DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 292 and 375

[Docket Nos. RM19–15–000 and AD16–16–000]

Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978

AGENCY: Federal Energy Regulatory Commission, Department of Energy.

ACTION: Notice of proposed rulemaking.

SUMMARY: In this notice of proposed rulemaking, the Federal Energy Regulatory Commission proposes to revise its regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 in light of changes in the energy industry since 1978.

DATES: Comments are due December 3, 2019.

ADDRESSES: Comments, identified by docket number, may be filed electronically at *http://www.ferc.gov* in acceptable native applications and print-to-PDF, but not in scanned or picture format. For those unable to file electronically, comments may be filed by mail or hand-delivery to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC 20426. The Comment Procedures Section of this document contains more detailed filing procedures.

FOR FURTHER INFORMATION CONTACT:

Lawrence R. Greenfield (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–6415, *lawrence.greenfield@ferc.gov.*

Helen Shepherd (Technical Information), Office of Energy Market Regulation, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–6176, *helen.shepherd@ferc.gov.*

Thomas Dautel (Technical Information), Office of Energy Policy and Innovation, Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426, (202) 502–6196, *thomas.dautel@ferc.gov.*

SUPPLEMENTARY INFORMATION:

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1. In this notice of proposed rulemaking (NOPR), the Federal Energy Regulatory Commission (Commission) proposes to revise its regulations (PURPA Regulations) [1] implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA) [2] in light of changes in the energy industry since 1978.

2. PURPA was enacted in 1978 as part of a package of legislative proposals intended to reduce the country's dependence on oil and natural gas, which at the time were in short supply and subject to dramatic price increases. PURPA sets forth a framework to encourage the development of alternative generation resources that do not rely on fossil fuels and cogeneration facilities that make more efficient use of the heat produced from the fossil fuels that were then commonly used in the production of electricity. The Commission issued the PURPA Regulations to implement PURPA in 1980.

3. Circumstances have changed considerably since the Commission implemented its PURPA Regulations in 1980. For one thing, advances in technology and the discovery of significant new natural gas reserves have resulted in plentiful supplies of relatively inexpensive natural gas. As a result, there no longer is the same need to provide incentives to address shortages of natural gas. Moreover, unlike in 1980, when the electric industry was made up principally of vertically integrated utilities that were reluctant to purchase power from independent generators, today the electric industry provides open access transmission and there are vibrant wholesale electric markets in much of the country where independent generators can sell their power at competitive prices. These markets have supported the addition of significant amounts of new independently-owned generation resources, including renewable resources. In addition, there are a number of federal and state programs that provide further incentives for the development of alternative resources, such as renewable resources. Consequently, the majority of renewable resources in operation today do not rely on PURPA.

4. Congress not only directed the Commission to establish rules to implement PURPA, but also directed that the Commission revise those rules ''from time to time thereafter[.]'' [3] The Commission now is proposing to revise its PURPA Regulations to rebalance the benefits and obligations of the Commission's PURPA Regulations in light of the changes in circumstances since the PURPA Regulations were promulgated in 1980. As explained more fully herein, the Commission proposes to grant state regulatory authorities that oversee regulated electric utilities and nonregulated electric utilities (collectively, for ease of reference, referred to as states) the flexibility in key respects to incorporate competitive market pricing in the rates paid by electric utilities to qualifying small power production facilities and qualifying cogeneration facilities under PURPA (collectively, QFs). These proposed changes constitute a package of reforms the Commission believes will continue to encourage QFs while at the same time addressing concerns that have been raised regarding the Commission's current PURPA Regulations.

5. *First,* the Commission proposes to grant states the flexibility to require that energy rates (but not capacity rates) in QF power sales contracts and other legally enforceable obligations (LEO) [4] vary in accordance with changes in the purchasing electric utility's as-available avoided costs at the time the energy is delivered. Under this proposal, if a state exercises this flexibility, a QF would no longer have the ability to elect to have its energy rate be fixed for the term of the contract or LEO.[5]

6. *Second,* the Commission proposes to grant states additional flexibility to allow QFs to have a fixed energy rate, but to provide that such state-authorized fixed energy rate can be based on projected energy prices during the term of a QF's contract based on the anticipated dates of delivery.

7. *Third,* the Commission proposes to grant states the flexibility to set ''as-available'' QF energy rates: (1) For QFs selling to electric utilities located in organized electric markets defined in 18 CFR 292.309(e), (f), or (g),[6] at the locational marginal price (LMP); and (2) for QFs selling to electric utilities located outside of organized electric markets defined in 18 CFR 292.309(e), (f), or (g), at competitive prices from liquid market hubs or calculated from a formula based on natural gas price indices and specified heat rates. Further, states would have the flexibility to set energy and capacity rates pursuant to a competitive solicitation process conducted pursuant to transparent and non-discriminatory procedures. In each case, the Commission's proposal would entail granting the states options to employ additional approaches in setting QF rates beyond those commonly employed today. Under the Commission's proposal, the states would have the flexibility to choose to adopt one or more of these options or to continue setting QF rates under the existing standards currently set out in the PURPA Regulations.

8. *Fourth,* the Commission proposes to provide that an electric utility's obligation to purchase from QFs may be reduced to the extent the purchasing electric utility's supply obligation has been reduced by a state retail choice program.

9. *Fifth,* the Commission proposes to modify its current ''one-mile rule'' for determining whether generation facilities should be considered to be part of a single facility for purposes of determining qualification as a qualifying small power production facility. Specifically, the Commission proposes to allow electric utilities, state regulatory authorities, and other interested parties to show that facilities between one and ten miles apart (*i.e.,* more than one mile apart and less than ten miles apart) actually are a single facility (with distances one mile or less still irrebuttably a single facility, and distances ten miles or more irrebuttably separate and different facilities). The Commission also proposes to allow an entity seeking QF status to provide further information in its certification (whether a self-certification or a Commission certification) to preemptively defend against subsequent

[1] 18 CFR part 292. In connection with the proposed revisions to the PURPA Regulations, the Commission also proposes to revise its delegation of authority to Commission staff in 18 CFR part 375.

[2] 16 U.S.C. 796(17)–(18), 824a–3.

[3] 16 U.S.C. 824a–3(a).

[4] The Commission has held that a LEO can take effect before a contract is executed and may not necessarily be incorporated into a contract. *JD Wind 1, LLC,* 129 FERC ¶ 61,148, at P 25 (2009), *reh'g denied,* 130 FERC ¶ 61,127 (2010) (''[A] QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations.''). For ease of reference, however, references herein to a contract also are intended to refer to a LEO that is not incorporated into a contract.

[5] Moreover, any state—whether located in regions where energy prices are competitively based or whether located in regions where they are not—would be permitted to require that the fixed energy rate established at the time of the contract include provisions, established at the time the contract is established, providing for revisions to the energy rate at regular intervals, consistent with, for example, a purchasing electric utility's integrated resource plan, to reflect updated avoided cost calculations.

[6] These are the markets operated by Midcontinent Independent System Operator, Inc.; PJM Interconnection, L.L.C.; ISO New England Inc.; New York Independent System Operator, Inc.; Electric Reliability Council of Texas; California Independent System Operator, Inc.; and Southwest Power Pool, Inc.

challenges by identifying factors affirmatively demonstrating that its facility is indeed a separate facility at a separate site from other facilities. The Commission further proposes to add a definition of the term ''electrical generating equipment'' to the PURPA Regulations and to clarify how the distance between facilities is to be calculated.

10. *Sixth,* the Commission proposes to revise its regulations implementing PURPA section 210(m), which provide for the termination of an electric utility's obligation to purchase from a QF with nondiscriminatory access to certain markets. Currently, there is a rebuttable presumption that QFs with a net capacity at or below 20 MW do not have nondiscriminatory access to such markets. The Commission proposes to reduce the rebuttable presumption for small power production facilities (but not cogeneration facilities) from 20 MW to 1 MW.

11. *Seventh,* the Commission proposes to clarify that a QF must demonstrate commercial viability and financial commitment to construct its facility pursuant to objective and reasonable state-determined criteria before the QF is entitled to a contract or LEO.

12. *Finally,* the Commission proposes to allow a party to protest a self-certification or self-recertification of a facility without being required to file a separate petition for declaratory order and to pay the associated filing fee.

13. The Commission believes these proposed changes will enable the Commission to continue to fulfill its statutory obligations under sections 201 and 210 of PURPA, as explained in more detail in the relevant sections below. In particular, consideration of transparent, competitive market prices in appropriate circumstances would help to identify an electric utility's avoided costs in a simpler, more transparent, and more predictable manner that would, in conjunction with the Commission's other existing and proposed PURPA Regulations, act to encourage QFs. Allowing energy prices, but not capacity prices, to vary in QF contracts would protect consumers without materially affecting QF financing and, indeed, likely would make it easier for QFs to obtain longer-term contracts that support financing.[7] Further, the proposed revisions to the PURPA Regulations relating to the one-mile rule and PURPA section 210(m) would better implement the Commission's understanding of Congress' intent in enacting those provisions in light of current circumstances.

14. The Commission seeks comment on these proposed reforms 60 days from the date of publication of this NOPR in the **Federal Register**.

I. Background

A. Circumstances Underlying the Passage of PURPA in 1978 and the Commission's Promulgation of Its PURPA Regulations in 1980

15. PURPA was part of a legislative package Congress enacted in 1978 to address the energy crisis then facing the country.[8] As the Supreme Court explained in *FERC* v. *Mississippi,* in passing PURPA Congress was aware that domestic oil production had lagged behind demand, and the country had become increasingly dependent on foreign oil—which could jeopardize the country's economy and undermine its independence.[9] Roughly a third of the nation's electricity was generated using oil and natural gas,[10] and Congress concluded that increased reliance on cogeneration and small power production could significantly contribute to conserving this energy.[11] The Fuel Use Act, another part of that legislative package with the same ultimate goal in mind, similarly required federal agencies to ''carry out programs designed to *prohibit or discourage the use of natural gas and petroleum* as a primary energy source and by taking such actions as lie within their authorities to maximize the efficient use of energy *and conserve natural gas and petroleum.*'' [12] In short, as recognized by the Supreme Court, Congress passed PURPA to address the consequences of shortages of oil and natural gas (and electric utilities' decreasing efficiency in their generating capacities), which adversely impacted rates to customers and the economy as a whole.[13]

16. Congress enacted PURPA section 210 in 1978 to address the energy crisis by encouraging the development of QFs and thereby reducing the country's demand for traditional fossil fuels.[14] To accomplish this, section 210(a) directed that the Commission ''prescribe, and from time to time thereafter revise, such rules as [the Commission] determines necessary to encourage cogeneration and small power production,'' [15] including rules requiring electric utilities to offer to sell electricity to, and purchase electricity from, QFs. Section 210(f) required each state regulatory authority and nonregulated electric utility to implement the Commission's rules.

17. In 1980, the Commission issued Order Nos. 69 and 70, which promulgated the required rules that, with minor exceptions, remain in effect today.[16] The Commission explained that, at the time of the passage of PURPA, QFs faced three major obstacles: (1) Electric utilities were not required to purchase their electric output or to make purchases at an appropriate rate; (2) electric utilities sometimes charged discriminatorily high rates for backup services; and (3) QFs ran the risk of being considered public utilities themselves and thus being subject to state and federal regulation as utilities.[17] Further, at that time, there was no open access transmission and essentially no competition in electric wholesale markets. Electric utilities were vertically-integrated and held dominant

[7] As explained below, some states have established limited contract durations as a way of limiting long-term price risk from fixed energy rate purchases from QFs. The Commission considers that, by addressing the concern that has led to the imposition of short-term contracts, the changes proposed herein will provide opportunities for longer-term contracts, which will encourage the development of QFs.

[8] *See* Public Law 95–617, 92 Stat. 3117. In addition to PURPA, the package included: the Energy Tax Act of 1978, Public Law 95–618, 92 Stat. 3174; the National Energy Conservation Policy Act, Public Law 95–619, 92 Stat. 3206; the Powerplant and Industrial Fuel Use Act of 1978, Public Law 95–620, 92 Stat. 3289; and the Natural Gas Policy Act of 1978, Public Law 95–621, 92 Stat. 3351.

[9] *FERC* v. *Miss.,* 456 U.S. 742, 756 (1982).

[10] *Id.* at 745.

[11] *Id.* at 757.

[12] 42 U.S.C. 8301(b)(7) (emphasis added).

[13] *FERC* v. *Miss.,* 456 U.S. at 745–46.

[14] *Id.* at 750.

[15] 16 U.S.C. 824a–3(a).

[16] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978,* Order No. 69, FERC Stats. & Regs. ¶ 30,128 (cross-referenced 10 FERC ¶ 61,150), *order on reh'g,* Order No. 69–A, FERC Stats. & Regs. ¶ 30,160 (1980) (cross-referenced at 11 FERC ¶ 61,166), *aff'd in part & vacated in part sub nom. Am. Elec. Power Serv. Corp.* v. *FERC,* 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst.* v. *Am. Elec. Power Serv. Corp.,* 461 U.S. 402 (1983) (*API*); *Small Power Production and Cogeneration Facilities—Qualifying Status,* Order No. 70, FERC Stats. & Regs. ¶ 30,134 (cross-referenced at 10 FERC ¶ 61,230), *orders on reh'g,* Order No. 70–A, FERC Stats. & Regs. ¶ 30,159 (cross-referenced at 11 FERC ¶ 61,119) *and* FERC Stats. & Regs. ¶ 30,160 (cross-referenced at 11 FERC ¶ 61,166), *order on reh'g,* Order No. 70–B, FERC Stats. & Regs. ¶ 30,176 (cross-referenced at 12 FERC ¶ 61,128), *order on reh'g,* FERC Stats. & Regs. ¶ 30,192 (1980) (cross-referenced at 12 FERC ¶ 61,306), *amending regulations,* Order No. 70–D, FERC Stats. & Regs. ¶ 30,234 (cross-referenced at 14 FERC ¶ 61,076), *amending regulations,* Order No. 70–E, FERC Stats. & Regs. ¶ 30,274 (1981) (cross-referenced at 15 FERC ¶ 61,281).

[17] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,863.

market positions. As a result of their control over transmission access, it was virtually impossible for third parties—whether independent power producers or other electric utilities—to compete with them to make sales of electricity.

18. Given the Congressional mandate described above, the Commission determined in Order No. 69 to set rates for sales by QFs equal to the purchasing electric utilities' avoided costs.[18] The Commission also directed that electric utilities provide backup electric energy to QFs on a non-discriminatory basis and at just and reasonable rates,[19] and that utilities interconnect with QFs.[20] Pursuant to section 210(e) of PURPA,[21] the Commission further provided exemptions from many provisions of the Federal Power Act (FPA) and state laws governing utility rates and financial organization.[22]

B. Changes in Circumstances Subsequent to the Commission's Promulgation of Its PURPA Regulations in 1980

19. In the past 40 years, there have been three important changes in the circumstances that prompted Congress to pass PURPA in 1978. First, the situation with respect to the availability of natural gas has changed completely. The Commission recently outlined the sweeping changes that have taken place in the natural gas industry, and the resulting greater availability of natural gas.[23] As the Commission explained, over the last decade, the United States has seen an unprecedented change in the dynamics of the natural gas market and the relevant supply and demand. Led by advancements in production technologies, primarily in accessing shale reserves, natural gas supplies have increased dramatically. Domestic natural gas production, which appeared to peak in the early 1970s at 21.7 Tcf per year, has recently increased from 18.1 Tcf in 2005 to 30.4 Tcf in 2018.[24] The U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2019 forecasts continued supply growth over the next 25 years, increasing to nearly 40 Tcf by 2035 and 43 Tcf by 2050.[25] In short, there no longer are shortages of natural gas supply.

20. Second, since 1978, the outlook for the development of alternatives to natural gas and oil-fired resources, such as renewable resources, has changed equally dramatically. The once-nascent renewables industry has grown and matured over the past 40 years, and has only accelerated subsequent to the 2005 amendment of PURPA. Renewable resources likewise benefit from the availability of federal tax credits[26] and from state-mandated renewable portfolio standards (RPS) that require electric utilities to procure electric energy from renewable resources.[27] The cost of renewable facilities, including solar, also has dropped substantially,[28] to the point that the levelized cost of electricity (LCOE) from solar facilities is now or is shortly expected to approach the LCOE from traditional electric generation.[29] Similarly, a recent report from Lawrence Berkeley National Lab finds that wind power purchase agreements are being executed at around $0.02/kWh, which compares favorably to projected future fuel costs for natural gas-fired generation.[30]

21. According to EIA, in the first 5 months of 2019, renewable resources (including hydro) provided a significant share (approximately 20 percent) of the net electricity generated in the United States.[31] The Commission's monthly Energy Infrastructure Update Report shows that, as of July of 2019, the installed nameplate capacity of renewable resources, again including hydro, represented approximately 22 percent of the entire available installed capacity in the United States.[32]

22. Furthermore, EIA projects that approximately 65 percent of capacity additions in 2019 will come from renewable resources.[33] Although almost 100 percent of all renewable resources in 1995 were QFs, since 2005 QFs have made up only 10 to 20 percent of all renewable resource capacity in service in the United States. Consequently, today most renewable resources are not relying on PURPA in order to develop and operate. This decreasing reliance on PURPA suggests that some generation capacity that might otherwise qualify as and be built as small power productions under PURPA is being built, through wholesale market constructs that have developed since the Commission first implemented PURPA.

23. Another development pursued by regions (such as the Regional Greenhouse Gas Initiative) or states (like California and New York) has been state-initiated efforts to promote carbon reduction and through RPS programs require electric utilities to supply a specified percentage of their customers' loads from renewable resources or through the establishment of

[18] 18 CFR 292.304(a)(2); *see API,* 461 U.S. at 412–18.

[19] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,887–90; *see also* 18 CFR 292.305.

[20] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,874; *see also* 18 CFR 292.303(c).

[21] 16 U.S.C. 824a–3(e).

[22] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,864; *accord id.* at 30,863, 30,894–96; *see also* 18 CFR 292.601–.602.

[23] *Certification of New Interstate Natural Gas Facilities,* 163 FERC ¶ 61,042 (2018).

[24] EIA, Monthly Energy Review, Aug. 27, 2019 (in table 4.1 see column labeled ''Natural Gas Production (Dry)'' on the Annual tab of the xls version) *https://www.eia.gov/totalenergy/data/monthly/.*

[25] EIA, Annual Energy Outlook 2018, at tbl.13 (Jan. 24, 2019) (in table see row labeled ''Dry Gas Production'' under the reference case) (Annual Energy Outlook 2019), *https://www.eia.gov/outlooks/aeo/data/browser/#/?id=13-AEO2019&cases=ref2018&sourcekey=0.*

[26] Although Congress has reauthorized the federal production tax credit, the federal production tax credit is still currently scheduled to phase out over the next several years. *See* U.S. Dep't of Energy, *Renewable Energy Production Tax Credit, https://www.energy.gov/savings/renewable-electricity-production-tax-credit-ptc* (''Wind facilities commencing construction by December 31, 2019, and all other qualifying facilities commencing construction by January 1, 2018 can qualify for this credit. The value of the credit for wind steps down in 2017, 2018 and 2019. . . . For all other technologies, the credit is not available for systems whose construction commenced after December 31, 2017.'').

[27] As of February 1, 2019, 29 states, Washington, DC, and three territories had adopted mandatory renewable portfolio standards, while eight states and one territory had set renewable energy goals. *See* National Conference of State Legislatures, *State Renewable Portfolio Standards and Goals, http://www.ncsl.org/research/energy/renewable-portfolio-standards.aspx.*

[28] According to the EIA, the ''overnight'' (interest excluded) capital costs for utility-scale onshore wind and fixed tilt photovoltaic systems decreased by approximately 25 percent and 67 percent respectively, just during the period from 2013 to 2017. *See* EIA, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, https://www.eia.gov/analysis/studies/powerplants/capitalcost/.*

[29] EIA, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019* (Feb. 2019), *https://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf.* However, EIA cautions against directly comparing the costs of dispatchable and nondispatchable generation: ''Because load must be continuously balanced, generating units with the capability to vary output to follow demand (dispatchable technologies) generally have more value to a system than less flexible units (nondispatchable technologies) such as those using intermittent resources to operate. The LCOE values for dispatchable and non-dispatchable technologies are listed separately in the tables because comparing them must be done carefully. *See* EIA, *Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2019* (Jan. 2019), *https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.*

[30] *See* Lawrence Berkeley National Lab, *Wind Technologies Market Report, https://emp.lbl.gov/wind-technologies-market-report/.*

[31] *See* EIA, *August 2019 Monthly Energy Review* at Figure 7.2a, *https://www.eia.gov/totalenergy/data/monthly.*

[32] Office of Energy Projects, *Energy Infrastructure Update For July2019* at 4 (July 2019), *https://www.ferc.gov/legal/staff-reports/2019/july-energy-infrastructure.pdf.*

[33] EIA, Today in Energy, *New electric generating capacity in 2019 will come from renewables and natural gas* (Jan. 10, 2019), *https://www.eia.gov/todayinenergy/detail.php?id=37952* (Form EIA–860M, Preliminary Monthly Electric Generator Inventory).

requirements to purchase renewable energy certificates (RECs). Presently, 29 states and the District of Columbia have mandatory RPS programs.[34] This trend has further influenced increasing investment in renewables in the United States.

24. Unlike renewable generation, cogeneration is a technology that is imbedded in an industrial process.[35] Record evidence suggests that cogeneration has not achieved recent increases in penetration similar to renewable generation, and also remains more dependent on PURPA. For example, from 2008—2017, over 67 percent of industrial cogeneration additions obtained QF status.[36] However, energy produced by cogeneration in 2008 equaled 304.5 TWh, decreasing to 293.9 TWh in 2018.[37] Furthermore, this trend of decreasing cogeneration output goes back even further; for example in 2005 cogeneration output equaled 321.6 TWh.[38]

25. Third, the introduction of QFs as competing sources of electricity to the incumbent electric utilities has led to the development of significant non-QF independent power production. Development of independent power production, in turn, has been a major factor in the establishment of vibrant competitive markets in much of the United States. Pursuant to the Energy Policy Act of 1992, the Commission, through Order No. 888 and related orders, has overseen the development of competition and competitive wholesale electricity markets.[39] In addition, regional transmission organizations (RTO) and independent system operators (ISO) serve two-thirds of electricity consumers in the United States.[40] This development has transformed the electric industry in the intervening years and has significantly reduced the barriers to entry that faced QFs when PURPA was enacted.

26. Congress recognized the important effect of the development of these organized competitive markets when it enacted, as part of the Energy Policy Act of 2005, PURPA section 210(m). Among other things, section 210(m) permits electric utilities to request termination of their obligation to purchase electricity from QFs having access to RTO/ISO markets (or markets of comparable competitive quality).[41] In so doing, we interpret Congress as recognizing that the development of competition in the electric industry created conditions that sufficiently encouraged the development of cogeneration and small power production facilities, at least in the RTO/ISO markets and in markets of comparable competitive quality.

27. Since PURPA was amended in 2005, competition and competitive markets have spread even further, and have spurred additional development of independently-owned generation both inside and outside of the RTO/ISO markets. For example, EIA data shows that net generation of energy by non-utility owned renewable resources [42] in the United States escalated from 51.7 TWh in 2005 when EPAct 2005 was passed, to 340 TWh in 2018.[43] This also has included significant growth in non-utility renewable resources in states outside of RTOs. For example, net generation by non-utility renewable resources in the region defined by EIA as the Mountain State region [44] increased from 3.6 TWh in 2005 to 19.5 TWh in 2012, and to 42.5 TWh in 2018.[45] Pacific Northwest (Oregon and Washington) net non-utility generation from renewable resources increased from 1.5 TWh in 2005, to 8.7 TWh in 2012, and to 10.6 TWh in 2018.[46] In the Southeast region of the country, non-utility renewable resources saw a lesser increase from 2.6 TWh in 2005 to 2.7 TWh in 2012, but expanded to 6.5 TWh in 2018.[47]

C. Need for Revisions to the Commission's PURPA Regulations in Light of Changed Circumstances

28. In 2016, the Commission conducted a technical conference in Docket No. AD16–16–000 (Technical Conference) to address issues involving the implementation of PURPA. The Technical Conference covered such issues as: (1) Various methods for calculating avoided cost; (2) the obligation to purchase pursuant to a LEO; (3) application of the one-mile rule; and (4) the rebuttable presumption the Commission has adopted under PURPA section 210(m) that QFs 20 MW and below do not have nondiscriminatory access to competitive organized wholesale markets.[48] In addition to the oral presentations made at the Technical Conference, the Commission received numerous written comments on these and other subjects regarding the need to revise the PURPA Regulations. The Commission has found these oral presentations and comments to be helpful, and the revisions proposed in this NOPR were informed by the record of the Technical Conference, which the Commission is incorporating into this proceeding.

29. Consistent with the direction from Congress that the Commission revise its PURPA Regulations ''from time to time'' [49] and considering the changes in the energy industry described above, the Commission preliminarily finds, based on the data described in the preceding section and the comments received at the Technical Conference, that the Commission's PURPA Regulations should be modernized. First, currently there is an increased supply of natural gas resulting from advanced production techniques that have opened up large new natural gas reserves. Second, vertically integrated utilities no longer dominate the wholesale electric markets throughout the United States as they did

[34] Galen Barbose, Lawrence Berkeley National Laboratory, *U.S. Renewable Portfolio Standards 2018 Annual Status Report* at 6 (Nov. 2018), *http://eta-publications.lbl.gov/sites/default/files/2018_annual_rps_summary_report.pdf.*

[35] *See* American Forest & Paper Association and Electricity Consumers Resource Council Supplemental Comments, Docket No. AD16–16–000, at 5 (Nov. 30, 2018).

[36] *Id.*

[37] This data was taken from EIA's Electricity Data Browser, *www.eia.gov/electricity/data/browser* (the total of net generation by independent power producers cogeneration, commercial cogeneration, and industrial cogeneration).

[38] *Id.*

[39] *See Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996), (cross-referenced at 75 FERC ¶ 61,080, *order on reh'g,* Order No. 888–A, FERC Stats. & Regs. ¶ 31,048 at 30,176, (cross-referenced at 78 FERC ¶ 61,220, *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); *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities,* Order No. 697, 119 FERC ¶ 61,295, *clarified,* 121 FERC ¶ 61,260 (2007), *order on reh'g,* Order No. 697–A, 123 FERC ¶ 61,055, *clarified,* 124 FERC ¶ 61,055, *order on reh'g,* Order No. 697–B, 125 FERC ¶ 61,326 (2008), *order on reh'g,* Order No. 697–C, 127 FERC ¶ 61,284 (2009), *order on reh'g,* Order No. 697–D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom. Mont. Consumer Counsel* v. *FERC,* 659 F.3d 910 (9th Cir. 2011).

[40] ISO/RTO Council, *The Role of ISOs and RTOs, https://isorto.org.*

[41] 16 U.S.C. 824a–3(m).

[42] The EIA renewable resources data discussed herein is based on the EIA ''other renewables'' category of generation resources, which consists of wind, utility scale solar, geothermal, and biomass resources.

[43] This data was taken from EIA's Electricity Data Browser, *www.eia.gov/electricity/data/browser* (select net generation, other renewables, independent power producers).

[44] Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming.

[45] This data was taken from EIA's Electricity Data Browser, *www.eia.gov/electricity/data/browser.*

[46] *Id.*

[47] Florida, Georgia, Alabama, and Mississippi.

[48] Supplemental Notice of Technical Conference, *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* Docket No. AD16–16–000 (May 9, 2016).

[49] 16 U.S.C. 824a–3(a).

in the past, and the participation of independently owned generation no longer is the exception but is the rule in much of the country. Consequently, electric prices increasingly are established based on competitive factors in many regions. Third, significant renewable resources have been developed outside of PURPA based on other programs that specifically target renewable resources, as well as on the falling costs of such resources.

30. In addition, there is evidence suggesting that the Commission's rationale for allowing a QF to fix its avoided cost rate for the term of its contract, *i.e.,* that any overestimations and underestimations in avoided cost rates during the term of the contract would ''balance out'' over time,[50] may no longer be valid. This evidence suggests, instead, that overestimations of avoided cost have not been balanced by underestimations.[51] This trend may persist with the continuing general decline in the cost of electricity due to technological innovations, changes in the fuel mix, and conservation.[52] Further, testimony at the Technical Conference and data regarding the development of independently-owned generation resources suggest that it is not necessary for energy rates to be fixed in order to obtain financing.[53]

31. Consequently, the Commission is proposing revisions to its PURPA Regulations to rebalance the approach adopted in the 1980s. Because some of the small power producer generation technologies originally encouraged by PURPA are now being developed independent of PURPA, it appears appropriate to provide states flexibility to rely on the market tools that are available today to set QF rates. The Commission is proposing to allow states flexibility to ensure that the rates for energy sold by QFs to electric utilities more accurately reflect PURPA's requirement that the rates for purchases of energy from QFs not exceed ''the cost to the electric utility of the electric energy which, but for the purchase from such [QF], such utility would generate or purchase from another source'' at the time of delivery.[54] The Commission preliminarily finds that using a competitive price will continue to encourage the development of QFs and more closely adhere to PURPA's requirement that rates for purchases of energy from QFs not only be capped at avoided cost, but also be just and reasonable to the purchasing electric utility's electric consumers and in the public interest.[55] Given the targeted nature of the reforms proposed here, and the existing benefits to QFs that the Commission does not propose to amend and that were directly responsive to the barriers to QFs that PURPA sought to reduce,[56] the approach adopted here also maintains PURPA's protections against discrimination.[57]

The Commission believes that the revisions proposed here represent a reasonable package of benefits and obligations that would bring the Commission's implementation of PURPA into the modern era while at the same time continuing to satisfy PURPA's statutory mandates.

II. Discussion

A. QF Rates

32. The Commission proposes to revise its PURPA Regulations to permit states to incorporate competitive market forces in setting QF rates. First, the Commission proposes to allow states to exercise their discretion to set the energy component of the rate a purchasing electric utility pays for a QF's power based on market prices rather than on the purchasing electric utility's administratively-determined avoided cost rate. Thus, the Commission proposes to revise its PURPA Regulations with regard to energy rates to state that:

- States have the flexibility to require that ''as-available'' QF energy rates paid by electric utilities located in RTO/ISO markets be based on the market's locational marginal price (LMP) or similar energy price derived by the market, in effect at the time the energy is delivered.
- States have the flexibility to require that ''as-available'' QF energy rates paid by electric utilities located outside of RTO/ISO markets be based on competitive prices determined by: (1) Liquid market hub energy prices; or (2) formula rates based on observed natural gas prices and a specified heat rate.
- States have the flexibility to require that energy rates under QF contracts and LEOs be based on as-available energy rates determined at the time of delivery rather than being fixed for the term of the contract or LEO.
- States in RTO/ISO markets have the flexibility to instead implement an alternative approach of requiring that the fixed energy rate be calculated based on estimates of the present value of the stream of revenue flows of future LMPs or other acceptable as-available energy rates at the time of delivery.

33. Second, the Commission proposes to amend its regulations to make clear that States have the flexibility to require that energy and/or capacity rates be determined through a competitive solicitation process, such as an RFP. However, the Commission does not otherwise propose to change how the PURPA Regulations require the capacity component of a QF's rates to be determined.[58]

34. Although the Commission is proposing to modify how the states are permitted to calculate avoided costs, it is not terminating the requirement that the states continue to calculate, and to set QF rates at, such avoided costs.

35. The Commission has long emphasized that states have ''great latitude in determining the manner of implementation of the Commission's rules, provided that the manner chosen is reasonably designed to implement the requirements of Subpart C [which includes the pricing rules of § 292.304].'' [59] The modifications proposed here are intended to be consistent with this approach. The Commission intends that the states will continue to have ''great latitude'' in determining how to apply the revised rules, provided that such application is reasonably designed to implement any new rate provisions that may be adopted, as well as the other already-existing provisions of the PURPA Regulations.

1. Background

36. PURPA requires that the Commission promulgate rules, to be

[50] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,880.

[51] *See infra* note 101.

[52] *See e.g.,* EEI Supplemental Comments, Docket No. AD16–16–000, attach. A at 2–3 (June 25, 2018) (EEI Supplemental Comments).

[53] This evidence is discussed in detail below in Section II.A.5.b.

[54] 16 U.S.C. 824a–3(b), (d).

[55] 16 U.S.C. 824a–3(b)(1).

[56] *See, e.g., supra* notes 19–20, 22 (citing *inter alia* 18 CFR 292.303(c) (electric utility's obligation to interconnect), 292.305 (electric utility's obligation to provide backup power to QFs), 292.601–02 (QF exemption from public utility regulations in FPA and Public Utility Holding Company Act)).

[57] 16 U.S.C. 824a–3(b)(2).

[58] An electric utility is not required to pay for QF capacity that the state has determined is not needed. *See Hydrodynamics Inc.,* 146 FERC ¶ 61,193, at P 35 (2014) (*Hydrodynamics*) (referencing *City of Ketchikan, Alaska,* 94 FERC ¶ 61,293, at 62,061 (2001) (''[A]voided cost rates need not include the cost for capacity in the event that the utility's demand (or need) for capacity is zero. That is, when the demand for capacity is zero, the cost for capacity may also be zero.''); *Entergy Servs., Inc.,* 137 FERC ¶ 61,199, at P 56 (2011).

[59] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,891–92. The Commission explained that ''[s]uch latitude is necessary in order for implementation to accommodate local conditions and concerns, so long as the final plan is consistent with statutory requirements.'' *Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978,* 23 FERC ¶ 61,304, at 61,646 (1983).

implemented by the states,[60] establishing the rates electric utilities pay for purchases of QF energy. Under PURPA, such rates must: (1) Be just and reasonable to the electric consumers of the electric utility and in the public interest; (2) not discriminate against qualifying cogenerators or qualifying small power producers; [61] and (3) not exceed ''the incremental cost to the electric utility of alternative electric energy,'' [62] which is ''the cost to the electric utility of the electric energy which, *but for* the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.'' [63] The ''incremental cost to the electric utility of alternative electric energy'' referred to in prong (3) above, which sets out a statutory upper bound on a QF rate, has been consistently referred to by the Commission and industry by the short-hand phrase ''avoided cost,'' [64] although the term ''avoided cost'' itself does not appear in PURPA.

37. In addition, the PURPA Regulations currently provide a QF two options for how to sell its power to an electric utility. The QF may sell as much of its energy as it chooses when the energy becomes available, with the rate for the sale calculated at the time of delivery (the so-called ''as-available'' rate).[65] Alternatively, the QF may choose to sell pursuant to a contract over a specified term.[66]

38. If the QF chooses to sell under the second option, the PURPA Regulations then provide the QF the further option of receiving, in terms of pricing, either: (1) The purchasing electric utility's avoided cost calculated and fixed at the time the LEO is incurred; [67] or (2) the purchasing electric utility's avoided cost calculated at the time of delivery.[68]

39. In implementing the PURPA Regulations, the Commission recognized that a contract with avoided costs calculated at the time a LEO is incurred could exceed the electric utility's avoided costs at the time of delivery in the future, thereby seemingly violating PURPA's requirement that QFs not be paid more than an electric utility's avoided costs. But the Commission believed that the fixed avoided cost rate might also turn out to be lower than the electric utility's avoided costs over the course of the contract and that, ''in the long run, 'overestimations' and 'underestimations' of avoided costs will balance out.'' [69] The Commission's justification for allowing QFs to fix their rate at the time of the LEO for the entire life of the contract was that fixing the rate provides ''certainty with regard to return on investment in new technologies.'' [70]

40. The record developed in the Commission's technical conference docket, Docket No. AD16–16–000, where the Commission began its reconsideration of the PURPA Regulations, indicates that allowing QFs to fix their avoided cost rates at the time a LEO is incurred has resulted in overpayments as energy prices generally have declined over the years, leaving the fixed energy portion of the QF rate well above the purchasing electric utility's actual avoided energy costs at the time of delivery.[71] Some commenters have recommended that the Commission allow states to ''price generation [energy] from QFs at market prices, and to update those prices regularly so that the prices for qualifying facilities are not burdensome on customer rates'' and ''clarify that states can set avoided costs through [requests for proposal (RFPs)] or other forms of competitive solicitations,'' and that the Commission limit as-available avoided cost energy rates in a LEO to no higher than avoided cost rates at the time of delivery.[72]

41. Over the years subsequent to the issuance of the PURPA Regulations in 1980, the Commission has taken significant steps to implement changes to its rules and regulations to encourage the development of competitive wholesale electricity markets. After approving the first market-based rate tariff in 1989,[73] sales of electricity at market-based rates proliferated. This ultimately led to the issuance of Order No. 697 [74] in 2007, which established uniform regulations governing market-based rate sales. In addition, RTOs and ISOs with organized electric markets were established in the 2000s, and today serve two-thirds of electricity consumers in the United States.[75]

42. These developments have largely transformed the electric industry from one where rates were once based on administratively-determined cost of service ratemaking to one where rates now often are based on competitive market forces. This change has led the Commission to likewise consider whether to allow states to rely on competitive forces, rather than administrative determinations, to set as-available avoided cost energy rates.

2. LMP as a Permissible Rate for Certain As-Available QF Energy Sales

43. The Commission proposes to revise the PURPA Regulations in 18 CFR 292.304 to add subsections (b)(6) and (e)(1). In combination, these subsections would permit a state the flexibility to set the as-available energy rate paid to a QF by an electric utility located in an RTO/ISO at LMPs calculated at the time of delivery.

44. RTOs and ISOs generally use LMP to set day-ahead and real-time energy prices through competitive auctions that optimally dispatch resources to balance

[60] Nonregulated electric utilities implement the requirements of PURPA with respect to themselves. An electric utility that is ''nonregulated'' is any electric utility other than a ''state regulated electric utility.'' 16 U.S.C. 2602(9). The term ''state regulated electric utility,'' in contrast, means any electric utility with respect to which a state regulatory authority has ratemaking authority. 16 U.S.C. 2602(18). The term ''state regulatory authority,'' as relevant here, means a state agency which has ratemaking authority with respect to the sale of electric energy by an electric utility. 16 U.S.C. 2602(17).

[61] 16 U.S.C. 824a–3(b)(1)–(2).

[62] 16 U.S.C. 824a–3(b).

[63] 16 U.S.C. 824a–3(d) (emphasis added).

[64] *See* 18 CFR 292.101(b)(6) (defining avoided costs in relation to the statutory terms); *see also* Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,865 (''This definition is derived from the concept of ''the incremental cost to the electric utility of alternative electric energy'' set forth in section 210(d) of PURPA. It includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities.'').

[65] 18 CFR 292.304(d)(1).

[66] 18 CFR 292.304(d)(2)(a)–(b); *see also FLS Energy, Inc.*, 157 FERC ¶ 61,211, at P 21 (2016) (*FLS*) (citing 18 CFR 292.304(d)).

[67] 18 CFR 292.304(d)(2)(ii). Rates calculated at the time of a LEO (for example, a contract) do not violate the requirement that the rates not exceed avoided costs if they differ from avoided costs at the time of delivery. 18 CFR 292.304(b)(5).

[68] 18 CFR 292.304(d)(2)(i).

[69] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,880. *See also* 18 CFR 292.304(b)(5) (''In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.''); *Entergy Servs., Inc.*, 137 FERC ¶ 61,199 at P 56 (''Many avoided cost rates are calculated on an average or composite basis, and already reflect the variations in the value of the purchase in the lower overall rate. In such circumstances, the utility is already compensated, through the lower rate it generally pays for unscheduled QF energy, for any periods during which it purchases unscheduled QF energy even though that energy's value is lower than the true avoided cost.'').

[70] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,880.

[71] EEI Supplemental Comments, attach. A at 2–3 (June 25, 2018).

[72] *Id.* at 4.

[73] *See Citizens Power and Light Corp.*, 48 FERC ¶ 61,210 (1989).

[74] *Market-Based Rates for Wholesale Sales of Electric Energy, Capacity and Ancillary Services by Public Utilities*, Order No. 697, 119 FERC ¶ 61,295, *clarified*, 121 FERC ¶ 61,260 (2007), *order on reh'g*, Order No. 697–A, 123 FERC ¶ 61,055, *clarified*, 124 FERC ¶ 61,055, *order on reh'g*, Order No. 697–B, 125 FERC ¶ 61,326 (2008), *order on reh'g*, Order No. 697–C, 127 FERC ¶ 61,284 (2009), *order on reh'g*, Order No. 697–D, 130 FERC ¶ 61,206 (2010), *aff'd sub nom. Mont. Consumer Counsel* v. *FERC*, 659 F.3d 910 (9th Cir. 2011).

[75] ISO/RTO Council, *The Role of ISOs and RTOs*, *https://isorto.org.*

supply and demand, while taking into account actual system conditions including congestion on the transmission system. As described in the Commission Energy Primer written by Commission staff, ''[t]he RTO markets calculate a LMP at each location on the power grid. . . . All sellers receive the LMP for their location and all buyers pay the market clearing price for their location.'' [76] While the various RTOs and ISOs may calculate LMP somewhat differently, the Commission has recognized that LMPs ''reflect the true marginal cost of production, taking into account all physical system constraints, and these prices would fully compensate all resources for the variable cost of providing service.'' [77] Prices in such an LMP-based rate structure ''are designed to reflect the least-cost of meeting an incremental megawatt-hour of demand at each location on the grid, and thus prices vary based on location and time.'' [78]

45. The Commission therefore preliminarily finds that LMP is an accurate measure of avoided costs. Unlike, for example, average system-wide cost measures of avoided cost used by many states, LMP could provide an accurate measure of the varying actual avoided costs for each receipt point on an electric utility's system where the utility receives power from QFs. LMP is the per MWh cost of obtaining incremental supplies at each point. Further, these prices are not rigid, long-lasting prices as tends to be the case currently for administratively-determined avoided costs, but prices that are calculated daily (for the day-ahead markets) and/or every five minutes (for real-time markets) and vary to reflect changing system conditions (*e.g.,* they tend to rise as demand increases and the system operator dispatches increasingly expensive supplies to meet that higher demand). The Commission also notes that Congress, through enactment of section 210(m) of PURPA, appears to recognize that RTO/ISO LMP pricing provides sufficient encouragement for QFs.

46. Consequently the Commission believes it is appropriate to consider giving states the flexibility to employ LMP pricing for QF energy rates. Specifically, the Commission proposes to make clear in the PURPA Regulations that a state may use LMP as a rate for as-available QF energy sales to electric utilities located in an RTO/ISO market.[79]

47. The Commission requests comment on whether the real-time prices established in the California Independent System Operator, Inc. (CAISO)-administered Energy Imbalance Market (EIM) [80] are similar for these purposes to the LMP in RTOs/ISOs. In this regard, the Commission requests comment on whether there are any reasons why prices developed in the EIM similarly ''reflect the least-cost of meeting an incremental megawatt-hour of demand at each location on the grid,'' [81] as the Commission has found to be the case with LMP rates.[82]

48. In addition to continuing to set QF energy rates at avoided costs, using LMPs for as-available energy pricing brings many other benefits. LMPs, in contrast to the administrative pricing methodologies used to set as-available QF rates by many states, could promote the more efficient use of the transmission grid, promote the use of the lowest-cost generation, and provide for transparent price signals.[83]

49. Furthermore, when Congress added PURPA § 210(m) as part of EPAct 2005, Congress provided for the Commission to terminate electric utilities' obligation to make new purchases from QFs that have nondiscriminatory access to the RTO/ISO markets and markets of comparable competitive quality. The Commission interprets this amendment as representing an acknowledgement by Congress that access to these markets provides sufficient encouragement to QFs.

50. The Commission understands that some states already use LMP to establish avoided cost energy rates under our PURPA Regulations.[84] The Commission thus proposes also to clarify that, while a state in the past may have been able to conclude that LMP was an appropriate measure of the energy component of avoided costs,[85] a state would be able to adopt LMP as a per se appropriate measure of the as-available energy component of avoided costs.[86]

3. Use of Other Competitive Prices as a Permissible Rate for Certain As-Available QF Energy Sales

51. The Commission proposes to revise the PURPA Regulations in 18 CFR 292.304 to add a subsection (b)(7) which, in combination with new subsection (e)(1), would permit a state to set the as-available energy rate paid to a QF by electric utilities located outside of RTO/ISO markets at a

[76] Federal Energy Regulatory Commission, *Energy Primer, A Handbook of Market Basics,* at 60 (Nov. 2015), *available at https://www.ferc.gov/market-oversight/guide/energy-primer.pdf.*

[77] *Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Order No. 831, 157 FERC ¶ 61,115, at P 7(2016), *order on reh'g and clarification,* Order No. 831–A, 161 FERC ¶ 61,156 (2017).

[78] *Sacramento Mun. Util. Dist.* v. *FERC,* 616 F.3d 520, 524 (D.C. Cir. 2010) (*SMUD*); *see also FERC* v. *Elec. Power Supply Ass'n,* 136 S.Ct. 760, 768–69 (2016) (describing how LMP is typically calculated).

[79] Although not regulated by the Commission, the Commission proposes to include in this definition of LMP the LMP established in the market governed by the Electric Reliability Council of Texas.

[80] By seeking comment regarding the CAISO EIM prices, the Commission does not mean to imply that real-time energy prices established by CAISO within its balancing authority area do not already satisfy the requirement for setting as-available QF rates.

[81] *SMUD,* 616 F.3d at 524.

[82] Use of real time prices in the EIM was addressed at the Technical Conference, but only in the context of whether that market could satisfy the requirements for termination of the mandatory purchase obligation under PURPA section 210(m)(1)(C). *See* Supplemental Notice of Technical Conference, *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* Docket No. AD16–16–000 (May 9, 2016). The Commission here requests comments on whether it would be appropriate to use the EIM price to develop an as-available energy rate.

[83] *See, e.g., Cal. Indep. Sys. Operator Corp.,* 105 FERC ¶ 61,140, at PP 48–50 (2003). *Cf. Price Formation in Energy and Ancillary Servs. Markets Operated by Regional Transmission Organizations and Indep. Sys. Operators,* 153 FERC ¶ 61,221, at P 2 (2015).

[84] *See Exelon Wind 1, LLC,* 140 FERC ¶ 61,152, at P 11 (2012), *reconsideration denied,* 155 FERC ¶ 61,066 (2016) (recognizing that the Texas Public Utility Commission has permitted Southwestern Public Service Company to set avoided costs at LMP); Xcel Energy Services Inc., Request for Reconsideration, Docket No. EL12–80–001, at 13 & n.23 (Sept. 27, 2012) (stating that Maryland, New Jersey, North Carolina, Virginia, Connecticut, New Hampshire, Kentucky, and Michigan have set avoided costs at LMP).

[85] *See* 18 CFR 292.304(e).

[86] We recognize that this proposal could be seen as a departure from the Commission's statement in *Exelon Wind 1, LLC,* 140 FERC ¶ 61,152, at P 52 (2012), *reconsideration denied,* 155 FERC ¶ 61,066 (2016) (''The problem with the methodology proposed by [Southwestern Public Service Company] and adopted by the Texas Commission is that it is based on the price that a QF would have been paid had it sold its energy directly in the [Energy Imbalance Service] Market, instead of using a methodology of calculating what the costs to the utility would have been for self-supplied, or purchased, energy 'but for' the presence of the QF or QFs in the markets, as required by the Commission's regulations.''). The Commission has already found that this statement was overtaken by events, namely Southwest Power Pool, Inc.'s evolution from an energy imbalance service market into an Integrated Marketplace, with day-ahead and real-time energy and operating reserve markets and the Texas Commission's approving a separate request from Southwestern Public Service Company to substitute LMP for Locational Imbalance Prices in calculating avoided costs. *Exelon Wind 1, LLC,* 155 FERC ¶ 61,066 at P 11. The Commission acknowledges that, if adopted in a final rule, the reasoning in this NOPR supports the departure from our precedent. *See Cal. Pub. Utils. Comm'n* v. *FERC,* 879 F.3d 966, 977 (9th Cir. 2018) (''When an agency changes policy, the requirement that it provide a reasoned explanation for its action demands, at a minimum, that the agency 'display awareness that it *is* changing position.''') (citing *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009)).

competitive price (Competitive Price) calculated at the time of delivery. Competitive Prices would be defined as: (1) Energy rates established at liquid market hubs; or (2) energy rates determined pursuant to formulas based on natural gas price indices and a proxy heat rate for an efficient natural gas combined-cycle generating facility. In each case, the state would need to find that the Competitive Price reasonably represents a competitive market price for the purchasing electric utility, consistent with Congress's directive that QF rates not exceed ''the incremental cost to the electric utility of alternative electric energy.'' [87] Other conditions also would have to be satisfied, as explained below.

a. Background

52. The Commission recognizes that competitive bilateral energy markets have arisen outside of the RTO/ISO energy markets. Particularly in the western United States, price hubs such as the Mid-Columbia (Mid-C) and Palo Verde hubs are liquid markets with prices the Commission has recognized as representing competitive market prices at those hubs.[88] Further, the price of electricity generated by efficient combined-cycle natural gas generation facilities would appear to represent a reasonable measure of a competitive energy price.[89]

53. For the same reasons described above that LMPs represent an appropriate energy rate for QFs purchasing from electric utilities located in RTO/ISO markets, the Commission proposes to find that Competitive Prices can represent appropriate rates for QFs selling to electric utilities located outside of RTO/ISO markets. Like LMP, liquid market hubs would rely on competition to derive an avoided cost price at particular points and times. From a price determination perspective, liquid market hub prices differ from LMP mainly in that they measure price at only one or a few points, whereas RTOs/ISOs derive unique LMPs for all receipt and delivery points on a specific area of the system. However, depending on how far away a particular purchasing electric utility or selling QF may be from the liquid market hub in question, the Commission believes that it may be appropriate to allow the states to set as-available energy rates based on Market Hub prices.

54. Natural gas indices coupled with the heat rate of an efficient natural gas combined-cycle generating facility may also be a reasonably accurate measure of avoided cost, at least in those markets where natural gas commonly is the marginal fuel. In such markets, we would expect that new supplies of energy would need to be offered at a price equal to or less than the incremental cost of using these efficient gas units in order to economically displace them. Thus, using natural gas indices and the heat rate of a combined-cycle unit to establish avoided cost also relies on competitive market forces, in this case competitive forces in natural gas markets for the fuel used by natural gas combined cycle) facilities the purchasing electric utility would generate itself or purchase from another source but for the sale from the QF.[90]

b. Commission Proposal

55. The Commission proposes in sections 292.304(b)(7) and (e)(1) to give states the flexibility to set QF energy rates for sales to electric utilities located outside of RTO/ISO markets based on Competitive Prices, *i.e.,* prices determined at liquid market hubs (Market Hub Prices), or prices determined by a formula based on natural gas price indices and a specified proxy heat rate for an efficient natural gas combined-cycle generating facility (Combined Cycle Prices).

i. Market Hub Prices

56. The Commission proposes to define Market Hub Prices as prices determined at a liquid market hub to which the purchasing electric utility has reasonable access. States electing to set QF energy rates using a Market Hub Price also would identify the particular market hub used to set the price. Such determination would require the state to find that the prices at such hub are competitive prices that actually relate to the costs an electric utility would avoid but for the purchase from the QF.

57. The following represents examples of factors the Commission believes a state reasonably could consider in making this determination: (1) Whether the hub is sufficiently liquid that prices at the hub represent a competitive price; [91] (2) whether the prices developed at the hub are sufficiently transparent; (3) whether the electric utility has the ability to deliver power from such hub to its load, even if its load is not directly connected to the hub; [92] and (4) whether the hub represents an appropriate market to derive an energy price for the electric utility's purchases from the relevant QFs given the electric utility's physical proximity to the hub. The above factors are not intended to be exhaustive and states reasonably could consider other factors in identifying a relevant liquid trading hub for setting QF energy rates. The Commission seeks comment on additional factors or standards for consideration by the states in determining whether liquid trading hubs could be used to set an electric utility's as-available energy avoided cost rate.

58. The Commission also understands that, in order for prices at market hubs to represent a purchasing electric utility's avoided costs, the market hub price may need to be subject to adjustments to account for transmission costs the electric utility would incur before such prices could serve as a factor in determining appropriate QF rates.[93] In addition, the Commission understands that market prices in a region may be determined based on a formula that incorporates prices at more than one market hub located in the region. The Commission seeks comment on whether under this proposal a state should be permitted to set QF rates at energy prices in a region that are based on a formula that includes adjustments to the market hub price or that incorporates prices at more than one market hub located in the region, when such prices represent standard pricing practice in the region where the purchasing electric utility is located.

ii. Combined Cycle Prices

59. In regions where there are no RTOs/ISO or market hubs, a competitive

[87] 16 U.S.C. 824a–3(b).

[88] *See Price Discovery in Natural Gas and Electric Markets,* 109 FERC ¶ 61,184, at P 66 (2004) (approving the use of published prices at market hubs with sufficient liquidity to set prices charged in tariffs); *El Paso Electric Co.,* 148 FERC ¶ 61, 051, at P 7 (2014) (approving the use of the Palo Verde price to set imbalance charges); *Idaho Power Co.,* 121 FERC ¶ 61,181 at P 27 (2007) (approving use of Mid-Columbia prices to set energy imbalance charge); *PacifiCorp,* 95 FERC ¶ 61,463, at 61,463 (2001) (approving setting energy imbalance rate at average of four market hub prices); *Pinnacle West Energy Corp.,* 92 FERC ¶ 61,248, at 61,791 (2000) (accepting the use of the Palo Verde price to set prices for affiliate transactions because the Palo Verde Index is a recognized market hub with competitive prices).

[89] *See, e.g., ISO New England Inc.,* 131 FERC ¶ 61,147, at P 5 (2010) (calculating the competitive price cap for imports into ISO New England equal to a published fuel price times a proxy heat rate).

[90] *See* 16 U.S.C. 824a–3(d).

[91] In considering whether a hub is sufficiently liquid, states could, for example, consider such factors as those identified by the Commission in *Price Discovery in Natural Gas and Electric Markets,* 109 FERC ¶ 61,184 at P 66.

[92] This factor might not apply if the purchase of energy avoided by the electric utility is from a resource whose energy is priced based on the hub price even though the purchasing electric utility does not have the ability to deliver energy from the hub itself to its load.

[93] Other adjustments also may be necessary in other situations in order for the adjusted hub price to reasonably reflect the purchasing electric utility's avoided cost.

price for energy may be established as the price of energy generated from an efficient natural gas combined cycle generating facility. The Commission proposes to allow states to set QF as-available energy rates at Combined Cycle Prices, defined as a formula rate established by the state using published natural gas price indices and a proxy heat rate for an efficient natural gas combined-cycle generating facility. The state would need to determine that the resulting Combined Cycle Price represents an appropriate approximation of the purchasing electric utility's avoided costs. This determination would involve consideration of such factors as, for example: (1) Whether the cost of energy from an efficient natural gas combined cycle generating facility represents a reasonable approximation of a competitive price in the purchasing electric utility's region; (2) whether natural gas priced in accordance with particular proposed natural gas price indices would be available in the relevant market; (3) whether there should be an adjustment to the natural gas price to appropriately reflect the cost of transporting natural gas to the relevant market; and (4) whether the proxy heat rate used in the formula should be updated regularly to reflect improvements in generation technology. Again, the above factors are not exhaustive and states would have flexibility to apply other factors that also might be appropriate for consideration.

iii. Other Approaches to Competitive Pricing for Certain As-Available QF Energy Sales

60. The Commission observes that electric utilities may purchase energy at market-oriented prices other than those that would qualify under the standards identified above.

The two options presented above are not intended to supersede the states' existing ability to set as-available energy rates based on an electric utility's avoided costs. The states would continue to be free, under the Commission's existing PURPA Regulations, to determine that competitive energy prices included in an electric utility's power purchase agreement represent the electric utility's avoided cost of energy and to set avoided cost energy rates for that utility based on its contract rate. Nothing proposed here would prevent a state from establishing an avoided cost rate based on such a contract, provided that all the necessary conditions for determining avoided costs apply.[94]

4. Permitting the Energy Rate Component of a Contract To Be Fixed at the Time of the LEO Using Forecasted Values of the Estimated Stream of Market Revenues

61. Frequently, price forecasts are available for LMPs in RTOs/ISOs, for liquid market hubs located outside of RTOs/ISOs, and for natural gas pricing hubs. Such forecasts could be used to allow QFs to request a fixed energy rate component calculated at the time a LEO is incurred. The Commission therefore proposes to add a new option in § 292.304(d)(1)(iii) permitting fixed energy rates to be based on forecasted estimates of the stream of revenue flows during the term of the contract. In other words, states could rely on market estimates of forecasted energy prices at the times of delivery over the anticipated life of the contract—such estimates are commonly referred to as a forward price curve—to develop a fixed energy rate component for that contract when such estimates reflect the purchasing electric utility's avoided costs.

62. The fixed energy rate component of the contract could be a single energy rate, based on the amortized present value of the forecast energy prices, or it could be a series of specified energy rates that are different in future years (or other periods).[95] Under this proposal, the QF would be able to establish, at the time the LEO is incurred, the applicable energy rate(s) for the entire term of a contract when the contract is signed; however, the energy rate in the contract could be different from year-to-year (or some other period) and nevertheless comply with the current § 292.304(d)(1)(ii) requirement that the energy rate be fixed for the term of the contract.[96]

5. Providing for Variable Energy Rates in QF Contracts

a. Background

63. As explained above, if a QF chooses to sell energy and/or capacity pursuant to a contract, the PURPA Regulations provide the QF the option of receiving the purchasing electric utility's avoided cost calculated and fixed at the time the LEO is incurred.[97] The Commission's justification for allowing QFs to fix their rate at the time of the LEO for the entire term of a contract was that fixing the rate provides certainty necessary for the QF to obtain financing.[98] The Commission stated that its regulations pertaining to LEOs "are intended to reconcile the requirement that the rates for purchases equal the utilities' avoided costs with the need for qualifying facilities to be able to enter contractual commitments based, by necessity, on estimates of future avoided costs." [99] Further, the Commission agreed with the "need for certainty with regard to return on investment in new technologies." [100]

64. The provision that QFs be permitted to fix their rates for the entire term of a contract or other LEO has proved to be one of the most controversial aspects of the Commission's PURPA Regulations. Some commenters at the Technical Conference submitted data indicating that energy prices generally have declined over the years, leaving the fixed energy portion of the QF rate, even when levelized, well above market prices that likely would represent the purchasing electric utility's actual avoided energy costs at the time of delivery.[101] Based on this concern, some

[94] Further, as explained in more detail below, energy and/or capacity rates for QFs could be established through a competitive solicitation process, such as an RFP.

[95] As explained above, the PURPA Regulations already require that the fixed energy rate would need to account for the operating characteristics of the QF, including the QF's ability to deliver energy during peak periods and the utility's ability to dispatch energy from the QF. *See* 18 CFR 292.304(e)(2).

[96] This is permissible under the Commission's existing PURPA Regulations. *See Windham Solar LLC,* 157 FERC ¶ 61,134, at PP 5–6 (2016) (*Windham Solar*) ("[A]lthough state regulatory authorities cannot preclude a QF . . . from obtaining a legally enforceable obligation with a forecasted avoided cost rate, we remind the parties that the Commission's regulations allow state regulatory authorities to consider a number of factors in establishing an avoided cost rate. These factors which include, among others, the availability of capacity, the QF's dispatchability, the QF's reliability, and the value of the QF's energy and capacity, allow state regulatory authorities to establish lower avoided cost rates for purchases from intermittent QFs than for purchases from firm QFs." (citing 18 CFR 292.304(e)–(f)) (footnote omitted).

[97] 18 CFR 292.304(d)(2)(ii). Rates calculated at the time of a LEO (for example, a contract) do not violate the requirement that the rates not exceed avoided costs if they differ from avoided costs at the time of delivery. 18 CFR 292.304(b)(5).

[98] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,880 (justifying the rule on the basis of "the need for certainty with regard to return on investment in new technologies").

[99] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,880.

[100] *Id.*

[101] *See* Alliant Energy Comments, Docket No. AD16–16–000, at 5 (Nov. 7, 2016) ("Current market-based wind prices in the Iowa region of MISO are approximately 25% lower than the PURPA contract obligation prices [Interstate Power and Light Company] is forced to pay for the same wind power for long-term contracts entered into as of June 2016. As a result, PURPA-mandated wind power purchases associated with *just one project* could cost Alliant Energy's Iowa customers an

Continued

commenters recommended that the Commission allow states to ''price generation [energy] from QFs at market prices, and to update those prices regularly so that the prices for qualifying facilities are not burdensome on customer rates'' and that the Commission should limit avoided cost energy rates in a LEO to no higher than avoided cost rates at the time of delivery.[102] QFs, in turn argued that elimination of the option to fix QF rates for the term of a contract would threaten a QF's ability to obtain financing.[103]

65. Further, it is clear that the desire to limit the effect of fixed QF contract rates has directly led to PURPA implementation issues that affect QF financing in other respects, particularly with respect to the length of QF contracts.[104] For example, a commissioner of the Idaho Public Service Commission (Idaho Commission) testified at the Technical Conference that the Idaho Commission's decision to limit QF contracts to a two-year term was based on the Idaho Commission's concern that longer contract terms at fixed rates would lead to payments above avoided costs.[105] Similarly, Southern Company testified that the fixed payment requirement is ''resulting in . . . typically shorter contract term lengths.'' [106] Golden Spread Electric Cooperative recommended that if the fixed cost requirement is not eliminated, the Commission permit shorter contract terms, ''as short as one-year or three years at most.'' [107]

66. The Commission proposes to revise § 292.304(d) of the PURPA Regulations to permit a state to limit a QF's option to elect to fix at the outset of a LEO the energy rate for the entire length of its contract, and instead allow the state to require QF energy rates to vary during the term of the contract. However, under the proposed revisions to § 292.304(d), a QF would continue to be entitled to a contract with avoided *capacity* costs calculated and fixed at the time the LEO is incurred. Only the contractual *energy* rate could be required by a state to vary.

67. To the extent that a QF is not entitled to capacity payments because a purchasing electric utility is not avoiding any capacity as a consequence of entering into a contract with a QF, the QF's contract could be limited by a state under the proposed rule to variable energy payments. However, in that event, the only costs being avoided by the purchasing electric utility would be the incremental costs of purchasing or producing energy at the time the energy is delivered.[108] Further, the state would retain the ability to require that the QF's energy rate be fixed at the time the LEO is incurred.

68. In Order No. 69, the Commission allowed avoided costs to be calculated and fixed at the time a LEO is first incurred because the Commission believed that any overestimations or underestimations ''will balance out.'' [109] The Commission now finds compelling the record evidence, discussed in section II.A.5.a. above, that overestimations have not been adequately balanced by underestimations in past years. Further, this trend may persist into the future with the continuing general decline in the cost of both wind and solar generation.[110] Consequently, the Commission believes that it may be necessary to allow states to provide for a variable energy rate in order to reflect more accurately the purchasing electric utility's avoided costs and therefore satisfy the statutory requirement that QF rates not exceed the utility's avoided cost and ''be just and reasonable to the electric consumers of the electric utility and in the public interest.'' [111]

69. The Commission recognizes that the current PURPA Regulations allowing a QF to fix its rates for the term of a contract were based on the recognition that fixed rates are beneficial for obtaining financing for QF projects. QF developers continue to assert today that they require fixed rates to finance new projects. However, the Commission does not view the proposed modification to the PURPA Regulations as materially affecting the ability of QFs to obtain financing. This is the case for a number of reasons.

70. First, the Commission's proposed modifications would allow a state to set a variable energy rate, but not a variable avoided capacity rate at the time of a LEO. The Commission understands that fixed energy rates are not generally required in the electric industry in order for electric generation facilities to be financed. For example, RTO/ISO capacity markets provide only for fixed capacity payments, leaving capacity owners to sell their energy into the organized electric markets at LMPs that vary based on market conditions at the time the energy is delivered.[112] These fixed capacity and variable energy payments have been sufficient to permit the financing of significant amounts of

incremental $17.54 million above market wind prices over the next 10 years.'') (emphasis in original); EEI Supplemental Comments, Docket No. AD16–16–000, attach. A at 3–4 (June 25, 2018) (EEI Supplemental Comments) (''On August 1, 2014, a 10-year fixed price contract at the Mid-Columbia wholesale power market trading hub was priced at $45.87/MWh. On June 30, 2016, the same contract was priced as $30.22/MWh, a decline of 34% in less than two years. However, over the next 10 years, PacifiCorp has a legal obligation to purchase 51.9 million MWhs under its PURPA contract obligations at an average price of $59.87/MWh. The average forward price curve for the Mid-Columbia trading hub during the same period is $30.22/MWh, or 50% below the average PURPA contract price that PacifiCorp will pay. The additional price required under long-term fixed contracts will cost PacifiCorp's customers $1.5 billion above current forward market prices over the next 10 years.''); Comm'r Kristine Raper, Idaho Commission Comments, Docket No. AD16–16–000, at 3–4 (June 29, 2016) (''Idaho Power demonstrated that the average cost for PURPA power since 2001 has exceed the Mid-Columbia (Mid-C) Index Price and is projected to continue to exceed the Mid-C price through 2032. Likewise, PacifiCorp's levelized avoided cost rates for 15-year contract terms in Wyoming shows a decrease of approximately 50% from 2011 through 2015 (from approximately $60 per megawatt-hour to less than $30 per megawatt-hour).'').

[102] EEI Supplemental Comments, attach. A at 4; *see also* Southern Company Comments, Docket No. AD16–16–000, at 7 (June 29, 2016) (''the avoided energy cost payment to the QF should be based on actual avoided energy cost at the time the QF delivers energy'').

[103] *See* Technical Conference Tr. at 26:22–25, 27:1–3 (Solar Energy Industries Association) (''The Power Purchase Agreement is the single most important contract of the development and financing of an energy project that's not owned by a utility. Without the long-term commitment to buy the output of that agreement at a fixed price, there is no predictable stream of revenue. Without a predictable stream of revenues, there is no financing. Without any financing, there is no project.'').

[104] *See* Natural Resources Defense Council Comments, Docket No. AD16–16–000, at 4 (June 30, 2016).

[105] *See* Technical Conference Tr. at 142–43 (Idaho Commission) (''No matter the starting point, allowing QFs to fix their avoided cost rates for long terms results in rates which will eventually exceed and overestimate avoided cost rates into the future. The longer the term, the greater the disparity. . . . [The Idaho Commission] recently reduced PURPA contract lengths to two years in order to correct the disparity. We didn't reduce contract lengths to kill PURPA. We did it to allow periodic adjustment of avoided cost rates.'').

[106] *Id.* at 202 (Southern Company).

[107] Golden Spread Electric Cooperative Comments, Docket No. AD16–16–000, at 10 (June 29, 2016).

[108] *See, e.g., City of Ketchikan,* 94 FERC at 62,061 (''[A]voided cost rates need not include the cost for capacity in the event that the utility's demand (or need) for capacity is zero. That is, when the demand for capacity is zero, the cost for capacity may also be zero.'').

[109] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,880.

[110] *See* EIA, Today in Energy, *Average U.S. construction costs for solar and wind continued to fall in 2016* (Aug. 8, 2018), *available at https://www.eia.gov/todayinenergy/detail.php?id=36813* (''Based on 2016 EIA data for newly constructed utility-scale electric generators (those with a capacity greater than one megawatt) in the United States, annual capacity-weighted average construction costs for solar photovoltaic systems and onshore wind turbines declined . . . .'').

[111] 16 U.S.C. 824a–3(b)(1).

[112] *See, e.g., ISO New England Inc.,* 147 FERC ¶ 61,172, at P 2 (2014) (resources receiving capacity awards must offer into energy market).

new capacity in the RTOs and ISOs.[113] Testimony presented at the Technical Conference similarly showed that non-QF independent power projects located outside of RTOs enter into contracts with fixed capacity and variable energy prices.[114] Other comments at the Technical Conference suggested that a fixed capacity charge likewise would be adequate for financing a QF project.[115]

71. In addition to the fact that the Commission is not changing the requirement that QF capacity rates be fixed, the Commission anticipates that some may prefer basing variable QF contract energy rates on transparent competitive market prices over the term of the contract. Such rates are based on observable and foreseeable market forces, and thus the electric industry has developed forecasts for these competitive markets that are commonly accepted by the Commission and the industry as reasonable estimates of future prices.[116] Such estimates may provide some support for financing purposes.

72. Further, there are financial products available, such as contracts for differences, which allow generation owners to hedge their exposure to fluctuating energy prices.[117] Such financial products can provide additional comfort to lenders regarding the level of energy rate revenues that a QF can expect from the energy it delivers, in addition to the fixed capacity payments the QF is entitled to receive under its contract.

73. Moreover, although it may have been true at the time the Commission promulgated its PURPA Regulations in 1980 that QFs needed to fix their energy rate for the term of their contract in order to obtain financing of their facilities, there is evidence that this no longer is true. This evidence comes in the form of data, described below, showing that independent generators that have not qualified as QFs under PURPA (including renewable resources that could qualify as QFs but have not sought QF status) have been able to obtain financing for new facilities. That owners of such facilities, which do not have recourse to the avoided cost provisions of PURPA, have been able to obtain financing for new projects is highly relevant to the question of whether the existing PURPA avoided cost provisions—including the requirement to enter into contracts with fixed energy rates—are necessary for QFs to obtain financing.

74. For example, EIA data shows that, since 2005, QFs have made up only 10 to 20 percent of all renewable resource capacity in service in the United States, demonstrating that most renewable resources no longer need to rely on PURPA avoided cost rates to sell their output economically.[118] EIA data also shows that net generation of energy by non-utility owned renewable resources[119] in the United States escalated from 51.7 TWh in 2005 when EPAct 2005 was passed, to 340 TWh in 2018.[120] While much of this growth was in states located in RTOs/ISOs, there also was significant growth of non-utility renewable generation in other states. For example, net generation by non-utility renewable resources in the region defined by EIA as the Mountain State region[121] increased from 3.6 TWh in 2005 to 19.5 TWh in 2012, and to 42.5 TWh in 2018.[122] Pacific Northwest (Oregon and Washington) net non-utility generation from renewable resources increased from 1.5 TWh in 2005, to 8.7 TWh in 2012, and to 10.6 TWh in 2018.[123]

75. EIA data on independently-owned natural gas-fired generation capacity tells a similar story. Natural gas-fired capacity without the requisite cogeneration technology cannot qualify as qualifying small power production or cogeneration, and thus most of this capacity will not be within the scope of the PURPA avoided cost rate provisions. EIA data shows that, in 2018, 44.4 percent of all energy produced by natural gas-fired generation in the United States was generated by independently-owned capacity.[124] The total amount of energy produced in 2018 by independently-owned natural gas-fired generation was 651 TWh, an increase of 13.7 percent from 2017.[125] Again, the percentage of independently-owned natural gas generation outside of RTOs/ISOs was lower than in RTOs/ISOs, but still was significant. In the Mountain states region, 21.4 percent of the energy produced by natural gas-fired generation 2018 was produced by independently-owned capacity, and in Oregon and Washington 45.4 percent of natural gas-fired energy was produced by independently-owned capacity.[126] It thus is apparent that independent owners of non-QF generation have been, and continue to be, able to obtain financing for their facilities.

76. The Commission does not suggest that this evidence supports the conclusion that substantial non-QF capacity is being financed and constructed without any form of fixed revenue to support financing. Rather, the evidence demonstrates that the existing PURPA avoided cost rate provisions are not necessary for some independent power generators to put in place contractual arrangements, including fixed revenue streams, that are sufficient to obtain financing. QFs, which have the advantage of mandatory purchase requirements, should be better positioned than non-QFs to negotiate the necessary contractual arrangements for financing. Moreover, QFs are as equally well positioned as non-QF independent generators to take

[113] *See, e.g.,* Monitoring Analytics, LLC., *Third Quarter, 2018 State of the Market Report for PJM, January through September,* at 249, Table 5–6 (Nov. 8, 2018) (over 23,000 MW of new capacity constructed in PJM Interconnection, L.L.C. since 2007–2008; including over 16,000 MW of new capacity added in the last four years), *available at http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q3-som-pjm.pdf.*

[114] *See* Technical Conference Tr. at 167–69 (Southern Company) (''So if we enter into a bilateral contract with an independent power producer for combustion turbine or combined cycle capacity, we don't fix the energy price. The capacity payment is a fixed payment. That's their fixed [stream]. The energy price is typically indexed to the price of natural gas.''); *see also id.* at 178 (American Forest & Paper Association) (''Now, you sign a long-term IPP contract. That contract [has] got a variable energy cost in it.'').

[115] *See* Solar Energy Industries Association Comments, Docket No. AD16–16–000, at 3 (June 29, 2016) (''Developers need rates for such sales of *energy and/or capacity* to be fixed'') (emphasis added).

[116] *See generally ITC Great Plains, LLC,* 126 FERC ¶ 61,223, at P 43 (2009) (study evaluating benefits of transmission project based on price forecasts ''provides a reasonable basis to conclude that ITC Great Plains' projects will reduce the cost to serve load by reducing congestion through facilitating integration and delivery of low-cost wind energy in the [Southwest Power Pool, Inc.] region and providing greater transfer capability'').

[117] *See, e.g., Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Order No. 841, 162 FERC ¶ 61,127, at P 299 (2018) (noting that ''market participants that purchase energy from the RTO/ISO markets . . . may enter into bilateral financial transactions to hedge the purchase of that energy'').

[118] *See* EIA, Today in Energy, *North Carolina has More PURPA-Qualifying Solar Facilities than any other State,* figure entitled *PURPA qualifying facilities (1980–2015) percent of total renewable capacity* (Aug. 23, 2015), *available at https://eia.gov/todayinenergy/detail.php?id=27632.*

[119] The EIA renewable resources data discussed herein is based on the EIA ''other renewables'' category of generation resources, which consists of wind, utility scale solar, geothermal, and biomass resources.

[120] This data was taken from EIA's Electricity Data Browser, *available at www.eia.gov/electricity/data/browser.*

[121] Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, and Wyoming.

[122] This data was taken from EIA's Electricity Data Browser, *available at www.eia.gov/electricity/data/browser.*

[123] *Id.*

[124] EIA, *Electric Power Monthly with Data for December 2018,* at Table 1.7.B, *available at https://www.eia.gov/electricity/monthly/current_month/epm.pdf.*

[125] *Id.*

[126] *Id.*

advantage of federal and state incentives designed to encourage the construction of renewable resources.

77. Finally, as described above, states and utilities have responded to the requirement that QF contract rates be fixed for the term of a contract by shortening the terms of those contracts and taking other steps that some argue make it more difficult for a QF to obtain a financeable contract. Representatives of QFs explained that short contract terms make financing difficult, and they cited the Idaho Commission's decision to limit contracts to a two-year term as being especially harmful.[127] Because the decisions to impose short contract terms were based largely on the current requirement that QFs be able to fix their rates, particularly energy rates, for the term of their contracts, allowing states to require contractual energy rates to vary could result in longer QF contracts, and perhaps other more favorable treatment, that would improve the financeability of QF projects.

78. Although the Commission believes that the above evidence supports the conclusion that a fixed capacity rate and a variable energy rate should be adequate to support financing for QFs, the Commission solicits further information from interested entities on the ability of QFs to obtain financing based on contracts with a fixed capacity rate and a variable energy rate. In particular, the Commission solicits information on any independently owned projects (QF and non-QF) that required a fixed energy rate in addition to a fixed capacity rate to obtain financing and on independently owned projects (QF and non-QF) that were able to obtain financing without a fixed energy rate.

b. Implementation of the Commission's Proposal

79. The proposal described above is not mandatory. The Commission proposes to give the states the flexibility to continue to allow QFs to fix their contract energy rates as of the date of their LEO. The Commission's proposal here gives states the additional flexibility to consider imposing some measure of variability to QF contract energy rates when a state determines that it is necessary to do so to comply with the statutory requirement that QF rates not exceed the utility's avoided costs.

80. Further, the Commission understands that one standard form of QF contract rate currently employed by a number of utilities is a one-part rate, applicable to each MWh of energy delivered by the QF, which is calculated to reflect both avoided capacity costs and avoided energy costs. Such contracts also typically impose a must purchase obligation on the purchasing utility. The Commission's proposed rule is not intended to prevent states from implementing such an approach to setting QF contract rates in the future. However, as explained above, the Commission is not modifying the requirement in the PURPA Regulations that QFs have the option of fixing their contract capacity rates as of the date of the LEO.

81. Consequently, the Commission proposes that, to the extent that a state determines to establish a one-part QF contract rate that recovers both avoided capacity and avoided energy costs, the rate must continue to be subject to the QF's option to select a fixed rate for the term of the contract, as provided in § 304(d)(2)(ii). Any requirement to impose a variable energy QF contract rate would need to be accomplished through a multi-part rate that includes separate avoided capacity cost rates and avoided energy cost rates.[128]

6. Consideration of Competitive Solicitations To Determine Avoided Costs

82. The Commission proposes to revise the PURPA Regulations in 18 CFR 292.304 to add subsection (b)(8). In combination with new subsection (e)(1), this subsection would permit a state the flexibility to set avoided energy and/or capacity rates using competitive solicitations (*i.e.,* RFPs), conducted pursuant to appropriate procedures.

83. The Commission recognizes that one way to enable the industry to move towards more competitive QF pricing is to allow states to establish QF avoided cost rates through an RFP process. Such an approach has been suggested on a number of occasions, including in the National Association of Regulatory Utility Commissioners' (NARUC) supplemental comments submitted in Docket No. AD16–16–000, where NARUC proposed that

> energy and capacity needs . . . would be filled by conducting competitive solicitations for energy and capacity. These competitive solicitations, or request for proposals (RFPs), would be open to all QFs and would be overseen by State commissions or administered independently of any individual market participant to mitigate anti-competitive behavior of the buyer.[129]

84. The Commission previously has explored this issue. In 1988, the Commission issued a Notice of Proposed Rulemaking proposing to adopt regulations that would allow bidding procedures to be used in establishing rates for purchases from QFs.[130] That rulemaking proceeding, along with several related proceedings, ultimately was withdrawn as overtaken by events in the industry.[131]

85. Since then, the Commission held in a 2014 order addressing the specific facts of the RFP at issue that an electric utility's obligation to purchase power from a QF under a LEO could not be curtailed based on a failure of the QF to win an only occasionally-held RFP.[132] In a separate proceeding involving a different RFP, the Commission declined to initiate an enforcement action where the state RFP was an alternative to a PURPA program.[133]

86. Given this precedent, the Commission proposes to amend its regulations to clarify that a state could establish QF avoided cost rates through an appropriate RFP process. Consistent with its general approach of giving states flexibility in the manner in which they determine avoided costs, the Commission does not propose in this NOPR to prescribe detailed criteria governing the use of RFPs as tools to determine rates to be paid to QFs, as well as to determine other contract terms. States arguably may be in the best position to consider their particular local circumstances, including questions of need, resulting economic impacts, amounts to be purchased through auctions, and related issues.

[127] *See* Technical Conference Tr. at 70 (Solar Energy Industries Association); 73 (California Cogeneration Council).

[128] If, however, the QF contract rate is appropriately based solely on avoided energy costs with no avoided capacity cost component, then that rate could be implemented on a variable basis in accordance with the requirements of these proposed rules.

[129] NARUC Supplemental Comments, Docket No. AD16–16–000, at 2 (July 20, 2018).

[130] *Regulations Governing Bidding Programs,* FERC Stats. & Regs. ¶ 32,455 (1988) (cross-referenced at 42 FERC ¶ 61,323) (*Bidding NOPR*); *see also Administrative Determination of Full Avoided Costs,* FERC Stats. & Regs. ¶ 32,457 (1988) (cross-referenced at 42 FERC ¶ 61,324) (*ADFAC NOPR*).

[131] *See Regulations Governing Bidding Programs,* 64 FERC ¶ 61,364 at 63,491–92 (1993) (terminating *Bidding NOPR* proceeding); *see also Administrative Determination of Full Avoided Costs,* 84 FERC ¶ 61,265 (1998) (terminating *ADFAC NOPR* proceeding).

[132] *See, e.g., Hydrodynamics,* 146 FERC ¶ 61,193 at PP 31–35. RFP processes have been used more recently in a number of states, including Georgia, North Carolina, and Colorado. Georgia's RFP process is described at Ga. Comp. R. & Regs. 515–3–4.04(3) (2018). North Carolina's RFP process is described at 4 N.C. Admin. Code 11.R8–71 (2018). Colorado's RFP process is described at *SPower Development Co.* v. *Colorado Pub. Utils. Comm'n,* 2018 WL 1014142 (D. Colo. Feb. 22, 2018).

[133] *Winding Creek Solar LLC,* 151 FERC ¶ 61,103, *reconsideration denied,* 153 FERC ¶ 61,027 (2015). *But see Winding Creek Solar LLC* v. *Peterman,* 932 F.3d 861 (9th Cir. 2019).

87. Nevertheless, in considering what constitutes proper design and administration of an RFP, it is appropriate for the Commission to establish certain minimum criteria governing the process by which RFPs are to be conducted in order for an RFP to be used to set QF rates. In that regard, the Commission has addressed competitive solicitations in prior orders in a number of contexts that provide potential guidance to states and others. For example, the Commission's policy for the establishment of negotiated rates for merchant transmission projects,[134] the Bidding NOPR, and the *Hydrodynamics* case [135] all suggest factors that could be considered in establishing an appropriate RFP that is conducted in a transparent and non-discriminatory manner. These factors include, among others: (a) An open and transparent process; (b) solicitations should be open to all sources to satisfy that purchasing electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity; [136] (c) solicitations conducted at regular intervals; (d) oversight by an independent administrator; and (e) certification as fulfilling the above criteria by the state regulatory authority or nonregulated electric utility. The Commission proposes that a state may use an RFP to set avoided energy and capacity rates provided that such competitive solicitation process is conducted pursuant to procedures ensuring the solicitation is conducted in a transparent and non-discriminatory manner. Such an RFP must be conducted in a process that includes, but is not limited to, the factors identified above which are set forth in proposed § 292.304(b)(8) of the Commission's Regulations.

88. In addition, the Commission seeks comment on whether it should provide further guidance on whether, and under what circumstances, an RFP can be used as a utility's exclusive vehicle for acquiring QF capacity.[137]

B. Relief From Purchase Obligation in Competitive Retail Markets

89. Section 292.303(a) of the PURPA Regulations requires electric utilities generally to purchase ''any energy and capacity which is made available from a qualifying facility.'' [138] The Commission proposes to modify this regulation to provide electric utilities relief from this purchase obligation to the extent their supply obligations are reduced by a state's retail choice program.

1. Background

90. Historically, electric utilities were responsible for serving all of the load within their franchised service territories. Since the 1990s, however, some states have restructured their electricity markets to incorporate retail choice, which allows retail electric customers to choose alternative electricity suppliers and not purchase from their local electric utility. This type of restructuring may have decreased electric utilities' obligations to serve load, *i.e.,* they no longer are required to serve load that otherwise would be their native load. However, electric utilities were still generally required to continue to serve as the Provider of Last Resort (POLR) and serve customers that were not obtaining electricity from competitive electric retail suppliers. Electricity for POLR load often is procured through a competitive solicitation process with contracts of one year or less. This allows customers to leave POLR service and enter into contracts with competitive electricity suppliers while protecting electric utilities from having to honor long-term contracts for a shifting customer base.

2. Commission Proposal

91. It is reasonable for electric utilities' PURPA capacity purchase obligations to be reduced to the extent retail choice reduces their supply obligations. To the extent POLR supplies are obtained through solicitations having a particular contract term such as one year, the length of the utility's PURPA purchase contract should match the term of the POLR supply solicitation contracts in order to more accurately reflect the utility's avoided costs.

92. The Commission proposes to add regulatory text at the end of § 292.303(a) of the PURPA Regulations to provide that the purchase obligation may be reduced to the extent the purchasing electric utility's supply obligation has been reduced by a state retail choice program. The Commission proposes, through this change, to provide that state regulatory authorities and nonregulated electric utilities have flexibility to respond to the possibility that, over time, a utility's POLR supply obligation may decrease (or increase). The Commission intends that this proposal would apply prospectively from the effective date of the final rule and would not disturb contracts in effect at the time the utility's supply obligation is reduced.

C. Evaluation of Whether QFs Are Separate Facilities

93. The PURPA Regulations and Commission precedent establish an irrebuttable presumption that affiliated small power production facilities using the same energy resource, but which are more than one mile apart from each other, are located at separate sites and thus are separate facilities. This irrebuttable presumption therefore renders such facilities eligible for the benefits of PURPA if each facility, individually, has a maximum power production capacity of 80 MW or less.[139] Section 292.204(a)(2)(ii) of the PURPA Regulations states that to measure one mile, ''the distance between facilities shall be measured from the electrical generating equipment of a facility,'' [140] but the PURPA Regulations do not define what constitutes electrical generating equipment or explain how to measure the distance between facilities.

94. As discussed below, the Commission proposes to amend §§ 292.204(a) and 292.207 of the PURPA Regulations to allow entities challenging a QF certification to show that affiliated small power production facilities more than one mile apart and less than ten miles apart, are actually part of a single facility, and not separate facilities; the presumption, in other words, would be a *rebuttable* presumption for facilities over one mile apart and less than ten miles apart. The Commission also proposes amending § 292.202 to include a definition of ''electrical generating equipment'' and § 292.204(a)(2)(ii) to

[134] *Allocation of Capacity on New Merchant Transmission Projects and New Cost-Based, Participant-Funded Transmission Projects,* 142 FERC ¶ 61,038 (2013).

[135] *See Hydrodynamics,* 146 FERC ¶ 61,193 at P 32 n.70 (citing *Bidding NOPR,* FERC Stats. & Regs. ¶ 32,455 at 32,030–42). The Commission notes that, while QFs not awarded a contract pursuant to an RFP would retain their existing PURPA right to sell energy as available to the electric utility, if the state has concluded that such QF puts tendered after an RFP was held are ''not needed,'' the capacity rate may be zero because an electric utility is not required to pay a capacity rate for such puts if they are not needed. *See Hydrodynamics,* 146 FERC ¶ 61,193 at P 35 (referencing *City of Ketchikan, Alaska,* 94 FERC at 62,061 (''[A]voided cost rates need not include the cost for capacity in the event that the utility's demand (or need) for capacity is zero. That is, when the demand for capacity is zero, the cost for capacity may also be zero.'')).

[136] *See* 18 CFR 292.304(e); *Windham Solar LLC,* 157 FERC ¶ 61,134 at PP 5–6.

[137] Even if an RFP were used as an exclusive vehicle for an electric utility to obtain QF capacity, QFs that do not receive an award in the RFP would be entitled to sell energy to the electric utility at its as-available avoided energy cost rate.

[138] 18 CFR 292.303(a).

[139] *N. Laramie Range Alliance,* 139 FERC ¶ 61,190, at PP 22–24 (2012) (*Northern Laramie*). *See* 18 CFR 292.204(a)(1).

[140] 18 CFR 292.204(a)(2)(ii).

specify how to measure the distance between facilities that have multiple separate sets of ''electrical generating equipment'' such as is often the case with wind farms and solar facilities.

1. Background and Need for Reform

a. Ability To Rebut Presumption of Separate Sites

95. PURPA defines a small power production facility as ''a facility which is an eligible solar, wind, waste, or geothermal facility, or a facility which (i) produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, geothermal resources, or any combination thereof; and (ii) *has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 MW.*'' [141] The 80 MW limit on the size of a facility that can qualify as a small power production facility requires a definition of what it means to be ''located at the same site,'' to determine whether a QF satisfies the 80 MW limit.

96. Currently, § 292.204(a) of the PURPA Regulations provides that small power production facilities are considered to be at the same site if they are located within one mile of each other, use the same energy resource, and are owned by the same person(s) or its affiliates.[142] This regulatory provision is commonly referred to as ''the one-mile rule'' and is used to calculate the size of a facility and to distinguish what is a separate facility. The Commission has stated that the one-mile rule is an irrebuttable presumption—facilities within one mile are ''at the same site'' and facilities more than a mile apart from each other are not.[143]

97. In recent years, arguments have been raised that some QF developers of small power production facilities are circumventing the one-mile rule, and thereby circumventing PURPA, by strategically siting small power production facilities that use the same energy resource—primarily wind farms made up of multiple individual wind turbines—slightly more than one mile apart in order to qualify as separate small power production facilities that are protected by the irrebuttable presumption that facilities more than a mile apart are separate QFs.[144]

b. Electrical Generating Equipment

98. Section 292.204(a)(2)(ii) of the PURPA regulations states that, to measure one mile, ''the distance between facilities shall be measured from the *electrical generating equipment* of a facility.'' [145] The Commission has suggested in orders what is *not* considered ''electrical generating equipment,'' [146] but has never defined or elaborated on what equipment meets the definition of ''electrical generating equipment.'' For example, wind farms are typically comprised of multiple wind turbines spread over some geographic area; however, each wind turbine could be considered ''electrical generating equipment.''

99. Similarly, solar facilities can be spread over some geographic area (albeit likely not as large a footprint as a wind farm), potentially creating confusion as to whether the one mile is measured from the edge of the panels at one facility to the edge of the panel at the next facility, or from the center point of each solar array. Additionally, the Commission has not specified how to measure the distance between facilities that have multiple separate sets of ''electrical generating equipment.''

2. Proposed Changes to Subpart B—Qualifying Cogeneration and Small Power Production Facilities

a. Rebuttable Presumption of Separate Facilities

100. The Commission proposes to allow entities challenging a QF certification to rebut the presumption that affiliated facilities located more than one mile apart are considered to be separate QFs. The Commission proposes that this change would be effective as of the date of a final rule, which means that such challenges could only be made to QF certifications and recertifications that are submitted after the effective date of the final rule in this proceeding.

101. The Commission proposes that an entity can seek to rebut the presumption only for those facilities that are located more than one mile apart and less than ten miles apart. The Commission believes that, just as there are some facilities that may be so close that it is reasonable to irrebuttably treat them as a single facility (those a mile or less apart), so there are some facilities that are sufficiently far apart that it is reasonable to treat them as irrebuttably separate facilities. That latter distance, the Commission believes, is ten miles or more apart. Thus, if two affiliated facilities are one mile or less apart they are currently and will continue to be irrebuttably presumed to be a single facility at a single site. If affiliated facilities are ten miles or more apart, they will be irrebuttably presumed to be separate facilities at separate sites.

102. If affiliated facilities are between one and ten miles apart (*i.e.,* more than one mile apart and less than ten miles apart) there will still be a presumption, but it will be a *rebuttable* presumption, that they are separate facilities at separate sites. Purchasing electric utilities and others thus would be able to file a protest attempting to rebut the presumption for facilities more than one mile apart and less than ten miles apart, and argue that they should be treated as a single facility. The Commission may also act *sua sponte.* The Commission proposes, as explained below, that self-certifications will remain effective after a protest has been filed, until such time as the Commission issues an order revoking the certification.

103. The Commission proposes allowing an entity seeking QF status to provide further information in its certification (both self-certification and Commission certification), to preemptively defend against rebuttal by asserting factors that affirmatively show that two facilities are indeed separate facilities at separate sites.[147] Anyone challenging the QF certification would be allowed to assert factors to show that the facilities are actually part of the same, single facility.

104. The Commission proposes limiting protests challenging QF status by requiring any entity filing a protest to specify facts that make a prima facie demonstration that the facility described in the self-certification, self-recertification, or Commission certification does not satisfy the requirements for QF status. General allegations or unsupported assertions would not be a basis for denial of certification. The Commission further

[141] 16 U.S.C. 796(17)(A) (emphasis added).

[142] 18 CFR 292.204(a). Hydroelectric facilities have slightly different rules, which reference water from the same impoundment.

[143] *Northern Laramie,* 139 FERC ¶ 61,190 at PP 22–24.

[144] *See, e.g.,* EEI Comments, Docket No. AD16–16–000, at 5 (Nov. 7, 2016); National Rural Electric Cooperative Association Comments, Docket No. AD16–16–000, at 7 (Nov. 7, 2016); Southern Company Comments, Docket No. AD16–16–000, at 9–10 (Nov. 7, 2016); NARUC Supplemental Comments, Docket No. AD16–16–000, at 3 (Nov. 7, 2016).

[145] 18 CFR 292.204(a)(2)(ii) (emphasis added).

[146] In Order No. 70, the Commission stated: ''The comments noted that some facilities may include equipment for gathering energy to be used in the facility which may extend up to a number of miles from the generating facility. The Commission believes that the one-mile limit should be measured from the generating facilities.'' Order No. 70, FERC Stats. & Regs. ¶ 30,134 at 30,943.

[147] While a QF with a net power production capacity of 1 MW or less is not required to formally certify its QF status (either through Commission certification or self-certification), if the QF's status is later challenged the QF would be able to respond by affirmatively demonstrating that its facilities are not located at the same site as other affiliated facilities and thus that the QF does not exceed the 80 MW size limitation.

proposes limiting protests to QF status by requiring that once the Commission has affirmatively certified an applicant's QF status through either a Commission certification proceeding or in response to protests challenging QF status, any later protest to a QF's existing certification asserting that facilities further than one mile apart are part of a single QF must demonstrate changed circumstances that call into question the continued validity of the earlier certification.

105. The Commission proposes that physical and ownership factors may be asserted to rebut or defend against rebuttal. Noting that no single factor would be dispositive, the Commission proposes the factors listed below:

(1) Physical characteristics including such common characteristics as: Infrastructure, property ownership, interconnection agreements, control facilities, access and easements, interconnection facilities up to the point of interconnection to the distribution or transmission system, collector systems or facilities, points of interconnection, motive force or fuel source, off-take arrangements, property leases, and connections to the electrical grid; and (2) ownership/other characteristics, including such characteristics as whether the facilities in question are: Owned or controlled by the same person(s) or affiliated persons(s), operated and maintained by the same or affiliated entity(ies), selling to the same electric utility, using common debt or equity financing, constructed by the same entity within 12 months, managing a power sales agreement executed within 12 months of a similar and affiliated facility in the same location, placed into service within 12 months of an affiliated project's commercial operation date as specified in the power sales agreement, or sharing engineering or procurement contracts. The Commission solicits comments on whether the Commission should rely on some or any of these factors, or other factors, or whether the various factors should be considered together and weighed.

106. Finally, for its PURPA Regulations, the Commission generally relies on the definition of an ''affiliate'' provided in its regulations at § 35.36(a)(9). The Commission will continue to rely on this definition and notes that subsection (iii) of the Commission's regulation provides that the Commission may determine, after appropriate notice and opportunity for hearing, that a person stands in such relation to a specified company that there is likely to be an absence of arm's-length bargaining in transactions between them as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that the person be treated as an affiliate.[148] The Commission intends, when applying its rules on separate facilities, to consider this provision of its regulations, when entities otherwise would not be deemed affiliates under the other provisions of the definition, to determine whether a person nevertheless should be treated as an affiliate. In doing so, the Commission could take into consideration many of the same factors that would reasonably be considered in evaluating whether facilities located over one and less than ten miles apart are a single facility or separate facilities.

107. The Commission believes that this change, together with the proposed definition of ''electrical generating equipment'' and revision to the FERC Form No. 556 discussed below, would more closely align with Congress's requirement that QFs seeking to certify as small power production facilities are in fact below the statutory limit for such facilities.[149]

b. Electrical Generating Equipment

108. The Commission proposes defining ''electrical generating equipment'' to refer to all boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar panels and/or inverters, fuel cell equipment and/or other primary power generation equipment used in the facility, excluding equipment for gathering energy to be used in the facility. The Commission expects that each wind turbine on a wind farm and each solar panel in a solar facility would be considered ''electrical generating equipment'' because each wind turbine and each solar panel is independently capable of producing electric energy. We seek comments on this approach, and on what—if not individual wind turbines and solar panels—should be considered ''electrical generating equipment'' for wind and solar plants.

109. The Commission also proposes specifying how to measure the distance between facilities that have multiple separate sets of ''electrical generating equipment'' such as wind farms and solar facilities. In this NOPR, the Commission proposes measuring the distance between the nearest ''electrical generating equipment'' of any two facilities such that, for the facilities to be considered irrebuttably separate, all such equipment of one QF must be at least ten miles away from all such equipment of another QF. We believe this is the appropriate way to measure the distance between affiliated sets of ''electrical generating equipment'' because this reflects the distance between the components directly tied to producing electric energy.

110. The Commission seeks comment on this approach, and whether alternative approaches would be more appropriate. For example, some parties have suggested in QF certification proceedings that the Commission could use the geographic center of the plant footprint or a weighted average of the locations of the individual pieces of ''electrical generating equipment.''[150] The Commission is concerned these approaches may be easily gamed, but seeks comment on whether they may be constructed in a way that would prevent gaming, and whether such formulations would be preferable to the approach proposed above.

3. Corresponding Changes to the FERC Form No. 556

111. If the changes to the evaluation of whether QFs are separate facilities are implemented as proposed above, the Commission proposes corresponding changes to the FERC Form No. 556. Currently, item 8a of Form No. 556 requires that the applicant identify any facilities with electrical generating equipment within one mile of the instant facility's electrical generating equipment, as shown below in Figure 1.

[148] 18 CFR 35.36(a)(9)(iii).

[149] *See* 16 U.S.C. 796(17)(A)(ii) (defining small power production facility as *inter alia* ''a facility which is an eligible solar, wind, waste, or geothermal facility, or a facility which—. . . has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts.'').

[150] *See Beaver Creek Wind II, LLC,* 160 FERC ¶ 61,052, at P 9 (2017).

Figure 1: Item 8a of the current Form No. 556

8a Identify any facilities with electrical generating equipment located within 1 mile of the electrical generating equipment of the instant facility, and for which any of the entities identified in lines 5a or 5b, or their affiliates, holds at least a 5 percent equity interest.

Check here if no such facilities exist. ☐

	Facility location (city or county, state)	Root docket # (if any)	Common owner(s)	Maximum net power production capacity
1)		QF -		kW
2)		QF -		kW
3)		QF -		kW

☐ Check here and continue in the Miscellaneous section starting on page 19 if additional space is needed

112. The Commission proposes adding a new item 8b,[151] which would be similar to the current item 8a, except that it would cover affiliated facilities whose nearest electrical generating equipment is *greater than 1 mile and less than 10 miles* from the electrical generating equipment of the instant facility.

113. The Commission proposes that the instructions for the new item 8b would also allow applicants with facilities identified under item 8b (*i.e.,* facilities more than one mile apart and less than ten miles apart) to, if they choose, explain (in the Miscellaneous section starting on page 19 of the form) why the facilities identified under item 8b should be considered separate facilities, considering the relevant physical and ownership factors. We further propose to provide reference, in the instructions to the new item 8b, to the paragraphs of the final rule under this rulemaking which discuss the relevant physical and ownership factors that may be asserted to defend against rebuttal.

114. The Commission seeks comment on whether item 8a (existing) should be revised and item 8b (as newly proposed) written to require that the applicant specify the distance from the instant facility to each affiliated facility listed. We also seek comment on whether items 8a and (new) 8b should require the applicant to document (in the Miscellaneous section on page 19 of the Form No. 556) how the distances reported were calculated. Specifically, we seek comment on whether the applicant should be required to identify the particular electrical generating equipment and associated geographic coordinates used in calculating the distance(s) between the facility(ies).

115. The Commission notes that item 8a currently requires applicants to list all affiliated ''facilities.'' Under this requirement, an applicant would have to list all affiliated QFs and affiliated *non*-QFs. We request comment on whether such a requirement is more burdensome than necessary. It is not clear that requiring the listing of affiliated *non*-QFs is necessary in monitoring for compliance with the relevant QF regulations, which are concerned only with the distance between affiliated *QFs.* Particularly under the newly proposed item 8b, where applicants would list facilities located more than one mile apart but less than ten miles apart, many more facilities are likely to be listed than are currently listed in the existing item 8a. As such, we seek comment on whether we should revise item 8a (existing) and write item 8b (as newly proposed) to require that applicants list only affiliated *QFs,* or whether there is reason to continue to require all affiliated facilities to be listed.

116. The Commission also seeks comment on whether item 3c (geographic coordinates) and the Geographic Coordinates instructions on page 4 of the current Form No. 556 should be modified such that reporting of geographic coordinates should be required for *all* applications, rather than only for applications where there is no facility street address (as is now the case). We believe such information may provide more transparency in approximate distances between facilities, and that such transparency may be useful for both the public and Commission staff in monitoring compliance with the Commission's QF regulations.

117. We note, as we did in Order No. 732,[152] and as we do in the general form instructions on page 4 of the Form No. 556, that such coordinates can be obtained through certain free online map services (with links and instructions available through the Commission's QF website); GPS devices (including smartphones, which are now nearly ubiquitous); Google Earth; property surveys; various engineering or construction drawings; property deeds; or municipal or county maps showing property lines. We also note that the Commission has a link on its QF web page (*www.ferc.gov/QF*) which provides assistance with determining geographic coordinates of facilities. As such, we believe that the burden that would be created by requiring every QF to provide geographic coordinates would be limited. Even so, we seek comment on whether the value of the information to the public and the Commission would outweigh the limited burden.

D. PURPA Section 210(m) Rebuttable Presumption of Nondiscriminatory Access to Markets

118. In accordance with PURPA section 210(m), the PURPA Regulations permit an electric utility to file an application with the Commission requesting relief from the requirement to enter into new contracts or obligations to purchase electric energy from a QF if the Commission finds that a QF has nondiscriminatory access to certain markets. As relevant here, the PURPA Regulations establish a rebuttable presumption that QFs with a net power production capacity at or below 20 MW lack nondiscriminatory access to such markets. The Commission now proposes

[151] Subsequent items in that section of the form would be retained, but re-numbered and moved down accordingly.

[152] *Revisions to Form, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production or Cogeneration Facility,* Order No. 732, 130 FERC ¶ 61,214, at P 100 (2010).

to revise the PURPA Regulations to reduce the capacity level at which this presumption attaches for small power production facilities, but not cogeneration facilities, from 20 MW to 1 MW.[153]

1. Background

119. In 2005, Congress amended PURPA section 210 to add section 210(m), which was intended to reflect the fact that organized electric markets have been created in RTOs/ISOs that provide alternative markets for sales by QFs. Section 210(m) provides for termination of the requirement that an electric utility enter into a new obligation or contract to purchase from a QF if the QF, in fact, has nondiscriminatory access to certain defined types of markets.[154]

120. In Order No. 688, the Commission identified certain specified markets as qualifying for section 210(m) relief from the PURPA mandatory purchase obligation, provided that QFs, in fact, have nondiscriminatory access to such markets.[155] Because section 210(m) requires the Commission to make a final determination on applications to terminate the requirement to enter into new obligations or contracts to purchase from QFs within 90 days of the application, the Commission established certain rebuttable presumptions to make the processing of the applications possible given this 90-day action requirement.

121. As relevant here, one of those rebuttable presumptions, contained in § 292.309(d)(1) of the PURPA Regulations,[156] is that a QF with a net power production capacity at or below 20 MW does *not* have nondiscriminatory access to markets. In creating this rebuttable presumption, the Commission found persuasive arguments that some QFs may, in practice, not have nondiscriminatory access to markets in light of their small size.

122. The Commission noted that there was agreement among commenters representing both QFs and utilities that small size could affect a QF's ability to access markets.[157] The Commission explained that smaller QFs often are interconnected at the distribution level and that QFs interconnected at the distribution level may, in practice, lack the same level of access to markets as those connected to transmission lines.[158] The Commission also explained that smaller QFs were more likely to have to overcome obstacles that larger QFs would not have to overcome, such as jurisdictional differences, pancaked delivery rates, and administrative burdens to obtaining access to distant buyers.

123. The Commission found that such difficulties supported a rebuttable presumption that smaller QFs have ''substantially less ability to access wholesale markets than do larger QFs.'' [159] The Commission further explained that it set this rebuttable presumption at 20 MW, rather than at a much smaller size of one or two MW, to reflect its understanding of ''the general nature of QFs' interconnection practices and the relative capabilities of small entities'' to participate in markets.[160] The Commission acknowledged that ''[t]here is no perfect bright line that can be drawn,'' but stated that it ''reasonably exercised [its] discretion in adopting a 20 MW or below demarcation for purposes of determining which QFs are unlikely to have nondiscriminatory access to markets.'' [161]

124. Order No. 688 placed the burden of proof on the electric utility to demonstrate that a smaller QF has nondiscriminatory access to energy markets.[162] The Commission, in Order No. 688, did not specify what evidence a utility could set forth to rebut the presumption, but noted that ''relevant evidence may include the extent to which the QF has been participating in the market or is owned by, or is an affiliate of, a[n] entity that has been participating in the relevant market.'' [163]

125. The Commission in Order No. 688 stated that ''[t]here is nothing in section 210(m) of PURPA to suggest that Congress intended to ensure a QF's commercial viability. Nor does the statute require the Commission to find that the 'economic and technical equivalent to mandatory purchase is available through a competitive market' before it terminates the requirement that an electric utility enters into a new contract or obligation to purchase electric energy from QFs.'' [164]

2. Commission Proposal

126. In 2006, when Order No. 688 was issued, the organized electric markets had been in existence for only a few years and were not well understood by all market participants. Now, twelve years later, the markets are more mature, and the mechanics of participation in such markets are improved and better understood. Consequently, the Commission believes that small power production facilities below 20 MW should be able to participate in such markets under most circumstances. The Commission therefore proposes to revise § 292.309(d) of the PURPA Regulations to reduce the net power production capacity level at which the presumption of nondiscriminatory access to a market attaches for small power production facilities, but not cogeneration facilities, from 20 MW to 1 MW.

127. The Commission believes that, in light of the maturation of organized electric markets, such a reduction is consistent with Congress's intent to relieve electric utilities of their obligation to purchase when a QF has nondiscriminatory access to competitive markets. Under current market conditions, it is fair to expect that small power production facilities above 1 MW can acquire the administrative and technical expertise necessary to obtain nondiscriminatory access to a market.

128. The Commission, in establishing the presumption that QFs whose net power production capacity was 20 MW or below lacked nondiscriminatory access to markets defined in sections 210(m)(1)(A)–(C) of PURPA, acknowledged that ''there is no unique and distinct megawatt size that uniquely determines if a generator is small.'' [165] In using 20 MW to separate the presumption that large QFs had nondiscriminatory access and small QFs lacked such access, the Commission recognized: (1) Order No. 671's exemption for QFs that are 20 MW or smaller from sections 205 and 206 of the FPA; and (2) Order Nos. 2006 and 2006–

[153] The Commission also proposes to revise the PURPA Regulations to replace ''Midwest Independent Transmission System Operator, Inc. (Midwest ISO)'' and ''ISO New England, Inc.'' in 18 CFR 292.309(e), with ''Midcontinent Independent System Operator, Inc. (MISO)'' and ''ISO New England Inc.,'' respectively.

[154] *See* 16 U.S.C. 824a–3(m).

[155] *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities,* Order No. 688, 117 FERC ¶ 61,078, at PP 9–12 (2006), *order on reh'g,* Order No. 688–A, 119 FERC ¶ 61,305 (2007), *aff'd sub nom. Am. Forest & Paper Ass'n* v. *FERC,* 550 F.3d 1179 (D.C. Cir. 2008).

[156] 18 CFR 292.309(d)(1).

[157] *E.g.,* Order No. 688, 117 FERC ¶ 61,078 at PP 72–73; Order No. 688–A, 119 FERC ¶ 61,305 at P 103.

[158] Order No. 688–A, 119 FERC ¶ 61,305 at PP 94–103.

[159] *Id.* P 96.

[160] *Id.* P 101.

[161] *Id.* P 95.

[162] 18 CFR 292.310(d)(2) (to the extent an electric utility seeks relief from the purchase obligation with respect to a QF 20 MW or smaller, the electric utility bears burden to prove the QF has nondiscriminatory access to the wholesale markets).

[163] Order No. 688, 117 FERC ¶ 61,078 at P 78. In saying this, however, the Commission did not intend to suggest that these two facts alone would necessarily be a basis for granting relief from PURPA's mandatory purchase obligation. *PPL Elec. Utils. Corp.,* 145 FERC ¶ 61,053, at P 23 & n.25 (2013), *order denying reh'g,* 148 FERC ¶ 61,207 (2014).

[164] Order No. 688, 117 FERC ¶ 61,078 at P 37.

[165] Order No. 688–A, 119 FERC ¶ 61,305 at P 97.

A's setting 20 MW as the demarcation for different interconnection standards between small and large generators.[166] While the Commission has not (and does not here) propose to revise the exemptions for QFs from sections 205 and 206 of the FPA, the Commission has taken steps to ease both interconnection and market access for generation resources with small capacities since it first implemented section 210(m) of PURPA.

129. For example, the Commission has required public utilities to provide a Fast-Track interconnection process for some interconnection customers whose capacity is up to and including 5 MW (up from the previous 2 MW threshold),[167] and has required each RTO/ISO to revise its tariff to include a participation model for electric storage resources that establishes a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW.[168] While both of these changes do not apply only to generation types that could become QFs or to RTOs/ISOs, we believe they generally show that small power production facilities below 20 MW, specifically those whose capacity exceeds 1 MW now have greater access to the markets defined in section 210(m)(1) of PURPA than they did when the Commission first established the presumptions of market access. Under this proposal, like QFs over 20 MW today, small power production facilities over 1 MW would be able to rebut the presumption of access due to operational characteristics or transmission constraints.[169]

130. The Commission does not propose to make the same reduction applicable to cogeneration facilities. Unlike small power production facilities, which are constructed solely to produce and sell electricity, cogeneration facilities seeking QF certification after February 2, 2006 are statutorily required to show that they are intended primarily to provide heat for an industrial, commercial, residential or institutional process rather than fundamentally for sale to an electric utility.[170] Consequently, the production and sale of electricity is a byproduct of these processes, and owners of cogeneration facilities might not be as familiar with energy markets and the technical requirements for such sales. Retention of the existing 20 MW level for the presumption of access to markets therefore would be appropriate for cogeneration facilities.

3. Reliance on RFPs and Liquid Market Hubs To Terminate Purchase Obligation

131. NARUC has proposed that the Commission allow utilities to rely on RFPs (in combination with liquid market hubs) to establish eligibility to terminate a utility's purchase obligation pursuant to PURPA section 210(m)(1)(C).[171] After describing generally how such a proposal might be structured, NARUC suggests that ''[t]he Commission should create a yardstick of characteristics that describe in detail how a utility could qualify for an exemption under subparagraph (C).'' [172]

132. Under the PURPA Regulations, electric utilities already may seek to terminate their mandatory purchase obligation pursuant to PURPA section 210(m)(1)(C) by demonstrating that a particular market is of comparable competitive quality to markets described in PURPA section 210(m)(1)(A) and (B).[173] The current PURPA Regulations are not prescriptive about how an electric utility must make such a demonstration and nothing in the PURPA Regulations or precedent would bar an electric utility from arguing that RFPs in combination with liquid market hubs are sufficient to satisfy PURPA section 210(m)(1)(C).

133. The Commission believes that a properly structured proposal along the lines proposed by NARUC potentially could satisfy the statutory requirements under PURPA section 210(m)(1)(C) and will consider such proposals on a case-by-case basis. Although the Commission does not in this NOPR propose additional criteria a utility or utilities may rely on to satisfy PURPA section 210(m)(1)(C), the Commission seeks comments on any specific factors that would be useful to consider in determining how a utility or utilities may satisfy PURPA section 210(m)(1)(C).

E. Legally Enforceable Obligation

134. Section 292.304(d) of the PURPA Regulations provides that a QF can choose to have its rates based on the avoided cost calculated at the time of delivery *or at the time a LEO is incurred.* However, the PURPA Regulations do not specify when or how a LEO is established.[174] To date, the Commission has not identified specific criteria that states must follow in determining when a LEO is established.

135. Although not specifying such criteria, the Commission has found that certain prerequisites to QFs obtaining a LEO imposed by some states—such as a utility's execution of an interconnection agreement or power purchase agreement—are unreasonable.[175] The

[166] *See* Order No. 688, 117 FERC ¶ 61,078 at P 76, *order on reh'g,* Order No. 688–A, 119 FERC ¶ 61,305 at P 97; *see also* 18 CFR 292.601(c)(1) (''sales of energy or capacity made by qualifying facilities 20 MW or smaller, or made pursuant to a contract executed on or before March 17, 2006 or made pursuant to a state regulatory authority's implementation of section 210, the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 824a–1, shall be exempt from scrutiny under sections 205 and 206''); *Revised Regulations Governing Small Power Production and Cogeneration Facilities,* Order No. 671, 114 FERC ¶ 61,102, at P 98 (2006), *order on reh'g,* Order No. 671–A, 115 FERC ¶ 61,225 (2006) (establishing exemption for QFs 20 MW or below from 205 and 206 of FPA); *Standardization of Small Generator Interconnection Agreements and Procedures,* Order No. 2006, 111 FERC ¶ 61,220, at P 75, *order on reh'g,* Order No. 2006–A, 113 FERC ¶ 61,195 (2005), *order granting clarification,* Order No. 2006–B, 116 FERC ¶ 61,046 (2006).

[167] *Small Generator Interconnection Agreements and Procedures,* Order No. 792, 145 FERC ¶ 61,159, at P 103 (2013), *clarifying,* Order No. 792–A, 146 FERC ¶ 61,214 (2014).

[168] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators,* Order No. 841, 162 FERC ¶ 61,127, at P 265 (2018).

[169] *See* 18 CFR 292.309(c), (e), (f).

[170] *See* 16 U.S.C. 824a–3(n); 18 CFR 292.205(d)(3). We recognize that cogeneration facilities seeking certification 5 MW or smaller after February 2, 2006 are presumed to satisfy this requirement. 18 CFR 292.205(d)(4).

[171] *See* NARUC Supplemental Comments, Docket No. AD16–16–000 (Oct. 17, 2018).

[172] *Id.,* attach. A at 9.

[173] Order No. 688–A, 119 FERC ¶ 61,305 at P 43 (''Congress believed the two types of markets identified in subparagraphs (A) and (B), while distinct between themselves, contain certain competitive qualities that justify termination of the purchase requirement for any QF with nondiscriminatory access to those markets. Subparagraph (C) directs the Commission to consider these competitive qualities when analyzing whether there are other markets that, while not meeting the specific requirements of subparagraphs (A) and (B), are sufficiently competitive to justify termination of the purchase requirement.''); *cf. Pub. Serv. Co. of N.M.,* 140 FERC ¶ 61,191, at PP 29–38 (2012) (denying application to terminate mandatory purchase obligation on the grounds that the Four Corners Hub is not of comparable competitive quality to markets in sections 210(m)(1)(A) and (B) of PURPA).

[174] *But see, e.g., FLS,* 157 FERC ¶ 61,211 at P 23 (''[R]equiring a QF to tender an executed interconnection agreement is equally inconsistent with PURPA and our regulations. Such a requirement allows the utility to control whether and when a legally enforceable obligation exists—*e.g.,* by delaying the facilities study or by delaying the tendering by the utility to the QF of an executable interconnection agreement.''); Memorandum of Agreement between Idaho Public Utilities Commission and Federal Energy Regulatory Commission at 2 (Dec. 24, 2013), *available at https://www.ferc.gov/legal/mou/mou-idaho-12-2013.pdf* (Idaho Commission acknowledging that ''a legally enforceable obligation may be incurred prior to the formal memorialization of a contract to writing'').

[175] *See, e.g., FLS,* 157 FERC ¶ 61,211 at P 26 (requiring signed interconnection agreement as prerequisite to legally enforceable obligation is inconsistent with PURPA Regulations); *Grouse Creek Wind Park, LLC,* 142 FERC ¶ 61,187, at P 40 (2013) (*Grouse Creek*) (finding that requiring a QF to file complaint as prerequisite to a legally enforceable obligation is inconsistent with PURPA Regulations); *Murphy Flat Power, LLC,* 141 FERC ¶ 61,145, at P 24 (2012) (finding that requiring a signed and executed contract with an electric utility as a prerequisite to a legally enforceable obligation

Commission does not propose to overturn this precedent because the Commission continues to believe that imposition of the prerequisites addressed in its precedent is unreasonable and does not satisfy PURPA's requirement that the Commission prescribe rules as necessary to encourage the development of QFs.

136. As discussed below, however, the Commission proposes to amend § 292.304(d) of the PURPA Regulations to require that a QF demonstrate its commercial viability and financial commitment to construct its facility through objective and reasonable state-determined criteria before being entitled to a LEO.

1. Background and Need for Reform

137. The Commission created the concept of a LEO in Order No. 69 ''to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility.'' [176] The Commission has held that requiring a fully-executed contract or executed interconnection agreement as a condition precedent to obtaining a LEO is inconsistent with PURPA.[177]

138. The record indicates that some QFs believe that informing a utility that the QF intends to sell energy to that utility at some point in the future is sufficient to create a LEO and thereby establish the price for future deliveries, regardless of whether the QF project being considered ever generates electricity.[178] This approach, Xcel explains, puts the electric utility and its customers at risk since the utility is required to reliably plan its system and resources for a QF that will not be operational for many years, or not at all, thereby creating uncertainty for the utility and its consumers.[179] Conversely, QF developers argue generally that they need the certainty of a LEO to obtain the financing to build their facilities in the first place, as QFs do not have the same ability that the electric utilities have to ''rate base'' their facilities and, thereby, guarantee capital recovery.[180]

139. While it is up to states to reasonably determine the circumstances and thus when a legally enforceable obligation arises,[181] states may not impose obstacles that make it unreasonably difficult to obtain a LEO.[182] Given the significant changes in the electric industry since PURPA's enactment, as discussed above, the Commission finds that it now may be appropriate to: (1) Specify the commercial viability of a QF and financial commitment to construct the proposed project as the necessary pre-requisites for obtaining a LEO; and (2) provide guidance for states as to what types of criteria may be applied to make the necessary demonstration.

2. Commission Proposal

140. The Commission proposes to add regulatory text in § 292.304(d)(3) of the PURPA Regulations to require QFs to demonstrate that a proposed project is commercially viable and the QF has a financial commitment to construct the proposed project pursuant to objective, reasonable, state-determined criteria in order to be eligible for a LEO. The Commission further proposes to provide that, although a showing of commercial viability and the QF's financial commitment to construct the project is required, states have flexibility as to what constitutes an acceptable showing of commercial viability and financial commitment.

141. Our objective in requiring a showing of commercial viability and the QF's financial commitment to construct the project is to ensure that no electric utility obligation is triggered for those QF projects that are not sufficiently advanced in their development and, therefore, for which it would be unreasonable for a utility to include in its resource planning, while at the same time ensuring that the purchasing utility does not unilaterally and unreasonably decide when its obligation arises. States may require a showing, for example, that a QF has satisfied, or is in the process of undertaking, at least some of the following prerequisites: (1) Obtaining site control adequate to commence construction of the project at the proposed location; (2) filing an interconnection application with the appropriate entity; (3) securing local permitting and zoning; or (4) other similar, objective, reasonable criteria that allow a QF to demonstrate its commercial viability and financial commitment to construct the facilities. These indicia are not intended to be exhaustive and the Commission seeks comment on these indicia and others that also might be appropriate for consideration.

142. We believe requiring QFs to demonstrate their commercial viability and financial commitment to construct the facilities based on such indicia before obtaining a LEO will allow electric utilities to reliably plan for their systems ensuring resource adequacy. Additionally, states' development and definition of objective and reasonable factors to determine commercial viability and financial commitment to construct a facility encourage the development of QFs by providing QFs

is inconsistent with PURPA Regulations); *Rainbow Ranch Wind, LLC,* 139 FERC ¶ 61,077 (2012) (same); *Cedar Creek Wind, LLC,* 137 FERC ¶ 61,006, at P 36 (2011) (*Cedar Creek*) (same).

[176] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,880.

[177] *FLS,* 157 FERC ¶ 61,211 at P 26; *Cedar Creek,* 137 FERC ¶ 61,006 at P 35.

[178] *See, e.g.,* EEI Supplemental Comments, attach. A at 7.

[179] *See* Xcel Comments, Docket No. AD16–16–000, at 15–16 (Nov. 7, 2016) (''If a utility is required to enter into a LEO with a QF, it will (or may be required to) factor the capacity associated with that LEO into its resource planning efforts. And if that project does not materialize—for whatever reason—the utility's resource plan will need to change. Depending on the amount of capacity associated with the LEO or LEOs that the utility has pending, the utility may have to scramble to replace the capacity associated with the now non-existent LEO(s). Such a scramble would very likely result in payment of above-market prices for capacity and energy, again violating the indifference standard. Moreover, additional capacity over and above the capacity associated with the non-existent QF might have been procured, at additional cost to customers, to manage the variability of that anticipated QF. Of greater concern would be a situation where additional capacity is simply not available to make up for the capacity that the QF was expected to provide under the LEO, putting system reliability at risk and potentially putting the utility at risk of violations of NERC reliability standards approved by the Commission. Further, attempting to lock in long-term prices far in advance of the start date of deliveries under a LEO creates significant potential for payments in excess of avoided cost rates.'').

[180] *Compare* EEI Supplemental Comments, attach. A at 7 *with* Renewable Energy Coalition Comments, Docket No. AD16–16–000, at 11–12 (Nov. 7, 2016) (''Long-term contracts allow existing QFs to remain economically viable in times of long resource sufficiency periods with low avoided cost rates. . . . Unlike utilities, which can spread the costs of resource acquisition over the entire useful life of a facility, QFs do not have this option because doing so could expose ratepayers to unnecessary risk from deviations in avoided costs.''); *and* Northwest and Intermountain Power Producers Coalition Comments, Docket No. AD16–16–000, at 5 (Nov. 4, 2016) (''To earn a return on investment, there must first be the prospect of a return on investment. It takes at least 15 years in most cases involving [Northwest and Intermountain Power Producers Coalition] members to recover their invested capital and to retire the debt incurred to build a renewable energy facility. It takes a contract term of 20 years to earn a justifiable return on that investment.'').

[181] *W. Penn Power Co.,* 71 FERC ¶ 61,153, at 61,495 (1995) (*West Penn*) (''It is up to the States, not this Commission, to determine the specific parameters of individual QF power purchase agreements, including the date at which a legally enforceable obligation is incurred under State law. Similarly, whether the particular facts applicable to an individual QF necessitate modifications of other terms and conditions of the QF's contract with the purchasing utility is a matter for the States to determine. This Commission does not intend to adjudicate the specific provisions of individual QF contracts.'' (footnotes omitted)).

[182] *See, e.g., Cedar Creek,* 137 FERC ¶ 61,006 at P 35 & n.57 (citing *West Penn,* 71 FERC ¶ 61,153 at 61,495).

with more certainty as to when they will obtain a LEO.[183]

F. QF Certification Process

1. Background and Need for Reform

143. The Commission provides two paths for an entity to obtain QF status: self-certification and Commission certification.[184] Self-certification, the procedures for which are contained in § 292.207(a) of the PURPA Regulations,[185] is the more common method of certification. When an applicant self-certifies (or self-recertifies), it certifies that its facility satisfies the requirements for QF status. Under the self-certification (or self-recertification) approach a QF is assigned a docket number, and Commission staff reviews the filing to discern that the information required in Form No. 556 appears to have been included, but a notice of the self-certification typically is not published in the **Federal Register** and Commission staff does not otherwise evaluate whether the applicant meets the requirements for QF status.

144. The Commission recognized that the self-certification process may not always satisfy the needs of certain stakeholders or interested entities. Accordingly, the Commission established, in § 292.207(b) of the PURPA Regulations,[186] what is called the ''optional procedure'' for QF status. Under the optional procedure, an entity may file an application for a determination by the Commission that a facility meets the requirements for QF status. The application is noticed in the **Federal Register**, the Commission decides whether the applicant meets the requirements for QF status, and then issues an order either granting or denying the requested certification.

145. After the enactment of EPAct 2005, which imposed new requirements for QF status for ''new'' cogeneration facilities,[187] the Commission issued Order No. 671,[188] which implemented new requirements for QF status including a formal filing requirement for all QFs claiming QF status whether through self-certification or Commission certification.[189] As part of that implementation, for the first time, notices of some (but not all) self-certifications were required to be published in the **Federal Register**. Specifically, § 292.207(a)(iv) provides that self-certifications or self-recertifications, other than for ''new'' cogeneration facilities, would not be published in the **Federal Register**. In 2010, in Order No. 732, the Commission adopted an exemption from the filing requirement for generating facilities with net power production capacities of 1 MW or less.[190]

146. The Commission has explained that, to challenge the self-certification of a QF, an entity must file a petition for declaratory order and pay the associated filing fee, which currently is $28,990. The Commission in *Chugach Electric Association, Inc.* explained that Order No. 671 did not create a right for a challenging entity to submit a motion for revocation in response to a notice of self-certification. Rather, the Commission explained that QF self-certification is effective upon filing, and therefore challenging a self-certification requires a separate petition for declaratory order asking that the Commission revoke QF status.[191]

147. A concern with the existing procedures with respect to self-certification is whether protestors should bear the burden of filing a separate petition for declaratory order and paying the associated filing fee for a declaratory order to object to a questionable self-certification.[192]

2. Commission Proposal

148. The Commission proposes to change § 292.207(a) of the PURPA Regulations to allow a party to intervene and to file a protest of a self-certification or self-recertification of a facility without the necessity of filing a separate petition for declaratory order and without having to pay the filing fee required for a declaratory order. Because an applicant for self-certification or self-recertification is required to serve a copy of its submission on interested electric utilities (principally those it is interconnected with and those it will be selling to) as well as the relevant state regulatory authorities, the Commission will allow interested persons 30 days from the date of filing at the Commission to intervene and/or to file a protest (without paying a filing fee).[193]

149. Any party submitting a protest would have the burden of specifying facts that make a prima facie demonstration that the facility described in the self-certification or self-recertification does not satisfy the requirements for QF status.[194] General allegations that the facility is not a QF without reference to the specific regulatory provision that has not been satisfied (and without an explanation why the provision has not been satisfied), or unsupported assertions that the self-certification does not satisfy an aspect of the PURPA Regulations, would not satisfy this burden and would not be a basis for denial of certification. However, if this prima facie burden is met, then the burden would shift to the applicant submitting the self-certification or self-recertification to demonstrate that the claims raised in the protest are incorrect and that certification is, in fact, warranted.

150. As explained above, QF self-certification is effective upon filing, and remains effective if a protest is filed, until such time as the Commission rules that certification is revoked. The Commission proposes that it would issue an order within 90 days of the date the protest is filed. The Commission also reserves the right to request more information from the protester, the entity seeking QF status, or both.[195] If

[183] Because QFs already in operation have necessarily demonstrated a commitment to construct the project, the Commission does not intend commercial viability and financial commitment requirements to serve as prerequisites to QFs already in operation with existing LEOs to obtaining new LEOs.

[184] There is no fee for a self-certification; there is, however, a fee for Commission certification. 18 CFR 381.505. For 2018, an application for Commission certification requires a filing fee of $23,330 for small power production facilities and $26,410 for cogeneration facilities. In recent years, the Commission has received approximately 5 applications per year for Commission-certification, with the remaining applicants (approximately 3,400 per year) filing for self-certification of their facilities. *See Commission Information Collection Activities,* Notice of information Collection and Request for Comments, Docket No. IC19–16–000, 84 FR 9317, 9318 (Mar. 7, 2019). The Commission will not issue notice of nor process an application for Commission certification without receipt of the applicable fee.

[185] 18 CFR 292.207(a).

[186] 18 CFR 292.207(b).

[187] ''New'' cogeneration facilities are defined as any cogeneration facility that was either not certified a qualifying cogeneration facility on or before August 8, 2005, or that had not filed a notice of self-certification, self-recertification or an application for Commission certification or Commission recertification as a qualifying cogeneration facility prior to February 2, 2006. 18 CFR 292.205(d)(1).

[188] Order No. 671, 114 FERC ¶ 61,102, *order on reh'g,* Order No. 671–A, 115 FERC ¶ 61,225 (2006).

[189] *See* 18 CFR 292.203(a)(3), (b)(2).

[190] *Revisions to Form, Procedures, and Criteria for Certification of Qualifying Facility Status for a Small Power Production or Cogeneration Facility,* Order No. 732, 130 FERC ¶ 61,214 (2010).

[191] *Chugach Elec. Assoc., Inc.,* 121 FERC ¶ 61,287, at PP 51–54 (2007); *see also Hydro Investors, Inc.* v. *Trafalgar Power, Inc.,* 94 FERC ¶ 61,207, at 61,780, *reh'g denied,* 95 FERC ¶ 61,120 (2001).

[192] EEI Supplemental Comments, attach. A at 16.

[193] 18 CFR 292.207(c)(1).

[194] *See* 18 CFR 385.211.

[195] Such information requests could be issued by the Commission or by staff under any applicable delegated authority. For example, the Director of the Office of Energy Market Regulation is authorized under 18 CFR 375.307(b)(3)(ii) to ''[i]ssue and sign requests for additional

the Commission requests more information, the time period for the Commission order would be extended to 60 days from the filing of a complete answer to the information request.

151. There may be instances, however, when the Commission needs additional time to review the record in light of the nature of the protests. In those cases, the Commission proposes that, in addition to any extension resulting from a request for information, the Commission also may toll the 90-day period during which the Commission commits to act for one additional 60-day period. The Commission proposes to delegate to the Commission's Secretary, or the Secretary's designee, the authority to toll the 90-day period for this purpose.

152. The Commission believes these procedures will allow for timely but thorough review of protested self-certifications and re-certifications. The Commission seeks comment on whether these procedures impose an undue burden on the QF even though the QF remains certified pending the review.

III. Information Collection Statement

153. The Paperwork Reduction Act [196] requires each federal agency to seek and obtain the Office of Management and Budget's (OMB) approval before undertaking a collection of information (including reporting, record keeping, and public disclosure requirements) directed to ten or more persons or contained in a rule of general applicability. OMB regulations require approval of certain information collection requirements contemplated by proposed rules (including deletion, revision, or implementation of new requirements).[197] 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 a rule will not be penalized for failing to respond to the collection of information unless the collection of information displays a valid OMB control number.

Public Reporting Burden: In this NOPR, the Commission proposes to revise its regulations implementing PURPA. The principal changes that affect information collection, *i.e.,* the Form No. 556, are as follows: *first,* the Commission proposes to change its current ''one-mile rule'' for determining whether generation facilities should be considered to be part of a single facility for purposes of determining qualification as a qualifying small power production facility, by allowing electric utilities, state regulatory authorities, or other interested parties to show that facilities over one and less than ten miles apart actually are a single facility; and *second,* to allow a party to protest a self-certification or self-recertification of a facility without a fee.

The estimated changes to the burden and cost [198] of the information collection affected by this NOPR, *i.e.,* Form No. 556, follow.

FERC–556, AS MODIFIED BY THE NOPR IN DOCKET NOS. RM19–15–000 AND AD16–16–000

Facility type	Filing type	Number of respondents (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)	Cost per respondent ($) (5) ÷ (1)
Cogeneration Facility > 1 MW.	Self-certification	10	1.25	12.5	8 hrs.; $632	100 hrs.; $7,900	$790.
Cogeneration Facility > 1 MW.	Application for FERC certification.	1	1.25	1.25	55 hrs.; $4,345	68.75 hrs.; $5,431.25	$5,431.25.
Small Power Production Facility > 1 MW, > 1 Mile, < 10 Miles from Affiliated Facility.	Self-certification	20	1.25	25	8 hrs.; $632	200 hrs.; $15,800	$790.
Small Power Production Facility > 1 MW, > 1 Mile, < 10 Miles from Affiliated Facility.	Application for FERC certification.	1	1.25	1.25	55 hrs.; $4,345	68.75 hrs.; $5,431.25	$5,431.25.
Cogeneration and Small Power Production Facility ≤ 1 MW (Self-Certification) [199].	Self-certification	312	1.25	390	4 hrs.; $316	1,560 hrs.; $123,240	$395.
Small Power Production Facility > 1 MW, ≤ 1 Mile from Affiliated Facility.	Self-certification	no change	no change	no change	no change	no change	no change.
Small Power Production Facility > 1 MW, ≤ 1 Mile from Affiliated Facility.	Application for FERC certification.	1	1.25	1.25	55 hrs.; $4,345	68.75 hrs.; $5,431.25	$5,431.25.
Small Power Production Facility > 1 MW, ≥ 10 Miles from Affiliated Facility.	Self-certification	1,980	1.25	2,475	8 hrs.; $632	19,800 hrs.; $1,564,200	$790.
Small Power Production Facility > 1 MW, ≥ 10 Miles from Affiliated Facility.	Application for FERC certification.	no change	no change	no change	no change	no change	no change.
Total						22,235 hrs.; $1,727,433.75	

information regarding applications, filings, reports and data processed by the Office of Energy Market Regulation.''

[196] 44 U.S.C. 3501–21.

[197] *See* 5 CFR 1320.11.

[198] The burden costs are based on FERC's 2018 average annual salary plus benefits of $164,820 (or $79/hour). The Commission believes that industry is similarly situated in terms of staff costs and skill sets.

[199] Not required to file.

Title: FERC–556, Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility.

Action: Revisions to existing collection FERC–556.

OMB Control No.: 1902–0075.

Respondents: Facilities that are self-certifying their status as a cogenerator or small power producer or that are submitting an application for Commission certification of their status as a cogenerator or small power producer; and electric utilities, state regulatory authorities, or other entities submitting comments on, or protests to, the self-certification or application for Commission certification.

Frequency of Information: Ongoing.

Necessity of Information: The Commission proposes the changes in this NOPR in order to revise its implementation of PURPA in light of changes in the electric industry since the enactment of PURPA in 1978.

Internal Review: The Commission has reviewed the proposed changes and has determined that such changes are necessary. These requirements conform to the Commission's need for efficient information collection, communication, and management within the energy industry.

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

Comments concerning the collection of information and the associated burden estimate may also be sent to: 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]. Due to security concerns, comments should be sent electronically to the following email address: *oira_submission@omb.eop.gov*. Comments submitted to OMB should refer to FERC–556 and OMB Control No. 1902–0075.

IV. Environmental Analysis

154. The Commission is required to prepare an Environmental Assessment (EA) or an Environmental Impact Statement (EIS) for any action that may have a significant adverse effect on the quality of the human environment.[200] Whether and how the revisions proposed here, however, would affect QF development and the environment is speculative.

155. The proposed changes to the PURPA Regulations do not authorize or fund particular QFs, nor do they license QFs or issue permits for QFs to operate. They do not authorize or prohibit a generator's use of any particular technologies or fuels, nor do they mandate or limit where QFs should or should not be built. They do not exempt QFs from any Federal, state or local environmental, siting, or other similar laws or regulatory requirements. And while the Commission establishes factors that are to be taken into account by the states in setting QF rates, it is the states and not the Commission that set QF rates. It is impossible to know what actions the states may take in response to the revisions proposed here, and how any such actions would, on balance, impact QF development and the environment going forward—especially given that QFs include not only renewable resources such as solar and wind resources but also renewable resources that, per Congress' directive, depend on waste (such as waste coal) as an energy input[201] and cogeneration that often depends on fossil fuels as an energy input.[202] Moreover, as explained above, PURPA requires that the Commission must prescribe, and from time to time thereafter revise, such rules as the Commission determines necessary to encourage QFs,[203] and the Commission's rules as revised as proposed here would continue to encourage QFs. Given these facts any environmental impacts analysis of the revisions proposed here would be speculative and not meaningfully inform the Commission or the public of the revisions' impact on QF development or, correspondingly, of any associated potential impacts on the environment; there are, in short, no reasonably foreseeable environmental impacts for the Commission to consider.[204] Therefore, the Commission will not prepare an environmental document.

V. Regulatory Flexibility Act Certification

156. The Regulatory Flexibility Act of 1980 (RFA)[205] generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities. In lieu of preparing a regulatory flexibility analysis, an agency may certify that a proposed rule will not have a significant economic impact on a substantial number of small entities.[206]

157. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[207] The SBA size standard for electric utilities is based on the number of employees, including affiliates.[208] Under SBA's current size standards, the threshold for a small entity (including its affiliates) is 250 employees for cogeneration and small power production applicants in the following NAICS[209] categories:

- NAICS code 221114 for Solar Electric Power Generation
- NAICS code 221115 for Wind Electric Power Generation
- NAICS code 221116 for Geothermal Electric Power Generation
- NAICS code 221117 for Biomass Electric Power Generation
- NAICS code 221118 for Other Electric Power Generation

The threshold for a small entity (including its affiliates) is 500 employees for NAICS code 221111 for Hydroelectric Power Generation.

This proposed rule directly affects QFs, the majority of which the Commission estimates are small businesses. But, as reflected in the burden and cost estimates provided above, the Commission does not anticipate that any additional reporting burden or cost imposed on QFs, regardless of their status as a small or large business, would be significant.[210] The proposed revisions may result in additional information being submitted

[200] *Regulations Implementing the National Environmental Policy Act,* Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[201] 16 U.S.C. 796(17); 18 CFR 292.202(b), 292.204(b).

[202] 16 U.S.C. 796(18); 18 CFR 292.205.

[203] 16 U.S.C. 824a–3(a).

[204] While courts have held that NEPA requires "reasonable forecasting," an agency is not required "to engage in speculative analysis" or "to do the impractical, if not enough information is available to permit meaningful consideration." *N. Plains Res. Council* v. *Surface Transp. Board,* 668 F.3d 1067, 1078 (9th Cir. 2011).

[205] 5 U.S.C. 601–12.

[206] 5 U.S.C. 605(b).

[207] 13 CFR 121.101.

[208] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77,343 (Dec. 23, 2013).

[209] The North American Industry Classification System (NAICS) is an industry classification system that Federal statistical agencies use to categorize businesses for the purpose of collecting, analyzing, and publishing statistical data related to the U.S. economy. United States Census Bureau, *North American Industry Classification System, https://www.census.gov/eos/www/naics/* (accessed April 11, 2018).

[210] The average cost per response is estimated to be $594.39 (or $1,727,433.75/2,906.25 responses).

by some small power production QF applicants and self-certifiers (those with affiliated small power production facilities using the same fuel source located over one and less than ten miles away, and with a combined total capacity greater than 80 MW). The Commission estimates that less than ten percent of QF applications and self-certifications meet these criteria.

158. Accordingly, pursuant to section 605(b) of the RFA, the Commission certifies that this proposed rule will not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

159. 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 December 3, 2019. Comments must refer to Docket No. RM19–15–000 and AD16–16–000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

160. The Commission encourages comments to be filed electronically via the eFiling link on the Commission's website 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.

161. 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.

162. 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

163. 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.

164. 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.

165. User assistance is available for eLibrary and the Commission's website 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.*

List of Subjects in 18 CFR Part 292

Electric power; Electric power plants; Electric utilities.

By direction of the Commission. Commissioner Glick is dissent in part with a separate statement attached.

Issued: September 19, 2019.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission proposes to amend Parts 292 and 375, Chapter I, Title 18, *Code of Federal Regulations,* as follows.

PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION

■ 1. The authority citation for part 292 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

■ 2. Amend § 292.101 by adding paragraphs (b)(12) through (16) to read as follows:

§ 292.101 Definitions.

* * * * *

(b) * * *

(12) *Locational marginal price* means the price for energy at a particular location as determined in a market defined in § 292.309(e), (f), or (g).

(13) *Competitive Price* means a Market Hub Price or a Combined Cycle Price.

(14) *Market Hub Price* means a price for as-delivered energy determined pursuant to § 292.304(b)(7)(i).

(15) *Combined Cycle Price* means a price for as-delivered energy determined pursuant to § 292.304(b)(7)(ii).

(16) *Competitive Solicitation Price* means a price for energy and/or capacity determined pursuant to § 292.304(b)(8).

■ 3. Amend § 292.202 by adding paragraph (t) to read as follows:

§ 292.202 Definitions.

* * * * *

(t) *Electrical generating equipment* means all boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar panels and/or inverters, fuel cell equipment and/or other primary power generation equipment used in the facility, excluding equipment for gathering energy to be used in the facility.

■ 4. Amend § 292.204 by revising paragraph (a) to read as follows:

§ 292.204 Criteria for qualifying small power production facilities.

(a) *Size of the facility*—(1) *Maximum size.* Except as provided in paragraph (a)(4) of this section, the power production capacity of a facility for which qualification is sought, together with the power production capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site, may not exceed 80 megawatts.

(2) *Method of calculation.* (i)(A) For purposes of this paragraph (a)(2)(i)(A), there is an irrebuttable presumption that facilities located one mile or less from the facility for which qualification is sought are located at the same site as the facility for which qualification is sought.

(B) For purposes of this paragraph (a)(2)(i)(B), for facilities for which qualification is filed on or after [DATE 60 DAYS AFTER DATE OF PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], there is an irrebuttable presumption that facilities located ten miles or more from the facility for which qualification is sought are facilities located at separate sites from the facility for which qualification is sought.

(C) For purposes of this paragraph (a)(2)(i)(C), for facilities for which qualification is filed on or after [DATE 60 DAYS AFTER DATE OF PUBLICATION OF THE FINAL RULE IN THE **FEDERAL REGISTER**], there is a rebuttable presumption that facilities located over one and less than ten miles from the facility for which qualification is sought are facilities located at separate sites from the facility for which qualification is sought.

(D) For hydroelectric facilities, facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought and use water from the same impoundment for power generation.

(ii) For purposes of making the determination in clause (i), the distance between facilities shall be measured from the electrical generating equipment of the facility for which qualification is sought and the nearest electrical generating equipment of the other facility using the same energy resource and owned by the same person(s) or its affiliates.

(3) *Rebuttal.* (i) *Filing a Protest.* Any person who opposes either a self-certification submitted pursuant to § 292.207(a) or a Commission certification filed pursuant to § 292.207(b) may submit a protest attempting to rebut the presumption that facilities located over one mile and less than ten miles from the facility for which qualification is sought are separate facilities at separate sites from the facility for which qualification is sought.

(ii) *Limitations on rebuttal.* Once the Commission has affirmatively certified an applicant's QF status either in response to a protest opposing a self-certification or in a Commission certification proceeding, any later challenge to a QF's certification asserting that facilities more than one mile and less than ten miles apart are located at the same site must demonstrate a material change in the relevant circumstances that calls into question the continued validity of the certification.

(4) *Waiver.* The Commission may modify the application of paragraph (a)(2) of this section, for good cause.

(5) *Exception.* Facilities meeting the criteria in section 3(17)(E) of the Federal Power Act (16 U.S.C. 796(17)(E)) have no maximum size, and the power production capacity of such facilities shall be excluded from consideration when determining the maximum size of other small power production facilities less than ten miles of such facilities.

* * * * *

■ 5. Amend § 292.207 by revising paragraphs (a) and (b) to read as follows:

§ 292.207 Procedures for obtaining qualifying status.

(a) *Self-certification.* (1) *Form No. 556.* The qualifying facility status of an existing or a proposed facility that meets the requirements of § 292.203 may be self-certified by the owner or operator of the facility or its representative by properly completing a Form No. 556 and filing that form with the Commission, pursuant to § 131.80 of this chapter, and complying with paragraph (c) of this section.

(2) *Factors.* For small power production facilities pursuant to § 292.204, the owner or operator of the facility or its representative may, when completing the Form No. 556, provide information asserting factors showing that the facility for which qualification is sought is at a separate site from other facilities using the same energy resource and owned by the same person(s) or its affiliates.

(3) *Protests and Interventions.* Any protest to and any intervention in a self-certification must be filed in accordance with §§ 385.211 and 385.214 of this chapter, on or before 30 days from the date the self-certification is filed. Any protest must provide evidence to substantiate the claims in the protest.

(4) *Commission action.* Self-certification is effective upon filing. If no protests are timely filed, no further action by the Commission is required for a self-certification to be effective. If protests are timely filed, a self-certification will remain effective until the Commission issues an order revoking QF certification. The Commission will act on the protest within 90 days from the date the protest is filed; provided that, if the Commission requests more information from the protester, the entity seeking QF certification, or both, the time for the Commission to act will be extended to 60 days from the filing of a complete answer to the information request. In addition to any extension resulting from a request for information, the Commission also may toll the 90-day period for one additional 60-day period if so required to rule on a protest. Authority to toll the 90-day period for this purpose is delegated to the Secretary or the Secretary's designee.

(b) *Optional procedure—Commission certification.* (1) *Application for Commission certification.* In lieu of the self-certification procedures in paragraph (a) of this section, an owner or operator of an existing or a proposed facility, or its representative, may file with the Commission an application for Commission certification that the facility is a qualifying facility. The application must be accompanied by the fee prescribed by part 381 of this chapter, and the applicant for Commission certification must comply with paragraph (c) of this section.

(2) *General contents of application.* The application must include a properly completed Form No. 556 pursuant to § 131.80 of this chapter. For small power production facilities pursuant to § 292.204, the owner or operator of the facility or its representative may, when completing the Form No. 556, provide information asserting factors showing that the facility for which qualification is sought is at a separate site from other facilities using the same energy resource and owned by the same person(s) or its affiliates.

* * * * *

■ 6. Section 292.303 is revised to read:

§ 292.303 Electric utility obligations under this subpart.

(a) *Obligation to purchase from qualifying facilities.* Subject to paragraph (b) of this section, each electric utility shall purchase, in accordance with § 292.304, unless exempted by § 292.309 and § 292.310, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (e) of this section.

(b) *Reduction in purchase obligation.* The obligation of an electric utility to purchase from a qualifying facility may be reduced to the extent that a purchasing electric utility's supply obligation has been reduced by a state's retail choice program.

(c) *Obligation to sell to qualifying facilities.* Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, unless exempted by § 292.312, energy and capacity requested by the qualifying facility.

(d) *Obligation to interconnect.*

(1) Subject to paragraph (d)(2) of this section, any electric utility shall make such interconnection with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with § 292.306.

(2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under part II of the Federal Power Act.

(e) *Transmission to other electric utilities.* If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304(e)(4) and shall not include any charges for transmission.

(f) *Parallel operation.* Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with § 292.308.

■ 7. Amend § 292.304 by

■ a. Adding paragraphs (b)(6), (b)(7), (b)(8); and

■ b. Revising paragraphs (d), and (e).

The addition and revisions read as follows:

§ 292.304 Rates for purchases.

* * * * *

(b) * * *

(6) *Locational Marginal Price.* A state regulatory authority or nonregulated electric utility may use a locational marginal price as a rate for as-available qualifying facility energy sales to purchasing utilities located in a market operated defined in § 292.309(e), (f), or (g).

(7) *Competitive Price.* A state regulatory authority or nonregulated electric utility may use a Competitive Price as a rate for as-available qualifying facility energy sales to purchasing electric utilities located outside a market defined in § 292.309(e), (f), or (g). A Competitive Price may be either a Market Hub Price or a Combined Cycle Price, determined as follows:

(i) A *Market Hub Price* is a price established at a liquid market hub to which a state regulatory authority or nonregulated electric utility determines the purchasing electric utility has reasonable access, based on its evaluation of the relevant factors, including but not limited to the following:

(A) Whether the hub is sufficiently liquid that prices at the hub represent a competitive price;

(B) Whether prices developed at the hub are sufficiently transparent;

(C) Whether the purchasing electric utility has the ability to deliver power from such hub to its load, even if its load is not directly connected to the hub; and

(D) Whether the hub represents an appropriate market to derive an energy price for the purchasing electric utility's purchases from the relevant QFs given the electric utility's physical proximity to the hub or other factors.

(ii) A *Combined Cycle Price* is a price determined pursuant to a formula established by a state regulatory authority or nonregulated electric utility using published natural gas price indices and a proxy heat rate for an efficient natural gas combined-cycle generating facility. Before establishing such a formula rate, a state regulatory authority or nonregulated electric utility must determine that the resulting Combined Cycle Price represents an appropriate approximation of the purchasing electric utility's avoided cost, based on its evaluation of the relevant factors, including but not limited to the following:

(A) Whether the cost of energy from an efficient natural gas combined cycle generating facility represents a reasonable approximation of a competitive price in the purchasing electric utility's region;

(B) Whether natural gas priced pursuant to particular proposed natural gas price indices would be available in the relevant market;

(C) Whether there should be an adjustment to the natural gas price to appropriately reflect the cost of transporting natural gas to the relevant market; and

(D) Whether the proxy heat rate used in the formula should be updated regularly to reflect improvements in generation technology.

(8) *Competitive Solicitation Price.* A state regulatory authority or nonregulated electric utility may use a price determined pursuant to a competitive solicitation process to establish qualifying facility energy and/or capacity rates for sales to purchasing electric utilities, provided that such competitive solicitation process is conducted pursuant to procedures ensuring the solicitation is conducted in a transparent and non-discriminatory manner including, but not limited to, the following:

(i) The solicitation process is an open and transparent process;

(ii) Solicitations should be open to all sources, to satisfy that purchasing electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity;

(iii) Solicitations are conducted at regular intervals;

(iv) Solicitations are subject to oversight by an independent administrator; and

(v) Solicitations are certified as fulfilling the above criteria by the relevant state regulatory authority or nonregulated electric utility.

* * * * *

(d) *Purchases "as available" or pursuant to a legally enforceable obligation.* (1) Each qualifying facility shall have the option either:

(i) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing electric utility's avoided costs calculated at the time of delivery; or

(ii) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, except as provided in subsection (d)(2) below, be based on either:

(A) The avoided costs calculated at the time of delivery; or

(B) The avoided costs calculated at the time the obligation is incurred.

(iii) The rate for delivery of energy calculated at the time the obligation is incurred may be based on estimates of the present value of the stream of revenue flows of future locational marginal prices, or Competitive Prices during the anticipated period of delivery.

(2) Notwithstanding paragraph (d)(1)(ii)(B) of this section, a state regulatory authority or nonregulated electric utility may require that rates for purchases of energy from a qualifying facility pursuant to a legally enforceable obligation to vary through the life of the obligation, and to be set at the as-available energy price applicable to the purchasing electric utility determined at the time of delivery.

(3) *Obtaining a legally enforceable obligation.* A qualifying facility must demonstrate commercial viability and financial commitment to construct its facility pursuant to criteria determined by the state regulatory authority or nonregulated electric utility as a prerequisite to a qualifying facility obtaining a legally enforceable obligation. Such criteria must be objective and reasonable.

(e) *Factors affecting rates for purchases.* (1) A state regulatory authority or nonregulated electric utility may establish rates for purchases of energy from a qualifying facility based on a purchasing electric utility's locational marginal price calculated by the applicable market defined in § 292.309(e), (f), or (g), or the purchasing electric utility's applicable Competitive Price. Alternatively, a state regulatory authority or nonregulated electric utility may establish rates for purchases of energy and/or capacity from a qualifying facility based on a Competitive Solicitation Price. To the extent that capacity rates are not set pursuant to this section, capacity rates shall be set pursuant to subsection (2).

(2) To the extent that a state regulatory authority or nonregulated electric utility does not to set energy and/or capacity rates pursuant to

paragraph (e)(1) of this section, the following factors shall, to the extent practicable, be taken into account in determining rates for purchases from a qualifying facility:

(i) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;

(ii) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(A) The ability of the electric utility to dispatch the qualifying facility;

(B) The expected or demonstrated reliability of the qualifying facility;

(C) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(D) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the electric utility's facilities;

(E) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(F) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(G) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(iii) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2)(ii) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(iv) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

■ 8. Amend § 292.309 by revising paragraphs (d), (e), and (f) to read as follows:

§ 292.309 Termination of obligation to purchase from qualifying facilities.

* * * * *

(d)(1) For purposes of § 292.309(a)(1), (2), and (3), there is a rebuttable presumption that a qualifying cogeneration facility with a capacity at or below 20 megawatts does not have nondiscriminatory access to the market.

(2) For purposes of § 292.309(a)(1), (2), and (3), there is a rebuttable presumption that a qualifying small power production facility with a capacity at or below 1 megawatt does not have nondiscriminatory access to the market.

(3) For purposes of implementing paragraphs (d)(1) and (d)(2) of this section, the Commission will not be bound by the standards set forth in § 292.204(a)(2).

(e) Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, L.L.C. (PJM), ISO New England Inc. (ISO–NE), and New York Independent System Operator, Inc. (NYISO) qualify as markets described in § 292.309(a)(1)(i) and (ii), and there is a rebuttable presumption that small power production facilities with a capacity greater than one megawatt and cogeneration facilities with a capacity greater than 20 megawatts have nondiscriminatory access to those markets through Commission-approved open access transmission tariffs and interconnection rules, and that electric utilities that are members of such regional transmission organizations or independent system operators (RTO/ISOs) should be relieved of the obligation to purchase electric energy from the qualifying facilities. A qualifying facility may seek to rebut this presumption by demonstrating, *inter alia,* that:

(1) The qualifying facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or

(2) The qualifying facility lacks access to markets due to transmission constraints. The qualifying facility may show that it is located in an area where persistent transmission constraints in effect cause the qualifying facility not to have access to markets outside a persistently congested area to sell the qualifying facility output or capacity.

(f) The Electric Reliability Council of Texas (ERCOT) qualifies as a market described in § 292.309(a)(3), and there is a rebuttable presumption that small power production facilities with a capacity greater than one megawatt and cogeneration facilities with a capacity greater than 20 megawatts have nondiscriminatory access to that market through Public Utility Commission of Texas (PUCT) approved open access protocols, and that electric utilities that operate within ERCOT should be relieved of the obligation to purchase electric energy from the qualifying facilities. A qualifying facility may seek to rebut this presumption by demonstrating, *inter alia,* that:

(1) The qualifying facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or

(2) The qualifying facility lacks access to markets due to transmission constraints. The qualifying facility may show that it is located in an area where persistent transmission constraints in effect cause the qualifying facility not to have access to markets outside a persistently congested area to sell the qualifying facility output or capacity.

* * * * *

PART 375—THE COMMISSION

■ 1. The authority citation for part 375 continues to read as follows:

Authority: 5 U.S.C. 551–557; 15 U.S.C. 717–717w, 3301–3432; 16 U.S.C. 791–825r, 2601–2645; 42 U.S.C. 7101–7352.

■ 2. Section 375.302(v) is revised to read:

§ 375.302 Delegations to the Secretary.

* * * * *

(v) Toll the time for action on requests for rehearing, and toll the time for action on protested self-certifications and self-recertifications of qualifying facilities.

The following will not appear in the Code of Federal Regulations:

FEDERAL ENERGY REGULATORY COMMISSION

	Docket Nos.
Qualifying Facility Rates and Requirements	RM19–15–000
Implementation Issues Under the Public Utility Regulatory Policies Act of 1978	AD16–16–000

(Issued September 19, 2019)

GLICK, Commissioner, *dissenting in part:*

1. I dissent in part from today's notice of proposed rulemaking (NOPR) because it would effectively gut the Public Utility Regulatory Policies Act (PURPA).[1] Our basic

[1] Public Law 95–617, 92 Stat. 3117 (1978).

responsibilities under PURPA are three-fold: (1) To encourage the development of qualifying facilities (QFs); (2) to prevent discrimination against QFs by incumbent utilities; and (3) to ensure that the resulting rates paid by electricity customers remain just and reasonable and in the public interest.[2] As discussed further below, it is not clear from the record or the discussion in today's NOPR that many of the proposed changes will satisfy those requirements. Although the record developed in response to this NOPR will give us a basis to address those issues, I am deeply concerned that the Commission has failed so far to show that certain aspects of its proposal satisfy our basic responsibilities under the law.

2. It appears that the Commission no longer believes that PURPA is necessary. I disagree. I believe that the goals of PURPA—including the need to expand competition and reduce our reliance on fossil fuels[3]—remain as relevant now as ever. But our apparent disagreement is beside the point. Whether PURPA's goals remain relevant is a decision for Congress, not an administrative agency. The Commission should not be seizing the reins from Congress in order to isolate an important debate about national energy policy within an independent regulatory agency.

I. PURPA's Continuing Relevance Is an Issue for Congress To Decide

3. A fundamental reform to a major energy statute, particularly one that Congress has been debated for decades, ought to come from Congress, not an independent regulatory agency. For more than forty years, the Commission has rather consistently interpreted Congress's directives in PURPA. During that time, Congress has repeatedly considered legislation to amend the statute, in some cases to expand its reach and in others to pare it back. Indeed, almost from the moment PURPA was passed, Congress began to hear many of the arguments being used today to justify scaling the law back. Yet Congress only on one occasion—in 2005—significantly amended the statute. After a lengthy debate, which included proposals to repeal PURPA, Congress adopted the Energy Policy Act of 2005 (EPAct 2005), which left in place PURPA's basic framework but added a series of provisions that relieved utilities of their requirements in regions of the country with robust wholesale energy markets.[4] Over the course of the last fourteen years, Congress has continued to consider a wide range of proposals to reform PURPA, some of which would have enacted into law many of the proposals advanced in this NOPR. But Congress did not enact any of these reforms.

4. Today's NOPR flips that dynamic on its head. It removes an important debate from the halls of Congress and isolates it within the Commission. That may help to achieve certain stakeholders' objectives and, no doubt, some Members of Congress that have unsuccessfully sought to further reform PURPA will applaud this outcome. But what should concern all of us is that resolving these sorts of questions by regulatory edict rather than congressional legislation is neither a durable nor desirable approach for developing energy policy.

5. With those concerns in mind, the Commission's explanation of the purported need for reform rings hollow. The majority recites statistics to show that the energy landscape has changed over the last 40 years. And there is no doubt that it has. Renewables are growing rapidly and, in some parts of the country, are being financed in large numbers without PURPA's protections.[5] Natural gas production has increased in similarly dramatic fashion and recently surpassed coal as the country's principal source of fuel for generating electricity.[6] But reams of statistics do not make a law irrelevant. The majority and I might disagree about PURPA and the importance of its objectives, but that is not a dispute that we, as Commissioners, should resolve. A policy debate about the continuing relevance of PURPA—which, make no mistake, is what this NOPR is really about—is an issue for Congress to resolve.

II. Certain Proposed Revisions Are Inconsistent With Our Statutory Obligations

6. In addition to my general concerns about the direction and intent of today's NOPR, I have a number of more discrete objections regarding aspects of the Commission's proposal. I raise these concerns in particular because I believe that neither the record established to date nor the rationale articulated in today's NOPR suggest that these changes are consistent with our obligations under PURPA. Accordingly, I am especially interested in reviewing the record developed in response to these elements of the proposed rule and I encourage parties to address these issues in detail in their comments.

A. Avoided Cost

7. No issue has consumed as much attention in the debates over PURPA as how to set avoided cost. Following PURPA's enactment in 1978, the Commission introduced a framework for setting ''avoided cost'' that allows each individual state to consider a wide range of factors in identifying the ''full'' costs that are avoided when a utility purchases energy and capacity from a QF.[7] The basic idea is that the avoided cost figure should reflect the full cost that the utility would incur *but for* the purchase of the QF output of energy or capacity, with each individual state enjoying considerable flexibility in implementing that concept.[8] The Commission's regulations also provide states the flexibility to accommodate Congress's intent that the rates paid to QFs ''look beyond'' just ''instantaneous cost savings'' in order to consider savings over a longer time horizon.[9]

8. The NOPR proposes two fundamental changes to how avoided cost is calculated and applied to QFs. First, it proposes to eliminate the requirement that a utility must afford a QF the option to enter a contract at an avoided cost energy rate that is fixed or known for the duration of the contract.[10] As things stand now, a QF generally has two options for selling its output to a utility. Under the first option, the QF can sell its energy on an as-available basis and receive an avoided cost rate calculated at the time of delivery. This is generally known as the as-available option. Under the second option, a QF can enter into a fixed duration contract at an avoided cost rate that is fixed either at the time the QF establishes a legally enforceable obligation or at the time of delivery. This is generally known as the contract option. The ability to choose between both types sale options has played an important role in fostering the development of a variety of QFs. For example, the as-available option provides a way for QFs whose principal business is not generating electricity, such as industrial cogeneration facilities, to monetize their excess electricity generation. The contract option, by contrast, provides QFs who are principally in the business of generating electricity, such as small renewable electricity generators, a relatively stable option that will allow them to secure financing. Together, the presence of these two options have allowed the Commission to satisfy its statutory mandate to encourage the development of QFs and ensure that the rates they receive are non-discriminatory.

9. I am concerned that the Commission's proposal to allow utilities to eliminate the

[2] *See* 16 U.S.C. 824a–3 (2018).

[3] *See Am. Paper Inst., Inc.* v. *Am. Elec. Power Serv. Corp.,* 461 U.S. 402, 405 (1983) (describing Congress's intent in enacting PURPA).

[4] Public Law 109–58, 119 Stat. 594 (2005).

[5] *See Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* 168 FERC ¶ 61,184, at PP 19–21 (2019) (NOPR).

[6] U.S. Energy Info. Admin., *What is U.S. electricity generation by energy source?, https://www.eia.gov/tools/faqs/faq.php?id=427&t=3* (last visited Sept. 19, 2019).

[7] *See* 18 CFR 292.304(e) (2019).

[8] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978,* Order No. 69, FERC Stats. & Regs. ¶ 30,128, at 30,865 (cross-referenced 10 FERC ¶ 61,150), *order on reh'g,* Order No. 69–A, FERC Stats. & Regs. ¶ 30,160 (1980) (cross-referenced at 11 FERC ¶ 61,166), *aff'd in part & vacated in part sub nom. Am. Elec. Power Serv. Corp.* v. *FERC,* 675 F.2d 1226 (D.C. Cir. 1982), *rev'd in part sub nom. Am. Paper Inst.* v. *Am. Elec. Power Serv. Corp.,* 461 U.S. 402 (1983) (*API*).

[9] H.R. Rep. 95–1750, at 98–99 (1978) (Conf. Rep.) (''In interpreting the incremental cost of alternative energy, the Conferees expect that the Commission and the states may look beyond the costs of alternative sources which are instantaneously available to the utility. Rather the Commission and states should look to the reliability of that power and the cost savings to the utility which may result at some later date by reasons of supply to the utility at that time of power from the cogenerate or small power producers.'').

[10] The NOPR proposes to eliminate the contract option for the energy component, keeping the long-term contract requirement in place for capacity. That sounds more reasonable than it will often be in practice. The NOPR later clarifies that the fixed capacity value may be zero if the state determines that the electric utility does not have a need for additional capacity resources. *See* NOPR, 168 FERC ¶ 61,184 at P 67. That would also mean that, in some instances, there would be no fixed element in an avoided cost contract, which would seem inconsistent with the Commission's rationale justifying variable energy price contracts. *See id.* P 70.

fixed-price contract option will make it more difficult—or in some cases impossible—for QFs to obtain financing. The option to enter a contract with a fixed or known price has played in essential role in encouraging QF development.[11] In addition, those contracts have played an important role in ensuring that QFs receive non-discriminatory rates, especially in areas of the country with vertically integrated utilities that are guaranteed to recover the costs of their prudently incurred investments through retail rates.[12] Neither the record nor the rationale in this NOPR addresses these concerns in a manner that is even remotely convincing.

10. Second, I am concerned about the implications of the Commission's proposal to determine that a locational marginal price (LMP) is a *per se* reasonable measure of an as-available avoided cost for energy and to preliminarily advance several other ''Competitive Prices'' that would also be sufficient.[13] Current regulations require states to consider factors, including reliability and when the QF is available, when calculating the avoided cost rate. Today's NOPR proposes to allow states to ignore these factors and, instead, rely entirely on LMP or a price set at a ''liquid market hub.'' That rule would apply across the country, irrespective of whether the QF has access non-discriminatory access to competitive markets.[14] That is notwithstanding the fact that the evidence the Commission relies on to justify this proposal comes overwhelmingly from regions with sophisticated RTO and ISO markets and/or restructured utilities.

11. As an initial matter, I support introducing more competition into the Commission's implementation of PURPA. Liquid price signals can be useful and transparent inputs that are worthy of *considering* as part of the overall calculation of an appropriate avoided cost number that includes both the short-term and long-term costs avoided by the utility's purchases from QFs. But referencing the words ''competitive'' and ''market'' over and over again is not the same thing as proof that there is sufficient market competition. Many regions of the country—often the same regions where the debates about PURPA are most heated—have not established competitive markets, let alone non-discriminatory access to those markets for independent generators, even if there are liquid market hubs for spot energy purchases. When combined with the Commission's proposal to allow utilities to eliminate the contract option, discussed above, QFs may be reduced to relying solely on some synthetic measure of what spot prices would be in a competitive market based on gas prices and heat rates. I am not persuaded that this will satisfy our obligation to encourage QFs.

12. Nor am I confident that this proposal will not result in discriminatory rates. In regions of the country with vertically integrated utilities (including some parts of RTO/ISO markets) the relevant utility will almost always receive guaranteed cost-recovery on its generation investments. Indeed, state regulators will often effectively pre-approve certain incumbent utility investments through those utilities' integrated resource plans, making it highly unlikely that the utility investments will ultimately be disallowed as imprudent. Under those circumstances, it is not clear to me how a rule that conclusively presumes that LMP—let alone some other measure of price—is a non-discriminatory rate in those regions.

13. I recognize that in some regions of the country—such as the RTOs and ISOs with developed real-time and day-ahead markets and largely restructured utilities—this may be an appropriate approach for calculating the as-available rate for energy, at least for relatively large QFs. But the NOPR's proposed revisions are not limited to those regions and are not even predicated on utilities themselves actually relying on LMP, liquid market hubs, or other calculations of ''Competitive Prices.'' In any case, neither the record nor the rationale in this NOPR addresses these concerns in a convincing manner.

B. Reducing the 20 MW Rebuttable Presumption

14. The Commission is also proposing to reduce the threshold for the rebuttable presumption of non-discriminatory access to competitive wholesale markets within RTOs and ISOs from 20 MW to 1 MW. This proposal would, in essence, relieve most utilities within RTOs and ISOs from the must-purchase obligation for any resource greater than 1 MW based on the theory that those resources have non-discriminatory access to the RTO and ISO markets.[15]

15. The Commission created the rebuttable presumption framework in response to Congress's enactment of section 210(m) in EPAct 2005. The Commission explained that QFs smaller than 20 MW often face more challenges than larger QFs in accessing competitive wholesale markets and therefore presumptively do not have non-discriminatory access.[16] The challenges it identified included issues such as interconnection at the distribution level, jurisdictional differences, pancaked delivery rates, and administrative burdens to obtaining access to distant buyers.[17]

16. Today's NOPR contains precious little justification to support that change and does not cite a single piece of record evidence supporting its proposal.[18] That may be because it seems a stretch to suggest that a 1 MW resource can generally access and compete in markets as sophisticated and complex as, for example, PJM Interconnection, L.L.C., on a similar footing as the resources in the portfolio of a large vertically integrated utility or merchant power generator.

17. These are among the most important issues presented in this NOPR. I hope that the parties will assemble a correspondingly robust record that allows to us to dig into them in detail and evaluate whether the Commission's proposals are consistent with our obligations under the statute.

III. PURPA Should Be Revised To Create More Competition, Not Less

18. Insofar as I can tell, the Commission interprets the success of PURPA since 1978 as evidence that the law is no longer needed and that the Commission should revise its regulations so that they do less to encourage QFs. I draw a slightly different conclusion from the same evidence. I view PURPA's success in deploying gigawatts of relatively low-cost electricity as proof of the benefits of introducing competition into the bulk power system.

19. Several proposals in the record would do just that. For example, the National Association of Regulatory Commissioners (NARUC) submitted a proposal for how the Commission might implement section 210(m)(1), which was added by the Energy Policy Act of 2005. The new provision provided three bases for FERC to terminate a utility's must-purchase obligation under PURPA, all of which hinged on QFs' access to competitive wholesale electricity markets.[19] The NARUC proposal urged the

[11] *See, e.g.,* June 29, 2016 Technical Conf. Tr. at 26–27 (Solar Energy Industries Association) (''The Power Purchase Agreement is the single most important contract of the development and financing of an energy project that's not owned by a utility. Without the long-term commitment to buy the output of that agreement at a fixed price, there is no predictable stream of revenue. Without a predictable stream of revenues, there is no financing. Without any financing, there is no project.'').

[12] *See* Statement of Travis Kavulla, Docket No. AD16–16–000, at 2 (June 29, 2016) (''Whether compensation for a QF is a matter of market clearing prices or of administrative decision-making is largely a reflection of how larger or utility-owned generation is compensated.'').

[13] NOPR, 168 FERC ¶ 61,184 at PP 50, 55–60.

[14] The NOPR proposes to allow states or utilities to use this liquid market price only for the ''as-available'' energy sales rate, not the capacity rate or for QFs that choose the contract option. But given that the Commission is also proposing to allow utilities to eliminate the fixed-price contract option for energy sales, QFs may have no choice but to rely on the ''as-available'' option for sales of energy.

[15] This issue, as much as any other, has been subject to vigorous debate in Congress. *See supra* at 3.

[16] *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities,* Order No. 688, 117 FERC ¶ 61,078, at PP 9–12 (2006), *order on reh'g,* Order No. 688–A, 119 FERC ¶ 61,305 (2007), *aff'd sub nom. Am. Forest & Paper Ass'n* v. *FERC,* 550 F.3d 1179 (D.C. Cir. 2008).

[17] NOPR, 168 FERC ¶ 61,184 at P 121.

[18] To the contrary, the Commission has found that QFs less than 20 MW may not have non-discriminatory access, even within RTO/ISO markets. In just the last few years, the Commission has explained that barriers such as transmission constraints are the very ''circumstances explained in Order No. 688 that gave rise to the rebuttable presumption that smaller QFs lack nondiscriminatory access to markets.'' *N. States Power Co.,* 151 FERC ¶ 61,110, at P 34 (2015). Today's NOPR fails to provide any explanation for the departure from the Commission's existing policy.

[19] Section 210m(1) provides:

(A)(i) Independently administered, auction-based day ahead and real-time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or

(B)(i) transmission and interconnection services that are provided by a Commission approved regional transmission entity and administered

Commission to give meaning to section 210m(1)(C) of the Federal Power Act by establishing criteria by which a vertically integrated utility outside of an RTO or ISO could apply to terminate the must-purchase obligation if it conducts sufficiently competitive auctions or RFPs for energy and capacity.[20] In other words, it would use the pathway established by Congress's amendments to PURPA to create more opportunity and competition in areas where, for non-incumbent utilities, PURPA is often the only game in town.

20. The NARUC proposal was a whitepaper, not a detailed NOPR. It would surely require more development before we could determine whether it satisfies PURPA's statutory requirements. Nevertheless it represented a step in the right direction that would have been consistent with PURPA's pro-competitive purposes. It was also an idea that we could have—and should have—amply explored through a technical conference or other proceeding since the Chairman indicated his intent to go forward with revisions to PURPA.

21. The Solar Energy Industries Association also put forward a pro-competitive proposal of the type that I would like to have explored in more detail in this NOPR.[21] The proposal would address competitive solicitations as a means of procuring energy and capacity from all new generation resources, including QFs. It also discussed the potential for these competitive solicitations to set avoided cost under certain circumstances. As with the NARUC proposal, this proposal would revise PURPA to include more genuine competition rather simply revising the regulations to do less to encourage QFs.

22. Rather than seeking to expand competition, the majority is instead using the success of competition in certain parts of the country as a reason to scale back PURPA throughout the country. In some areas of the country, particularly those with developed RTO and ISO markets and with few, if any, vertically integrated utilities, competition is the norm and PURPA may not be necessary, at least for generators that are sufficiently large and sophisticated to participate on an equal footing with other market participants. But it does not necessarily follow that the healthy competition we see in those regions means that PURPA does not continue to play a vital role in other parts of the country, including those without RTO and ISO markets or where vertically integrated utilities dominate. To put it bluntly, the success that a QF might have in selling its energy and capacity within ISO New England Inc. tells you very little about the success a similar resource might have in the Southeast or the West, at least without PURPA. I worry that applying lessons learned in the truly competitive regions of the country to the less competitive regions will actually result in less competition and, ultimately, higher prices for consumers.

23. I support certain aspects of this NOPR that I believe are consistent with the Commission's proper role in administering PURPA and are supported by the record developed so far. First and foremost, I agree that it is time to address the ''one-mile'' rule, which currently provides an irrebuttable presumption that resources located more than a mile apart are separate QFs.[22] There is evidence compiled as part of the Commission's 2016 technical conference on PURPA that suggests that this rule is susceptible to gaming and that some developers are splitting what should fairly be considered one project into a series of discrete projects spread separated by a mile each.[23] I do not believe that is what Congress had in mind when it set out to promote small power production facilities in PURPA. The NOPR proposes what I believe is a reasonable framework for addressing this issue and I look forward to reviewing the comments we receive.

24. In addition, I support the proposal to require that QFs demonstrate commercial viability before securing a legally enforceable obligation with the relevant utility. It seems only fair to require that a proposed QF demonstrate that it is not speculative and will likely enter service before a utility incurs an obligation to purchase that QF's output at any particular price. The proposal in today's NOPR appears to strike a reasonable balance between allowing QFs to secure a commitment for purchase early enough in their development cycle so that they can use it to facilitate financing while preventing QFs from locking-in avoided-cost rates too far ahead of their actual delivery of any energy or capacity. Nevertheless, in contrast to the one-mile rule, the record on this question is relatively underdeveloped and I hope that parties will address the specifics of this proposal in detail.

25. Finally, I support the proposal to allow stakeholders to protest self-certification of QFs. If an entity believes a resource does not qualify as a QF, it should have the opportunity to protest the QF's filing in the same way that stakeholders have the opportunity to protest most other Commission filings. At the very least, it seems unfair to require them to file a declaratory order, and pay tens of thousands of dollars, in order to inform the Commission of their views.

* * *

26. The Commission seems to believe that PURPA's time has passed. But that is Congress's decision to make, not the Commission's. So long as PURPA is on the books, we must faithfully implement the requirements of the law. Although I support certain elements of today's NOPR, I am concerned that many of the Commission's proposals will fall short of our statutory obligations. In addition, I am also disappointed that the Commission is not doing more to explore using PURPA to expand opportunities for genuine competition, including through section 210(m)—the avenue for reform that Congress enacted in 2005. I believe that focusing on expanding opportunities for genuine competition would far better serve the public interest than simply rebalancing the scales against QFs, which seems to be the principal goal of today's NOPR.

For these reasons, I respectfully dissent in part.

Richard Glick,
Commissioner.

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pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term, and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

16 U.S.C. 824a–3(m)(1) (2018)

[20] National Association of Regulatory Utility Commissioners Supplemental Comments, Docket No. AD16–16–00 (Oct. 17, 2018), Attachment A at 8; *id.* (proposing the Commission's *Edgar-Allegheny* criteria as a basis for evaluating whether a proposal was adequately competitive).

[21] Solar Energy Industries Association Supplemental Comments, Docket No. AD16–16–000 (Aug. 28, 2019).

[22] 18 CFR 292.204(a) (2019).

[23] *See* Statement of Paul Kjellander, Docket No. AD16–16–000, at 4–5 (June 29, 2016); Portland General Electric Company Comments, Docket No. AD16–16–000, at 6 (June 29, 2016).