format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

27. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

28. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters are not required to serve copies of their comments on other commenters.

IV. Document Availability

29. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

30. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number (excluding the last three digits) in the docket number field.

31. User assistance is available for eLibrary and the Commission's Web site during normal business hours from the Commission's Online Support at 202–502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202)502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

By direction of the Commission.

Issued: November 17, 2016.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

[FR Doc. 2016–28193 Filed 11–23–16; 8:45 am]

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DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM16–6–000]

Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to revise its regulations to require all newly interconnecting large and small generating facilities, both synchronous and non-synchronous, to install and enable primary frequency response capability as a condition of interconnection. To implement these requirements, the Commission proposes to revise the *pro forma* Large Generator Interconnection Agreement (LGIA) and the *pro forma* Small Generator Interconnection Agreement (SGIA). The proposed changes are designed to address the increasing impact of the evolving generation resource mix and to ensure that the relevant provisions of the *pro forma* LGIA and *pro forma* SGIA are just, reasonable, and not unduly discriminatory or preferential. The Commission also seeks comment on whether its proposals in this Notice of Proposed Rulemaking are sufficient at this time to ensure adequate levels of primary frequency response, or whether additional reforms are needed.

DATES: Comments are due January 24, 2017.

ADDRESSES: Comments, identified by docket number, may be filed in the following ways:

- Electronic Filing through *http://www.ferc.gov.* Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format.
- *Mail/Hand Delivery:* Those unable to file electronically may mail or hand-deliver comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

Instructions: For detailed instructions on submitting comments and additional information on the rulemaking process, see the Comment Procedures Section of this document.

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

1. In this Notice of Proposed Rulemaking (NOPR), the Federal Energy Regulatory Commission (Commission) proposes to modify the *pro forma* Large Generator Interconnection Agreement (LGIA) and the *pro forma* Small Generator Interconnection Agreement (SGIA), pursuant to its authority under section 206 of the Federal Power Act (FPA) to ensure that rates, terms and conditions of jurisdictional service remain just and reasonable and not unduly discriminatory or preferential.[1] The proposed modifications would require all new large and small generating facilities, including both synchronous and non-synchronous, interconnecting with a LGIA or SGIA to install, maintain and operate equipment capable of providing primary frequency response as a condition of interconnection. The Commission also proposes to establish certain operating requirements, including maximum droop and deadband parameters in the *pro forma* LGIA and *pro forma* SGIA. The Commission does not propose to apply these requirements to generating facilities regulated by the Nuclear Regulatory Commission. In addition, the Commission does not propose in these reforms to impose a headroom requirement for new generating facilities. The Commission also does not propose to mandate that new generating facilities receive any compensation for complying with the proposed requirements in this NOPR.

2. The proposed revisions address the Commission's concerns that the existing *pro forma* LGIA contains limited primary frequency response requirements that apply only to synchronous generating facilities and do not account for recent technological advancements that have enabled new non-synchronous generating facilities to now have primary frequency response capabilities. Further, the Commission believes that it may be unduly discriminatory or preferential to impose primary frequency response requirements only on new large generating facilities but not on new small generating facilities, and the reforms proposed here would impose

[1] 16 U.S.C. 824e (2012).

comparable primary frequency response requirements on both new large and small generating facilities.

3. In addition, and as discussed below in paragraph 57, the Commission also seeks comment on whether its proposals in this NOPR are sufficient at this time to ensure adequate levels of primary frequency response, or whether additional reforms are needed.

4. The Commission seeks comment on the proposed reforms and requests for comment sixty (60) days after publication of this NOPR in the **Federal Register**.

I. Background

A. Frequency Response

5. Reliable operation of an Interconnection [2] depends on maintaining frequency within predetermined boundaries above and below a scheduled value, which is 60 Hertz (Hz) in North America. Changes in frequency are caused by changes in the balance between load and generation, such as the sudden loss of a large generator or a large amount of load. If frequency deviates too far above or below its scheduled value, it could potentially result in under frequency load shedding (UFLS), generation tripping, or cascading outages.[3]

6. Mitigation of frequency deviations after the sudden loss of generation or load is driven by three primary factors: inertial response, primary frequency response, and secondary frequency response.[4] Primary frequency response actions begin within seconds after system frequency changes and are mostly provided by the automatic and autonomous actions (*i.e.,* outside of system operator control) of turbine-governors, while some response is provided by frequency responsive loads.[5] Primary frequency response actions are intended to arrest abnormal frequency deviations and ensure that system frequency remains within acceptable bounds. An important goal for system planners and operators is for the frequency nadir,[6] during large disturbances, to remain above the first stage of UFLS set points within an Interconnection.

7. Frequency response is a measure of an Interconnection's ability to arrest and stabilize frequency deviations following the sudden loss of generation or load, and is affected by the collective responses of generation and load throughout the Interconnection. When considered in aggregate, the primary frequency response provided by generators within an Interconnection has a significant impact on the overall frequency response. NERC Reliability Standard BAL–003–1.1 defines the amount of frequency response needed from balancing authorities [7] to maintain Interconnection frequency within predefined bounds and includes requirements for the measurement and provision of frequency response.[8] While NERC Reliability Standard BAL–003–1.1 establishes requirements for balancing authorities, it does not include any requirements for individual generator owners or operators.[9]

8. Unless otherwise required by tariffs or interconnection agreements, generator owners and operators can independently decide whether units are configured to provide primary frequency response.[10] The magnitude and duration of a generator's response to frequency deviations is generally determined by the settings of the unit's governor [11] (or equivalent controls) and other plant level (*e.g.,* ''outer-loop'') control systems. In particular, the governor's droop and deadband settings have a significant impact on the unit's provision of primary frequency response. In addition, plant-level or ''outer-loop'' controls, unless properly configured, can override or nullify a generator's governor response and return the unit to operate at a scheduled pre-disturbance megawatt set-point.[12] In 2010, NERC conducted a survey of generator owners and operators and found that only approximately 30 percent of generators in the Eastern Interconnection provided primary frequency response, and that only approximately 10 percent of generators provided sustained primary frequency response.[13] This suggests that many generators within the Interconnection disable or otherwise set their governors or outer-loop controls such that they provide little to no primary frequency response.[14]

9. Declining frequency response performance has been an industry concern for many years. NERC, in conjunction with EPRI, initiated its first examination of declining frequency response and governor response in 1991.[15] More recently, as noted in the

[2] An Interconnection is a geographic area in which the operation of the electric system is synchronized. In the continental United States, there are three Interconnections, namely the Eastern, Texas, and Western Interconnections.

[3] UFLS is designed for use in extreme conditions to stabilize the balance between generation and load. Under frequency protection schemes are drastic measures employed if system frequency falls below a specified value. *See Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards,* Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,682, at PP 4–10 (2011) (Order No. 763 NOPR) at PP 4–10.

[4] In the Notice of Inquiry issued in Docket No. RM16–6–000 on Feb. 8, 2016, the Commission provided detailed discussion of how inertia, primary frequency response, and secondary frequency response interact to mitigate frequency deviations. *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response,* 154 FERC ¶ 61,117, at PP 3–7 (2016) (NOI). *See also Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation,* Lawrence Berkeley National Laboratory, at 13–14 (Dec. 2010), *http://energy.lbl.gov/ea/certs/pdf/lbnl-4142e.pdf* (LBNL 2010 Report).

[5] NOI, 154 FERC ¶ 61,117 at P 6. The Commission also noted that regulation service is different than primary frequency response because generating facilities that provide regulation respond to automatic generation control signals and regulation service is centrally coordinated by the system operator, whereas primary frequency response service, in contrast, is autonomous and is not centrally coordinated. Schedule 3 of the *pro forma* Open Access Transmission Tariff (OATT) bundles these different services together, despite their differences. *See Id.* n.66.

[6] The point at which the frequency decline is arrested (following the sudden loss of generation) is called the frequency nadir, and represents the point at which the net primary frequency response (real power) output from all generating units and the decrease in power consumed by the load within an Interconnection matches the net initial loss of generation (in megawatts (MW)).

[7] NERC's Glossary of Terms defines a balancing authority as ''(t)he responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports Interconnection frequency in real time.''

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

[9] The Commission has also accepted Regional Reliability Standard BAL–001–TRE–01 (Primary Frequency Response in the ERCOT Region) as mandatory and enforceable, which does establish requirements for generator owners and operators with respect to governor control settings and the provision of primary frequency response within the Electric Reliability Council of Texas (ERCOT) region. *North American Electric Reliability Corporation,* 146 FERC ¶ 61,025 (2014).

[10] *See* NOI, 154 FERC ¶ 61,117 at PP 18–19.

[11] A governor is an electronic or mechanical device that implements primary frequency response on a generator via a droop parameter. Droop refers to the variation in real power (MW) output due to variations in system frequency and is typically expressed as a percentage (*e.g.,* 5 percent droop). Droop reflects the amount of frequency change from nominal (*e.g.,* 5 percent of 60 Hz is 3 Hz) that is necessary to cause the main prime mover control mechanism of a generating facility to move from fully closed to fully open. A governor also has a deadband parameter which establishes a minimum frequency deviation (*e.g.,* ±0.036 Hz) from nominal that must be exceeded in order for the governor to act.

[12] For more discussion on ''premature withdrawal'' of primary frequency response, *see* NOI, 154 FERC ¶ 61,117 at PP 49–50.

[13] *See* NERC *Frequency Response Initiative Report: The Reliability Role of Frequency Response* (Oct. 2012), *http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf* (NERC Frequency Response Initiative Report) at 95.

[14] However, as noted below, some commenters note that nuclear generating units are restricted by their U.S. Nuclear Regulatory Commission operating licenses regarding the provision of primary frequency response.

[15] NERC Frequency Response Initiative Report at 22.

NOI, while the three U.S. Interconnections currently exhibit adequate frequency response performance above their Interconnection Frequency Response Obligations,[16] there has been a significant decline in the frequency response performance of the Western and Eastern Interconnections.[17]

B. Prior Commission Actions

10. In Order Nos. 2003 [18] and 2006,[19] the Commission adopted standard procedures for the interconnection of large and small generating facilities, including the development of standardized *pro forma* generator interconnection agreements and procedures. The Commission required public utility transmission providers [20] to file revised OATTs containing these standardized provisions, and use the LGIA and SGIA to provide non-discriminatory interconnection service to Large Generators (*i.e.,* generating facilities having a capacity of more than 20 MW) and Small Generators (*i.e.,* generators having a capacity of no more than 20 MW). The *pro forma* LGIA and *pro forma* SGIA have since been revised through various subsequent proceedings.[21]

11. As relevant here, the *pro forma* LGIA and *pro forma* SGIA are largely silent on any requirements with respect to primary frequency response. In particular, the only requirement in the *pro forma* LGIA or *pro forma* SGIA related to primary frequency response is contained within current Article 9.6.2.1 of the *pro forma* LGIA (Governors and Regulators), which provides that *if* speed governors are installed, they should be operated in automatic mode.[22] A speed governor implements the primary frequency response provided by a synchronous generating facility; however, Article 9.6.2.1 does not address governor settings or plant-level controls, which also affect the ability of a generating facility to provide primary frequency response. In addition, Article 9.6.2.1 does not require the installation of the necessary equipment for frequency response capability (*i.e.,* governors or equivalent controls). Finally, the *pro forma* SGIA does not contain any provisions related to primary frequency response.

C. Efforts To Evaluate the Impacts of the Changing Resource Mix

12. The Commission's *pro forma* generator interconnection agreements and procedures were developed at a time when traditional synchronous generating facilities with standard governor controls and large rotational inertia were the predominant sources of electricity generation. However, the nation's resource mix has undergone significant change since the issuance of Order Nos. 2003 and 2006. This transformation has been characterized by the retirement of baseload, synchronous generating facilities and the integration of more distributed generation, demand response, and natural gas generating facilities, and the rapid expansion of non-synchronous variable energy resources (VERs) such as wind and solar.[23] For example, the U.S. Energy Information Administration (EIA) has observed that the U.S. added approximately 13 gigawatts (GW) of wind, 6.2 GW of utility scale solar photovoltaic (PV), and 3.6 GW of distributed solar PV generating facilities in 2014 and 2015.[24] Conversely, NERC has reported [25] that almost 42 GW of synchronous generating facilities (*e.g.,* coal, nuclear, and natural gas) have retired between 2011 and 2014, and the EIA recently reported that nearly 14 GW of coal and 3 GW of natural gas generating facilities retired in 2015.[26]

13. While technological advancements have enabled wind and solar generating facilities to now have the ability to provide primary frequency response, this functionality has not historically been a standard feature that was included and enabled on non-synchronous generating facilities. Moreover, wind and solar generating facilities typically operate at their maximum operating output, leaving no capacity (or ''headroom'') [27] to provide primary frequency response during under-frequency conditions.

14. Given the changes in the resource mix and concerns about the significant decline in frequency response for the Eastern and Western Interconnections,[28] NERC has undertaken several initiatives to evaluate the impacts of the changing resource mix, particularly with respect to primary frequency response. For example, in 2014, NERC initiated the Essential Reliability Services Task Force (Task Force) to analyze and better understand the impacts of the changing resource mix and develop technical assessments of essential reliability services.[29] The Task Force focused on three essential reliability services: Frequency support, ramping capability, and voltage support.[30] The Task Force considered the seven ancillary

[16] The Interconnection Frequency Response Obligations are established by NERC and are designed to require sufficient frequency response for each Interconnection (*i.e.,* the Eastern, ERCOT, Quebec and Western Interconnections) to arrest frequency declines even for severe, but possible, contingencies.

[17] NOI, 154 FERC ¶ 61,117 at P 20.

[18] *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g,* Order No. 2003–A, FERC Stats. & Regs. ¶ 31,160, *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).

[19] *Standardization of Small Generator Interconnection Agreements and Procedures,* Order No. 2006, FERC Stats. & Regs. ¶ 31,180, *order on reh'g,* Order No. 2006–A, FERC Stats. & Regs. ¶ 31,196 (2005), *order granting clarification,* Order No. 2006–B, FERC Stats. & Regs. ¶ 31,221 (2006).

[20] A public utility is a utility that owns, controls, or operates facilities used for transmitting electric energy in interstate commerce, as defined by the FPA. *See* 16 U.S.C. 824(e) (2012). A non-public utility that seeks voluntary compliance with the reciprocity condition of an OATT may satisfy that condition by filing an OATT, which includes a LGIA and SGIA. *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146, at PP 840–845.

[21] *E.g., Small Generator Interconnection Agreements and Procedures,* Order No. 792, 145 FERC ¶ 61,159 (2013), *clarifying,* Order No. 792–A, 146 FERC ¶ 61,214 (2014); *Reactive Power Requirements for Non-Synchronous Generation,* Order No. 827, 81 FR 40,793 (Jun. 23, 2016), 155 FERC ¶ 61,277 (2016); *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities,* Order No. 828, 81 FR 50,290 (Aug. 1, 2016), 156 FERC ¶ 61,062 (2016).

[22] Article 9.6.2.1 of the *pro forma* LGIA.

[23] The term VER is defined as a device for the production of electricity that is characterized by an energy source that: (1) Is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. *See, e.g., Integration of Variable Energy Resources,* Order No. 764, FERC Stats. & Regs. ¶ 31,331, at P 210 (2012).

[24] *See, U.S. electric generation capacity additions, 2015 vs. 2014,* EIA (March 2016), *https://www.eia.gov/todayinenergy/detail.php?id=25492.*

[25] *See* NERC 2015 LTRA (Dec. 2015), *http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2015LTRA%20-%20Final%20Report.pdf.*

[26] *See Electricity generating capacity retired in 2015 by fuel and technology,* EIA (May 2016), *http://www.eia.gov/todayinenergy/detail.php?id=25272.*

[27] Headroom refers to the difference between the current operating point of a generator and its maximum operating capability, and represents the potential amount of additional energy that can be provided by the generating facility in real-time.

[28] *See* NERC *Frequency Response Initiative Industry Advisory—Generator Governor Frequency Response,* at slide 10 (Apr. 2015), *http://www.nerc.com/pa/rrm/Webinars%20DL/Generator_Governor_Frequency_Response_Webinar_April_2015.pdf.* (NERC 2015 Frequency Response Webinar). *See* also LBNL 2010 Report at pp xiv–xv.

[29] Essential reliability services are referred to as elemental reliability building blocks from resources (generation and load) that are necessary to maintain the reliability of the Bulk-Power System. *See* Essential Reliability Services Task Force Scope Document, at 1 (Apr. 2014), *http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Scope_ERSTF_Final.pdf.*

[30] Essential Reliability Services Task Force Measures Report, at 22 (Dec. 2015), *http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf.*

services[31] adopted by the Commission in Order Nos. 888[32] and 890[33] as a subset of the essential reliability services that may need to be augmented by additional services as the Bulk-Power System[34] characteristics change.

15. The Task Force did not recommend new reliability standards or specific actions to alter the existing suite of ancillary services; however, it did make certain conclusions with regard to primary frequency response. Specifically, the Task Force concluded that it is prudent and necessary to ensure that primary frequency response capabilities are present in the future generation resource mix, and recommended that all new generators support the capability to manage frequency.[35]

16. In addition, as part of its ongoing analysis of primary frequency response concerns, NERC observed in a 2012 report that a number of generators implemented deadband settings that were so wide as to effectively defeat the ability to provide primary frequency response.[36] The report also notes that many generators provide frequency response in the wrong direction during a disturbance.[37] Additionally, in February 2015, NERC issued an Industry Advisory that determined that a significant portion of generators within the Eastern Interconnection use deadbands or governor control settings that either inhibit or prevent the provision of primary frequency response.[38] Moreover, as noted in the NOI, NERC observed in 2015 that in many conventional steam plants, deadband settings exceed ±0.036 Hz, resulting in primary frequency response that is not sustained, and that the vast majority of the gas turbine fleet is not frequency responsive.[39] In response to these issues and other concerns, NERC's Operating Committee approved a voluntary Primary Frequency Control Guideline that contains recommended settings for generator governors and other plant control systems, and encourages generators within the three U.S. Interconnections to provide sustained and effective primary frequency response.[40] NERC's Guideline recommends maximum 5 percent droop and ±0.036 Hz deadband settings for most generating facilities.[41]

D. Initiatives by Individual Transmission Providers

17. While the *pro forma* LGIA and *pro forma* SGIA do not provide specific requirements related to frequency response, some public utility transmission providers have included provisions related to primary frequency response in their LGIA, SGIA, OATTs, and/or business practice manuals.

18. For example, ISO New England Inc. (ISO–NE) and New York Independent System Operator, Inc. (NYISO) have adopted provisions to their LGIAs that establish more specific requirements for governor operation.[42] In particular, ISO–NE requires each generator within its region with a capability of 10 MW or more, including VERs, to operate with a functioning governor with specified droop and deadband settings, *i.e.,* maximum 5 percent droop and ±0.036 Hz deadband, and to also ensure that the provision of primary frequency response is not inhibited by the effects of outer-loop controls.[43]

19. PJM Interconnection, L.L.C. (PJM) has implemented governor droop and deadband requirements, *i.e.,* maximum 5 percent droop and ±0.036 Hz deadband, for all generating facilities excluding nuclear facilities with a gross plant/facility aggregate nameplate rating greater than 75 MVA.[44] PJM also recently added new interconnection requirements requiring new non-synchronous generators to interconnect with ''enhanced inverters'' that have various capabilities including, among other things, the ability to provide primary frequency response.[45]

20. Midcontinent Independent System Operator, Inc. (MISO) requires governor operation as a condition for providing regulating reserve but does not require specific settings.[46] Also, the Commission recently accepted tariff provisions proposed by the California Independent System Operator Corporation (CAISO) to require governor operation, specified droop and deadband settings, *i.e.,* maximum 5 percent droop and ±0.036 Hz deadband, and provisions for sustained primary frequency response for its participating generators that have traditional governor controls.[47]

E. Notice of Inquiry

1. Summary

21. On February 18, 2016, the Commission issued the NOI to explore issues regarding essential reliability

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[31] The seven *pro forma* ancillary services set forth in Order Nos. 888 and 890 are: (1) Scheduling, System Control and Dispatch Service; (2) Reactive Supply and Voltage Control from Generation Sources Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve—Spinning Reserve Service; (6) Operating Reserve—Supplemental Reserve Service; and (7) Generator Imbalance Service.

[32] *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 (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).

[33] *Preventing Undue Discrimination and Preference in Transmission Service,* Order No. 890, FERC Stats. & Regs. ¶ 31,241, *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, *order on clarification,* Order No. 890–D, 129 FERC ¶ 61,126 (2009).

[34] Section 215(a)(1) of the Federal Power Act (FPA), 16 U.S.C. 824o(a)(1) (2012) defines ''Bulk-Power System'' as those ''facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof) [and] electric energy from generating facilities needed to maintain transmission system reliability.'' The term does not include facilities used in the local distribution of electric energy. *See also Mandatory Reliability Standards for the Bulk-Power System,* Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 76, *order on reh'g,* Order No. 693–A, 120 FERC ¶ 61,053 (2007).

[35] Essential Reliability Services Task Force Measures Report at vi.

[36] NERC Frequency Response Initiative Report at 92.

[37] NERC Frequency Response Initiative Report at 96–97.

[38] NERC Generator Governor Frequency Response Industry Advisory (Feb. 2015), *http://www.nerc.com/pa/rrm/bpsa/Alerts%20DL/2015%20Alerts/NERC%20Alert%20A-2015-02-05-01%20Generator%20Governor%20Frequency%20Response.pdf.*

[39] NOI, 154 FERC ¶ 61,117 at P 50 (citing to NERC 2015 Frequency Response Webinar at 1).

[40] *See* NERC Primary Frequency Control Guideline Final Draft (Dec. 2015), *http://www.nerc.com/comm/OC/Reliability%20Guideline%20DL/Primary_Frequency_Control_final.pdf* (NERC Primary Frequency Control Guideline). *See also* NERC Operating Committee Meeting Minutes (Jan. 2016), *http://www.nerc.com/comm/OC/AgendasHighlightsMinutes/Operating%20Committee%20Minutes%20-%20Dec%2015-16%202015-Final.pdf.*

[41] *See* NERC Primary Frequency Control Guideline at 7–9.

[42] *See* ISO–NE, Transmission, Markets and Services Tariff, Schedule 22 Large Generator Interconnection Procedures (9.0.0), Appendix 6, 9.6.2.2; NYISO, NYISO Tariffs, NYISO OATT, 30.14 OATT Att. X Appendices (8.0.0), Appendix 6, 9.5.4.

[43] *See* ISO–NE's Operating Procedure No. 14 I (Governor Control), *http://www.iso-ne.com/rules_proceds/operating/isone/op14/op14_rto_final.pdf.*

[44] PJM's *pro forma* interconnection agreements obligate interconnection customers within its region to abide by all PJM rules and procedures, including rules set forth in PJM's Manuals (*See* PJM Tariff, Attachment O 8.0). *See also* PJM Manual 14D 7.1.1 (Generator Real-Power Control), *http://www.pjm.com/~/media/documents/manuals/m14d.ashx.*

[45] *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097, at n.58 (2015).

[46] *See* MISO, FERC Electric Tariff, Module C, Energy and Operating Reserve Markets 39.2.1B (34.0.0) (''All Regulation Qualified Resources in the Day-Ahead Energy and Operating Reserve Market must be capable of automatically responding to and alleviating frequency deviations through a speed governor or similar device in accordance with the Applicable Reliability Standards.'').

[47] *CAISO,* 156 FERC ¶ 61,182, at PP 10–12 and 17 (2016).

services and the evolving Bulk-Power System.[48] In particular, the Commission asked a broad range of questions on the need for reform of its rules and regulations regarding the provision of and compensation for primary frequency response. The Commission explained that there is a significant risk that, as conventional synchronous generating facilities retire or are displaced by increased numbers of VERs that do not typically contribute to system inertia or have primary frequency response capabilities, the net amount of frequency responsive generation online will be reduced.[49] The Commission also explained that these developments and their potential impacts could challenge system operators in maintaining reliability.[50] Further, the Commission explained that NERC Reliability Standard BAL–003–1.1 and the *pro forma* LGIA and *pro forma* SGIA do not specifically address a generator's ability to provide frequency response.[51] The Commission noted, however, that while in previous years many non-synchronous generating facilities were not designed with primary frequency response capabilities, the technology now exists for new non-synchronous generating facilities to install primary frequency response capability.[52]

22. Accordingly, the Commission requested comments on three main sets of issues. First, the Commission sought comment on whether amendments to the *pro forma* LGIA and *pro forma* SGIA are warranted to require all new generating facilities, both synchronous and non-synchronous, to have primary frequency response capabilities as a precondition of interconnection.[53] Second, the Commission sought comment on the performance of existing generating facilities and whether primary frequency response requirements for these facilities are warranted.[54] Finally, the Commission sought comment on compensation for primary frequency response.[55]

2. Comments on Modifying the Pro Forma LGIA and Pro Forma SGIA

23. The Commission received a robust response from industry, with 47 entities collectively submitting nearly 700 pages of comments that provided responses to some or all of the questions posed by the NOI.[56] Relevant to the proposed revisions considered in this NOPR, the Commission received numerous comments on whether the *pro forma* LGIA and *pro forma* SGIA should be revised to include requirements for all newly interconnecting generating facilities, whether synchronous or non-synchronous, to install primary frequency response capability.[57]

a. Comments in Support of Modifying the pro forma LGIA and pro forma SGIA

24. Most commenters support, or are not opposed to, revising the *pro forma* LGIA and SGIA to impose primary frequency response capability requirements on all new generating facilities as suggested in the NOI.[58] Several commenters indicate that the nation's changing resource mix could create reliability concerns related to the provision of primary frequency response. For example, PJM Utilities Coalition states that while newer generating facilities are not installing frequency response capability, the existing generating facilities that do provide this essential reliability service have more limited capability, due to the cost of operation and planned retirements, placing the grid at further risk.[59] Peak Reliability, the reliability coordinator for the Western Interconnection, states that as baseload generation retires, the number of generators providing primary frequency response is reduced and may present reliability challenges for system operators, as fewer options are available to reduce frequency deviations following an unexpected loss of generation or load.[60] CAISO asserts that due to the increased proportion of renewable generating facilities operating in CAISO's balancing authority area, there may not be sufficient frequency responsive capacity online when the system has high renewable output and low load levels.[61] Bonneville states that the trend of declining frequency response capability will continue with a changing resource mix, unless provisions are put in place to assure that adequate inertial and primary frequency response capability are available in the future.[62] NERC states that the rapidly changing resource mix may reduce the level of available frequency capability.[63]

25. Numerous commenters assert that they recognize the benefits of revising the *pro forma* LGIA and *pro forma* SGIA to require primary frequency response capabilities for new generators. NERC, for example, asserts that new primary frequency response requirements for generators will improve operator flexibility for system restoration and island capability and help balancing authorities meet their frequency response obligations.[64] NERC also asserts that revisions to the *pro forma* LGIA and *pro forma* SGIA would result in measurable, clear requirements applicable to all new generating facilities in a fair and equitable manner.[65] NERC points out, however, that primary frequency response capability, by itself, would not require a resource to respond if called upon to help a balancing authority meet its frequency response obligation, and that, as a result, it is important to have mechanisms to ensure that sufficient frequency response capability is not only available but ready to respond at all times.[66] CASIO, Indicated ISOs/RTOs, MISO, and a number of trade associations also support modifications to the *pro forma* LGIA and *pro forma* SGIA for new generating facilities to install primary frequency response capability.[67] PJM Utilities Coalition states that, with all new generating facilities (both synchronous and non-synchronous) being fully capable of providing primary frequency response, requiring this capability will ensure that system operators have the ability to reliably operate the grid of the future.[68] Peak Reliability states that it supports modifications to the *pro forma* LGIA and *pro forma* SGIA and that requiring generating facilities to install or provide frequency response in the initial stages of the interconnection process will ensure that the grid is able to maintain

[48] NOI, 154 FERC ¶ 61,117.

[49] *Id.* P 12.

[50] *Id.* P 14.

[51] *Id.* P 41.

[52] *Id.* P 43.

[53] *Id.* PP 2 and 44–45.

[54] *Id.* PP 2, 46, and 52.

[55] *Id.* PP 2, 53–54.

[56] The Appendix lists the entities that submitted comments and the shortened names that are used throughout this NOPR.

[57] NOI, 154 FERC ¶ 61,117 at P 45.

[58] APPA, *et al.* Comments at 6; Bonneville Comments at 6; CAISO Comments at 2; California Cities Comments at 2; ELCON Comments at 5; EEI Comments at 12; EPSA, *et al.* Comments at 8; Howard F. Illian Comments at 43; Idaho Power Comments at 1; IEEE–PES Comments at 1; Indicated ISOs/RTOs Comments at 3; ITC, *et al.* Comments at 1; MISO Comments at 4; MISO TOs Comments at 6; NARUC Comments at 3; NERC Comments at 17; North American Generator Forum Comments at 2; Peak Reliability Comments at 4; PG&E Comments at 2; SoCal Edison Comments at 4; Southern Company Comments at 2; Tri-State Generation Comments at 3; WIRAB Comments at 3.

[59] PJM Utilities Coalition Comments at 3.

[60] Peak Reliability Comments at 4.

[61] CAISO Comments at 2.

[62] Bonneville Comments at 2.

[63] NERC Comments at 17.

[64] *Id.*

[65] *Id.*

[66] *Id.* at 18.

[67] APPA, *et al.* Comments at 2; CAISO Comments at 2; EEI Comments at 3; EPSA, *et al.* Comments at 8; Indicated ISOs/RTOs Comments at 3; MISO Comments at 4; North American Generator Forum Comments at 2.

[68] PJM Utilities Coalition Comments at 4–5.

this essential service even as the resource mix changes.[69]

26. Other commenters also express support for revising the *pro forma* LGIA and *pro forma* SGIA. Bonneville points out that selling primary frequency response capability would not provide sufficient incentive for new generating facilities to invest in such capability, and argues that the only way to ensure that there is enough primary frequency response capability is to require new generators to install it.[70] WIRAB advises that while current studies do not indicate that there is a shortage of primary frequency response in the Western Interconnection and that all generators do not need to provide primary frequency response all of the time, the Commission should, however, require that all new generator owners install primary frequency response capability because of the changing resource mix in the Western Interconnection and the associated uncertainty regarding the future provision of primary frequency response.[71]

27. Several commenters that generally support revising the *pro forma* LGIA and *pro forma* SGIA also express certain concerns. For example, Southern Company expresses support for revising the *pro forma* LGIA and *pro forma* SGIA, but caveats its support by arguing that new regulations for primary frequency response should include an ''opt-out'' provision that would allow balancing authorities that do not anticipate frequency response shortfalls to delay the implementation of the new *pro forma* LGIA and *pro forma* SGIA requirements until these needs are actually anticipated in their regions in order to avoid higher costs.[72] EPSA, *et al.* state that while they do not fully oppose amending the *pro forma* LGIA and *pro forma* SGIA, they recommend that the Commission explore more effective and cost efficient ways to address the range of issues posed in the NOI and consider a measured approach before mandating governors for all prospective interconnecting generation.[73]

28. Some commenters that support modifying the *pro forma* LGIA and *pro forma* SGIA also assert that the costs of implementing primary frequency response capability for new generating facilities are low.[74] For example, APPA, *et al.* state that the capability for providing primary frequency response is almost always installed in synchronous generation, and that the inclusion of this additional control for new non-synchronous generating facilities would likely add only nominal costs.[75] EEI asserts that all new generating facilities coming online can be fully capable of providing primary frequency response and that the associated cost of installing such capability during initial manufacturing or construction of a new VER is small when considering the overall cost of the new generating facility.[76]

29. In contrast to new generating facilities, some entities, however, explain that the costs of retrofitting existing generating facilities with primary frequency response capability could be significant in some cases.[77] For example, WIRAB states that the high cost of retrofitting existing generators to install the necessary control equipment supports limiting the requirement to new generators and taking early action now.[78]

30. In regards to nuclear generating facilities, some commenters indicate that nuclear plants have separate licensing requirements under the Nuclear Regulatory Commission and should not be required to provide primary frequency response. For example, the Nuclear Energy Institute asserts that while nearly all new generating facilities should be able to provide primary frequency response, nuclear plants are not well-suited to provide primary frequency response due to restrictions by their operating licenses issued by the Nuclear Regulatory Commission.[79] The Nuclear Energy Institute also asserts that turbine controls on most nuclear units are designed to maintain the internal steam pressure and are not intended to react to changes in the grid.[80] Similarly, the MISO TOs assert that requiring nuclear units to have primary frequency response capability would be contrary to Nuclear Regulatory Commission licensing requirements, and could have a detrimental effect on the safety of the nuclear fleet.[81]

31. In the NOI, the Commission also sought comment on whether it would be appropriate to include recommended governor settings contained within NERC's Primary Frequency Control Guideline in the *pro forma* LGIA and *pro forma* SGIA.[82] Numerous commenters express support for including NERC's recommended governor control settings in the *pro forma* LGIA and *pro forma* SGIA.[83] Some commenters note that NERC's Guideline is consistent with existing regulations or practices in certain regions.[84] Indicated ISOs/RTOs point out that common primary frequency response settings for generators in an Interconnection will enhance reliability by reducing maneuvering by individual generators.[85] MISO asserts that NERC's Guideline provides a sound baseline.[86] NERC notes that its Guideline was developed by technical committees with expertise and judgment of the electric industry, and accordingly, the Guideline is the ''most advanced set of nation-wide best practices and information currently available to support frequency response capability.'' [87]

32. However, not all entities that support modifying the *pro forma* LGIA and *pro forma* SGIA endorse the inclusion of NERC's recommended governor settings. For example, EEI states that it does not support including prescriptive performance requirements for governor control settings or other performance indicators in the *pro forma* LGIA or *pro forma* SGIA due to the physical, technical, or operational limitations of new generating facilities to provide primary frequency response.[88] Similarly, APPA, *et al.* state that they do not support revising the *pro forma* LGIA and *pro forma* SGIA to include the recommended settings contained within NERC's Guideline at this time.[89] MISO TOs state that some transmission owners in MISO believe that NERC's recommended governor settings are appropriate for traditional synchronous generating facilities, but recommend additional consideration for other generation technologies.[90] On the other hand, MISO TOs state that other transmission owners in MISO request

[69] Peak Reliability Comments at 4–5.

[70] Bonneville Comments at 21.

[71] WIRAB Comments at 5–6.

[72] Southern Company Comments at 2–3.

[73] EPSA, *et al.* Comments at 8–9.

[74] APPA, *et al.* Comments at 6; Bonneville Comments at 8; California Cities Comments at 2; EEI Comments at 13; Indicated ISOs/RTOs Comments at 5; MISO Comments at 4; SoCal Edison Comments at 2.

[75] APPA, *et al.* Comments at 6.

[76] EEI Comments at 13.

[77] APPA, *et al.* Comments at 6; Bonneville Comments at 8; California Cities Comments at 8; EEI Comments at 14; Idaho Power Comments at 4; WIRAB Comments at 6.

[78] WIRAB Comments at 6.

[79] Nuclear Energy Institute Comments at 1 and 4.

[80] Nuclear Energy Institute Comments at 4.

[81] MISO TOs Comments at 7.

[82] NOI, 154 FERC ¶ 61,117 at P 45.

[83] *See e.g.,* Bonneville Comments at 7; IEEE–PES Comments at 1; Indicated ISOs/RTOs Comments at 4; California Cities Comments at 2; WIRAB Comments at 7.

[84] Indicated ISOs/RTOs Comments at 4; SoCal Edison Comments at 4; Peak Reliability Comments at 7; Manitoba Comments at 8.

[85] Indicated ISOs/RTOs Comments at 5.

[86] MISO Comments at 4.

[87] NERC Comments at 12.

[88] EEI Comments at 15–17.

[89] APPA, et al. Comments at 8.

[90] MISO TOs Comments at 8.

flexibility and assert that specified governor settings should not be ''hard-wired'' or dictated in the *pro forma* LGIA and *pro forma* SGIA.[91]

b. Comments Opposed To Modifying the pro forma LGIA and pro forma SGIA

33. Other commenters contend that the *pro forma* LGIA and *pro forma* SGIA should not be modified to require primary frequency response capability from new generating facilities.[92] Some commenters argue that requiring all new generating facilities to have primary frequency response capability will result in extra costs above those necessary to ensure reliability.[93] For example, APS argues that a global mandate to provide primary frequency response or to require generating facilities to be primary frequency response capable would result in significantly increased costs while providing a disproportionately minor impact on improving reliability.[94] Powerex asserts that modifying the *pro forma* LGIA and *pro forma* SGIA to include minimum primary frequency response requirements will increase the cost of entry for new generators, particularly VERs, which typically are not designed with such capability.[95] Several commenters note that there would be a significant opportunity cost for certain generating facilities to reserve headroom for the provision of primary frequency response.[96]

34. Some of the commenters that are opposed to modifying the *pro forma* LGIA and pro *forma* SGIA assert that they prefer a market-based approach instead of a requirement for new generating facilities to install primary frequency response capability.[97] For example, AWEA asserts that, initially, the *pro forma* LGIA and *pro forma* SGIA should not be revised to require new generating facilities to have primary frequency response capability, and only if market-based steps do not satisfactorily address the need for primary frequency response, then the Commission could consider an additional requirement for new generating facilities to have such capability as a final step.[98]

35. Other commenters oppose mandatory requirements and prefer a voluntary approach to improving primary frequency response performance.[99] For example, TVA asserts that if current voluntary actions fail to show improvement in primary frequency response, then the *pro forma* LGIA and *pro forma* SGIA could be revised to contain a general primary frequency response requirement, similar to reactive power, but that NERC should be directed to establish governor settings and performance requirements through the NERC Standards Development Process instead of the Commission including such requirements in the *pro forma* LGIA and *pro forma* SGIA.[100] Some commenters assert that governor control details are better left to individual balancing authorities.[101] For example, APS argues that the Commission should allow balancing authorities to determine the type and magnitude of generating facilities within its balancing authority area that are frequency-response enabled.[102] APS also points out that any need to install frequency response capability or otherwise support frequency response performance can and should be evaluated and agreed upon between a generating facility and the transmission provider during the interconnection study process.[103]

II. Discussion

A. Primary Frequency Response Requirements

1. The Need for Reform

36. Pursuant to FPA section 206, the Commission preliminarily finds that conditions have changed since the issuance of Order Nos. 2003 and 2006 and certain aspects of the *pro forma* LGIA and *pro forma* SGIA may now be unjust, unreasonable, unduly discriminatory, or preferential.[104] Specifically, as discussed above, the record indicates that while the frequency response performance of the Eastern and Western Interconnections is currently adequate, the frequency response performance of both Interconnections has significantly declined from historic values.[105] Furthermore, the record shows that there is an ongoing evolution of the nation's generation resource mix, including significant retirements of baseload generation and an increasing proportion of VERs interconnecting to the electric grid.[106] Several commenters point out that there is significant risk that the rapidly changing resource mix may reduce the level of available frequency response capability online.[107] This is in part because, as noted in the NOI, VERs have not been consistently designed with primary frequency response capabilities.[108] The record suggests, however, that VER manufacturers have made significant technological advancements in recent years to develop primary frequency response capability for VERs.[109] In addition, NERC, in conjunction with various industry stakeholders, has developed more robust technical guidance for the operation of governors or equivalent controls.[110] As a result of the evolving resource mix and the potential for adverse impacts on primary frequency response, the Commission is concerned that there may be potential reliability impacts if it does not undertake the reforms proposed in this NOPR. Moreover, the Commission is concerned that certain aspects of the existing *pro forma* LGIA and *pro forma* SGIA may no longer be just and reasonable.

37. First, the current requirements for governor controls in the *pro forma* LGIA do not reflect advances in technology or the latest recommended operating practices. Specifically, current Article 9.6.2.1 states that ''speed governors,'' if installed, must be operated in automatic

[91] MISO TOs Comments at 8.

[92] AES Companies Comments at 6; Apex Comments at 6; APS Comments at 6; AWEA Comments at 12; Chelan County Comments at 2; ESA Comments at 2; Grid Storage Consulting Comments at 2; Microgrids Resources Coalition Comments at 3; NRECA Comments at 9; Powerex Comments at 5; SDG&E Comments at 3; SolarCity Comments at 1; TVA Comments at 2.

[93] Apex Comments at 5–6; APS Comments at 6; AWEA Comments at 12; Chelan County Comments at 2; Powerex Comments at 5; Solar City Comments at 1.

[94] APS Comments at 6. It is unclear whether the increased costs referenced by APS refer only to the costs for the necessary equipment to provide primary frequency response or the costs associated with maintaining the headroom necessary to provide primary frequency response.

[95] Powerex Comments at 5.

[96] Apex Comments at 7; Solar City Comments at 1; AWEA Comments at 6.

[97] Apex Comments at 6; AWEA Comments at 12; Chelan County Comments at 2; ESA Comments at 2; SDG&E Comments at 3.

[98] AWEA Comments at 12.

[99] APS Comments at 8; NRECA Comments at 6; TVA Comments at 2.

[100] TVA Comments at 2–3 and 5.

[101] APS Comments at 8; AES Companies Comments at 8.

[102] APS Comments at 8.

[103] *Id.* at 15.

[104] The Commission routinely evaluates the effectiveness of its regulations and policies in light of changing industry conditions to determine if changes are necessary. *See, e.g.,* Order No. 764, FERC Stats. & Regs. ¶ 31,331.

[105] *See* NERC 2015 Frequency Response Webinar at 10, NERC Frequency Response Initiative Report at 22, and LBNL 2010 Report at pp xiv–xv.

[106] *See, e.g.,* P 12, *supra* (describing recent and ongoing changes in the nation's generation mix).

[107] *See, e.g.,* Bonneville Comments at 2; CAISO Comments at 2; NERC Comments at 17; Peak Reliability Comments at 4; PJM Utilities Coalition Comments at 3.

[108] NOI, 154 FERC ¶ 61,117 at PP 42–43.

[109] *See, e.g.,* PJM Utilities Comments at 4–5; EEI Comments at 13. *See also* PJM Interconnection, L.L.C., Docket No. ER15–1193–000 (March 6, 2015) Transmittal Letter at 11. *See also* NERC 2014 LTRA, at 27 (Nov. 2014), *http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014LTRA_ERATTA.pdf.*

[110] *See* P 16, *supra.*

mode. However, many of the new generating facilities interconnecting to the grid, such as wind and solar, do not utilize traditional speed governors; instead they utilize enhanced inverters and other plant supervisory control technology that can be designed to include primary frequency response capability.[111] Therefore, due to advancements in technology, the Commission preliminarily finds that the existing references to ''speed governors'' in Article 9.6.2.1 that apply only to synchronous resources are outdated, and therefore may no longer be just and reasonable.

38. Second, since the issuance of Order No. 2003 and the establishment of the *pro forma* LGIA, NERC, in conjunction with industry stakeholders, has amassed a significant body of knowledge in regards to the operation of generator governors and plant control systems. For example, as noted above, NERC observed in 2012 that a number of generators implemented deadband settings that were so wide as to effectively defeat the ability to provide primary frequency response, and that many generators provide frequency response in the wrong direction during a disturbance.[112] Additionally, as noted above, NERC observed in 2015 that in many conventional steam plants, deadband settings exceed a ±0.036 Hz dead band, resulting in primary frequency response that is not sustained, and that the vast majority of the gas turbine fleet is not frequency responsive.[113]

39. The record here suggests that the actual governor and plant control system settings that are being implemented by some generator owners and/or operators may be defeating the intent of Article 9.6.2.1 of the *pro forma* LGIA. In response to these issues, NERC, through the work of its various task forces, subcommittees, and initiatives, has developed a voluntary Guideline that includes recommended droop and deadband settings based on significant investigation.[114] However, the *pro forma* LGIA does not currently reflect these updated recommended practices for governor and plant control system settings of generating facilities.

40. Third, given the nation's evolving resource mix and the potential adverse impacts on primary frequency response as noted in the NOI and pointed out by several commenters, the Commission believes that changes to the *pro forma* LGIA and *pro forma* SGIA may be necessary to provide for the continued reliable operation of the power system. As noted above, the Task Force concluded that all new generating facilities should be required to be capable of providing primary frequency response.[115] However, the *pro forma* LGIA does not currently require large generating facilities to install such capability; rather, it only requires governor operation in ''automatic mode'' *if* a ''speed governor'' is installed.[116]

41. In addition, the Commission is concerned that the current *pro forma* SGIA may be unduly discriminatory or preferential because it does not establish any specific requirements with respect to the installation or operation of governors or equivalent frequency control equipment. In particular, the *pro forma* SGIA does not have a similar provision to Article 9.6.2.1 of the *pro forma* LGIA. The Commission has previously acted under FPA section 206 to remove inconsistencies between the *pro forma* LGIA and *pro forma* SGIA when there is no economic or technical basis for treating large and small generating facilities differently.[117] Similarly, in this instance, the record developed from the NOI appears to suggest that small generating facilities are capable of installing and enabling governors at low cost in a manner comparable to large generating facilities.[118] As discussed above, the record indicates that there have been significant advances in technology, as well as the development of more robust technical guidance for the operation of governors or equivalent controls for both large and small generating facilities.[119] In particular, the IEEE–P1547 Working Group noted that its new IEEE–1547 standard for interconnecting distributed generation will likely include certain requirements for providing primary frequency response.[120] Given these low-cost technological advances, the Commission does not anticipate that these additional requirements added in the *pro forma* SGIA will present a barrier to entry for small generating facilities. And, given the need for additional primary frequency response capability and an increasingly large market penetration of small generating facilities, the Commission believes that there is a need to add these requirements to the *pro forma* SGIA to help ensure adequate primary frequency response capability.

42. Moreover, as noted above, a number of commenters assert that costs for new generating facilities to install the capability of providing primary frequency response are low, suggesting that there is not a financial barrier to small generating facilities installing the capability to provide frequency response.[121] PJM's recent changes to require both small and large non-synchronous generating facilities to use enhanced inverters, which include primary frequency response capability, among other functions, further support this notion.[122]

2. Commission Proposal

43. To remedy the potentially unjust, unreasonable, and unduly discriminatory or preferential practices described above, the Commission preliminarily finds that revisions to the *pro forma* LGIA and *pro forma* SGIA are appropriate. The Commission believes that revising the *pro forma* LGIA and *pro forma* SGIA to require all new generating facilities to install, maintain, and operate a functioning governor or equivalent controls, consistent with the proposed requirements described below, will help to ensure adequate primary frequency response capability as the resource mix continues to evolve, ensure fair and consistent treatment for all types of generating facilities, help balancing authorities meet their frequency response obligations pursuant to NERC Reliability Standard BAL–003–1.1, and help improve reliability during

[111] *See* Electric Power Research Institute, *Recommended Settings for Voltage and Frequency Ride Through of Distributed Energy Resources* (May 2015) at 27, *http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002006203. See also* National Renewable Energy Labs (NREL), *Advanced Grid-Friendly Controls Demonstration Project for Utility-Scale PV Power Plants,* at 1–2 (Jan. 2016), *http://www.nrel.gov/docs/fy16osti/65368.pdf.*

[112] *See* P 16, *supra.*

[113] *Id.*

[114] *See* NERC Primary Frequency Control Guideline.

[115] *See* P 15, *supra.*

[116] Article 9.6.2.1 of the *pro forma* LGIA.

[117] *See Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities,* Order No. 828, 81 FR 50,290 (Aug. 1, 2016), 156 FERC ¶ 61,062 (2016), (The Final Rule revised the *pro forma* SGIA such that small generating facilities have frequency and voltage ride through requirements comparable to large generating facilities).

[118] IEEE–P1547 Working Group Comments at 1, 5, and 7. Moreover, the Commission notes that other commenters stated costs of installing primary frequency response capability are generally low, but did not differentiate between small and large generating facilities. *See, e.g.,* APPA, *et al.* Comments at 6; California Cities Comments at 2; EEI Comments at 13; Indicated ISOs/RTOs Comments at 3–5; SoCal Edison Comments at 2.

[119] *See* PP 13, 36, *supra.*

[120] IEEE–P1547 Working Group Comments at 1, 5, and 7.

[121] *See, e.g.,* APPA, *et al.* Comments at 2; EEI Comments at 13; Indicated ISOs/RTOs Comments at 5; SoCal Edison Comments at 2.

[122] *PJM Interconnection, L.L.C.,* 151 FERC ¶ 61,097 at P 28 (the Commission stated that it ''find[s] that PJM's proposal will not present a barrier to non-synchronous resources.'').

system restoration and islanding situations.[123]

44. In particular, the Commission proposes to revise the *pro forma* LGIA and *pro forma* SGIA to include the following: (1) Requirements for new large and small generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection; (2) requirements for governor or equivalent controls to be operated, at a minimum, with maximum 5 percent droop and ±0.036 Hz deadband settings; (3) requirements to ensure the timely and sustained response to frequency deviations, including provisions to prevent plant-level (*i.e.,* outer-loop) control equipment from inhibiting primary frequency response and resulting in premature withdrawal; and (4) a requirement for droop parameters to be based on nameplate capability with a linear operating range of 59 to 61 Hz. Additionally, as informed by NOI commenters, the Commission believes that it is not necessary to impose a generic headroom requirement or subject newly interconnecting nuclear generating facilities to the new requirements. The Commission does not propose to mandate any separate compensation related to the proposed requirements. The Commission seeks comment on the proposed reforms, as discussed more fully below.

45. Specifically, the Commission proposes to revise existing sections 9.6 and 9.6.2.1 of the *pro forma* LGIA and to include proposed new sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.3. Similarly, the Commission proposes to revise existing section 1.8 of the *pro forma* SGIA and add proposed new sections 1.8.4, 1.8.4.1, 1.8.4.1.1, 1.8.4.1.2, and 1.8.4.1.3.[124]

46. The Commission's proposed revisions to the *pro forma* LGIA and *pro forma* SGIA would apply to new generating facilities that execute or request the unexecuted filing of interconnection agreements on or after the effective date of any Final Rule issued in Docket No. RM16–6–000. The Commission also proposes to apply the requirements to any large or small generating facility that has an executed or has requested the filing of an unexecuted LGIA or SGIA as of the effective date of any Final Rule in Docket No. RM16–6–000, but that takes any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date of any Final Rule in Docket No. RM16–6–000.

47. In particular, the proposed revisions to the *pro forma* LGIA and *pro forma* SGIA would require new large and small generating facilities to install, maintain, and operate a functioning governor or equivalent controls, which the Commission proposes to define as the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the generating facility's real power output in accordance with the proposed maximum droop and deadband parameters and in the direction needed to correct frequency deviations. The Commission seeks comment on this proposal.

48. The Commission also proposes to require new large and small generating facilities to install, maintain and operate governor or equivalent controls with the ability to operate with a maximum 5 percent droop and ±0.036 Hz deadband parameter, consistent with NERC's recommended guidance. As noted above, the Commission sought comment in the NOI on whether NERC's recommended guidance for governor settings related to droop and deadband should be included in the *pro forma* LGIA and *pro forma* SGIA, and numerous commenters agreed stating that NERC's Guideline provides a sound baseline.[125] Therefore, the Commission preliminarily finds that a maximum droop setting of 5 percent and deadband setting of ±0.036 Hz are appropriate to include in the *pro forma* LGIA and *pro forma* SGIA as interconnection requirements for new generating facilities. The Commission notes that these proposed requirements are *minimum* requirements; therefore, if a new generating facility elects, in coordination with its transmission provider, to operate in a more responsive mode by using lower droop or tighter deadband settings, nothing in these requirements would prohibit it from doing so.[126] The Commission seeks comment on these proposed requirements for droop and deadband settings.

49. The Commission also proposes to prohibit all new large and small generating facilities from taking any action that would inhibit the provision of primary frequency response, except under certain conditions as discussed below. The lack of coordination between governor and plant-level control systems can result in premature withdrawal of primary frequency response by allowing additional plant control systems to reverse the action of the governor to return the unit to operating at a pre-selected target set-point.[127] NERC's Guideline explains that ''in order to provide sustained primary frequency response, it is essential that the prime mover governor, plant controls and remote plant controls are coordinated.'' [128] Accordingly, the Commission proposes to require new generating facilities that respond to frequency deviations to not inhibit primary frequency response, such as by coordinating plant-level, outer-loop control equipment with the governor or equivalent controls, except under certain operational constraints including, but not limited to, ambient temperature limitations, outages of mechanical equipment, or regulatory requirements. The Commission also proposes to require new generating facilities to respond to frequency deviations without undue delay and to sustain the response until at least system frequency returns to a stable value within the governor's deadband setting. The Commission believes this proposed requirement for sustained response is consistent with the current requirements of PJM and ISO–NE as well as similar OATT revisions recently implemented by CAISO.[129] The Commission seeks comment on the proposed requirements for sustained response. In particular, the Commission seeks comment on whether these provisions will be sufficient to prevent plant-level (*i.e.,* outer-loop) controls from inhibiting primary frequency response.

50. Regarding droop settings, in its comments to the NOI, MISO proposed that a linear droop should be available between 59 to 61 Hz.[130] The

[123] *See* NERC Comments at 17. *See also* NERC Essential Reliability Services Task Force Measures Framework Report at iv.

[124] The specific proposed modifications and additions to the *pro forma* LGIA and *pro forma* SGIA are set forth at PP 52–53, below.

[125] *See e.g.,* Bonneville Comments at 7; California Cities Comments at 2; IEEE–PES Comments at 2; Indicated ISOs/RTOs Comments at 4; MISO Comments at 4; WIRAB Comments at 7.

[126] Moreover, the Commission proposes that nothing in these requirements would prohibit the implementation of asymmetrical droop settings (*i.e.,* different droop settings for under-frequency and over-frequency conditions), provided that each segment has a droop value of no more than 5 percent.

[127] NERC Frequency Response Initiative Report at 31. *See also* NOI, 154 FERC ¶ 61,117 at P 49 (stating that primary frequency response withdrawal ''has the potential to degrade the overall response of the Interconnection and result in a frequency that declines below the original nadir'').

[128] NERC Primary Frequency Control Guideline at 4.

[129] *See, e.g.,* ISO–NE Operating Procedure OP–14 and PJM Manual 14D. *See also CAISO,* 156 FERC ¶ 61,182 at PP 10–12 and 17.

[130] MISO Comments at 4.

Commission believes that this is reasonable because it would allow for new generating facilities that remain connected during frequency deviations to provide a proportional response within this range of frequencies. Accordingly, the Commission proposes to require the droop parameter to be based on the nameplate capability of the unit and linear in operating range between 59 to 61 Hz. The Commission seeks comment on these proposed requirements for droop settings.

51. Several NOI commenters expressed concern about possible generic headroom requirements [131] that could result in significant opportunity costs.[132] The Commission clarifies that nothing in these proposed reforms will impose a generic headroom requirement for new generating facilities or affect the unit commitment and dispatch decisions of balancing authorities. Therefore, if a generating facility that is subject to these proposed requirements has been dispatched by its balancing authority to a set-point at which there is no available operating range to increase or decrease its output in response to frequency deviations, it would not be in violation of the proposed requirements in regards to providing sustained response. The Commission believes that the reliability benefits from the proposed modifications to the *pro forma* LGIA and *pro forma* SGIA do not require imposing additional costs that would result from a generic headroom requirement. The Commission also agrees with NOI commenters regarding the unique operating characteristics and regulatory requirements of nuclear generating facilities regulated by the Nuclear Regulatory Commission, and therefore proposes to exempt such generating facilities from the proposed reforms.[133] The Commission seeks comment on the proposal to not impose a generic headroom requirement and to not apply the new requirements to nuclear generating facilities.

52. In light of the above discussion, the Commission proposes to modify sections 9.6 and 9.6.2.1 of the *pro forma* LGIA and add new sections 9.6.4, 9.6.4.1, 9.6.4.2, and 9.6.4.3 as follows:

9.6 Reactive Power and Primary Frequency Response

9.6.2.1 *Voltage* Regulators. Whenever the Large Generating Facility is operated in parallel with the Transmission System and voltage regulators are capable of operation, Interconnection Customer shall operate the Large Generating Facility with its voltage regulators in automatic operation. If the Large Generating Facility's voltage regulators are not capable of such automatic operation, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative, and ensure that such Large Generating Facility's reactive power production or absorption (measured in MVARs) are within the design capability of the Large Generating Facility's generating unit(s) and steady state stability limits. Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the Transmission System or trip any generating unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Control Area on a comparable basis.

9.6.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Large Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Large Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or equivalent controls with the capability of operating with a maximum 5 percent droop and ±0.036 Hz deadband. The droop characteristic shall be based on the nameplate capacity of the Large Generating Facility, and shall be linear in the range of 59 to 61 Hz. The deadband parameter shall be the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Large Generating Facility's real power output in response to frequency deviations. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Large Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Large Generating Facility with the Transmission System, Interconnection Customer shall operate the Large Generating Facility consistent with provisions specified in Sections 9.6.4.1 and 9.6.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Large Generating Facilities. Nothing in Sections 9.6.4, 9.6.4.1 and 9.6.4.2 shall require the Large Generating Facility to operate above its minimum operating limit or below its maximum operating limit, or otherwise alter its dispatch to have headroom to provide primary frequency response.

9.6.4.1 Governor or Equivalent Controls. Whenever the Large Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Large Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall, in coordination with Transmission Provider, set the deadband parameter to a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider upon request. If Interconnection Customer needs to operate the Large Generating Facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable.

9.6.4.2 Sustained Response. Interconnection Customer shall ensure that the Large Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is provided without undue delay, and ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, outages of mechanical equipment, or regulatory requirements. The Large Generating Facility shall sustain the real power response at least until system frequency returns to a stable value within the deadband setting of the governor or equivalent controls.

9.6.4.3 Exemptions. Large Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 9.6.4, 9.6.4.1, and 9.6.4.2 of this Agreement.

53. Similarly, the Commission proposes to modify section 1.8 of the *pro forma* SGIA and add new sections 1.8.4, 1.8.4.1, 1.8.4.2 and 1.8.4.3 as follows:

1.8 Reactive Power *and Primary Frequency Response*

1.8.4 Primary Frequency Response. Interconnection Customer shall ensure the primary frequency response capability of its Small Generating Facility by installing, maintaining, and operating a functioning governor or equivalent controls. The term "functioning governor or equivalent controls" as used herein shall mean the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the Small Generating Facility's real power output in accordance with the droop and deadband parameters and in the direction needed to correct frequency deviations. Interconnection Customer is required to install a governor or

[131] A generic headroom requirement would require generating facilities to operate below maximum output at all times to ensure sufficient ability to increase their real power output in response to under-frequency conditions.

[132] *See, e.g.,* Apex Comments at 7; Solar City Comments at 1; AWEA Comments at 6.

[133] *See, e.g.,* Nuclear Energy Institute Comments at 1, 4; MISO TOs Comments at 7.

equivalent controls with the capability of operating with a maximum 5 percent droop and ±0.036 Hz deadband. The droop characteristic shall be based on the nameplate capacity of the Small Generating Facility, and shall be linear in the range of 59 to 61 Hz. The deadband parameter shall be the range of frequencies above and below nominal (60 Hz) in which the governor or equivalent controls is not expected to adjust the Small Generating Facility's real power output in response to frequency deviations. Interconnection Customer shall notify Transmission Provider that the primary frequency response capability of the Small Generating Facility has been tested and confirmed during commissioning. Once Interconnection Customer has synchronized the Small Generating Facility with the Transmission System, Interconnection Customer shall operate the Small Generating Facility consistent with the provisions specified in Sections 1.8.4.1 and 1.8.4.2 of this Agreement. The primary frequency response requirements contained herein shall apply to both synchronous and non-synchronous Small Generating Facilities. Nothing in Sections 1.8.4, 1.8.4.1 and 1.8.4.2 shall require the Small Generating Facility to operate above its minimum operating limit, below its maximum operating limit, or otherwise alter its dispatch to have headroom to provide primary frequency response.

1.8.4.1 Governor or Equivalent Controls. Whenever the Small Generating Facility is operated in parallel with the Transmission System, Interconnection Customer shall operate the Small Generating Facility with its governor or equivalent controls in service and responsive to frequency. Interconnection Customer shall, in coordination with Transmission Provider, set the deadband parameter to a maximum of ±0.036 Hz and set the droop parameter to a maximum of 5 percent. Interconnection Customer shall be required to provide the status and settings of the governor or equivalent controls to Transmission Provider upon request. If Interconnection Customer needs to operate the Small Generating facility with its governor or equivalent controls not in service, Interconnection Customer shall immediately notify Transmission Provider's system operator, or its designated representative. Interconnection Customer shall make Reasonable Efforts to return its governor or equivalent controls into service as soon as practicable.

1.8.4.2 Sustained Response. Interconnection Customer shall ensure that the Small Generating Facility's real power response to sustained frequency deviations outside of the deadband setting is provided without undue delay, and ensure that the response is not inhibited, except under certain operational constraints including, but not limited to, ambient temperature limitations, outages of mechanical equipment, or regulatory requirements. The Small Generating Facility shall sustain the real power response at least until system frequency returns to a stable value within the deadband setting of the governor or equivalent controls.

1.8.4.3 Exemptions. Small Generating Facilities that are regulated by the United States Nuclear Regulatory Commission shall be exempt from Sections 1.8.4, 1.8.4.1, 1.8.4.2 of this Agreement.

54. The Commission proposes to apply the primary frequency response requirements to any new large or small generating facility that executes or requests the unexecuted filing of a LGIA or SGIA on or after the effective date of any Final Rule issued in this proceeding. In addition, the Commission proposes to apply the requirements to any large or small generating facility that has an executed or has requested the filing of an unexecuted LGIA or SGIA as of the effective date of any Final Rule in Docket No. RM16–6–000, but that takes any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date of any Final Rule in Docket No. RM16–6–000. The Commission seeks comment on the proposed effective date including whether applying these requirements to existing generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement on or after the effective date of any Final Rule in Docket No. RM16–6–000 would be unduly burdensome.

55. The Commission does not propose in this NOPR to require that the interconnection customer receive any compensation for these proposed requirements. The Commission has previously accepted changes to transmission provider tariffs that similarly required interconnection customers to install primary frequency response capability or that established specified governor settings, without requiring any accompanying compensation.[134] While the Commission has not required compensation for similar requirements in the past, it clarifies that nothing in this NOPR is meant to prohibit a public utility from filing a proposal for primary frequency response compensation under FPA section 205, if it so chooses.[135]

B. Request for Comment

56. The Commission seeks comment on the proposed: (1) Requirements for new large and small generating facilities to install, maintain, and operate a governor or equivalent controls; (2) requirements for droop and deadband settings of 5 percent and ±0.036 Hz, respectively; (3) requirements for timely and sustained response; (4) requirement for droop parameters to be based on nameplate capability with a linear operating range of 59 to 61 Hz; (5) exemptions for new nuclear units; and (6) effective dates as discussed above. The Commission also seeks comment on its proposal to not impose a generic headroom requirement or mandate compensation related to the proposed reforms.

57. In the NOI, the Commission also sought comment on the performance of existing resources and whether primary frequency response requirements for these resources are warranted.[136] At this time, the Commission proposes only to adopt the reforms included in this NOPR regarding newly interconnecting large and small generating facilities. However, the Commission seeks comment regarding whether the reforms proposed in this NOPR are sufficient to ensure adequate levels of primary frequency response, or whether additional reforms are needed. In particular, the Commission seeks comment on whether additional primary frequency response performance or capability requirements for existing resources are needed, and if so, whether the Commission should impose those requirements by: (1) Directing the development or modification of a reliability standard pursuant to section 215(d)(5) of the FPA; or (2) acting pursuant to section 206 of the FPA to require changes to the *pro forma* OATT.

C. Proposed Compliance Procedures

58. The Commission proposes to require all public utility transmission providers to adopt the requirements of any Final Rule in Docket No. RM16–6–000 as revisions to the LGIA and SGIA in their OATTs within 60 days after the publication of the Final Rule in the **Federal Register**.

59. Some public utility transmission providers may have provisions in their existing LGIAs and SGIAs that the Commission has found to be consistent with or superior to the *pro forma* LGIA and *pro forma* SGIA. Where these provisions would be modified by the Final Rule, public utility transmission providers must either comply with the Final Rule or demonstrate that these previously-approved variations continue to be consistent with or superior to the *pro forma* LGIA and *pro forma* SGIA as modified by the Final Rule. The Commission also proposes to permit appropriate entities to seek

[134] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,097, at n.58 (2015); *CAISO*, 156 FERC ¶ 61,182, at PP 10–12 and 17 (2016); *New England Power Pool*, 109 FERC ¶ 61,155 (2004), *order on reh'g*, 110 FERC ¶ 61,335 (2005).

[135] 16 U.S.C. 824d (2012).

[136] NOI, 154 FERC ¶ 61,117 at PP 2, 46–52.

''independent entity variations'' from the proposed revisions to the *pro forma* LGIA and *pro forma* SGIA.[137]

60. The Commission would assess whether each compliance filing satisfies the proposed requirements stated above and issue additional orders as necessary to ensure that each public utility transmission provider meets the requirements of the subsequent Final Rule.

61. The Commission also proposes that transmission providers that are not public utilities would have to adopt the requirements of this proposal and subsequent Final Rule as a condition of maintaining the status of their safe harbor tariff or otherwise satisfying the reciprocity requirement of Order No. 888.[138]

III. Information Collection Statement

62. The Paperwork Reduction Act (PRA)[139] requires each federal agency to seek and obtain Office of Management and Budget (OMB) approval before undertaking a collection of information directed to ten or more persons, or contained in a rule of general applicability. OMB's regulations require the approval of certain information collection requirements imposed by agency rules.[140] Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this proposal will not be penalized for failing to respond to this collection of information unless the collection of information displays a valid OMB control number. Transmission providers are subject to the proposed revisions to the *pro forma* LGIA and SGIA.

63. In this NOPR, the Commission proposes to amend its *pro forma* LGIA and *pro forma* SGIA in accordance with section 35.28(f)(1) of its regulations.[141] The proposed revisions to the *pro forma* LGIA and *pro forma* SGIA would require new large and small generating facilities to install, maintain, and operate a functioning governor or equivalent controls which the Commission proposes to define as the required hardware and/or software that provides frequency responsive real power control with the ability to sense changes in system frequency and autonomously adjust the generating facility's real power output in accordance with the proposed maximum droop and dead band parameters and in the direction needed to correct frequency deviations. The NOPR proposes to require each public utility transmission provider to amend its *pro forma* LGIA and *pro forma* SGIA to require that all newly interconnecting large and small generating facilities, as well as all existing large and small generating facilities that take any action that requires the submission of a new interconnection request that results in the filing of an executed or unexecuted interconnection agreement, to adhere to the proposed requirements, on or after the effective date of any Final Rule issued in this proceeding.

64. The reforms in this NOPR would require filings of *pro forma* LGIAs and *pro forma* SGIAs with the Commission. The Commission anticipates the proposed reforms, once implemented, would not significantly change currently existing burdens on an ongoing basis. With regard to those public utility transmission providers that believe that they already comply with the proposed reforms in this NOPR, they could demonstrate their compliance in the filing required 60 days after publication of the Final Rule in the **Federal Register**. The Commission will submit the proposed reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[142] The Commission will use FERC–516B as a temporary ''placeholder'' information collection number.[143]

Burden Estimate:[144] The Commission believes that the burden estimates below are representative of the average burden on respondents. The estimated burden and cost for the requirements contained in this NOPR follow.[145]

FERC 516B, IN NOPR IN RM16–6

	Number of respondents[146] (1)	Annual number of responses per respondent (2)	Total number of responses (1) * (2) = (3)	Average burden (hours) & cost ($) per response (4)	Total annual burden hours & total annual cost ($) (3) * (4) = (5)
LGIA & SGIA changes/revisions	74	1	74	10 hours; $745.00	740 hours; $55,130.00.
Total			74		740 hours; $55,130.00.

There are no maintenance cost, installation cost or any additional cost or requirements after year 1.

Title: FERC–516B, Electric Rate Schedules and Tariff Filings.

Action: Revision of currently approved collection of information.

OMB Control No.: 1902–0286.

Respondents for this Rulemaking: Businesses or other for profit and/or not-for-profit institutions.

Frequency of Information: One-time during year 1.

Necessity of Information: The Commission proposes to revise its regulations to require all newly interconnecting large and small

[137] *See, e.g.,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 827.

[138] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,760–63.

[139] 44 U.S.C. 3501–3520 (2012).

[140] 5 CFR 1320.11 (2016).

[141] 18 CFR 35.28(f)(1) (2016).

[142] 44 U.S.C. 3507(d) (2012).

[143] The reporting requirements in this NOPR would normally be included under FERC–516 (OMB Control No. 1902–0096). However, FERC–516 is pending review at OMB in an unrelated action. Because only one item per OMB Control No. can be pending OMB review at a time, the Commission is temporarily using the information collection number FERC–516B (OMB Control No. 1902–0286) to ensure timely submittal of this NOPR to OMB.

[144] Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, disclose or provide information to or for a Federal agency, including: The time, effort, and financial resources necessary to comply with a collection of information that would be incurred by persons in the normal course of their activities (*e.g.,* in compiling and maintaining business records) will be excluded from the ''burden'' if the agency demonstrates that the reporting, recordkeeping, or disclosure activities needed to comply are usual and customary.

[145] For this information collection, the Commission staff estimates that industry is similarly situated in terms of hourly cost (wages plus benefits). Based on the Commission's average cost (wages plus benefits) for 2016, the Commission is using $74.50/hour.

[146] The NERC Compliance Registry lists 80 entities that administer a transmission tariff and provide transmission service. The Commission identifies only 74 as being subject to the proposed requirements because 6 are Canadian entities and are not under the Commission's jurisdiction.

generating facilities, both synchronous and non-synchronous, to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. To implement these requirements, the Commission proposes to revise the *pro forma* LGIA and the *pro forma* SGIA.

Internal Review: The Commission has reviewed the proposed changes and has determined that the changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information collection requirements.

65. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426 [Attention: Ellen Brown, Office of the Executive Director], email: *DataClearance@ferc.gov,* Phone: (202) 502–8663, fax: (202) 273–0873.

66. Comments on the collection of information and the associated burden estimate in the proposed rule should be sent to the Commission in this docket and may also be sent to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street NW., Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission], at the following email address: *oira_submission@omb.eop.gov.* Please refer to OMB Control No. 1902–0286 in your submission.

IV. Environmental Analysis

67. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[147] The Commission concludes that neither an Environmental Assessment or an Environmental Impact Statement is required for proposed revisions under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the FPA relating to the filing of schedules containing all rates and charges for the transmission or sale of electric energy subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications, and services.[148] The revisions proposed in this NOPR update and clarify the application of the Commission's standard interconnection requirements to synchronous and non-synchronous generators. Therefore, this NOPR falls within the categorical exemptions provided in the Commission's regulations, and therefore neither an Environmental Assessment nor an Environmental Impact Statement is required.

V. Regulatory Flexibility Act

68. The Regulatory Flexibility Act of 1980 (RFA) [149] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. The RFA does not mandate any particular outcome in a rulemaking. It only requires consideration of alternatives that are less burdensome to small entities and an agency explanation of why alternatives were rejected.

69. The Small Business Administration (SBA) revised its size standards (effective January 22, 2014) for electric utilities from a standard based on megawatt hours to a standard based on the number of employees, including affiliates. Under SBA's standards, some transmission owners will fall under the following category and associated size threshold: Electric bulk power transmission and control, at 500 employees.[150]

70. The Commission estimates that the total number of transmission providers, both public and non-public, affected by this NOPR is 74.[151] Of these, the Commission estimates that approximately 27.5 percent are small entities. The Commission estimates the average total cost to each of these entities will be minimal, requiring on average 10 hours, or $745.00. According to SBA guidance, the determination of significance of impact "should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors." [152] The Commission does not consider the estimated burden to be a significant economic impact. As a result, the Commission believes this NOPR would not have a significant economic impact on a substantial number of small entities.

71. The Commission estimates that the total annual number of new non-synchronous interconnections per year for the first few years of potential implementation under this NOPR would be approximately 200, representing approximately 5,000 MW of installed capacity. Of these, the Commission estimates that the majority are small entities. The Commission estimates the average total cost to each of these entities will be minimal, requiring on average approximately $3,300 per MW of installed capacity. According to SBA guidance, the determination of significance of impact "should be seen as relative to the size of the business, the size of the competitor's business, and the impact the regulation has on larger competitors." The Commission does not consider the estimated burden to be a significant economic impact on these entities because the cost is relatively minimal compared to the average capital cost per MW for wind and solar PV generation.[153] Additionally, the Commission does not believe that there will be substantial additional costs for new synchronous generators because synchronous generators already come equipped with governors that provide the capability to provide primary frequency response. Accordingly, the Commission believes that this NOPR would not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

72. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due January 24, 2017. Comments must refer to Docket No. RM16–6–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

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[147] Order No. 486, Regulations Implementing the National Environmental Policy Act, 52 FR 47897 (Dec. 17, 1987), FERC Stats. & Regs. Preambles 1986–1990 ¶ 30,783 (1987).

[148] 18 CFR 380.4(a)(15) (2015).

[149] 5 U.S.C. 601–612 (2012).

[150] 13 CFR 121.201, Sector 22 (Utilities), NAICS code 221121 (Electric Bulk Power Transmission and Control).

[151] The NERC Compliance Registry lists 80 entities that administer a transmission tariff and provide transmission service. The Commission identifies only 74 as being subject to the proposed requirements because 6 are Canadian entities and are not under the Commission's jurisdiction.

[152] U.S. Small Business Administration, *A Guide for Government Agencies: How to Comply with the Regulatory Flexibility Act,* at 18 (May 2012), *https://www.sba.gov/sites/default/files/advocacy/rfaguide_0512_0.pdf.*

[153] LBNL estimates that capital cost per MW of installed wind capacity is $1,690,000. *See* LBNL 2015 Wind Market Report (Aug. 2016), *https://emp.lbl.gov/sites/all/files/2015-windtechreport.final_.pdf*). NREL estimates that the capital cost per MW of installed solar PV capacity is $1,770,000. *See* NREL U.S. Photovoltaic Prices and Cost Breakdowns (Sep. 2015), *http://www.nrel.gov/docs/fy15osti/64746.pdf.*

73. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov*. The Commission accepts most standard word processing formats. Documents created electronically using word processing software should be filed in native applications or print-to-PDF format and not in a scanned format. Commenters filing electronically do not need to make a paper filing.

74. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE., Washington, DC 20426.

75. All comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments on other commenters.

VII. Document Availability

76. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street NE., Room 2A, Washington, DC 20426.

77. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

78. User assistance is available for eLibrary and the Commission's Web site during normal business hours from the Commission's Online Support at (202) 502–6652 (toll free at 1–866–208–3676) or email at *ferconlinesupport@ferc.gov,* or the Public Reference Room at (202) 502–8371, TTY (202)502–8659. Email the Public Reference Room at *public.referenceroom@ferc.gov.*

By direction of the Commission.

Issued: November 17, 2016.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

Appendix

LIST OF COMMENTERS (DOCKET NO. RM16–6–000)

AES Companies	AES Corporation/AES Energy Storage/Dayton Power and Light Company/Indianapolis Power and Light Company.
APPA, et al	American Public Power Association/Large Public Power Council/Transmission Access Policy Study Group.
AWEA	American Wind Energy Association.
Apex	Apex Compressed Air Energy Storage.
APS	Arizona Public Service Company.
Bonneville	Bonneville Power Administration.
CAISO	California Independent System Operator.
Chelan County	Chelan County Public Utility District.
California Cities	City of Anaheim/City of Azusa/City of Banning/City of Colton/City of Pasadena/City of Riverside.
EEI	Edison Electric Institute.
EDP	EDP Renewables North America.
EPRI	Electric Power Research Institute.
EPSA, et al	Electric Power Supply Association/Independent Power Producers of New York/New England Power Generators Association/Western Power Trading Forum.
ELCON	Electricity Consumers Resource Council.
ESA	Energy Storage Association.
Grid Storage Consulting	Grid Storage Consulting.
Howard F. Illian	Howard F. Illian
Idaho Power	Idaho Power Company.
Indicated ISOs/RTOs	Independent Electricity System Operator/ISO New England/New York Independent System Operator/PJM Interconnection/Southwest Power Pool.
IEEE–P1547 Working Group	Institute of Electrical and Electronics Engineers (IEEE) P1547 Standards Working Group.
IEEE–PES	IEEE Power and Energy Society Technical Council.
ITC, et al	International Transmission Company/Michigan Electric Transmission Company/ITC Great Plains/ITC Midwest.
Manitoba	Manitoba Hydro.
Microgrids Resources Coalition	Microgrids Resources Coalition.
MISO	Midcontinent Independent System Operator.
MISO TOs	Midcontinent Independent System Operator Transmission Owners.
NARUC	National Association of Regulatory Utility Commissioners.
NRECA	National Rural Electric Cooperative Association.
NERC	North American Electric Reliability Corporation.
North American Generator Forum	North American Generator Forum.
Nuclear Energy Institute	Nuclear Energy Institute.
PG&E	Pacific Gas and Electric Company.
Peak Reliability	Peak Reliability.
PJM Utilities Coalition	PJM Utilities Coalition.
Powerex	Powerex Corp.
Public Interest Organizations	Public Interest Organizations.
Ralph D. Masiello	Ralph D. Masiello.
SDG&E	San Diego Gas & Electric Company.
Solar City	Solar City Corporation.
SoCal Edison	Southern California Edison Company.
Southern Company	Southern Company.
Steel Producers	Steel Producers.

LIST OF COMMENTERS (DOCKET NO. RM16–6–000)—Continued

Tacoma Power	Tacoma Power.
TVA	Tennessee Valley Authority.
Tri-State Generation	Tri-State Generation and Transmission Association.
Union of Concerned Scientists	Union of Concerned Scientists.
WIRAB	Western Interconnection Regional Advisory Body.

[FR Doc. 2016–28321 Filed 11–23–16; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

[REG–107424–12]

RIN 1545–BK95

Update to Minimum Present Value Requirements for Defined Benefit Plan Distributions

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice of proposed rulemaking and notice of public hearing.

SUMMARY: This document contains proposed regulations providing guidance relating to the minimum present value requirements applicable to certain defined benefit pension plans. These proposed regulations would provide guidance on changes made by the Pension Protection Act of 2006 and would provide other modifications to these rules as well. These regulations would affect participants, beneficiaries, sponsors, and administrators of defined benefit pension plans. This document also provides a notice of a public hearing on these proposed regulations.

DATES: Written or electronic comments must be received by February 23, 2017. Outlines of topics to be discussed at the public hearing scheduled for March 7, 2017, must be received by February 23, 2017.

ADDRESSES: Send submissions to: CC:PA:LPD:PR (REG–107424–12), Room 5203, Internal Revenue Service, P.O. Box 7604, Ben Franklin Station, Washington, DC 20044. Submissions may be hand-delivered Monday through Friday between the hours of 8 a.m. and 4 p.m. to: CC:PA:LPD:PR (REG–107424–12), Courier's Desk, Internal Revenue Service, 1111 Constitution Avenue NW., Washington, DC, or sent electronically, via the Federal eRulemaking Portal at *http://www.regulations.gov* (IRS REG–107424–12). The public hearing will be held in the IRS Auditorium, Internal Revenue Building, 1111 Constitution Avenue NW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: Concerning the regulations, Neil S. Sandhu or Linda S.F. Marshall at (202) 317–6700; concerning submissions of comments, the hearing, and/or being placed on the building access list to attend the hearing, Oluwafunmilayo (Funmi) Taylor at (202) 317–6901 (not toll-free numbers).

SUPPLEMENTARY INFORMATION:

Background

Section 401(a)(11) of the Internal Revenue Code (Code) provides that, in order for a defined benefit plan to qualify under section 401(a), except as provided under section 417, in the case of a vested participant who does not die before the annuity starting date, the accrued benefit payable to such participant must be provided in the form of a qualified joint and survivor annuity. In the case of a vested participant who dies before the annuity starting date and who has a surviving spouse, a defined benefit plan must provide a qualified preretirement survivor annuity to the surviving spouse of such participant, except as provided under section 417.

Section 411(d)(6)(B) provides that a plan amendment that has the effect of eliminating or reducing an early retirement benefit or a retirement-type subsidy, or eliminating an optional form of benefit, with respect to benefits attributable to service before the amendment is treated as impermissibly reducing accrued benefits. However, the last sentence of section 411(d)(6)(B) provides that the Secretary may by regulations provide that section 411(d)(6)(B) does not apply to a plan amendment that eliminates an optional form of benefit (other than a plan amendment that has the effect of eliminating or reducing an early retirement benefit or a retirement-type subsidy).

Section 417(e)(1) provides that a plan may provide that the present value of a qualified joint and survivor annuity or a qualified preretirement survivor annuity will be immediately distributed if that present value does not exceed the amount that can be distributed without the participant's consent under section 411(a)(11). Section 417(e)(2) provides that, if the present value of the qualified joint and survivor annuity or the qualified preretirement survivor annuity exceeds the amount that can be distributed without the participant's consent under section 411(a)(11), then a plan may immediately distribute the present value of a qualified joint and survivor annuity or the qualified preretirement survivor annuity only if the participant and the spouse of the participant (or where the participant has died, the surviving spouse) consent in writing to the distribution.

Section 417(e)(3)(A) provides that the present value shall not be less than the present value calculated by using the applicable mortality table and the applicable interest rate.[1]

Section 417(e)(3)(B) of the Code, as amended by section 302 of the Pension Protection Act of 2006 (PPA '06), Public Law 109–280, 120 Stat. 780 (2006), provides that the term ''applicable mortality table'' means a mortality table, modified as appropriate by the Secretary, based on the mortality table specified for the plan year under section 430(h)(3)(A) (without regard to section 430(h)(3)(C) or (3)(D)).

Section 417(e)(3)(C) of the Code, as amended by section 302 of PPA '06, provides that the term ''applicable interest rate'' means the adjusted first, second, and third segment rates applied under rules similar to the rules of section 430(h)(2)(C) of the Code for the month before the date of the distribution or such other time as the Secretary may prescribe by regulations. However, for purposes of section 417(e)(3), these rates are to be determined without regard to the segment rate stabilization rules of section 430(h)(2)(C)(iv). In addition, under section 417(e)(3)(D), these rates are to be determined using the average yields for a month, rather than the 24-month average used under section 430(h)(2)(D).

Section 411(a)(13) of the Code, as added by section 701(b) of PPA '06, provides that an ''applicable defined benefit plan,'' as defined by section 411(a)(13)(C), is not treated as failing to meet the requirements of section 417(e)

[1] Under section 411(a)(11)(B), the same applicable mortality table and applicable interest rate are used for purposes of determining whether the present value of a participant's nonforfeitable accrued benefit exceeds the maximum amount that can be immediately distributed without the participant's consent.