acknowledgement that the costs of implementing the intra-hour scheduling reform *could be* significant, as well as the fact that the Commission did not specifically discredit cost estimates in the range of \$1-2 million. Simply because the Commission acknowledged that such costs are "not insignificant," however, does not mean that the Commission accepted \$1-2 million estimates as reasonable cost estimates for small public utilities. Indeed, the Commission acknowledged these higher cost estimates in the context of evaluating how the potential costs of the intra-hour scheduling reform measured against the potential benefits for all public utility transmission providers, not just *small* public utility transmission providers. In this context, the Commission found that even if the costs of the reform were on the higher side due to substantial use of intra-hour scheduling by customers, such costs would be justified in light of the significant benefits to customers in the form of reduced

¹⁴¹ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 384.

¹⁴² *See id.* (noting that approximately 100 VERs will be required to comply with Order No. 764, whereas 60 VERs will have the option to do so).

¹⁴³ *Id.* *See Transmission Access Policy Study Group v. FERC*, 225 F.3d 667, 738 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002) (recognizing that the Commission, in the context of an RFA certification, was not insensitive to the potential impact of Order No. 888 on small non-jurisdictional entities, allowing such entities to file for a waiver from compliance with the reciprocity conditions).

imbalance charges.¹⁴⁴ It bears emphasis that the discussion of potential costs in this section of Order No. 764 was in reference to *all* public utility transmission providers. It is therefore unremarkable that estimated costs for *small* public utility transmission providers, which the Commission discussed elsewhere in Order No. 764, would be different.

107. As the Commission explained in Order No. 764, a principal driver of costs associated with the intra-hour scheduling reform is the number of transmission customers who will request intra-hour schedules.¹⁴⁵ Due to their relative small size, the Commission expects small public utility transmission providers to have fewer customers that take advantage of intra-hour scheduling, and therefore fewer costs. As a result, NRECA's lower \$50,000 estimate is more in line with expected costs described in Order No. 764 to the ten public utility transmission providers that qualify as small entities for the complete implementation of the Commission's reforms, and the higher estimates (in the \$1-2 million range) are unlikely, as explained in Order No. 764 and clarified here.¹⁴⁶

108. The Commission based the \$13,500 estimate on the cost per small public utility transmission provider as described in the information collection statement in Order No. 764.¹⁴⁷ Specifically, the Commission estimated 118 hours of burden for each transmission provider. The Commission applied a \$114 per hour average wage¹⁴⁸ to the burden hour to arrive at the \$13,500 estimate (118 hours * \$114 per hour = \$13,452). The Commission believes that such costs are an accurate representation of both the staffing and software costs associated with the reforms required by Order No. 764. Additionally, the Commission estimate of \$13,500 per year is based on the expected cost

¹⁴⁴ *Id.* P 102.

¹⁴⁵ *Id.*

¹⁴⁶ NRECA itself acknowledged in its comments on the Proposed Rule that the costs of intra-hour scheduling should be manageable, stating that "NRECA expects that in some cases, there will be significant costs needed to implement this reform. But NRECA believes the costs will not be extraordinary, and that these costs can and should be mitigated through proper design and implementation." NRECA, Comments on Proposed Rule at 11.

¹⁴⁷ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 381.

¹⁴⁸ \$114 per hour represents the average cost of an attorney (\$200 per hour), consultant (\$150 per hour), technical (\$80 per hour), and administrative support (\$25 per hour).

over the first three years of compliance with Order No. 764, whereas the NRECA estimate of \$50,000 is characterized as “limited to upfront software modifications.”¹⁴⁹ Accordingly, we interpret NRECA’s \$50,000 estimate as related to a single investment rather than recurring yearly costs. With that in mind, considering the full three-year Commission estimate of \$40,500 (\$13,500 multiplied by three years), the Commission estimate is not much different from NRECA’s estimate of \$50,000.

109. Finally, even if the Commission were to consider NRECA’s software cost estimate as not included in the estimate described in Order No. 764, we nonetheless find that the combined Commission and NRECA cost estimates (the \$40,500 Commission three-year estimate plus the \$50,000 NRECA software cost estimate) would still not be a significant burden on small entities. The annual cost of these combined estimates would be approximately \$30,200 per year (\$90,500 divided by 3 years). The Commission would not consider this \$30,200 per year estimate to be a significant economic burden on small public utility transmission providers. Therefore, even if the Commission were to accept a burden estimate nearly double NRECA’s estimate, the Commission still would not be required to perform a final regulatory flexibility analysis under the RFA.

110. Accordingly, the Commission affirms Order No. 764’s conclusion that costs of that rule do not represent a significant economic impact on a substantial number of small entities.¹⁵⁰

The Commission orders:

(A) Requests for clarification and rehearing are granted or denied, as discussed in the body of this order.

(B) The deadline for compliance with Order No. 764 is hereby extended to November 12, 2013.

By the Commission. Commissioner Clark is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

¹⁴⁹ NRECA, Comments on Proposed Rule at 12.

¹⁵⁰ Order No. 764, FERC Stats. & Regs. ¶ 31,331 at P 384.

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