Third-Party Provision of Reactive Supply and Voltage Control and Regulation and Frequency Response Services

Docket No. AD14-7-000

April 22, 2014

Agenda

9:00 a.m. – 9:20 a.m. Welcome and Opening Remarks

9:20 a.m. – 11:50 a.m. Morning Roundtable Discussions: Should Reactive Supply And Frequency Response Be Considered Obligations Without Payment Or Services Provided For Payment?

Reactive Supply

As discussed in more detail in the staff report being released concurrently with this Notice, the electric industry has long required generators as a condition of interconnection to operate within a specified power factor range, in many cases without separately identified compensation for such operation.[1] That is, compensation may be part of a bundled rate, either at retail or at wholesale. Given the changes that have occurred and are occurring within the electric industry (e.g., more disaggregated ownership of generation resources and increased entry by non-conventional technologies), there is a question concerning obligation and compensation of reactive supply and frequency response.

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[1] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), at P 546, *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, at P 416, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008).

- In light of changed circumstances and with regard to wholesale power sales, should there now be payment for reactive power capability within the power factor range required in interconnection agreements?
    - If there should be a payment, should payment be cost based, determined through a competitive solicitation, or through some other market-based mechanism?
    - If there should be a payment, should all generators in a region be paid the same rate, or should the rate vary by the type, size, location, or capability of each generator?
    - If there should not be a payment, how does the Commission reconcile the fact that some generators may be recovering the costs associated with providing reactive power capability through bundled rates and other generators providing the service do not have the opportunity to do so?
    - Should the requirement to provide the service be contingent upon opportunity for cost recovery?
    - Why do some regions pay for reactive power and some not? Are there inherent differences in the way the systems were planned and constructed, the types of loads, the acceptable range of voltage, the amount of reactive power that is absorbed by the loads, or transmission system capabilities?

- How should cost-based payments for reactive power capability be structured?
    - Should the Commission continue to use the AEP methodology?[2]
    - Is there sufficient transparency of existing cost-based payments to generators?
    - Could the costs associated with transmission facilities that provide dynamic reactive power be used to help develop a generic cost-based reactive power rate that could be applied to all reactive power resources?

- What are the obligations of generators receiving payment for reactive power capability within the required power factor range?
    - Can the system operator require a generator to start up only to provide reactive power?

[2] *American Electric Power Service Corp.*, Opinion No. 440, 88 FERC ¶ 61,141 (1999).

Roundtable Participants

- Doug Hils, Director, Midwest System Operations, Duke Energy (Edison Electric Institute)
- Ryan Hanley, Director of Grid Engineering Solutions, SolarCity
- Dmitry Kosterev, Electrical Engineer, Bonneville Power Administration
- Stu Bresler, Vice President Market Operations, PJM Interconnection, L.L.C.
- Mike Jacobs, Senior Energy Analyst, Union of Concerned Scientists
- Vladimir Chadliev, Director-Global Grid Integration, First Solar, Inc.
- James Ginnetti, Senior Vice President External Affairs and Markets, EquiPower Resources Corp.

Frequency Response

The electric industry once routinely operated its generators with certain governor settings, most of those generators were turbine-generators with relatively fast response, and they were routinely dispatched below maximum output (to leave headroom for the governor to work with), so as to provide useful levels of frequency response from almost all synchronized generation, in many cases without providing a separate, unbundled payment for such operation. However, as with reactive power, the cost of maintaining that frequency response capability may have been recovered in bundled rates since most generation was owned by retail load serving entities.

- In light of changed circumstances, should there now be payment for appropriate performance (i.e. for providing frequency response service) or should some level of performance be more strongly required in interconnection agreements?
    - If there should be a payment, should it be cost based, determined through a competitive solicitation, or through some other market-based mechanism?
    - If there should be a payment, should all generators in a region be paid the same rate, or should the rate vary by the type, size, or capability of each generator?
    - If there should not be a payment, should all generators have the same requirement for providing frequency response service irrespective of whether the owner otherwise has access to rate recovery of the costs of maintaining such capability?
    - Should resources be required to provide some minimum quantity of frequency response as part of existing obligations such as interconnection requirements, and only be paid when providing additional amounts of

frequency response to meet a shortfall in achieving the balancing authority area's frequency response obligation?
    - Whether or not payments are made for providing frequency response service, should there be penalties assessed against resources that absorb frequency response (i.e., worsen responsiveness)?

- How should cost-based payments for frequency response service be structured?
    - Would the nature of frequency response service require a two-part payment; e.g., a capacity payment to maintain needed headroom and a performance payment for actual response?
    - Because a resource selling frequency response service would need to forego energy sales in order to maintain needed headroom for governor response, should a cost-based frequency response rate incorporate a lost opportunity cost payment reflecting that energy market impact?

- Should the Commission create a new frequency response ancillary service in the OATT, subdivide the existing Schedule 3 Regulation and Frequency Response ancillary service into two services with separate cost-based rates, or leave stand-alone frequency response service entirely to market mechanisms in the bilateral and organized markets?

- If frequency response service is either recognized through the OATT or incorporated into an RTO/ISO organized market, how should self-supply of frequency response be established and measured?

<u>Roundtable Participants</u>

- Doug Hils, Director, Midwest System Operations, Duke Energy (Edison Electric Institute)
- Dmitry Kosterev, Electrical Engineer, Bonneville Power Administration
- Sandip Sharma, Supervisor, Electric Reliability Council of Texas
- Erik Ela, Senior Engineer, National Renewable Energy Laboratory
- Clyde Loutan, Senior Advisor Renewable Energy Integration, California ISO
- Stu Bresler, Vice President Market Operations, PJM Interconnection, L.L.C.
- James Ginnetti, Senior Vice President External Affairs and Markets, EquiPower Resources Corp.
- Ryan Hanley, Director of Grid Engineering Solutions, SolarCity

11:50 a.m. – 12:50 p.m. Break For Lunch

12:50 p.m. – 2:50 p.m. Afternoon Roundtable Discussion: Market Power Screening Concerns Associated With Reactive Supply, Regulation, and Frequency Response Services.

The Commission analyzes horizontal market power for sales of energy and capacity using two indicative screens, the wholesale market share screen and the pivotal supplier screen, to identify sellers that raise no horizontal market power concerns and can otherwise be considered for market-based rate authority. The wholesale market share screen measures whether a seller has a dominant position in the relevant geographic market in terms of the number of megawatts owned or controlled by the seller, as compared to the uncommitted capacity of the entire market. A seller whose share of the relevant market is less than 20 percent during all seasons passes the wholesale market share screen. The pivotal supplier screen evaluates the seller's potential to exercise horizontal market power based on the seller's uncommitted capacity at the time of annual peak demand in the relevant market. A seller satisfies the pivotal supplier screen if its uncommitted capacity is less than the net uncommitted supply in the relevant market.

A major focus of Order No. 784 was identifying the circumstances under which the existing market power screens for sales of energy and capacity could be applied without significant modification to sales of specific ancillary services.[3] Below we discuss relevant issues as they relate to potential market-based rate sales of reactive power supply, regulation, and frequency response services.

Reactive Supply

For sales of reactive power, Order No. 784 was unable to identify appropriate assumptions that would enable use of the existing market power screens. To the extent market-based sales of reactive power make sense, the following questions are meant to further explore this issue.

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[3] *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies*, Order No. 784, 78 Fed. Reg. 46,178 (July 30, 2013), FERC Stats. & Regs. ¶ 31,349, at PP 20-61 (2013), *order on clarification*, Order No. 784-A, 146 FERC ¶ 61,114 (2014).

- To what extent can entities sell reactive power across balancing areas in a manner consistent with the assumptions reflected in existing market power screens for energy and capacity?
    - Regarding the assumption of the existing screens that all uncommitted generation resources can compete with each other, what type of equipment is needed to allow the various types of generation resource in the existing market power screens to provide or absorb reactive power, what types of resources and what proportion in the market typically have such equipment installed, and how easy and cost-effective is it to retrofit such equipment after initial construction for those that do not typically come with it installed?
    - Regarding the default geographic market reflected in the existing screens, under typical system conditions, would reactive power produced or consumed in one area of a multi-balancing authority area market necessarily be useful (and thus competitive) in another remote area of the same market? Similarly, would reactive power produced or consumed at the sites of retail load on the distribution grid necessarily be useful, and thus competitive, in a remote part of the same default geographic market?
- How would the relevant geographic market for reactive power be established?
- How can a market power screen be developed to consider transmission, distributed resources, and demand side alternatives to generator-supplied reactive power, and how would the distance limitations identified in response to the questions above, if any, be dealt with by such a market power screen?

Regulation Service

In Order No. 784, the Commission evaluated whether the existing market power screens for sales of energy and capacity could be applied to the sale of Schedule 3 Regulation and Frequency Response service without significant modification.[4] The Commission discussed Schedule 3 as a single service in Order No. 784, which is focused primarily on Automatic Generation Control (AGC)-based regulation. However, frequency response is distinct from regulation.[5] Frequency response involves the autonomous, automatic, and rapid reaction of an individual turbine-generator or other

[4] Order No. 784, FERC Stats. & Regs. ¶ 31,349 at PP 59-61.

[5] As used herein, frequency response refers to primary frequency response and regulation refers to secondary frequency response.

resource to change its output to rapidly dampen changes in frequency. In contrast, regulation is produced from either manual or automated dispatch (through AGC) from a centralized system.[6] In Order No. 888, the Commission found that governor-based autonomous frequency response did not merit a separate ancillary service because at the time the same resources that responded to regulation signals also provided governor response under then-standard industry practices.[7] As a result, the language of Order No. 888 discussing Schedule 3 was focused primarily on AGC-based central dispatch,[8] and we will treat regulation service in the same way in this workshop. We will also assume that RTO/ISO regulation markets do not need further refinement at this time, and therefore focus our regulation service discussion on bilateral regulation markets outside of RTOs and ISOs.

Because of certain technical and geographic issues associated with regulation service, Order No. 784 did not remove the general prohibition on third-party market-based sales of that service to a public utility transmission provider that is purchasing to satisfy its OATT requirement to offer ancillary services to its customers. However, arguments were raised in some comments that the equipment upgrades needed to enable an existing resource to begin selling this service may not be excessively expensive or time consuming. Additionally, while regulation service requires dispatch on multi-second intervals, which would mean that the first-tier resources considered in the existing market power screens would probably require special scheduling provisions like dynamic

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[6] *See Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024, at PP 8-9 (2014).

[7] "While the services provided by Regulation Service and Frequency Response Service are different, they are complimentary services that are made available using the same equipment." *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,707 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[8] "Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generation control equipment)…." *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,960, Schedule 3-Regulation and Frequency Response Service.

scheduling or pseudo-ties in order to supply this service to the destination market, some commenters argued that some regions are developing the needed agreements and infrastructure to make such special scheduling arrangements more widely available. The following questions are meant to further explore these two claims.

- To what extent can entities sell regulation service across balancing areas in a manner consistent with the assumptions reflected in existing market power screens for energy and capacity?
    - Regarding the assumption of the existing screens that all uncommitted generation resources can compete with each other, what type of equipment and communications are needed to allow the various types of generation resource in the existing market power screens to provide regulation service, what types of resources and what proportion in the market typically have such equipment installed, and how easy and cost-effective is it to retrofit such equipment and communications after initial construction for those that do not typically come with it installed?
    - Regarding the default geographic market reflected in the existing screens, are special scheduling provisions like dynamic scheduling or pseudo-ties needed to permit regulation service sellers in a first-tier balancing area to compete with sellers in neighboring balancing areas, and if so, how easy is it to secure such special scheduling provisions?
- How would the relevant geographic market for regulation service be established?
- How can a market power screen be developed to consider transmission, distributed resources, and demand side alternatives to generator-supplied regulation service, and if any of these new competitors are located at the sites of retail load on the distribution grid, would the regulation service they provide be useful throughout the default geographic market incorporated in the existing market power screens?

Frequency Response Service

As discussed above, frequency response service, if provided on a stand-alone basis, would have very different characteristics from regulation service. A significant difference would be the fact that the response would be automatic and autonomous, requiring no dispatch signal from any centralized system. The following questions are

meant to explore what if any impact this and other differences might have on the screening of market power for sales of this product.

- To what extent can entities sell autonomous frequency response service across balancing areas in a manner consistent with the assumptions reflected in existing market power screens for energy and capacity?
    - Regarding the assumption of the existing screens that all uncommitted generation resources can compete with each other, what type or settings of equipment or changes to their dispatch and operation are needed to allow the various types of generation resources in the existing market power screens to provide autonomous frequency response service, what types of resources and what proportion in the market typically have such equipment installed, and how easy and cost-effective is it to retrofit such equipment after initial construction for those that do not typically come with it installed?
    - Also, would the requirement for rapid reaction mean that not all of the available resources that would otherwise be incorporated in the existing market power screens for sales of energy and capacity should be considered capable of competing to provide frequency response service?
        - If so, are there any relatively simple adjustments that could be made to the existing market power screens to address this issue (e.g., an assumption that particular classes of generation should not be viewed as available capacity with respect to frequency response service)?
    - Regarding the default geographic market reflected in the existing screens, would the autonomous nature of frequency response service mean that no special scheduling provisions like dynamic scheduling or pseudo-ties are needed to permit sellers in a first-tier balancing area to compete with sellers in neighboring balancing areas?
- How would the relevant geographic market for frequency response service be established?
- How can a market power screen be developed to consider transmission, distributed resources, and demand side alternatives to generator-supplied frequency response service? If any of these competitors are located at the sites of retail load on the

distribution grid, would the frequency response service they provide be useful throughout the default geographic market incorporated in the existing market power screens?

Roundtable Participants

- Doug Hils, Director, Midwest System Operations, Duke Energy (Edison Electric Institute)
- Dmitry Kosterev, Electrical Engineer, Bonneville Power Administration
- Nick Miller, Director Energy Applications & Systems Engineering, GE Energy
- David Hunger, Vice President, Charles River Associates
- Clyde Loutan, Senior Advisor Renewable Energy Integration, California ISO
- James Ginnetti, Senior Vice President External Affairs and Markets, EquiPower Resources Corp.
- Ryan Hanley, Director of Grid Engineering Solutions, SolarCity

2:50 p.m. – 3:00 p.m. Wrap Up