DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Parts 292 and 375

[Docket Nos. RM19–15–000 and AD16–16–000; Order No. 872]

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

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final rule.

SUMMARY: In this Order, the Federal Energy Regulatory Commission issues its final rule approving certain revisions to its regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA). These changes will enable the Commission to continue to fulfill its statutory obligations under sections 201 and 210 of PURPA.

DATES: This rule is effective December 31, 2020.

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:

Table of Contents

I. Introduction

1. In this Order, the Federal Energy Regulatory Commission (Commission) issues its final rule approving certain revisions to its regulations (PURPA Regulations) [1] implementing sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA).[2]

2. On September 19, 2019, the Commission issued a notice of proposed rulemaking (NOPR) proposing to modify its PURPA Regulations.[3] Those regulations were promulgated in 1980 and have been modified in only specific respects since then. Approximately 130 separate comments were submitted in response to the NOPR,[4] several of which were submitted on behalf of multiple parties. In total, over 1,600 pages of comments were submitted, and in addition thousands of pages of exhibits

[1] 18 CFR part 292 (2019). In connection with the revisions to the PURPA Regulations, the Commission also is revising its delegation of authority to Commission staff in 18 CFR pt. 375.

[2] 16 U.S.C. 796(17)–(18), 824a–3.

[3] *Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* 168 FERC ¶ 61184 (2019) (NOPR).

[4] See Appendix for list of commenters.

were attached to the comments. The entities that filed comments are listed in Appendix A. This final rule addresses comments received in response to the NOPR.

3. We largely adopt the NOPR proposals. However, this final rule makes certain modifications to the NOPR proposals, as further discussed below.

4. Given the Commission's expressed intent in the NOPR to propose revisions to the PURPA Regulations that more closely adhere to the goals and terms of PURPA,[5] we considered comments regarding whether these proposals are consistent with the requirements of PURPA. Based on that review and further consideration, we adopt the following changes to the proposals in the NOPR, among certain others described below:

- We establish a rebuttable presumption, rather than a per se rule, that locational marginal prices (LMPs) may reflect a purchasing electric utility's avoided energy costs;
- We provide that any competitive solicitations used to establish avoided capacity costs must adhere to the Commission's *Allegheny*[6] standard for evaluating competitive solicitations;
- We do not adopt the proposed rule permitting states with retail competition to allow relief from the purchase obligation but instead clarify that the Commission's existing PURPA Regulations already require that states, to the extent practicable, must account for reduced loads in setting QF capacity rates;
- We clarify terminology we used in the NOPR relating to the determination of whether small power production facilities are separate facilities to focus not on whether they are *separate facilities,* but rather to mirror the statutory language and thus focus on whether they are at ''*the same site*'';
- We clarify in the regulations that protests may be made to initial self-certifications and applications for Commission certification, but only to self-recertifications and applications for Commission recertification making substantive changes to the existing certification;
- We identify additional factors that can be considered for small power production qualifying facilities (QFs) located more than one but less than 10 miles apart, such as evidence of shared control systems, common permitting and land leasing, and shared step-up transformers;
- We revise the regulations to lower the rebuttable presumption of small power production QFs' nondiscriminatory access to 5 MW, rather than 1 MW as proposed in the NOPR, and include factors that a small power production QF sized greater than 5 MW could rely on to rebut the presumption that it has nondiscriminatory access to markets defined in PURPA sections 210(m)(1); and
- We revise the proposed requirements to establish a legally enforceable obligation (LEO) to provide that with regard to the issue of obtaining permits, QFs need only have applied for all required permits, instead of being required to have already obtained those permits.

II. Overview

5. Before discussing each of the individual changes to the PURPA Regulations adopted herein, this final rule first addresses certain overall themes raised in the comments on the NOPR, both those supporting the NOPR and those opposing.

A. The Commission's PURPA Regulations, as Revised by This Final Rule, Continue To Encourage the Development of QFs Within the Requirements of PURPA's Statutory Limitations

6. PURPA section 210(a) requires that the Commission prescribe rules that it determines necessary to encourage the development of qualifying small power production facilities and cogeneration facilities.

7. The bulk of the criticism of the Commission's proposed rule changes is based on a widespread misunderstanding, as reflected in the comments on the NOPR, that PURPA and the PURPA Regulations were intended to encourage QF development without any limit, and that the rule changes proposed in the NOPR improperly reduce or even eliminate encouragement in contravention of the statute. Those commenters opposing the NOPR proposals argue that the Commission has determined, in contravention of the statute, that there no longer is a need to encourage QFs, or eliminated any provision that provides such encouragement.[7] Many of the commenters supporting the changes proposed in the NOPR applaud the Commission for eliminating what they argue amounts to an improper subsidy of QFs.[8]

8. Neither side is correct about either what PURPA and the current PURPA Regulations require, or the basis for the changes to the PURPA Regulations proposed in the NOPR.

9. As an initial matter, PURPA was not a directive to the Commission to encourage QF development without limitation. Indeed, as explained below, Congress included several limitations in PURPA. By reading the statute as a whole, and the PURPA Regulations as a whole as revised by this final rule, it is clear that the PURPA Regulations continue to encourage the development of QFs consistent with PURPA.[9]

10. We also emphasize that we do not by this final rule change other elements to the Commission's existing PURPA Regulations that continue to encourage QF development. These elements include, but are not limited to, rules that: (1) Require electric utilities to provide backup electric energy to QFs on a non-discriminatory basis and at just and reasonable rates; (2) require electric utilities to interconnect with QFs; and (3) provide exemptions to QFs from many provisions of the Federal Power Act (FPA) and state laws governing utility rates and financial organization.[10] These provisions encourage the development of QFs by relieving them of certain regulatory burdens otherwise imposed on sellers of power and ensure they can operate their facilities. Moreover, we stress that, besides the changes to the PURPA Regulations regarding applications to terminate a purchasing electric utility's mandatory purchase obligation under PURPA section 210(m) (see *infra* section IV.G), nothing in this final rule eliminates QFs' rights to sell electric energy or capacity as provided under PURPA.

11. As discussed in greater detail below, while PURPA provided for the encouragement of cogeneration and small power production, PURPA also provided that the Commission could not prescribe a rule that provided for ''a rate which exceeds the incremental cost to the electric utility of alternative electric energy.'' [11] Furthermore, PURPA requires the Commission to ''insure'' that the resulting rates ''shall be just and reasonable to the electric consumers of

[5] NOPR, 168 FERC ¶ 61,184 at P 31.

[6] *Allegheny Energy Supply Co., LLC,* 108 FERC ¶ 61,082, at P 18 (2004) (*Allegheny*).

[7] *See, e.g.,* Biological Diversity Comments at 14; ConEd Development Comments at 2; Harvard Electricity Law Comments at 4; New England Small Hydro Comments at 4; NIPPC, CREIA, REC, and OSEIA Comments at 3, 21, 28; Public Interest Organizations Comments at 9, 39; Solar Energy Industries Comments at 4; Southeast Public Interest Organizations Comments at 17.

[8] *See* Competitive Enterprise Institute Comments at 3; Progressive Policy Institute Comments at 1–2; SBE Council Comments at 2; Mr. Moore Comments at 1–2.

[9] 16 U.S.C. 824a–3(a).

[10] *See* 18 CFR 292.303(c), 292.305, 292.601–02.

[11] *Compare id. with* 16 U.S.C. 824a–3(b).

the electric utility and in the public interest[.]'' [12] Likewise, while PURPA provided for the encouragement of small power production, PURPA also limited the facilities which could be encouraged to those facilities with no more than 80 MW power production capacity at the same site.[13]

12. Nothing in the text of PURPA requires the establishment of a subsidy for QFs. This point was confirmed in the Conference Report accompanying PURPA's passage: ''The provisions of this section are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers.'' [14] Congress thus structured PURPA both specifically to give effect to its intent that QFs not be subsidized and also to impose other mandatory limits on the Commission's ability to encourage QFs that are relevant to this final rule, as briefly summarized below.

1. Avoided Cost Cap on QF Rates

13. PURPA section 210(b) sets out the standards governing the rates purchasing utilities must pay to QFs.[15] Sections 210(b)(1) and (b)(2) provide that QF rates ''shall be just and reasonable to the electric consumers of the electric utility and in the public interest'' and ''shall not discriminate against qualifying cogenerators or qualifying small power producers.'' [16] After establishing these standards, Congress then placed, in the final sentence of section 210(b), a cap on the level of the rates utilities could be required to pay QFs: ''No such rule prescribed under subsection (a) *shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy*.'' [17] As the Conference Report for PURPA explains:

> [T]he utility would not be required to purchase electric energy from a qualifying cogeneration or small power production facility *at a rate which exceeds the lower of* the rate described above, namely a rate which is just and reasonable to consumers of the utility, in the public interest, and nondiscriminatory, or the incremental cost of alternate electric energy. This limitation on the rates which may be required in purchasing from a cogenerator or small power producer *is meant to act as an upper limit on the price* at which utilities can be required under this section to purchase electric energy.[18]

14. This upper limit on QF rates established in section 210(b), equal to a purchasing utility's incremental costs, commonly called ''avoided costs,'' implements Congress's intent that QFs not be subsidized. It ensures that the purchasing utility cannot be required to pay more for power purchased from a QF than it would otherwise pay to generate the power itself or to purchase power from a third party.

15. Consistent with the statutory standard, when the Commission issued its PURPA Regulations in 1980, it set the rates for QFs at, but not above, the statutorily defined incremental or avoided cost of alternative electric energy.[19] The PURPA Regulations applied this limitation generally to QF rates, without distinguishing between as-available energy [20] and the fixed energy and capacity rate option applicable to long-term contracts or other legally enforceable obligations.[21] In either case, though, the PURPA Regulations essentially capped the rate paid to QFs at the purchasing electric utility's avoided costs.[22]

16. Order No. 69, in which the Commission promulgated the PURPA Regulations,[23] makes clear that the Commission also recognized that allowing the option for a fixed energy and capacity rate option for long-term contracts or other legally enforceable obligations could result in a rate that, at times, exceeded incremental or avoided cost of alternative electric energy. The Commission acknowledged in this regard that some commenters had asserted that, ''if the avoided cost of energy at the time it is supplied is less than the price provided in the contract or obligation, the purchasing utility would be required to pay a rate for purchases that would subsidize the qualifying facility at the expense of the utility's other ratepayers.'' [24] In response, the Commission stated that it ''recognize[d] this possibility, but is cognizant that in other cases, the required rate will turn out to be lower than the avoided cost at the time of purchase.'' [25] The Commission concluded that any over- and under-recoveries compared to avoided cost ''will balance out'' and, based on this conclusion, found that the fixed energy and capacity rate option applicable to long-term contracts or other legally enforceable obligations did not violate the statutory cap.[26] But, to be clear, the option the Commission implemented in 1980 was not based on any determination by the Commission that the rates in QF contracts may routinely exceed avoided costs in the ordinary course of events in order to encourage QFs.

2. Limitation on Small Power Production Facilities Located at the Same ''Site''

17. Another way in which Congress set boundaries on the Commission's ability to encourage development of QFs was to define small power production facilities, one of the categories of generators that under the statute is to be encouraged. The definition of small power production facilities applies to almost all renewable resources that wish to be QFs, requiring that those facilities have ''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.'' [27] In order to comply with this statutory requirement that the capacity of all small power production facilities ''located at the same site'' cannot exceed 80 MW, the Commission is required to define what constitutes a ''site.'' The Commission determined in 1980 that, essentially, those facilities that are owned by the same or affiliated entities and using the same energy resource should be deemed to be at the same site ''if they are located within one mile of the facility for which

[12] 16 U.S.C. 824a–3(b)(1).

[13] *Compare* 16 U.S.C. 824a–3(a) *with* 16 U.S.C. 796(17)(A)(ii).

[14] H.R. Rep. No. 95–1750, at 98 (1978) (Conf. Rep.).

[15] 16 U.S.C. 824a–3(b).

[16] *Id.*

[17] *Id.* (emphasis added). The statute defines an electric utility's ''incremental costs'' as ''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.'' 16 U.S.C. 824a–3(d); *see also* 18 CFR 292.101(b)(6) (implementing same and defining such ''incremental costs'' as ''avoided costs'').

[18] Conf. Rep. at 98 (emphasis added).

[19] *Compare* 16 U.S.C. 824a–3(b) & (d) *with* 18 CFR 292.101(b)(6), 292.304(a)(2) & (b)(2).

[20] 18 CFR 292.304(d)(1).

[21] 18 CFR 292.304(d)(2) (providing QFs the right to elect avoided costs calculated at the time of delivery or avoided costs calculated at the time the obligation is incurred). In this final rule, we refer to the QF's option for avoided costs calculated at the time the obligation is incurred as the fixed energy and capacity rate option. 18 CFR 292.304(d)(2).

[22] The regulations, however, also allowed both for negotiated rates that differed from the rates that would otherwise be applicable, *see* 18 CFR 292.301(b), and for rates to be set based on estimates of avoided costs even though such rates might differ from avoided costs at the time of delivery. *See* 18 CFR 292.304(b)(5).

[23] *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 30,880 (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., Inc.* v. *Am. Elec. Power Serv. Corp.,* 461 U.S. 402 (1983) (*API*).

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

[25] *Id.*

[26] *Id.*

[27] 16 U.S.C. 796(17)(A)(ii).

qualification is sought.'' [28] This definition, known as the ''one-mile rule,'' interpreted Congress's limitation of 80 MW located at the same site to apply to just those affiliated small power production qualifying facilities located within one mile of each other.

3. Termination of Purchase Obligation for QFs With Nondiscriminatory Access to Certain Competitive Markets

18. Finally, Congress amended PURPA in 2005 to further limit the statute. Congress amended PURPA section 210 to add section 210(m), which 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 has nondiscriminatory access to certain defined types of markets.[29] This amendment reflected Congress's judgment that non-discriminatory access to these markets provided adequate encouragement for those QFs.

19. Congress directed the Commission to implement this requirement, which it did in Order No. 688. In that order, the Commission identified certain markets in which utilities would no longer be subject to the PURPA mandatory purchase obligation under PURPA section 210(m) because certain QFs have nondiscriminatory access to such markets.[30] Although not required in the new PURPA section 210(m), the Commission established a rebuttable presumption that a QF with a net power production capacity at or below 20 MW does *not* have nondiscriminatory access to such markets.[31] In creating this rebuttable presumption, the Commission found persuasive arguments that some QFs may not have nondiscriminatory access to markets in light of their small size.

4. Final Rule's Updating of the PURPA Regulations

20. In this final rule, we are amending the PURPA Regulations, principally with regard to the three statutory provisions described above, *i.e.:* (1) The avoided cost cap on QF rates; (2) the 80 MW limitation applicable to the combined capacity of affiliated small power production QFs located at the same site; and (3) the termination of the mandatory purchase obligation for QFs with nondiscriminatory access to certain markets. Contrary to commenters' assertions that the Commission has determined that it no longer is necessary to encourage QFs and therefore that the Commission is making these changes in an impermissible attempt to undo PURPA,[32] we are modifying the PURPA Regulations based on demonstrated changes in circumstances since the current PURPA Regulations were first adopted to ensure that the regulations continue to comply with PURPA's statutory requirements established by Congress.

21. For example, as explained in more detail below, the Commission's expectation expressed in 1980 that over- and under-recovery in rates compared to avoided cost ''will balance out'' [33] was critical to the Commission's determination in 1980 that the fixed energy and capacity rate option applicable to long-term contracts or other legally enforceable obligations did not violate the statutory avoided cost cap on QF rates. However, record evidence now demonstrates that this expectation no longer is necessarily accurate. The Commission's change to the PURPA Regulations adopted in this final rule, giving states the ability to require variable energy rates in long-term contracts or other legally enforceable obligations, allows the states to better ensure that QF rates are at, but do not exceed, the statutory maximum rate established by Congress.

22. This change is important for purposes of compliance with PURPA's statutory mandates. As explained below, setting QF rates at avoided costs allows the Commission to comply with the statutory goals of encouraging QFs and providing for nondiscriminatory rates while at the same time ensuring that such rates are just and reasonable to consumers and do not subsidize QFs. The record shows that on some occasions long-term fixed QF rates were well above actual avoided costs, thereby causing consumers to subsidize those QFs in contravention of PURPA and the Commission's expectations.

23. Similarly, the changes implemented by the Commission in this final rule to the one-mile rule are intended to better ensure compliance with the statutory requirement that small power production facilities located at the same site cannot exceed 80 MW. And, 15 years after Congress added PURPA section 210(m), because the Commission can now make the determination, described below, that smaller QFs have non-discriminatory access to RTO/ISO markets, an update to the rebuttable presumption regarding non-discriminatory access to those markets is appropriate to better ensure compliance with the statute.

24. Some commenters incorrectly assert that the final rule impermissibly revises the PURPA Regulations in a way that no longer encourages QFs. PURPA section 210(a) provides not simply that the Commission is to prescribe rules that encourage QFs, but rather that the Commission is to ''prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage'' QFs. Carrying out Congress's directive to ''from time to time thereafter revise'' the rules is at the heart of what the Commission is doing in this final rule. Consistent with this directive, the Commission is considering revisions to ''such rules as it determines necessary to'' encourage QFs in light of current industry circumstances.[34]

25. The changes adopted in this final rule result from the need for the PURPA Regulations to continue to comply with the directives Congress established when it enacted PURPA in 1978, and then again when Congress amended PURPA in 2005. These changes are not based on any determination by the Commission that the encouragement directed by PURPA is no longer needed. The question of whether QFs should continue to be encouraged or not remains a question for Congress.

26. Moreover, PURPA also requires the Commission to insure that the rates for QF purchases be ''just and reasonable to the electric consumers of the electric utility and in the public interest[.]'' [35] The obligation to encourage is also limited by the requirement that, ''No such rule prescribed under subsection (a) [the encouragement provision] shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.'' [36]

27. We recognize that some of the comments opposing the NOPR may

[28] 18 CFR 292.204(a)(ii).

[29] *See* 16 U.S.C. 824a–3(m).

[30] *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).

[31] 18 CFR 292.309(d)(1).

[32] Biomass Power Comments at 2; Biological Diversity at 12; EPSA Comments at 6 (''[T]he NOPR changes 'would effectively gut' PURPA.''); NIPPC, CREA, REC, and OSEIA Comments at 28–29; Public Interest Groups Comments at 25 (''[T]he changes proposed in the NOPR will gut PURPA-mandated measures to encourage QF development.''); Solar Energy Industries Comments at 8–14.

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

[34] We view the revisions to our rules implementing PURPA that we adopt in this final rule as consistent with Congress's explicit directive that the Commission ''from time to time thereafter [to] revise'' the rules. We do not view Congress as intending that the Commission only ever consider the circumstances that existed in the late 1970s and not current circumstances, 40 years later.

[35] 16 U.S.C. 824a–3(b).

[36] 16 U.S.C. 824a–3(b).

have been influenced by the Commission's recitation in the Background section of the NOPR of the broad changes in circumstances since the PURPA Regulations were first promulgated 40 years ago, including the discovery of significant new natural gas reserves, the evolution of the electric industry to include a significant independent power presence, the establishment of organized competitive markets, and the advances in renewable energy technologies.[37] We clarify that the Commission referenced this general background information in the NOPR primarily to explain why it decided to re-evaluate its PURPA Regulations at all and as Congress said we should, and not necessarily to support the individual proposals included in the NOPR. The facts we rely on to propose specific changes, which include some, but not all, of those background facts, were cited in the specific sections of the NOPR describing those proposed changes. And the facts on which we rely to promulgate the specific changes in this final rule again are cited in the specific sections describing those changes.

B. The Final Rule Ensures That the Commission's Implementation of PURPA Continues To Benefit QFs, Purchasing Electric Utilities, and Electric Consumers

28. The final rule implements additional changes consistent with PURPA that also are designed to benefit QFs, purchasing utilities, and electric consumers. The changes to the PURPA Regulations adopted in this final rule will enable the Commission to continue satisfying the statutory requirement that the Commission promulgate rules to encourage QF development consistent with PURPA's requirements. Claims to the contrary by commenters to the effect that the ''proposals are uniformly biased against QF development'' [38] have no merit.

29. As an initial matter, we are not changing the determination in the PURPA Regulations that QF rates must equal a purchasing electric utility's full avoided costs.[39] As the Supreme Court noted in *API,* the full avoided cost rate requirement represents the maximum rate permitted under PURPA, and thereby provides important encouragement to QFs.[40] The Court explained that the full avoided cost rate requirement encourages QF development because QFs ''retain an incentive to produce energy under the full-avoided-cost rule so long as their marginal costs did not exceed the full avoided cost of the purchasing utility.'' [41]

30. In addition, several of the changes to the current PURPA Regulations implemented by this final rule are based expressly on a finding that they are beneficial to QFs as well as to purchasing utilities and ratepayers. For example, the provisions of the final rule allowing for energy rates to be based on transparent, competitive market prices—in appropriate circumstances—are supported by comments submitted at the Technical Conference, where representatives of QFs and utilities both expressed a preference for transparent prices for QFs.[42] This conclusion is supported by the Fitch Report, cited by NIPPC, CREA, REC, and OSEIA, explaining how Fitch evaluates the financial strength of renewable energy projects. In this report, Fitch states that it gives a ''stronger'' evaluation to projects with power sales contract prices that are ''indexed using simple, broad-based publicly available indexation formulas.'' [43]

31. Setting prices that are indexed using simple, broad-based publicly available formulas is precisely what the Commission's changes permitting reference to competitive market prices will achieve. Such prices reflect avoided costs in a simpler, more transparent, and predictable manner than through an administrative process, which should encourage the development of QFs while at the same time providing benefits to utilities and consumers. Using transparent market prices to establish as-available avoided cost rates also allows QFs, utilities, and the states to avoid the expenditure of the time and resources involved in litigating administratively-set avoided cost rates, and allows those rates to automatically adjust—up and down—as avoided costs change.

32. Similarly, the provisions regarding competitive solicitations adopted herein were added at the suggestion of both NARUC and certain developers of renewable resource QFs, such as Solar Energy Industries. These competitive solicitations can provide a fair and transparent method for QFs to establish full avoided cost rates. As Solar Energy Industries stated in its comments, ''[c]ompetitive solicitations, with adequate safeguards, can deliver substantial value.'' [44] Competitive solicitations may be an especially appropriate tool in those regions outside of Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) where there are no organized competitive markets where QFs can make sales.

33. Likewise, the LEO provisions adopted herein provide important benefits to QFs. Under the current PURPA Regulations, a LEO gives QFs the enforceable right to require utilities to purchase the QFs' power at avoided cost rates.[45] This is an important right that contributes to a QF owner's ability to obtain financing, especially the development financing needed to engage in the activities necessary to subsequently obtain construction and permanent financing. However, the PURPA Regulations are silent as to when and how a LEO is established, which can leave QFs uncertain as to when this key right has been established. By providing more specific guidance as to when a LEO is established, the new rule creates greater certainty for QFs (and utilities) on this important element of QF development.

[37] NOPR, 168 FERC ¶ 61,184, at PP 15–27.

[38] Harvard Electricity Law Comments at 1.

[39] *See* 18 CFR 292.304(b)(2); NOPR, 168 FERC ¶ 61,184 at P 34.

[40] *API,* 461 U.S. at 413. PURPA does not use the terms ''avoided cost'' or ''full avoided cost''; rather, PURPA uses the term ''incremental cost of alternative electric energy.'' The Commission's regulations and subsequent decisions have used the term ''avoided cost'' to explain the Commission's application of the ''incremental cost'' standard. The *API* decision and early Commission precedents referred to ''full'' avoided costs to distinguish between the Commission's decision to set QF rates at avoided costs and proposals from certain parties that rates be set at something less than avoided costs. We continue to use the terms avoided costs and full avoided costs as being consistent with the statutory term incremental cost.

[41] *Id.* at 416.

[42] *See* American Forest & Paper Association, Comments, Docket No. AD16–16–000, at 8 (filed June 8, 2016) (''To the extent possible, these determinations [of avoided costs] should not be made in a 'black box', but rather, as part of an open and transparent method and process.''); Edison Electric Institute (EEI) Comments, Docket No. AD16–16–000, at 3 (filed June 30, 2016) (''Where transparent competitive markets with day ahead prices exist, there is no reason to adhere to second-best avoided cost pricing mechanisms.'').

[43] NIPPC, CREA, REC, and OSEIA Comments at 37–38 (citing FitchRatings, Global Infrastructure & Project Finance, *Renewable Energy Project Rating Criteria,*'' at 3 (Feb. 26, 2019), *https://www.fitchratings.com/site/re/10061770*).

[44] Solar Energy Industries Comments at 38. Solar Energy Industries agreed that the competitive solicitation provisions proposed in the NOPR ''set forth many important safeguards,'' but recommended that additional safeguards be implemented. Those comments are discussed below, and we have specifically adopted Solar Energy Industries request made earlier in this proceeding that all competitive solicitations must be conducted pursuant to the Commission's *Allegheny* standard. *See* Solar Energy Industries Supplemental Comments, Docket No. AD16–16–000, at 32–34 (filed Aug. 28, 2019).

[45] *See* 18 CFR 292.304(d)(2). Although the final rule gives states the flexibility to require that energy rates vary over the term of the LEO and be calculated at the time of delivery, the final rule retains the QF's option to choose a fixed capacity rate calculated at the time the LEO is established.

34. Some commenters assert that the guidance provided by the Commission may make it more difficult to obtain a LEO.[46] Their specific concerns are discussed in detail below. But what those commenters ignore is that, by establishing objective and reasonable state-determined criteria limited to demonstrating commercial viability and financial commitment, we also are protecting QFs against onerous requirements for a LEO that hinder financing, such as a requirement for a utility's execution of an interconnection agreement[47] or power purchase agreement,[48] or requiring that QFs file a formal complaint with the state commission,[49] or limiting LEOs to only those QFs capable of supplying firm power,[50] or requiring the QF to be able to deliver power in 90 days.[51] By making clear in the PURPA Regulations that such conditions are not permitted, but describing which prerequisites a state may impose to establish a LEO to determine which QFs are commercially viable and financially committed, we are providing objective criteria to clarify when a LEO commences, which we find will encourage the development of QFs.

C. The Commission Is Not Eliminating Fixed Rate Pricing for QFs, But Rather Is Giving States the Flexibility To Require the Same Variable Energy Rate/Fixed Capacity Rate Construct That Applies Throughout the Electric Industry

35. Another misconception reflected in several comments is that the Commission proposed in the NOPR to eliminate fixed rate pricing for QFs. Commenters argue that QFs cannot obtain financing without fixed rates, and from this they claim that the proposal to give states the flexibility to require variable energy rates would have a devastating effect on future QF development.[52]

36. This assertion that the Commission has eliminated fixed rates for QFs is not correct. The NOPR proposal (which we adopt in this final rule) gave states the flexibility, should they choose to take advantage of this flexibility, to require that the avoided cost *energy* rates in QF contracts must vary depending on avoided costs at the time of delivery (rather than being fixed at the time a LEO is incurred). The NOPR thus made clear: ''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.''[53] We are retaining in this final rule the option granted to QFs to fix their capacity rates for the term of their contracts at the time the LEO is incurred.

37. The fact that we are giving states the flexibility to either require QF contracts to have fixed capacity and variable energy rates or to continue as before to provide QFs the option of fixed capacity and fixed energy rates—has important consequences for the ability of QF owners to finance their projects. The energy rates of purchasing electric utilities, upon which avoided cost energy rates would be based, typically reflect mainly the variable costs of producing energy, such as the cost of fuel and variable operations and maintenance (O&M), especially for a fossil fuel generator. Meanwhile, a purchasing electric utility's capacity rates, upon which avoided cost capacity rates would be based, tend to reflect fixed costs, including the financing costs of facilities (*i.e.,* debt repayment and a return on the equity invested in the facility).[54] Consequently, a fixed capacity rate in a QF contract based on a purchasing electric utility's capacity rates should typically be sufficient to recover the QF's financing costs and should therefore continue to facilitate QF financing. We recognize that a QF's financing costs may be different from the purchasing electric utility's avoided costs and, therefore, the full avoided cost rate that the QF receives may not support the financing of a QF. But this is a consequence of how Congress structured PURPA, which sets rates based on the avoided costs of the purchasing utility rather than on the actual costs the QF incurs producing the power being sold.[55]

38. Another important aspect of the variable energy rate/fixed capacity rate construct is that this is the standard rate structure used throughout the electric industry for power sales agreements that include the sale of capacity.[56] That states will be allowed to require QF contracts to be structured similarly to the contract structure used in the rest of the electric industry has important implications. In particular, this provides flexibility to states to ensure that the avoided cost rate will be closer to the actual rate the purchasing electric utility and its customers would have paid if the purchasing electric utility had generated this electric energy itself or purchased such electric energy from another source. Furthermore, the record evidence demonstrating significant amounts of non-QF generation facilities in operation today shows that the owners of such facilities are able to obtain financing based on this same variable energy rate/fixed capacity rate

[46] *See* NIPPC, CREA, REC, and OSEIA Comments at 81 (''[A]ny requirement to demonstrate financing to create a LEO violates the fundamental rule that the utility's actions should not be allowed to deny the QF a LEO because the utility could prevent creation of a LEO simply by refusing to sign the PPA needed to secure such financing.''); Public Interest Organizations Comments at 98 (''[T]he Commission's proposal to require QFs to demonstrate commercial viability in order to obtain a LEO will prevent many QFs from ever attaining commercial viability at all. Creating a new administrative obstacle to QF financing in this way flies in the face of PURPA's mandate to reduce barriers to QF development.''); Solar Energy Industries Comments at 41 (''Establishing higher barriers to a determination of 'commercial viability' will only lead QF developers to invest additional development capital and will simply weed out those smaller companies that choose not to, or are unable to, invest heavily in early-stage development activity before an avoided cost rate is known. It is unjust and unreasonable to cause QFs to invest tens of millions of dollars in site control, permit acquisition, interconnection, and other development costs simply to secure the opportunity to negotiate with the purchasing utility for a contractual commitment.''); Southeast Public Interest Organizations Comments at 41 (describing proposal as ''discourag[ing] QF development since achieving some of the indicia suggested by the Commission often circularly requires that QF developers have *already* obtained financing'').

[47] *See, e.g., FLS Energy, Inc.,* 157 FERC ¶ 61,211, at P 26 (2016) (*FLS*) (stating that requiring signed interconnection agreement as prerequisite to LEO is inconsistent with PURPA Regulations).

[48] *See, e.g., 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 LEO is inconsistent with PURPA Regulations).

[49] *See, e.g., Grouse Creek Wind Park, LLC,* 142 FERC ¶ 61,187, at P 40 (2013).

[50] *Exelon Wind 1, L.L.C.* v. *Nelson,* 766 F.3d 380, 400 (5th Cir. 2014).

[51] *Power Resource Group, Inc.* v. *Public Utility Comm'n of Texas,* 422 F.3d 231, (5th Cir. 2005).

[52] *See, e.g.,* Public Interest Organizations Comments at 35–38 (allowing variable rates will further discourage wind and solar QF development); Allco Comments at 9–11 (without the ability to obtain a fixed long-term forecasted rate, QF solar energy development will not exist).

[53] *See* NOPR, 168 FERC ¶ 61,184 at P 66.

[54] *See* Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,865.

[55] *See API,* 461 U.S. at 414, 415 (stating that ''Congress did not intend to impose traditional ratemaking concepts on sales by qualifying facilities to utilities'' and that QFs ''would retain an incentive to produce energy under the full-avoided-cost rule so long as their marginal costs did not exceed the full avoided cost of the purchasing utility'').

[56] *Cf. Town of Norwood* v. *FERC,* 962 F.2d 20, 21, 24 (D.C. Cir. 1992) (''The rate design before us, like most wholesale electric rates, consists of separate monthly demand and energy charges. The demand component is calculated to recover NEPCO's fixed (or capacity-related) costs, such as construction and debt service, which it incurs regardless of how much electricity it produces. The energy charge is designed to recover the company's variable costs, which it incurs only in the course of actually producing electricity; fuel is a prime example. . . . With the cost outlook constantly in flux due to changing economic conditions, some degree of volatility is necessary if prices are to signal the market accurately—as accurately, that is, as current prices can anticipate future costs. Price volatility alone, therefore, cannot provide a ground for overturning a marginal cost rate structure.'').

construct.[57] This represents important evidence that QFs likewise should be able to obtain financing under the same rate construct, especially considering that QFs benefit from the statutory right to sell pursuant to a mandatory purchase obligation while non-QFs do not have that right.[58]

D. The Rate Changes Implemented by This Final Rule Put QF Rates on the Same Footing as Electric Utility Rates and Are Not Discriminatory

39. The fact that variable energy rate/ fixed capacity rate contracts are standard in the electric industry also explains why, contrary to assertions made by a number of commenters, allowing states to require such contracts for QFs is not discriminatory.[59] QFs selling at wholesale pursuant to such contracts will be selling under the same rate structure employed in the power sales contracts typically used elsewhere in the electric industry, including by public utilities when they make sales at wholesale to each other, and QFs will be doing so at full avoided cost rates—the highest rates permitted under PURPA.

40. It is true that electric utilities with franchised service territories that make sales at retail are often effectively guaranteed the recovery of their energy costs in their retail rates by their state regulatory authorities—provided that such costs are prudently incurred. But the electric utilities' retail rates are cost-based, such that their rates are set based on costs they actually incur to produce electricity for their customers. Importantly, moreover, the incremental energy costs that an electric utility will recover from its retail customers at an incremental level would be the same energy costs that are used in determining the electric utilities' avoided costs that will, in turn, set the as-available avoided cost rates to be charged by QFs.

41. Thus, QF variable energy rate/ fixed capacity rate contracts not only would be structured similarly to the standard wholesale power sales agreements used in the electric industry, but application of traditional cost-based ratemaking principles to sales by QFs is exactly what would be required in order to provide QFs with the same guaranteed cost recovery that applies to electric utilities. Guaranteeing QFs cost recovery is fundamentally inconsistent with PURPA, which sets the rate the QF is paid at the purchasing electric utility's avoided cost, not at the QF's cost. Such a rate structure is not discriminatory.

E. The PURPA Compliance Issues Raised by Some Commenters Are Outside the Scope of This Rulemaking Proceeding

42. Finally, several commenters assert that certain states located outside of RTO/ISO markets are dominated by large integrated public utilities whose state commissions do not implement PURPA correctly.[60] They argue that, as a consequence, there is little development of independent generation—QFs or otherwise—in those states. They assert that the proposals in the NOPR might be appropriate in states with RTO/ISO markets that are subject to significant competition, but would only make matters worse outside of the RTO/ISO markets.

43. As explained above, several changes implemented by this final rule ensure that the PURPA Regulations will continue to encourage QF development. Other changes, such as allowing variable energy rates in QF contracts, not only ensure the PURPA Regulations are consistent with PURPA but also address some states' primary concern with the current PURPA Regulations, *i.e.,* the Commission's now allowing states the flexibility to set variable energy rates could mitigate the states' reluctance to implement PURPA in a way that better encourages development of QFs. For example, the Idaho Commission has indicated that its current policy of limiting QF contracts to two years is based on its concern about fixed QF rates, and that the ability to require variable energy rates could lead to longer contract terms.[61] We expect that these changes could facilitate QF development in states where little QF capacity has been added to date.

44. Further, commenters' claims about lack of QF development outside of the RTO/ISO markets appear to be overstated. For example, the most recent data from the U.S. Energy Information Administration (EIA) on the total amount of wind and solar QF capacity in each state shows that 9 of the 20 states with the greatest combined wind and solar QF capacity are located outside of the RTO/ISO markets.[62] Of these 9 states, three are located in the Southeast—the region asserted by commenters to be the most hostile to PURPA—including North Carolina, which has the highest total amount of wind and solar QF capacity in the country.[63] Other states in the top 20 include Idaho—with the fourth most wind and solar QF capacity—and Oregon,[64] two states that have been criticized as being hostile to PURPA. EIA data also shows that five of the top 10 states in terms of renewable QF capacity additions from 2008–17 are located outside of the RTO/ISO markets, including North Carolina (with the most renewable QF capacity additions), Idaho, Georgia, and Oregon,[65] each of

[57] EIA, *Form EIA–860 detailed data with previous form data Early Release (EIA–860A/860B)* (June 2, 2020), *https://www.eia.gov/electricity/data/eia860/* shows 77.6 GW of operational QF nameplate capacity and 450.453.5 GW of operational non-QF independent power producer nameplate capacity as of end 2019.

[58] Some commenters raise concerns with the Commission's reliance on the financing of non-QF generation facilities to support the conclusion that QFs could obtain financing with variable energy rate contracts, pointing out that the Commission has not identified any QFs that have obtained financing under this structure. The reason for this, however, is that QFs typically do not employ this structure because currently they are entitled to a fixed energy rate/fixed capacity rate construct. Accordingly, evidence regarding the financing of similar types of independently owned generation projects by non-QFs using such a construct constitutes the best and most relevant evidence of how it would affect QF financing.

[59] *See, e.g.,* EPSA Comments at 9 (''The NOPR avoided rate proposal must therefore be rejected because it puts QFs at a disadvantage to utility-owned generation, in violation of the non-discrimination mandate under PURPA.''); Public Interest Organizations Comments at 51 (''[L]imiting QFs to contracts providing no price certainty for energy values, while non-QF generation regularly obtains fixed price contracts and utility-owned generation receives guaranteed cost recovery from captive ratepayers, constitutes discrimination.'').

[60] American Dams Comments at 5–6; Biological Diversity Comments at 13; CA Cogeneration Comments at 6–7; Con Edison Comments at 2; ELCON Comments at 7–8; EPSA Comments at 1–2; IdaHydro Comments at 5; NIPPC, CREA, REC, and OSEIA Comments at 14–15; Solar Energy Industries Comments at 15–20, 24; SC Solar Alliance Comments at 3–4; Two Dot Wind Comments at 14–19.

[61] *See* Idaho Commission Comments at 4 (stating that an energy rate established at the time of contract formation that provides 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'' would allow states to consider longer term contracts without putting ratepayers at risk).

[62] EIA, *Form EIA–860 detailed data with previous form data (EIA–860A/860B) Release date* (June 2, 2020), *https://www.eia.gov/electricity/data/eia860/.* The top 20 states with combined QF solar and wind nameplate capacity in 2018 were: (1) California, Texas, Minnesota, Oklahoma, Massachusetts, New Mexico, Nebraska, New Jersey, Michigan, New York, Illinois (all fully or partially inside RTOs/ ISOs); and (2) North Carolina, Idaho, Utah, South Carolina, Georgia, Oregon, Colorado, Arizona, Wyoming(outside of RTOs/ISOs). We note that some of these states are located in both RTO/ISO and non-RTO/ISO regions.

[63] *Id.* We note that five of the 20 states with the most solar capacity—perhaps a better measure of the Southeast Region's PURPA compliance given the lack of wind resources in this region—are located in the Southeast.

[64] *Id.*

[65] *See* EIA, *PURPA-qualifying capacity increases, but it's still a small portion of added renewables* (Aug. 16, 2018), *https://www.eia.gov/todayinenergy/detail.php?id=36912.*

which commenters have identified as being hostile to PURPA.

45. But whether any individual state has or has not failed to implement the PURPA Regulations properly is not an issue for this final rule, which implements changes to the PURPA Regulations but does not modify Commission's rules for addressing claims that states are not complying with the Commission's existing PURPA Regulations. We promulgate this final rule based on the expectation that the states will fulfill their legal obligation to implement the Commission's PURPA Regulations as revised.[66]

46. Further, although Congress required the Commission to establish the general parameters for establishing QF rates, Congress delegated to the states—not the Commission—the role to set QF rates.[67] To the extent that any entity believes a state is failing to implement the Commission's PURPA Regulations, PURPA section 210(h) provides that entity an avenue to seek relief.[68]

III. Background

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

47. 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 traditional fossil fuels (*i.e.,* oil, natural gas and coal) 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.

48. To accomplish this goal, PURPA section 210(a) directs 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,'' [69] including rules requiring electric utilities to offer to sell electricity to, and purchase electricity from, QFs. PURPA section 210(f) required each state regulatory authority and nonregulated electric utility (together, states) to implement the Commission's rules.

49. In 1980, the Commission issued Order Nos. 69 and 70, which promulgated the required rules that, with limited exceptions, remain in effect today.[70] The Commission explained that, at the time of the passage of PURPA, cogenerators and small power producers faced three major obstacles: (1) Electric utilities were not required to purchase these generators' electric output or to make purchases at an appropriate rate; (2) electric utilities sometimes charged discriminatorily high rates for backup services; and (3) cogenerators and small power producers ran the risk of being considered public utilities themselves and thus being subject to state and federal regulation as utilities.[71] Further, at that time, there was no open access transmission and little competition in electric wholesale markets. Electric utilities were vertically-integrated and held dominant 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.

50. 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.[72] The Commission also directed that electric utilities provide backup electric energy to QFs on a non-discriminatory basis and at just and reasonable rates,[73] and that electric utilities interconnect with QFs.[74] Pursuant to section 210(e) of PURPA,[75] the Commission further provided exemptions from many provisions of the FPA and state laws governing utility rates and financial organization.[76]

B. Circumstances Leading to the Commission's Re-Evaluation of the PURPA Regulations and the Issuance of the NOPR

51. In the NOPR, the Commission described three important changes in the circumstances that had originally prompted Congress to pass PURPA in 1978. First, as the Commission explained, the United States has seen an unprecedented change in the dynamics of the natural gas market and the relevant supply and demand.[77] Led by advancements in production technologies, primarily in accessing shale reserves, natural gas supplies increased dramatically.[78] Further, the EIA forecasted continued supply growth over the next 25 years.[79] In short, as the Commission found in issuing the NOPR, there no longer are shortages of natural gas supply.

52. Second, the Commission found that, since 1978, the outlook for the development of alternatives to natural gas and oil-fired generation resources, such as renewable resources, has changed equally dramatically.[80] The once-nascent renewables industry has grown and matured over the past 40

[66] 16 U.S.C. 824a–3(f)(1). The same obligation to implement the Commission's PURPA Regulations as revised, we note, is imposed on nonregulated electric utilities. 16 U.S.C. 824–3(f)(2).

[67] *See* 16 U.S.C. 824a–3(f)(1) (''[E]ach State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.'').

[68] If the Commission, in response to a petition for enforcement under PURPA section 210(h) against a state regulatory authority, chooses not to initiate an enforcement action within 60 days of the filing of the petition, the statute authorizes the petitioning electric utility or QF to itself initiate a suit directly against the state in U.S. District Court. 16 U.S.C. 824a–3(h)(2)(B). The same statutory provision similarly governs petitions for enforcement against nonregulated electric utilities. *Id.* PURPA section 210(g) also provides for review of state regulatory authorities and nonregulated electric utilities in state fora. 16 U.S.C. 824a–3(g). The Commission's policies with respect to PURPA enforcement are more fully set out in its *Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978,* 23 FERC ¶ 61,304 (1983).

[69] 16 U.S.C. 824a–3(a).

[70] Order No. 69, FERC Stats. & Regs. ¶ 30,128; *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).

[71] Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,863. *See infra* P 78 & note 112 (addressing how the PURPA Regulations as revised continue to address these obstacles).

[72] 18 CFR 292.304(a)(2); *see API,* 461 U.S. at 412–18.

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

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

[75] 16 U.S.C. 824a–3(e).

[76] 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.

[77] NOPR, 168 FERC ¶ 61,184 at P 19.

[78] Domestic natural gas production, which appeared to peak in the early 1970s at 21.7 Tcf per year, increased from 18.1 Tcf in 2005 to 30.4 Tcf in 2018. 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/.*

[79] EIA's forecast showed supplies increasing to nearly 40 Tcf by 2035 and 43 Tcf by 2050. 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.*

[80] NOPR, 168 FERC ¶ 61,184 at P 20.

years and has only accelerated subsequent to the Energy Policy Act of 2005's amendment of PURPA. The Commission noted that the cost of building renewable facilities has decreased substantially to the point that the cost of renewable resources is now or is shortly expected to approach the cost of traditional electric generation.[81] The Commission also recognized that renewable resources (including hydro) provide a significant share of the electricity currently generated in the United States,[82] that most renewable resources today are not QFs,[83] and that 65 percent of capacity additions in 2019 were expected to come from renewable resources.[84]

53. 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.[85] In addition, RTOs and ISOs have developed competitive wholesale electric markets that serve roughly two-thirds of electricity consumers in the United States.[86]

54. In PURPA section 210(a), Congress directed not only that the Commission prescribe regulations, but that the Commission revise those regulations ''from time to time thereafter.'' [87] The Commission determined in the NOPR that, in light of these dramatic changes in circumstances since the passage of PURPA, it was appropriate to review the PURPA Regulations to determine whether changes to those regulations were warranted consistent with our statutory mandate.[88]

55. After identifying these three important changes in the industry that have taken place since 1980, we further identified evidence demonstrating that overestimations of avoided cost have not been balanced by underestimations, and that this trend may persist with the general decline in the cost of electricity.[89]

C. Summary of Changes to the PURPA Regulations Implemented by This Final Rule

56. We now are revising our PURPA Regulations based on the record of this proceeding, including comments submitted in the technical conference in Docket No. AD16–16–000 (Technical Conference),[90] the record evidence cited in the NOPR, and the comments submitted in response to the NOPR. These changes, including modifications to the proposals made in the NOPR, are summarized below.[91]

57. *First,* we grant states the flexibility to require that energy rates (but not capacity rates) in QF power sales contracts and other LEOs [92] vary in accordance with changes in the purchasing electric utility's as-available avoided costs at the time the energy is delivered. Under this change, if a state exercises this flexibility, a QF no longer would have the ability to elect to have its energy rate be fixed, but would continue to be entitled to a fixed capacity rate for the term of the contract or LEO.[93]

58. *Second,* we 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.

59. *Third,* we grant states flexibility to set ''as-available'' QF energy rates as follows: We are establishing a rebuttal presumption, rather than a per se rule as proposed in the NOPR, that the LMP established in the organized electric markets defined in 18 CFR 292.309(e), (f), or (g) represents the as-available avoided costs of electric utilities located in these markets.[94] So long as this

[81] *Id.* (citing EIA, *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants, https://www.eia.gov/analysis/studies/powerplants/capitalcost/;* 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;* Lawrence Berkeley National Lab, *Wind Technologies Market Report, https://emp.lbl.gov/wind-technologies-market-report/*). However, EIA has cautioned 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.

EIA, *Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2019,* at 2 (Feb. 2019), *https://www.eia.gov/outlooks/archive/aeo19/pdf/electricity_generation.pdf.*

[82] NOPR, 168 FERC ¶ 61,184 at P 21 (citing EIA, *August 2019 Monthly Energy Review* at Figure 7.2a, *https://www.eia.gov/totalenergy/data/monthly;* Office of Energy Projects, *Energy Infrastructure Update For July 2019* at 4 (July 2019), *https://www.ferc.gov/legal/staff-reports/2019/july-energy-infrastructure.pdf*).

[83] NOPR, 168 FERC ¶ 61,184 at P 22.

[84] *Id.* (citing 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).

[85] NOPR, 168 FERC ¶ 61,184 at P 25. The Commission cited to data showing that that net generation of energy by non-utility owned renewable resources in the United States escalated from 51.7 TWh in 2005 when EPAct 2005 was passed, to 340 TWh in 2018. This also 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 increased from 3.6 TWh in 2005 to 19.5 TWh in 2012, and to 42.5 TWh in 2018. 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. 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. NOPR, 168 FERC ¶ 61,184 at P 27 (citing data taken from EIA's Electricity Data Browser, *www.eia.gov/electricity/data/browser* (select net generation, other renewables, independent power producers)).

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

[87] 16 U.S.C. 824a–3(a).

[88] 16 U.S.C. 824a–3(b).

[89] *See* NOPR, 168 FERC ¶ 61,184 at P 30. Evidence submitted in response to the NOPR shows that, as a result, customers may be paying more than avoided costs. *See infra* PP 265 (''Duke Energy claims that, among the factors contributing to this overpayment of $2.26 billion for the remainder of these QF contracts, the primary factor has been the requirement to offer fixed avoided cost energy rates during a period of rapidly declining energy prices''), 268 (''Massachusetts DPU argues that a 10-year, fixed energy rate based on current New England wholesale energy market prices is highly likely to diverge from actual energy market prices over the ten-year contract term and could significantly harm ratepayers'').

[90] 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 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.

[91] In its post-NOPR comments, Bloom Energy requested that the Commission ''[u]pdate the definition of 'useful thermal energy output' of a topping-cycle cogeneration facility to reflect the commercialization of solid oxide fuel cells that produce heat for the industrial purpose of producing hydrogen, a fuel that the fuel cells use to generate electricity.'' Bloom Energy Comments at 2. We do not take action on this request in this proceeding because we do not view this proposal as a logical outgrowth of the NOPR.

[92] 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.

[93] 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.

[94] These are the markets operated by Midcontinent Independent System Operator, Inc.

presumption is not rebutted, a state can at its option establish as-available energy avoided cost rates for QFs selling to such electric utilities at the LMP. With respect to QFs selling to electric utilities located outside of the organized electric markets defined in 18 CFR 292.309(e), (f), or (g), states have the option to set as-available energy avoided cost rates at competitive prices from liquid market hubs or calculated from a formula based on natural gas price indices and specified heat rates, provided that the states first determine that such prices represent the purchasing electric utilities' avoided costs. The states would have the flexibility to choose to adopt one or more of these options or to continue setting QF rates under the standards long established in the PURPA Regulations.

60. *Fourth,* 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 consistent with the Commission's *Allegheny* standard, described in this final rule.

61. *Fifth,* we do not adopt the proposed rule permitting states with retail competition to allow relief from the purchase obligation. We instead clarify in this final rule that the Commission's existing PURPA Regulations already require that states, to the extent practicable, must account for reduced loads in setting QF capacity rates.

62. *Sixth,* we modify the Commission's ''one-mile rule'' for determining whether generation facilities are considered to be at the same site for purposes of determining qualification as a qualifying small power production facility. Specifically, we allow electric utilities, state regulatory authorities, and other interested parties to show that affiliated small power production facilities that use the same energy resource and are more than one mile apart and less than 10 miles apart actually are at the same site (with distances one mile or less apart still irrebuttably at the same site, and distances 10 miles or more apart irrebuttably at separate sites). We also allow a small power production facility seeking QF status to provide further information in its certification (whether a self-certification or an application for Commission certification) or recertification (whether a self-recertification or an application for Commission recertification) to defend preemptively against subsequent challenges, by identifying factors affirmatively demonstrating that its facility is indeed at a separate site from other affiliated small power production qualifying facilities. We further add a definition of the term ''electrical generating equipment'' to the PURPA Regulations to clarify how the distance between facilities is to be calculated.

63. *Seventh,* we allow an entity to challenge an initial self-certification or self-recertification without being required to file a separate petition for declaratory order and to pay the associated filing fee. However, we clarify in this final rule that such protests may be made to new certifications (both self-certifications and applications for Commission certification) but to only self-recertifications and applications for Commission recertifications making substantive changes to the existing certification.

64. *Eighth,* we revise the Commission's 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. We update the rebuttable presumption for small power production facilities (but not cogeneration facilities) from 20 MW to 5 MW and, in this final rule, revise the regulations to include examples of factors, among others, that QFs may argue show that they lack nondiscriminatory access to such markets.

65. *Finally,* we clarify that a QF must demonstrate commercial viability and a financial commitment to construct its facility pursuant to objective and reasonable state-determined criteria before the QF is entitled to a contract or LEO. States may not impose any requirements for a LEO other than a showing of commercial viability and a financial commitment to construct the facility. We also clarify in this final rule that, to the extent that the permitting factor is relied upon, a QF need only show that it has applied for all required permits and paid all applicable fees, and not that it has obtained such permits.

66. As explained in detail in the relevant sections below, these changes will enable the Commission to continue to fulfill its statutory obligations under sections 201 and 210 of PURPA. We emphasize that these changes are effective prospectively for new contracts or LEOs and for new facility certifications and recertifications filed on or after the effective date of this final rule; we do not by this final rule permit disturbance of existing contracts or LEOs or existing facility certifications.

IV. Discussion

A. General Legal Standards Under PURPA

67. Several comments were submitted regarding: (1) The requirement in PURPA section 210(a) that ''the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production''; and (2) the requirement in PURPA section 210(b) that rates paid by purchasing utilities to QFs ''shall not discriminate against qualifying cogenerators or qualifying small power producers.'' [95] In addition, a claim was made that the Commission has unlawfully delegated its authority to the states. These comments apply to several of the revisions implemented by this final rule and therefore are discussed prior to the discussion of specific revisions implemented herein.

1. Encouragement of QFs

a. Comments

68. Commenters make two general arguments regarding the statutory requirement that the Commission's PURPA Regulations should encourage QFs. First, they note that the statutory requirement that the PURPA Regulations encourage QFs is mandatory and that the Commission has no discretion to determine that such encouragement no longer is necessary. Harvard Electricity Law states that ''Congress'[s] mandate to encourage QFs is not contingent on industry conditions and does not expire.'' [96] Further, they assert, ''[t]he Commission may not overwrite Congress's instruction to issue rules that it 'determines necessary to encourage cogeneration and small power production.' '' [97] Public Interest Organizations similarly object to the NOPR as violating the encouragement requirement because, they assert, the NOPR ''reflect[s] a belief that the current rules support too much QF development and a desire to reduce the incentives in current rules for QF development.'' [98] NIPPC, CREA, REC, and OSEIA assert that ''[t]he Commission cannot take it

(MISO); PJM Interconnection, L.L.C. (PJM); ISO New England Inc. (ISO–NE); New York Independent System Operator, Inc. (NYISO); Electric Reliability Council of Texas (ERCOT); California Independent System Operator, Inc. (CAISO); and Southwest Power Pool, Inc. (SPP).

[95] 16 U.S.C. 824a–3(a), (b).

[96] Harvard Electricity Law Comments at 1.

[97] *Id.* at 4 (quoting PURPA section 210(a)).

[98] Public Interest Organizations Comments at 10.

upon itself to change the underlying policy directives to encourage QFs.'' [99]

69. Public Interest Organizations advance a second general argument based on the encouragement requirement, arguing that ''[t]o amend the rules, the Commission must first determine that the actual changes it proposes increase development and utilization of QFs.'' [100] Similarly, Allco attacks the NOPR on the grounds that ''the proposed changes do not encourage QF generation.'' [101]

b. Commission Determination

70. We agree with commenters that PURPA does not provide discretion to the Commission to determine whether QFs should be encouraged. That is a determination left to Congress, and we have not premised this final rule on a belief that QFs should not be encouraged. However, the requirement that the Commission promulgate regulations necessary to encourage QFs is not unbounded. Instead, as noted briefly earlier, there are statutory limitations on the extent that the PURPA Regulations can encourage QFs.

71. First, PURPA section 210(b) sets out standards with which the Commission must comply in setting QF rates. The last sentence of PURPA section 210(b) sets out an upper limit on such rates. ''No such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.'' [102]

72. If there were any doubt from the statutory language that incremental costs (avoided costs) are intended to be a hard cap on QF rates, such doubt is dispelled by the Conference Report to PURPA, which provided: ''This limitation on the rates which may be required in purchasing from a cogenerator or small power producer *is meant to act as an upper limit on the price* at which utilities can be required under this section to purchase electric energy.'' [103] The Conference Report also described the reason for the avoided cost cap on QF rates. ''The provisions of this section *are not intended to require the rate payers of a utility to subsidize* cogenerators or small power produc[er]s.'' [104]

73. Therefore, PURPA section 210(b) imposes an important limit on the Commission's ability to encourage QFs by imposing an upper boundary on the rates at which QFs may require electric utilities to purchase their electric energy. The Commission cannot require QF rates that exceed the avoided costs of the purchasing electric utility.[105]

74. Second, another way in which Congress limited the Commission's ability to encourage QFs was to define small power production facilities, the PURPA category applicable to almost all renewable resources that wish to be QFs, as having ''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.'' [106] The statutory 80 MW limitation, as well as any definition of ''the same site'' that may be established by the Commission, will of necessity have an effect on the encouragement of QFs, because it will limit the capacity of QFs both *ab initio* and also for those located at the same site to 80 MW.

75. Third, Congress amended PURPA section 210 to add section 210(m), which 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 has nondiscriminatory access to certain defined types of markets.[107] We interpret this amendment as reflecting Congress's judgment that these markets provide adequate encouragement for those QFs having nondiscriminatory access to such markets. To the extent that a party asserts that the termination of the purchase obligation for QFs with nondiscriminatory access to these markets discourages QFs, that party's argument is not with the Commission, but rather with Congress. PURPA section 210(m) obligates the Commission to grant any request to terminate a utility's obligation to purchase from a QF with nondiscriminatory access to the specified markets.[108]

76. Finally, we disagree with any suggestion that a rule originally adopted in 1980 cannot be changed once adopted, or that our revised regulations cannot be different in how they encourage QFs than the regulations the Commission issued in 1980.[109] For one thing, as explained above, PURPA itself includes certain limitations on the Commission's ability to encourage QFs, and a provision in the final rule intended to comply with these statutory limitations cannot be found to violate PURPA even if such a provision individually does not affirmatively encourage QFs to the same degree now as in 1980. As explained herein, we do not seek, through this final rule, to cease encouraging the development of QFs. Instead, this final rule is intended to ensure that the Commission is compliant with the statute in how it does encourage the development of QFs. In doing so, the Commission may end up encouraging QF development differently from the current PURPA Regulations, but the Commission's regulations continue to encourage QF development, as contemplated by PURPA.

77. Many of the commenters' assertions seem to be based on a reading of the statute that requires that every individual change made to the PURPA Regulations in isolation must individually encourage QFs notwithstanding the statute's provisions. But, as discussed above, Congress established boundaries in PURPA that must be considered, such as the ''cap'' on incremental costs; just and reasonable rates for electric customers; the 80 MW limit; and whether QFs have nondiscriminatory access to markets. Furthermore, the statutory requirement to encourage QF development applies to the PURPA Regulations—''such *rules* as [the Commission] determines necessary''—as a whole.[110]

78. In that regard, we find that the Commission's PURPA Regulations as a whole when modified by this final rule continue to encourage the development of QFs, consistent with PURPA. The PURPA Regulations in particular, continue to require that QF rates be set at full avoided costs, a provision the Supreme Court described as ''provid[ing] the maximum incentive for the development of cogeneration and small power production.'' [111] In addition, this final rule retains provisions of the PURPA Regulations adopted in 1980 that provide encouragement through other means

[99] NIPPC, CREA, REC, and OSEIA Comments at 29.

[100] Public Interest Organizations Comments at 11.

[101] Allco Comments at 8.

[102] Furthermore, PURPA section 210(b)(1) requires that QF rates be ''just and reasonable to the electric consumers of the electric utility and in the public interest.'' 16 U.S.C. 824a–3(b)(1). Although the exact scope of the ''just and reasonable to the electric consumers'' criterion has never been addressed explicitly, the Supreme Court held in *API* that the requirement in the PURPA Regulations that QF rates be set at full avoided costs does not violate this criterion. *API,* 461 U.S. at 415–16. This ''just and reasonable to the electric consumers'' criterion likely would be violated if the Commission were to allow a rate above the purchasing electric utility's avoided costs.

[103] Conf. Rep. at 98 (emphasis added).

[104] *Id.* (emphasis added).

[105] 16 U.S.C. 824a–3(b)(1).

[106] 16 U.S.C. 796(17)(A)(ii).

[107] *See* 16 U.S.C. 824a–3(m).

[108] *Id.* (''[N]o electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a [QF] if the Commission finds that the [QF] has nondiscriminatory access to [specified markets].'').

[109] *See* 18 U.S.C. 824a–3(a).

[110] *See* 16 U.S.C. 824a–3(a) (emphasis added).

[111] *API,* 461 U.S. at 418.

recognized by the Supreme Court in *FERC* v. *Miss.*[112] (*e.g.,* certain regulatory relief,[113] interconnection provisions,[114] and requirements that utilities sell power to QFs that will enable QFs to continue operations).[115] Moreover, several of the changes implemented by this final rule also provide additional encouragement for QFs as described in more detail below.

2. Discrimination

a. Comments

79. Commenters opposing the proposals in the NOPR also cite to the statutory requirement in PURPA section 210(b)(1) that QF rates ''shall not discriminate against'' QFs. EPSA asserts that ''[n]otably, this standard is more restrictive than the [FPA's] prohibition against 'unduly discriminatory' rates.'' [116] Public Interest Organizations state that ''[i]n other statutes, prohibiting price discrimination without the modifiers 'unreasonable' or 'undue,' means any difference in price for the same commodity.'' [117]

80. In discussing the requirement that QF rates not be discriminatory, some commenters compare the treatment afforded to QFs under the NOPR with the rate treatment applicable to public utilities. For example, NIPPC, CREA, REC, and OSEIA point out that ''[u]tilities can rate-base long-term investments, thereby ensuring that they can recover their capital investments plus an authorized return, and then also recover their actual operating costs under traditional cost-of-service ratemaking.'' [118] By contrast, Harvard Electricity Law asserts, ''QFs do not have the same ability that the electric utilities have to 'rate base' their facilities and, thereby, guarantee capital recovery.'' [119]

81. Based on this difference between utilities and QFs, commenters allege that certain aspects of the NOPR are discriminatory, including those provisions of the NOPR regarding the use of LMPs and other competitive rates to set as-available energy rates,[120] to allow for variable energy rates in QF contracts,[121] and to allow avoided costs to be set through competitive solicitations (*i.e.,* requests for proposals (RFPs)).[122]

b. Commission Determination

82. As an initial matter, we agree with EPSA that the statutory requirement in PURPA section 210(b)(1) that QF rates ''shall not discriminate against'' QFs is more restrictive than the FPA's prohibition against 'unduly discriminatory' rates.[123] However, the avoided cost cap on QF rates that limits the Commission's ability to encourage QFs, discussed above, also applies to the Commission's ability to address these claims of discrimination under PURPA. PURPA section 210(b) makes clear that ''[n]o such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.'' [124]

83. We are retaining in this final rule the requirement that QF rates be set at a purchasing utility's full avoided costs. The Supreme Court held in *API* that ''the full-avoided-cost rule plainly satisfies the nondiscrimination requirement.'' [125] Although the Court did not provide a detailed explanation for this holding, the reasoning is apparent. If the purchasing utility is paying the same rate to a QF for power that it otherwise would have paid for incremental power, by definition such a rate could not be discriminatory. But even if it were possible to posit a situation where the payment of a full avoided cost rate to a QF somehow were discriminatory, the Commission nevertheless would be prohibited by PURPA section 210(b) from requiring a rate to be paid to the QF that is *above* the full avoided costs of the purchasing electric utility.

84. For the same reasons, Public Interest Organizations are mistaken when they assert that, without the modifiers ''unreasonable'' or ''undue,'' any difference in price for the same commodity violates PURPA.[126] So long as a QF's rate is set at the purchasing utility's full avoided cost, the QF's rate should be the same as the rate the purchasing utility otherwise would be paying or the cost it would be incurring, and such a rate would not be discriminatory. And, in any event, as noted above, the Commission cannot require a rate that is any higher.

85. With respect to comparisons between QFs, with no guarantee of cost recovery, and electric utilities, which if they have a franchised service territory and sell at retail in that territory are effectively guaranteed the opportunity to seek to recover prudently-incurred costs in their retail rates, we observe that Congress acknowledged this difference when enacting PURPA. As emphasized in the PURPA Conference Report:

> The conferees recognize that cogenerators and small power producers are different from electric utilities, *not being guaranteed a rate of return on their activities* generally or on the activities vis a vis the sale of power to the utility and whose risk in proceeding forward in the cogeneration or small power production enterprise *is not guaranteed to be recoverable.*[127]

86. In recognizing this difference and yet not seeking to eliminate it, Congress also made clear its intent not to treat QFs like electric utilities in this regard:

> It is not the intention of the conferees that [QFs] become subject . . . to the type of examination that is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.[128]

87. Based on this legislative history, the Supreme Court concluded in *API* that, ''Congress did not intend to impose traditional ratemaking concepts on sales by qualifying facilities to utilities.'' [129] But application of traditional cost-based ratemaking principles to sales by QFs is

[112] 456 U.S. 742, 750–51 (1982) (holding that Congress ''felt that two problems impeded the development of nontraditional generating facilities: (1) Traditional electricity utilities were reluctant to purchase power from, and to sell power to, the nontraditional facilities, and (2) the regulation of these alternative energy sources by state and federal utility authorities imposed financial burdens upon the nontraditional facilities and thus discouraged their development'' (internal citations omitted)).

[113] 18 CFR 292.601–02.

[114] 18 CFR 292.303(c).

[115] 18 CFR 292.305.

[116] EPSA Comments at 8.

[117] Public Interest Organizations Comments at 47 (citing *FTC* v. *Anheuser-Busch, Inc.,* 363 U.S. 536, 549 (1960)).

[118] NIPPC, CREA, REC, and OSEIA Comments at 36; *see also* IdaHydro Comments at 11; Industrial Energy Consumers Comments at 12–13; SC Solar Alliance Comments at 5–10; Solar Energy Industries Comments at 33, 36–38.

[119] Harvard Electricity Law Comments at 28.

[120] *See, e.g.,* Public Interest Organizations Comments at 64 (stating that the use of competitive prices to set as-available energy avoided cost rates is discriminatory because non-QF generators are not limited to competitive prices and utilities can, and regularly do, pay effective prices for energy that exceed the price determined by competitive prices).

[121] *See, e.g.,* EPSA Comments at 9 (''The NOPR avoided rate proposal must therefore be rejected because it puts QFs at a disadvantage to utility-owned generation, in violation of the non-discrimination mandate under PURPA.''); Public Interest Organizations Comments at 51 (''[L]imiting QFs to contracts providing no price certainty for energy values, while non-QF generation regularly obtains fixed price contracts and utility-owned generation receives guaranteed cost recovery from captive ratepayers, constitutes discrimination.'').

[122] *See, e.g.,* Allco Comments at 12 (stating that allowing a state commission to use a competitive solicitation price is simply giving another tool to a state commission to kill QF projects).

[123] EPSA Comments at 8.

[124] Furthermore, as noted above, PURPA section 210(b)(1) requires that QF rates also be ''just and reasonable to the electric consumers of the electric utility and in the public interest.'' *See supra* note 102.

[125] *API,* 461 U.S. at 413.

[126] Public Interest Organizations Comments at 47 (citing *FTC* v. *Anheuser-Busch, Inc.,* 363 U.S. at 549).

[127] Conf. Rep. at 97–98 (emphasis added).

[128] *Id.* at 97.

[129] *API,* 461 U.S. at 414.

exactly what would be required in order to provide QFs with the same guaranteed cost recovery that applies to electric utilities. Also, guaranteeing QFs cost recovery is fundamentally inconsistent with PURPA, which sets the rate the QF is paid at the utility's avoided cost, not at the QF's cost.

88. It therefore is clear that Congress did not intend for the PURPA nondiscrimination criterion to require that QF rates be set in a way that guarantees recovery of a QF's own costs, even as Congress recognized that franchised electric utilities selling at retail typically do have such guarantees for their own costs. Congress thus withheld from the Commission the authority to provide to QFs the same opportunity to recover costs at retail that franchised electric utilities have to recover their costs at retail; it was done by Congress intentionally and cannot be impermissibly discriminatory.[130]

3. Unlawful Delegation and the Role of Nonregulated Electric Utilities

a. Comments

89. Allco argues that PURPA section 210(f) requires states to ''implement'' the Commission's rules, and that those rules cannot redelegate the Commission's authority. Allco claims that the statutory requirement to implement the Commission's rules cannot simply be a façade for delegating broad authority to states to undercut PURPA's directive that QF small power production must be encouraged. Allco concludes that Congress intended for the Commission to adopt actual rules rather than ''a menu of factors'' that essentially leaves states with all the discretion as to what to implement in order to encourage QF generation.[131]

90. Allco also asserts that the NOPR's proposed delegation of authority to nonregulated electric utilities is an unconstitutional delegation. According to Allco, such a delegation would mean that nonregulated electric utilities (some of which are among the largest utilities in the United States) were regulating themselves. Allco argues that a private entity such as a nonregulated electric utility cannot constitutionally be delegated regulatory power.[132]

91. Nebraska Board states that there is no state agency in Nebraska that has ratemaking authority over retail electric suppliers and that all retail electric suppliers are consumer-owned. Nebraska Board states its understanding that each retail electric supplier in Nebraska would have jurisdiction to exercise flexibilities provided to states in the NOPR.

92. Public Interest Organizations argue that the Commission failed to comply with PURPA section 210's requirement to consult with federal and state regulatory agencies with ratemaking authority.[133]

b. Commission Determination

93. Allco's unlawful delegation claims are misplaced. By enacting PURPA section 210(f)(1), Congress delegated to the states the obligation to implement the Commission's PURPA rules, and the Commission is acting consistent with that delegation. Congress's delegation to the states was upheld in *FERC* v. *Miss.*[134] and we are ensuring that the rules we have imposed abide by all the terms of the statute. Further, the Commission's current PURPA Regulations, promulgated in 1980, set forth a list of factors that the states are to consider, ''to the extent practicable,'' in setting QF rates.[135] In so doing, the Commission 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 18 CFR 292.304].'' [136] This final rule adds factors that must be taken into account to the extent practicable in setting rates, while retaining the ''great latitude'' the states always have had to implement the PURPA Regulations and which have been an important feature of the Commission's PURPA Regulations since their inception.

94. With respect to Allco's claim that the NOPR proposed an unconstitutional delegation to nonregulated electric utilities, we note that PURPA section 210(f)(2) specifically provides that ''each nonregulated electric utility shall, after notice and opportunity for public hearing, implement'' the Commission's rules regarding the rates to be paid to QFs. Consistent with this statutory provision, the PURPA Regulations regarding the setting of QF rates have applied to nonregulated electric utilities since those regulations were promulgated in 1980.[137] The final rule does nothing more than continue to implement this statutory requirement in the same way it always has been implemented. Given PURPA's unique statutory scheme involving state regulatory authorities, nonregulated electric utilities, QFs, and the Commission, we therefore reject Allco's assertion that the rules proposed in the NOPR—and adopted in this final rule—establish an unconstitutional delegation of authority to a private entity.[138] And it is beyond the Commission's purview to consider whether this statutory grant is constitutional.[139] Accordingly, when we refer to states in this final rule, we usually are referring to both state regulatory authorities and nonregulated electric utilities.

95. Regarding Public Interest Organizations assertion that the Commission failed to comply with PURPA section 210's requirement to consult with federal and state regulatory agencies with ratemaking authority, we find that the 2016 Technical Conference's invitation to the public (including state regulatory authorities) to speak, as well as the notice and comment process on the NOPR itself, encompasses the required consultation.[140] The notices soliciting

[130] *See* 16 U.S.C. 824a–3(a) (rules Commission is directed to prescribe ''may not authorize a [QF] to make any sale for purposes other than resale'').

[131] Allco Comments at 39–40.

[132] *Id.* at 40 (citing *Ass'n of Am. R.R.* v. *DOT,* 721 F.3d 666, 677 (D.C. Cir. 2013), *vacated on other grounds,* 135 S. Ct. 1225 (2015)).

[133] Public Interest Organizations Comments at 19 (citing 16 U.S.C. 824a–3(a)).

[134] 456 U.S. at 760 (''FERC has declared that state commissions may implement this by, among other things, 'an undertaking to resolve disputes between qualifying facilities and electric utilities arising under [PURPA].' '').

[135] 18 CFR 292.304(e).

[136] 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.

[137] *See* Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,864 (''The implementation of these rules is reserved to the State regulatory authorities and nonregulated electric utilities.'').

[138] *See* Allco Comments at 40.

[139] *Finnerty* v. *Cowen,* 508 F.2d 979, 982 (2d Cir. 1974) (explaining that administrative agencies ''have neither the power nor the competence to pass on the constitutionality of administrative or legislative action'') (quoting *Murray* v. *Vaughn,* 300 F. Supp. 688, 695 (D. R.I. 1969)); *see also Gibas* v. *Saginaw Mining Co.,* 748 F.2d 1112, 1117 (6th Cir. 1984) (''[A]dministrative bodies like the Board do not have the authority to adjudicate the validity of legislation which they are charged with administering.''); *Spiegel, Inc.* v. *FTC,* 540 F.2d 287, 294 (7th Cir. 1976) (finding that the federal agency erred by making a constitutional determination); *Downen* v. *Warner,* 481 F.2d 642, 643 (9th Cir. 1973) (''Resolving a claim founded solely upon a constitutional right is singularly suited to a judicial forum and clearly inappropriate to an administrative board.''); *cf. Woodrow* v. *FERC,* 2020 WL 2198050, at *9 (D.D.C. May 6, 2020) (''When Congress creates an intricate statutory-review process that incorporates agency consideration and ultimately an avenue to petition an Article III court, we assume it wants that scheme to control.'').

[140] *See* Notice Inviting Post-Technical Conference Comments, *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* Docket No. AD16–16–000 (Sept. 6, 2016); Supplemental Notice of Technical Conference, *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* Docket No. AD16–16–000 (Mar. 4, 2016)

comments were open to all state authorities. Indeed, since the Commission first announced that technical conference and up to our receipt of comments on the NOPR, representatives from several states have filed comments expressing their views on how the Commission should implement PURPA.

B. QF Rates

1. Overview

96. PURPA requires that the Commission promulgate rules, to be implemented by the states,[141] that ''shall insure'' that the rates electric utilities pay for purchases of electric energy from QFs meet the statutory criteria described above, including that ''[n]o such rule . . . shall provide for a rate which exceeds'' the purchasing utility's ''incremental cost . . . of alternative electric energy.'' [142] 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; [143] and, as noted above, (3) not exceed ''the incremental cost to the electric utility of alternative electric energy,'' [144] 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.'' [145] 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,'' [146] although the term ''avoided cost'' itself does not appear in PURPA.

97. In addition, the PURPA Regulations currently provide a QF two options for how to sell its power to an electric utility. The QF may choose to 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 (frequently referred to as a so-called ''as-available'' sale and rate).[147] Alternatively, the QF may choose to sell pursuant to a legally enforceable obligation or LEO (such as a contract) over a specified term.[148]

98. 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 at the time of delivery; [149] or (2) the purchasing electric utility's avoided cost calculated and fixed at the time the LEO is incurred.[150]

99. 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.'' [151] 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.'' [152]

100. In the NOPR, the Commission proposed to revise its PURPA Regulations to permit states to incorporate competitive market forces in setting QF rates. Specifically, the Commission proposed to revise its PURPA Regulations with regard to QF rates to provide states with 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 LMP, or similar energy price derived by the market, in effect at the time the energy is delivered.
- 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.
- 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.
- 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.
- require that energy and/or capacity rates be determined through a competitive solicitation process, such as an RFP, with processes designed to ensure that the competitive solicitation is performed in a transparent, non-discriminatory fashion.[153]

101. Although the Commission proposed to modify how the states are permitted to calculate avoided costs, it did not propose to terminate the requirement that the states continue to calculate, and to set QF rates at, such avoided costs.

102. We adopt these proposals in this final rule, with certain modifications. Each such proposal, and our final determination, is discussed further below.

2. Use of Competitive Market Prices To Set As-Available Avoided Cost Rates

103. In addition to commenting on the specific methods for determining as-available avoided cost rates, several

(announcing preliminary agenda and inviting interested speakers).

[141] 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).

[142] 16 U.S.C. 824a–3(b).

[143] 16 U.S.C. 824a–3(b)(1)–(2).

[144] 16 U.S.C. 824a–3(b).

[145] 16 U.S.C. 824a–3(d) (emphasis added).

[146] *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.'').

[147] 18 CFR 292.304(d)(1).

[148] 18 CFR 292.304(d)(2)(i)–(ii); *see also FLS,* 157 FERC ¶ 61,211 at P 21 (citing 18 CFR 292.304(d)). The LEO or contract is frequently referred to as a long-term transaction, when contrasted with an ''as available'' sale and rate.

[149] 18 CFR 292.304(d)(2)(i).

[150] 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).

[151] 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 (2011) (''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.'').

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

[153] NOPR, 168 FERC ¶ 61,184 at PP 32–33.

commenters addressed more generally the Commission's proposal in the NOPR that states be given the flexibility to use competitive market prices to set such rates. Before discussing the specific methods proposed in the NOPR, we first discuss the determination that the use of competitive market prices, however determined, can be an appropriate approach to determining as-available avoided cost rates.

a. NOPR Proposal

104. In the NOPR, the Commission proposed to give the states the flexibility to use competitive market prices to set as-available avoided cost rates. The Commission stated its belief that 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.[154]

105. For those utilities located in RTO/ISO markets, the NOPR identified LMP as a competitive market price that states could choose to adopt as representing an as-available avoided energy cost. The Commission explained that 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.[155] In addition to these benefits, the Commission observed that 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.[156]

106. For utilities located outside of RTO/ISO markets, the NOPR proposed to allow states to use two other potential competitively priced measures of a utility's as-available avoided cost rates: (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 such case, though, the state would need to find that that price reasonably represents a competitive market price that represents the avoided costs of the purchasing electric utility.[157]

b. Comments

107. Allco argues that the only reason for including the use of competitive market prices to set as-available energy rates is to create a menu of prices from which a state regulatory authority or unregulated electric utility can choose the lowest price. Allco claims this proposal would not encourage QF generation, would be inconsistent with the rules of economic dispatch, and would be inconsistent with the language of PURPA.[158] BluEarth makes similar arguments.[159] In contrast, El Paso Electric argues that state regulatory authorities should be able to set avoided cost rates based on the lesser of a market hub price or a combined cycle price.[160] Similarly, the California Commission argues that utilities located in organized markets (not just non-organized markets) should also be expressly permitted to use any competitive price (whether derived from a market hub, competitive solicitation, or a combined cycle price) to set avoided cost rates. The California Commission also argues that states should have the ability to use competitive prices for not just as-available energy pricing, but also for capacity pricing, and proposes minor modifications to the relevant regulation text proposed in the NOPR in order to clarify these points.[161]

108. The California Commission argues that the proposed regulations should be modified to: (1) Define the newly permissible avoided cost methodologies within the definitions section of Part 292; (2) eliminate any perception that the new methodologies can only be used to set avoided costs for as-available energy; (3) allow any appropriate market-based methodology to set avoided-cost rates for energy, capacity or both; and (4) define ''Organized Electric Market.'' [162] The California Commission believes that the new regulations should indicate: (1) That they do not provide states any more flexibility than they already have; (2) that utilities located in organized markets may use any Market Hub Price, Competitive Solicitation Price, or Combined Cycle Price to establish avoided-cost rates; and (3) that a price based on LMP or a Competitive Price is just and reasonable and nondiscriminatory.[163]

109. Some commenters object to the use of competitive markets prices on the grounds that these competitive prices represent only short-term, or spot prices that do not reflect the long-term marginal costs and other costs avoided by purchasing utilities.[164] Similarly, some commenters assert that competitive prices cannot support the financing of QFs.[165]

110. Public Interest Organizations argue that using competitive prices to set as-available energy avoided cost rates is discriminatory because non-QF generators are not limited to competitive prices and utilities can, and regularly do, pay effective prices for energy that exceed the price determined by competitive prices.[166] Several other commenters express concern about setting QF prices by referencing short-term liquid hub prices while allowing utilities to rate base and recover their long-term investments.[167] Industrial Energy Consumers argue that, if the Commission implements the liquid market hub proposal, there must be assurances that utilities' self-builds face the same market risk exposure as QFs. For example, they argue, if states expose QFs to variable rates for their energy output, utility-owned generation should also be exposed to variable rates for their energy output.[168]

111. Several commenters assert that QF rates should reflect benefits other than the avoided cost of energy.[169] For example, Biogas and Biomass Power state that non-energy benefits, like waste reduction and economic development must be incorporated into avoided cost determinations.[170] Biogas and Resources for the Future state that locational values should be incorporated into avoided cost calculations.[171] American Dams states that utilities' avoided

[154] *Id.* P 13.

[155] *Id.* P 45.

[156] *Id.* P 48 (citing *Cal. Indep. Sys. Operator Corp.,* 105 FERC ¶ 61,140, at PP 48–50 (2003); *Cf. Price Formation in Energy and Ancillary Servs. Mkts Operated by Reg'l Transmission Orgs. and Indep. Sys. Operators,* 153 FERC ¶ 61,221, at P 2 (2015)).

[157] NOPR, 168 FERC ¶ 61,184 at P 51.

[158] Allco Comments at 8.

[159] BluEarth Comments at 2.

[160] El Paso Electric Comments at 3–4.

[161] California Commission Comments at 23–27.

[162] *Id.* at 11–14.

[163] *Id.* at 23–25.

[164] IdaHydro Comments at 11; Southeast Public Interest Organizations Comments at 19; NIPPC, CREA, REC, and OSEIA Comments at 52, 55 (citing *Exelon Wind I, LLC,* 140 FERC ¶ 61,152, at P 52 (2012)); Union of Concerned Scientists Comments at 6.

[165] BluEarth Renewables Comments at 2; Biological Diversity at 8; Covanta Comments at 9; Public Interest Organization Comments at 43–44.

[166] Public Interest Organizations Comments at 64.

[167] IdaHydro Comments at 11; Industrial Energy Consumers Comments at 12–13.

[168] Industrial Energy Consumers Comments at 12–13.

[169] Biogas Comments at 1–2; Biomass Power Comments at 1; EPSA Comments at 14–16; Resources for the Future Comments at 4; Xcel Comments at 3–5.

[170] Biogas Comments at 2; Biomass Power Comments at 1.

[171] Biogas Comments at 1; Resources for the Future Comments at 4.

transmission charges should be included in avoided cost determinations.[172] Xcel states that hidden integration and utility planning costs should also be incorporated into avoided cost calculations.[173] American Dams argues that for high capital projects like hydro, the Commission should consider longer-term public benefits and not just short-term market pricing.[174]

112. Solar Energy Industries asserts that payments based on the LMP should not relieve the purchasing utility of the requirement to compensate the QF for any values in addition to electricity (*e.g.,* renewable energy credits, frequency response capabilities, pro-rated capacity value, etc.).[175]

113. California Utilities request that the Commission clarify that states may but are not required to consider state policies when establishing avoided costs.[176] Harvard Electricity Law requests that the Commission clarify its rule allowing states to set tiered rates.[177]

c. Commission Determination

114. As an initial matter, we observe that some of the concerns raised by commenters about the use of competitive market prices to set as-available energy rates for QFs are based on the incorrect assumption that the NOPR proposal would permit states to use competitive market prices to set as-available energy rates for QFs even when competitive market prices are below the purchasing utility's avoided costs. In fact, however, the use of competitive market prices to set QF rates is explicitly subject to the requirement that such prices are equal to the purchasing utility's avoided energy costs.[178] As the Supreme Court noted in *API,* the full avoided cost rate requirement represents the maximum rate permitted under PURPA, and thereby provides important encouragement to QFs.[179] And as the Supreme Court also noted in the same decision, ''the full-avoided-cost rule plainly satisfies the nondiscrimination requirement.'' [180] Further, in requiring full avoided cost rates, ''[t]he Commission did not ignore the interest of electric utility consumers 'in receiving electric energy at equitable rates.' '' [181]

115. For this reason, Allco is incorrect when it claims that the competitive price proposal represents a menu of prices that a state can select to choose the lowest rate. In the event that more than one competitive price option potentially could apply, the state would be required to select the option that reasonably reflects the purchasing utility's avoided costs, which is what PURPA requires.[182]

116. Further, the record supports the conclusion that the use of transparent, competitive market prices provides encouragement to QFs, represents the avoided cost, and can ensure that the rate does not exceed the incremental cost to the purchasing electric utility. In addition to the testimony to this effect presented at the technical conference and cited in the NOPR,[183] the conclusion is further supported by comments submitted in response to the NOPR. For example, NIPPC, CREA, REC, and OSEIA cite to a report by Fitch, which explains how Fitch evaluates the financial strength of renewable energy projects. In this report, Fitch states that it gives a ''stronger'' evaluation to projects with power sales contract prices that are ''indexed using simple, broad-based publicly available indexation formulas.'' [184] In addition, Solar Energy Industries notes the difficulties QFs face in expending large sums to develop their projects ''[f]or states that do not publish the avoided costs, or for utilities that treat their avoided cost methodologies as confidential trade secrets.''[185]

117. We agree with commenters who assert that competitive market prices represent only short-run spot prices that do not reflect electric utilities' long-run costs that QFs can displace. However, we are authorizing states to use competitive market prices only to establish as-available energy rates for QFs. The comments misunderstand the fundamental difference between the value to a purchasing utility of such as-available energy and the value to a purchasing utility of capacity.

118. A QF has no obligation under the as-available avoided cost rate provisions to deliver any set amount of electric energy at any point in the future, but merely is paid for the amount of electric energy actually delivered. Therefore, the delivery of as-available energy does not displace any long-term energy the purchasing electric utility would generate itself or purchase from another source but rather allows the purchasing utility to reduce the amount of energy it otherwise would generate itself or purchase from another entity at the time the QF delivers the energy. Because the QF has no obligation to deliver any energy in the future, the utility is unable to avoid constructing or contracting for capacity to meet its future needs as a consequence of the delivery of energy by the QF. As-available energy rates therefore appropriately reflect only the short-run value of energy delivered at the particular moment in time when and if the QF has energy available to be delivered to the utility.

119. A QF can displace an electric utility's own generation or purchases from alternative sources over the long-run when a QF sells capacity to a utility in addition to as-available energy. In contrast to as-available energy, a sale of capacity would typically compensate the QF for maintaining the capability to deliver a set amount of energy in the future (*i.e.,* capital costs),[186] and thus allows the purchasing utility to avoid the cost of making alternative arrangements, either through a self-build or an alternative purchase, to obtain that amount of energy. Consequently, the price of capacity purchased from a QF would reflect this long-run avoided cost. And this final rule does not alter a purchasing utility's

[172] American Dams Comments at 4.

[173] Xcel Comments at 3–5.

[174] American Dams Comments at 2.

[175] Solar Energy Industry Comments at 27–28.

[176] California Utilities Comments at 18–19.

[177] Harvard Electricity Law Comments at 32–33.

[178] Arguments that the various competitive market prices identified in this final rule do not represent avoided energy costs are addressed below with respect to each such specific market price.

[179] *API,* 461 U.S. at 413.

[180] *Id.*

[181] *Id.* at 415 (quoting Conf. Rep. at 97).

[182] In a competitive market, the transportation costs between any such two hubs and a QF would be such that they would make the QF rate the same, no matter which hub was selected. *See* FERC, *Energy Primer, A Handbook of Market Basics,* at 64 (June 2020), *https://www.ferc.gov/market-assessments/guide/energy-primer-2020.pdf* (Energy Primer) (''If there are no transmission constraints, or congestion, LMPs will not vary significantly across the RTO footprint. However, when transmission congestion occurs, LMPs will vary across the footprint because operators are not able to dispatch the least-cost generators across the entire region and some more expensive generation must be dispatched to meet demand in the constrained area.'').

[183] *See* American Forest & Paper Association Comments, Docket No. AD16–16–000, at 8 (filed June 8, 2016) (''To the extent possible, these determinations [of avoided costs] should not be made in a 'black box', but rather, as part of an open and transparent method and process.''); EEI Comments, Docket No. AD16–16–000, at 3 (filed June 30, 2016) (''Where transparent competitive markets with day ahead prices exist, there is no reason to adhere to second-best avoided cost pricing mechanisms.'').

[184] NIPPC, CREA, REC, and OSEIA Comments at 37–38 (citing *FitchRatings, Global Infrastructure & Project Finance, Renewable Energy Project Rating Criteria,* at 3 (Feb. 26, 2019), *https://www.fitchratings.com/site/re/10061770*).

[185] Solar Energy Industries Comments at 41.

[186] *See* Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,885 (''Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.'').

existing obligation to pay QFs for any avoided capacity benefit that allows the utility to avoid acquiring capacity.[187]

120. For these reasons, we decline to grant the California Commission's request to allow using competitive prices for not just as-available energy pricing, but also for capacity pricing.[188] We also reject the California Commission's request to permit all electric utilities, both those located in organized markets and those located in non-organized market areas, to use any competitive price (whether a Market Hub Price or Combined Cycle Price, or alternatively a Competitive Solicitation Price) to set avoided cost rates. The Market Hub Price and Combined Cycle Price, as well as the Competitive Solicitation Price are options that should generally reflect a purchasing electric utility's avoided as-available energy costs in non-RTO/ISO areas, while the LMP should generally reflect a purchasing electric utility's avoided as-available energy costs in RTO/ISO market areas.

121. With respect to the discrimination claims, our decision to give states the flexibility to use competitive prices is driven by the fact that the competitive market price represents the purchasing utility's avoided costs. And, as explained in Section IV.A.2 above, a rate set at full avoided costs by definition cannot be discriminatory and, in any event, the Commission is without authority under PURPA section 210(b) to require a rate above avoided costs.

122. Further, Industrial Energy Consumers are incorrect when they suggest that public utility energy rates do not vary with costs in the same way that the competitive market prices potentially applicable to QFs under the final rule vary. To the contrary, the Commission and most states provide for fuel adjustment clauses applicable to rates, which allow utility rates to adjust automatically with changes in utility fuel and purchased power costs.[189] And even utilities whose rates do not include fuel and purchased power adjustment clauses nevertheless typically must charge their retail customers cost-based rates, which means that their energy charges will vary from one rate case to the next as their fuel and purchased power costs vary from year to year. These mechanisms for ensuring that utility rates vary with the cost of energy result in variances in utility energy rates that are similar to the variance in QF energy rates for those states that elect a Competitive Price option (either a Market Hub Price or a Combined Cycle Price) for as-available avoided cost rates.

123. Finally, although we are sympathetic to the claims of certain QFs that they provide non-energy benefits (such as environmental benefits, waste reduction benefits, and economic development benefits) that are not reflected in avoided cost rates, PURPA section 210(b) prohibits the Commission from requiring QF rates to be set above full avoided costs. Because the Commission already requires states to set QF rates at full avoided costs, it is barred from requiring QF rates set higher than that based on the non-energy benefits that QFs may also provide. However, nothing in PURPA, the PURPA Regulations as they currently exist, or this final rule would prevent states from rewarding QFs for such non-energy benefits so long as that is done outside of PURPA, such as is now done for renewable energy credits (RECs) to compensate QFs for providing unique environmental or other non-PURPA benefits.[190] We address in the sections below each type of competitive price that could be used as an acceptable energy avoided cost.

3. LMP as a Permissible Rate for Certain As-Available Avoided Cost Rates

a. NOPR Proposal

124. The Commission proposed to revise 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.

125. The Commission explained that RTO/ISO markets calculate a LMP at each location on the RTO/ISO-controlled grid, and that all sellers receive the LMP for their location and all buyers pay the market clearing price for their location. The Commission further 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,[191] and explained that 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 in each period, and thus such prices can vary based on location and time.[192]

126. The Commission therefore preliminarily found 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, the Commission explained that 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 they 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). In addition, the Commission observed that 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.[193] Finally, the Commission also noted that Congress, through enactment of PURPA section 210(m), appears to have recognized that RTO/ISO LMP pricing provides sufficient encouragement for QFs.

127. The Commission requested comment on whether the real-time prices established in the CAISO-administered Energy Imbalance Market

[187] *See* Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,881–86 (describing how states must calculate avoided capacity costs).

[188] *See infra* sections IV.B.3–5. We note that states may use competitive solicitations to set both energy and capacity avoided cost rates. *See infra* section IV.B.8.

[189] *See* 18 CFR 35.14 (Fuel Cost and Purchased Economic Power Adjustment Clauses); ELCON, *Fuel Adjustment Clauses & Other Cost Trackers, https://elcon.org/fuel-adjustment-clauses-cost-trackers* (''Fuel adjustment clauses are in effect in almost all states.''); NARUC, Staff Subcommittee on Accounting and Finance, *Fuel and Purchased Power Survey Results* (Sept. 23, 2015), *https://pubs.naruc.org/pub/4AA28D50-2354-D714-5149-B773EFC3EFEF* (stating that only one state surveyed said that it did not employ a fuel adjustment clause).

[190] *See, e.g., American Ref-Fuel Co.,* 105 FERC ¶ 61,004, at PP 22–24 (2003), *denying reh'g,* 107 FERC ¶ 61,016 at PP 12, 15–16 (2004), *dismissing pet. for review sub nom. Xcel Energy Servs. Inc.* v. *FERC,* 407 F.3d 1242 (D.C. Cir. 2005).

[191] *Offer Caps in Mkts Operated by Reg'l Transmission Orgs. and Independent Sys. 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).

[192] *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).

[193] *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. Mkts Operated by Reg'l Transmission Orgs. and Indep. Sys. Operators,* 153 FERC ¶ 61,221, at P 2.

(EIM) [194] are similar for these purposes to the LMP in RTOs/ISOs. In this regard, the Commission requested comment on whether ''prices developed in the EIM similarly 'reflect the least-cost of meeting an incremental megawatt-hour of demand at each location on the grid,' as the Commission has found to be the case with LMP rates.'' [195]

128. The Commission understood that some states already use LMP to establish avoided cost energy rates under the existing PURPA Regulations.[196] The Commission thus proposed 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,[197] a state would, under the proposal in the NOPR, be able to adopt LMP as a per se appropriate measure of the as-available energy component of avoided costs.[198]

b. Comments

i. Comments in Opposition

129. Several commenters oppose the NOPR's LMP proposal.[199] American Biogas asserts that, by definition, LMP rates assume that generating facilities are receiving other compensation to fund their operations and that the marginal rate reflects only the value of the energy. American Biogas asserts that LMP ignores biogas facilities' unique municipal infrastructure role and multiple benefits to the community.[200] Covanta argues that avoided costs paid to small baseload QFs should incorporate all long-run avoided costs for capacity and energy and include other externalities such as the value of renewable baseload energy, greenhouse gas mitigation, landfill diversion, reliable and resilient power and other benefits of small baseload QFs.[201] Biological Diversity argues that LMP pricing ignores variability across the country and is inappropriate in regions like the Southeast which lack RTOs and ISOs and are instead still dominated by vertically-integrated monopolies.[202]

130. CA Cogeneration argues that LMP may not represent a truly competitive price for electricity because, in California, the majority of supply is through bilateral contracts, not through competitive bidding in the market. CA Cogeneration states that rooftop solar distorts LMP by reducing load and not bidding in its full long-term marginal cost.[203] CA Cogeneration states that LMPs can be well below the operating cost of conventional generation and combined heat and power, and even negative, especially when there is an abundance of procured resources such as hydro, solar, and wind.[204] CA Cogeneration asserts that combined heat and power can survive only if: (1) Fixed capacity prices are sufficiently high to cover the energy price risk; (2) the market price reflects the full cost of contracted power and includes all sources of supply; or (3) 18 CFR 292.304(f)(1) is modified to provide QF operations first priority, except in special circumstances related to reliability.[205]

131. ELCON argues that allowing utilities to use LMP and other competitive market prices would allow states to ignore long-standing factors established by Commission regulation in determining the avoided cost rates, including: (1) Availability of capacity or energy from a QF during the system daily and seasonal peak periods; (2) dispatchability and reliability; (3) the relationship of the availability of energy or capacity from the QF to the ability of the utility to avoid costs; (4) costs or savings from variations in line losses; and (5) application of technology-specific avoided cost rates.[206] ENGIE argues that allowing states to set energy rates at LMP, while also allowing them to set capacity rates at zero if it is determined that a utility has no need for capacity, could allow traditional utilities to corner the market on capacity, leaving smaller independent QFs to fill energy-only contracts at LMP.[207]

132. New England Small Hydro states that the Commission has not supported the NOPR's assertion that LMP is an accurate measure of avoided costs because the NOPR: (1) Inappropriately relies on the Energy Policy Act of 2005's changes in PURPA section 210(m) to support its proposed changes to calculation of the avoided cost rate; (2) ignores the costs that the utility pays to procure power (*i.e.,* RFPs, other power contracts, planned retirements); and (3) ignores the fact that LMP and the default service rates that exist in ISO–NE-based states are quite different.[208] In addition, New England Hydro states that, for the avoided cost calculation, the appropriate LMP is the day-ahead LMP, not the real-time LMP, because utilities primarily purchase energy in the day-ahead market pursuant to bilateral contracts or RFPs, not in the real-time market.[209] New England Hydro also believes that utilities or state regulatory bodies should be required to establish and maintain long-term avoided energy forecasts upon which

[194] The Commission noted that, by seeking comment regarding the Western EIM prices, the Commission did 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.

[195] NOPR, 168 FERC 61,184 at P 47 (quoting *SMUD,* 616 F.3d at 524). Use of real time prices in the Western 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 requested comments on whether it would be appropriate to use the Western EIM price to develop an as-available energy rate.

[196] *See Exelon Wind 1, LLC,* 140 FERC ¶ 61,152, at P 11, *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 (filed Sept. 27, 2012) (stating that Maryland, New Jersey, North Carolina, Virginia, Connecticut, New Hampshire, Kentucky, and Michigan have set avoided costs at LMP).

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

[198] The Commission recognized in the NOPR 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, *reconsideration denied,* 155 FERC ¶ 61,066 (''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 since found that this statement was overtaken by events, namely SPP'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 also has acknowledged that, if adopted in a final rule, the reasoning in the NOPR supported a departure from 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)).

[199] Biogas Comments at 2; Covanta Comments at 8–9; Biological Diversity Comments at 8–9; CA Cogeneration Comments at 8–9; ELCON Comments at 23–25; ENGIE Comments at 4; New England Small Hydro Comments at 8–11; NIPPC, CREA, REC, and OSEIA Comments at 53–60; Public Interest Organizations Comments at 52–64; Union of Concerned Scientists Comments at 4–9; Southeast Public Interest Organizations Comments at 21–25.

[200] Biogas Comments at 2.

[201] Covanta Comments at 8.

[202] Biological Diversity Comments at 8–9.

[203] CA Cogeneration Comments at 8–9.

[204] *Id.*

[205] *Id.*

[206] ELCON Comments at 23–24.

[207] ENGIE Comments at 4.

[208] New England Small Hydro Comments at 8–10.

[209] *Id.* at 10.

QF PURPA power purchase rates would be based.[210]

133. NIPPC, CREA, REC, and OSEIA claim that LMPs only promote more efficient use of the transmission grid in the short-term because factors such as temporary outages, equipment failures, weather extremes, and the like can cause LMPs to spike, but these have no impact on long-term transmission availability.[211] NIPPC, CREA, REC, and OSEIA believe that, while LMPs are a useful tool for developers to identify points on the grid where transmission is relatively more or less congested, developers have strong incentives to avoid congestion, and they will generally be guided to areas of low congestion during the transmission interconnection process, whether or not they face LMP-based contract prices. NIPPC, CREA, REC, and OSEIA claim that if transmission constraints prevent a generator from delivering power to a specific node, the LMP at that node cannot be an appropriate measure of costs avoided by purchase of power from that generator. NIPPC, CREA, REC, and OSEIA argue that LMP or Western EIM prices at the time of delivery are not a true measure of the long-term avoided costs of incumbent utilities unless those utilities are relying on those markets as a means to obtain long-term resources.[212]

134. NIPPC, CREA, REC, and OSEIA assert that the NOPR proposal fails to recognize: (1) the Commission's struggle to develop effective capacity markets in the RTO/ISO regions; (2) the fact that the merchant generation model is now in serious question; and (3) that the Commission's claim that Congress endorsed the use of LMP to set avoided cost rates by adoption of section 210(m) cannot be squared with the plain language of the statute.[213] NIPPC, CREA, REC, and OSEIA argue that there is substantial evidence that LMP prices are distorted by certain practices, such as zero-cost bids, so that plants operate uneconomically.[214] NIPPC, CREA, REC, and OSEIA further maintain that the 2000–01 California market demonstrated that these volatile short-term markets can reach extreme and unpredictable highs under stress conditions.[215]

135. Similarly, Public Interest Organizations cite to studies by the Sierra Club[216] and Bloomberg New Energy Finance,[217] for the proposition that the use of LMP as the QF price discriminates against QFs where utility-owned generation and non-QF generators are not limited to the LMP for recovery of their costs, and where utilities depress LMP through uneconomic dispatch of their own generation facilities.[218] Union of Concerned Scientists states that LMPs are not an accurate measure of avoided costs and should not be used to set QF rates because the practice of providing utility-owned generation with out-of-market cost-recovery in areas like MISO, PJM, SPP, the SERC Reliability Corporation, and the Western Electricity Coordinating Council suppresses the clearing prices in the markets where this is allowed.[219]

136. Southeast Public Interest Organizations argue that the NOPR's proposed avoided cost methodology does not take into account: (1) Long-term or seasonal purchases made from third parties or affiliates; (2) adjustments for transmission and distribution losses; (3) capacity deferrals; (4) avoided environmental compliance costs; or (5) a QF's dispatchability.[220] Southeast Public Interest Organizations state that LMP-based rates for QFs in Virginia have enticed little-to-no QF development in Virginia.[221] Southeast Public Interest Organizations urge the Commission either to rescind the NOPR's LMP provisions or at least to implement this provision on a case-by-case basis.[222]

(a) Utilizing Western EIM To Establish Avoided Costs

137. Solar Energy Industries argues that, because as-available QF resources are not eligible to participate in the Western EIM (also known as the CAISO EIM), either directly or through the purchasing utility, it would be inappropriate to use the Western EIM price as a proxy because that market does not factor in the participation of the QF resource.[223] ELCON asserts that the Western EIM is not a complete measure of avoided energy costs because the Western EIM merely covers imbalance conditions, and therefore does not capture the vast majority of unit commitment and dispatch scheduling cost parameters.[224] Union of Concerned Scientists asserts that allowing a state to adopt real-time prices established in the Western EIM as an accurate measure of avoided costs will be discriminatory.[225]

ii. Comments in Support

138. Several commenters support the Commission's proposal to permit a state the flexibility to use LMPs to set the as-available energy rate paid to a QF by an electric utility located in an RTO/ISO.[226]

139. CA Utilities state that the NOPR's LMP proposal is a return to the Commission's policy as expressed in *Winding Creek,*[227] and will facilitate payments to QFs that more accurately represent a utility's actual avoided costs. CA Utilities assert that the NOPR's LMP proposal affirms that a formula energy price contract complies with PURPA if coupled with a fixed capacity price. CA Utilities state that a formula energy price contract will have the additional benefit of avoiding the need to develop and administer a new PURPA contract.[228]

140. NRECA supports the Commission's proposal because many utilities that participate in the RTO/ISO markets offer the entirety of their generation into the market, and purchase all of their requirements to serve load from that market, at LMP prices.[229]

141. The Pennsylvania Commission supports the NOPR proposal because LMP prices vary through the day based on changing system conditions, such as changes in electricity demand, supply, congestion, and line losses. The Pennsylvania Commission asserts that, because some utilities in Pennsylvania

[210] *Id.* at 11.

[211] NIPPC, CREA, REC, and OSEIA Comments at 57–59.

[212] *Id.* at 55 (citing *Exelon Wind I,* 140 FERC ¶ 61,152 at P 52).

[213] *Id.* at 57–59.

[214] *Id.* at 55.

[215] *Id.* at 57.

[216] Public Interest Organizations Comments at 53–56 (citing Jeremy Fisher, Sierra Club, *Playing with Other People's Money, How Non-Economic Coal Operations Distort Energy Markets,* Sierra Club, Oct. 2019, at 4).

[217] *Id.* at 57 (citing William Nelson & Sophia Liu, *Half of U.S. Coal Fleet on Shaky Economic Footing; Coal Plant Operating Margins Nationwide,* Bloomberg New Energy Finance, March 26, 2018).

[218] *Id.* at 52–64.

[219] Union of Concerned Scientists Comments at 3–8.

[220] Southeast Public Interest Organizations Comments at 22.

[221] *Id.* at 23.

[222] *Id.* at 24.

[223] Solar Energy Industries Comments at 27.

[224] ELCON Comments at 24.

[225] Union of Concerned Scientists Comments at 9.

[226] APPA Comments at 11; Arizona Public Service Comments at 5; CA Utilities Comments at 17; Conn. Authority Comments at 13; DTE Electric Comments at 4; EEI Comments at 22–24; Comments at 4–5; Idaho Commission Comments at 3–4; Indiana Municipal Comments at 5; Kentucky Commission Comments at 4–5; NorthWestern Comments at 4–7; NRECA Comments at 6–7; Ohio Commission Energy Advocate Comments at 4–5; Pennsylvania Commission Comments at 7–9; South Dakota Commission Comments at 2; US Chamber of Commerce Comments at 4; We Stand Comments at 1; Xcel Comments at 5.

[227] CA Utilities Comments at 15–17 (citing *Winding Creek Solar LLC,* 151 FERC ¶ 61,103, at P 6 (2015)).

[228] *Id.* at 17.

[229] NRECA Comments at 6.

(and other states) have already incorporated LMP elements in their as-available energy rates, a corresponding revision to the Commission's regulations that incorporates such practices and harmonizes state and federal regulations would bring greater predictability to suppliers, electric utilities and customers.[230]

142. The Ohio Commission Energy Advocate believes that, in the parts of the country with organized nodal wholesale electricity markets, LMP is an appropriate and fair means by which to calculate avoided costs because electricity supply and demand must be balanced in real time. The Ohio Commission Energy Advocate notes that Ohio has nodal LMPs that reflect the true value of energy at the place and the time it is produced or delivered, and this value can change dramatically, even within a day or an hour. The Ohio Commission Energy Advocate concludes that reflecting the dynamic nature of electricity pricing in avoided cost calculations will send the most accurate price signals to QFs and will appropriately and fairly value the energy they produce.[231]

143. The South Dakota Commission supports using LMP for certain as-available QF energy sales because using LMP will increase states' flexibility. The South Dakota Commission regulates six vertically integrated electric utilities, five of which are RTO members, and five of which are multi-jurisdictional.[232]

144. Xcel submits that compensating QFs based on LMPs at the time of delivery will not impair QFs' ability to obtain financing because other factors can drive the ability to obtain financing, including other project options, location, size, interconnection costs, experience of the developer, current economic conditions, creditworthiness of the developer, economies of scale, and other factors. Xcel states that some resource specific information generally suggests that the right project in the right location can obtain financing if the project receives hourly payment based on LMPs.[233]

(a) Utilizing Western EIM To Establish Avoided Costs

145. NorthWestern and EIM Entities agree that the Western EIM real-time prices are similar to LMPs and reflect the least cost of meeting an incremental megawatt-hour of demand at each location on the grid.[234] Xcel asserts that prices in the Western EIM are calculated using the same methodology as LMPs because, in both cases, units are dispatched on a least-cost basis that respects applicable transmission constraints. Xcel requests that the Commission allow avoided costs to be based on Western EIM prices at the time of delivery absent a showing that prices would be suppressed in comparison to an LMP-style-market.[235] Arizona Public Service states that it is a participant in the Western EIM, and requests that states be given flexibility to set the as-available energy rate to be paid to a QF by an electric utility that participates in the Western EIM at the LMP.[236]

iii. Comments in Support With Requested Modifications/Clarifications

146. APPA urges the Commission to clarify that nothing in the proposed rule is intended to call into question state regulatory authorities' existing implementation of PURPA's avoided cost requirements, such as their existing use of LMP.[237]

147. Industrial Energy Consumers do not object to the use of LMP as the avoided cost rate for electric utilities' purchases of QF energy in RTO/ISO regions,[238] but they maintain that in non-RTO/ISO regions, there must be assurance that utilities' self-builds face the same market risk exposure as QFs.[239]

148. The Kentucky Commission supports the NOPR's LMP proposal but prefers that the Commission in the final rule allow states to determine whether the LMP calculation should use the generator LMP or the load LMP on a case-by-case basis.[240]

149. Solar Energy Industries assert that, where the purchasing utility has demonstrated that it procures its marginal energy from an LMP market, the utility may use the LMP price as a proxy for avoided energy costs calculated at the time the obligation is incurred, so long as there are published prices at the location.[241] Solar Energy Industries request that the Commission make clear that: (1) The flexibility to set QF payment rates for as-available energy at the applicable LMP requires an on-the record determination that the purchasing utility procures incremental energy from the identified LMP market at those prices; (2) payments based on an LMP do not relieve the purchasing utility of the requirement to compensate the QF for any values in addition to electricity (*e.g.,* renewable energy credits, frequency response capabilities, pro-rated capacity value, etc.); and (3) the state's flexibility to allow utilities to set QF payment rates for as-available energy at the applicable LMP does not in any way limit QFs' rights to establish a LEO or contract for a longer-term sale at fixed, full avoided costs.[242]

150. NorthWestern believes that as-available rates based on LMPs should accurately capture current events impacting prices, including times when there is a high saturation of energy available causing prices to be negative. However, NorthWestern believes that it is appropriate to deduct from the avoided cost rate the cost for ancillary services to balance and integrate energy resources.[243]

c. Commission Determination

151. We affirm with one modification the NOPR proposal to allow LMP to be used as a measure of as-available energy avoided costs for electric utilities located in RTO/ISO markets for the reasons set forth in the NOPR[244] and those provided by various commenters.

152. We recognize that an LMP selected by a state to set a purchasing utility's avoided energy cost component might not always reflect a purchasing utility's actual avoided energy costs. Accordingly, we find that it is appropriate to modify the option for a state to set avoided energy costs using LMP from a per se appropriate measure of avoided cost to a rebuttable presumption that LMP is an appropriate means to determine avoided cost. While a state could rely on the presumption, an aggrieved entity (such as a QF) may attempt to rebut the presumption that LMP reflects the purchasing electric utility's avoided costs. The aggrieved entity would be able to challenge the state's decision to rely on LMP in the appropriate forum, which could include any one or more of the following: (1) Initiating or participating in proceedings before the relevant state commission or governing body; (2) filing for judicial review of any state regulatory proceeding in state court (under PURPA section 210(g)); or, alternatively (3)) filing a petition for enforcement against the state at the Commission and, if the Commission declines to act, later filing a petition against the state in U.S.

[230] Pennsylvania Commission Comments at 7–8.

[231] Ohio Commission Energy Advocate Comments at 4–5.

[232] South Dakota Commission Comments at 2.

[233] Xcel Comments at 5–7.

[234] EIM Entities Comments at 2–3, 7–13; NorthWestern Comments at 4–5.

[235] Xcel Comments at 7–8.

[236] Arizona Public Service Comments at 5–6.

[237] APPA Comments at 9.

[238] Industrial Energy Consumers Comments at 11.

[239] *Id.* at 12.

[240] Kentucky Commission Comments at 4–5.

[241] Solar Energy Industries Comments at 25–26.

[242] *Id.* at 27–28.

[243] NorthWestern Comments at 4–5.

[244] NOPR, 168 FERC ¶ 61,184 at PP 44–45.

district court (under PURPA section 210(h)(2)(B)).[245]

153. Commenters have not persuaded us that LMP may not presumptively reflect a purchasing electric utility's avoided energy costs. LMP sets day-ahead and real-time energy prices through competitive auctions in RTOs/ISOs that optimally dispatch resources to balance supply and demand, while taking into account actual system conditions including congestion on the transmission system. We continue to find that: (1) LMPs reflect the true marginal cost of production of energy, taking into account all physical system constraints; (2) these prices would fully compensate all resources for their variable cost of providing service; (3) LMP prices 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; and (4) unlike average system-wide cost measures of the avoided energy cost used by many states, LMP should provide a more accurate measure of the varying actual avoided energy costs, hour by hour, for each receipt point on an electric utility's system where the utility receives power from QFs.[246]

154. Various commenters have provided additional reasons for supporting the NOPR proposal concerning LMP. NRECA explains that LMP rates for energy are appropriate because many utilities that participate in the RTO/ISO markets offer the entirety of their generation into the market at LMP prices and buy all of their load requirements from the market at LMP prices.[247] This scenario described by NRECA is a common one, and it demonstrates that the market itself, with its LMP pricing, can be the electric utility resource that would be displaced by a QF purchase. Furthermore, as argued by Pennsylvania Commission, because some utilities in Pennsylvania and other states have already incorporated LMP in their as-available energy rates, a corresponding revision to the Commission's regulations that incorporates such practices and harmonizes state and federal regulations would bring greater predictability to suppliers, electric utilities and customers.[248]

i. Arguments Against the NOPR Proposal

155. Commenters have not offered persuasive arguments for rejecting the use of LMP for avoided cost energy rate determination. We disagree with the argument made by Union of Concerned Scientists,[249] NIPPC, CREA, REC, and OSEIA,[250] and Public Interest Organizations[251] that LMP should not be used as a measure of avoided energy costs because LMP prices are depressed in many markets where self-scheduling rights and state cost-recovery mechanisms for fuel and operating costs create the opportunity for market participation at a loss. We recognize that, all other things being equal, self-scheduling of resources may impact market clearing prices. This potential price effect, however, does not mean that the LMP is not an accurate measure of avoided energy costs. The Commission's regulations, using language from PURPA section 210(d), define avoided costs as ''the incremental costs to an electric utility of electric energy or capacity or both which, *but for* the purchase from the qualifying facility or qualifying facilities, such electric utility would generate for itself *or purchase from another source.*''[252]

156. In organized wholesale electric market areas, the electric utility purchases that would be displaced by QF purchases would, as NRECA explains, in all likelihood be priced at the relevant LMP. These LMPs are impacted by many factors, such as self-scheduling, generator outages, and transmission outages, that may result in LMPs that are lower or higher than they might otherwise have been. Thus, while self-scheduling or other factors may impact LMPs, in any case, an electric utility's purchases during periods when these price impacts are occurring would be made at the resulting LMPs, whatever those LMPs may be. Therefore, LMPs meet the Commission's long-standing definition of avoided costs for a purchasing electric utility, even if they happen to reflect price impacts from self-scheduling or other factors.

157. Furthermore, while commenters discuss the possibility that utility-owned coal-fired resources are self-scheduling only because retail ratepayers are subsidizing such activities, even if such claims were true they would not alter the above analysis. The LMPs that result from a market that includes self-scheduled resources still represent the price of purchases in the market that would be displaced by the QF purchase.

158. In addition, we reject the related request for clarification made by Solar Energy Industries,[253] *i.e.,* that the flexibility to set QF payments for as-available energy at the applicable LMP should require an on-the-record determination that the purchasing utility procures incremental energy from the identified LMP market at those prices. Unless an aggrieved entity seeks to rebut this presumption in a state avoided cost adjudication, rulemaking, legislative determination, or other proceeding, that state would not need to make such an on-the-record determination before it decides to use LMP.

159. Entities may seek to rebut the presumption in particular cases, as described earlier, and whether the utility actually procures energy from the identified LMP market or from resources with prices tied to the identified LMP may be a relevant factor in such rebuttal arguments. Consistent with the reasons described above for why there should be such a rebuttable presumption in favor of LMP, this delineation of rights appropriately places the initial burden on entities seeking to rebut the presumption, rather than on the states who wish to rely on LMP for setting avoided cost rates for as-available energy. The Commission could consider such issues if and when they may arise in individual cases appropriately brought to the Commission, including whether the state has adequately justified its use of that rebuttable presumption.

160. We reject the arguments made by NIPPC, CREA, REC, and OSEIA that, more generally, prices for long-term QF contracts should be set by reference to long-term price indices or other indicators that genuinely reflect the long-term costs of generation avoided by the purchasing utility.[254] This final rule only addresses as-available energy, and as-available energy prices by definition are short term, as explained below in Section IV.B.7.c.

161. We also reject the arguments made by NIPPC, CREA, REC, and OSEIA that, while the NOPR is correct that LMPs are intended to promote more efficient use of the transmission grid,

[245] *See Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978,* 23 FERC ¶ 61,304.

[246] *See* NOPR, 168 FERC ¶ 61,184 at PP 44–45 (citing *SMUD,* 616 F.3d at 524; *FERC* v. *Elec. Power Supply Ass'n,* 136 S. Ct. at 768–69 (describing how LMP is typically calculated); Order No. 831, 157 FERC ¶ 61,115, at P 7, *order on reh'g and clarification,* Order No. 831–A, 161 FERC ¶ 61,156).

[247] NRECA Comments at 6.

[248] Pennsylvania Commission Comments at 7–8.

[249] Union of Concerned Scientists Comments at 3–8.

[250] NIPPC, CREA, REC, and OSEIA Comments at 52.

[251] Public Interest Organizations Comments 52–64.

[252] 18 CFR 292.101(b)(6) (emphasis added).

[253] Solar Energy Industry Comments at 27–28.

[254] NIPPC, CREA, REC, and OSEIA Comments at 53.

that is true only in the short term since factors such as temporary outages, equipment failures, weather extremes, and the like can cause LMPs to spike, but these have no impact on long-term transmission availability. LMPs promote efficient use of the transmission grid in the long term as well as the short term. Persistence of significant price separation between different LMP nodes provides an indication of the value of various possible transmission system upgrades and can show transparently how system efficiencies may be improved by such transmission system upgrades. Developers may have some incentive to avoid congestion without LMPs, but LMPs provide an important price signal as to how economic or uneconomic a particular production site may be. In any event, the potential for more efficient use of the transmission grid is merely an additional benefit of using LMP for avoided energy cost determinations. Our adoption of LMP as a measure of avoided energy costs in the RTO/ISO markets is based principally on the fact that, in RTO/ISO markets, LMP accurately represents the purchasing electric utility's avoided energy cost at the time the energy is delivered, for the reasons described earlier.

162. We also are not persuaded by arguments that, if transmission constraints prevent a generator from delivering power to a specific node, the LMP at that node cannot be an appropriate measure of costs avoided by purchase of power from that generator. As discussed above, an avoided cost rate should reflect not only the cost of energy that was avoided by the purchasing electric utility, but also the cost to deliver the QF energy to the purchasing electric utility's load, such that the total cost avoided is reflected in the rate. In an RTO/ISO market, a state appropriately is entitled to consider whether the cost of delivery from the QF node to the load node (including any redispatch costs necessary to facilitate such delivery over a system that is otherwise constrained between those nodes) should be reflected in the LMP at the QF supply node. In instances commenters refer to where transmission constraints prevent a generator from delivering power to a specific node, we disagree that such delivery is actually ''prevented.'' Rather, redispatch of system resources would be necessary to facilitate the delivery, and the respective LMPs reflect those redispatch costs.

163. We also reject the argument made by NIPPC, CREA, REC, and OSEIA that the 2000–01 California market demonstrated that volatile short-term markets can reach extreme and unpredictable highs under stress conditions.[255] First we note that, in the wake of the 2000–2001 California energy crisis, all RTO/ISO markets developed more comprehensive *ex ante* market power mitigation measures than existed in CAISO at that time, including offer caps and reference level replacement offers, meant in part to moderate such extremes.[256] In any event, any price volatility that may currently exist in LMP markets, regardless of the reason for the price volatility, and regardless of whether the volatility causes LMPs to be lower or higher, nevertheless accurately represents the avoided cost of the purchasing electric utilities in those markets in those hours, as explained elsewhere in this final rule.

164. Finally, we remain convinced that Congress recognized that RTO/ISO LMP pricing provides sufficient encouragement for QFs through the enactment of PURPA section 210(m) with its directive that, essentially, the mandatory purchase obligation can be lifted upon QFs having non-discriminatory access to RTO/ISO markets. As noted earlier, however, our decision to grant states the flexibility to rely on a rebuttable presumption that RTO/ISO LMP pricing is an appropriate measure of avoided energy costs (and thus set as-available energy rates in reliance on LMPs) reflects our view that, in RTO/ISO markets, as a general matter LMP indeed accurately represents the purchasing electric utility's avoided energy costs.

165. We also disagree with ELCON's [257] argument that LMP should not be used to measure avoided costs because that would allow states to ignore long-standing factors established by the Commission that should be used to determine avoided costs. The factors referenced by ELCON are relevant to the traditional administrative determination of avoided cost, and our revisions to the regulations preserve these factors for that purpose and for avoided capacity costs. If a state chooses instead to rely on LMP to set avoided energy cost rates, then it will necessarily not be using those administrative means of determining avoided costs, and these factors thus will not be relevant.

166. We are not persuaded by the arguments of various commenters that LMP cannot be used for avoided cost rates because it ignores the unique municipal infrastructure role and the multiple benefits of the community of biogas facilities,[258] including the value of renewable baseload energy, greenhouse gas mitigation, landfill diversion, reliable and resilient power and other benefits of small baseload QFs.[259] PURPA frames the determination of QF rates in terms of avoided cost and does not authorize the Commission in determining QF rates, particularly as-available energy rates, to consider non-energy-related factors such as a generator's unique municipal infrastructure role, greenhouse gas mitigation, and landfill diversion.

167. We also are not persuaded by the argument of CA Cogeneration that LMP may not represent a truly competitive price for electricity in California since the majority of California supply is through bilateral contracts, not through competitive bidding in the market, and that other factors also distort LMP such as roof top solar. CA Cogeneration, in essence, objects to the state of California's decision to award preferred resource status to some resources, such as solar and wind, and not others, such as cogeneration. These are procurement decisions made at the state level in connection with resource planning and retail ratemaking. Even if those decisions impact the resulting LMPs, as CA Cogeneration claims, that impact would not invalidate the arguments made above for why LMP is presumptively an appropriate measure of as-available energy avoided costs in RTO/ISO markets. The aggrieved entity would be able to challenge the state's decision to rely on LMP in the appropriate forum, which could include any one or more of the following: (1) Initiating or participating in proceedings before the relevant state commission or governing body; (2) filing for judicial review of any state regulatory proceeding in state court (under PURPA section 210(g)); or, alternatively (3) filing a petition for enforcement against the state at the Commission and, if the Commission declines to act, later filing a petition against the state in U.S. district court (under PURPA section 210(h)(2)(B)).[260]

[255] NIPPC, CREA, REC, and OSEIA Comments at 57. Curiously, these commenters here essentially take the position that higher LMPs and resulting higher avoided cost energy rates, which would normally seem to be beneficial to QFs, are instead now anathema.

[256] *See generally Wholesale Competition in Regions with Organized Elec. Mkts.,* Order No. 719, 125 FERC ¶ 61,071 (2008), *order on reh'g,* Order No. 719–A, 128 FERC ¶ 61,059, *order on reh'g,* Order No. 719–B, 129 FERC ¶ 61,252 (2009).

[257] ELCON Comments at 23–24.

[258] Biogas Comments at 2.

[259] Covanta Comments at 8.

[260] *See Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978,* 23 FERC ¶ 61,304.

168. We reject the argument made by New England Small Hydro that the Commission has not supported its view that LMP is an accurate measure of avoided costs since LMP ignores the costs that the utility pays to procure power, including through competitive solicitations, other power contracts, planned retirements and other factors that are considered in a utility's long-term plans; and ignores the fact that LMP and the default service rates that exist in ISO–NE-based states are quite different.[261] The costs that a purchasing utility pays to procure power, including through competitive solicitations, other power contracts, planned retirements and other factors that are considered in a utility's long-term plans may be relevant to the utility's purchase of capacity using long-term contracts, but not to the determination of the proper as-available energy avoided cost rate to be paid to QFs, which rates will necessarily vary as system conditions vary over time, as reflected by variances in LMP over time. The fact that LMP and the default service rates that exist in ISO–NE-based states may diverge is to be expected because the latter, unlike the as-available energy rates charged by QFs in RTO/ISO markets that LMP is being used to price, normally include transmission and distribution costs (and possibly firm supplier capacity costs) necessary to ensure that firm supply is continually available to residential customers.[262] While utilities or state regulatory authorities continue to have the authority to establish and maintain long-term avoided energy forecasts upon which QF PURPA power purchase rates may be based, and to recognize the actual future energy costs incorporated in new power contracts that are being signed by New England utilities, elsewhere in this final rule the Commission explains why the use of variable prices can be appropriate for long-term energy contracts.

169. We are not persuaded by the argument of Southeast Public Interest Organizations that the NOPR does not establish a framework for just and reasonable and nondiscriminatory rates because the proposed avoided cost methodology does not take into account any long-term or seasonal purchases made from third parties or affiliates, adjustments for transmission and distribution losses, capacity deferrals, avoided environmental compliance costs, or dispatchability of the QF.[263] LMP pricing, in fact, does reflect transmission and distribution losses. The other factors that the Southeast Public Interest Organizations mention here, such as environmental compliance costs, dispatchability, long-term or seasonal purchases and capacity deferrals, are factors that are more applicable to the pricing of capacity and long-term contracts, not the pricing of as-available energy, which is what the Commission's NOPR proposal as adopted in this final rule addresses.

170. The Commission rejects the argument made by Biological Diversity[264] that LMP pricing ignores the variability of conditions across the country. LMP prices by definition vary as supply, demand, and system conditions change across the country. In any event, the Commission agrees that LMP pricing would not currently be applicable in regions like the Southeast that lack RTOs and ISOs and thus that do not use LMP.

171. We further reject the argument made by ENGIE that allowing states to set energy rates using LMPs combined with the ability to set capacity rates at zero if it is determined that a utility has no need for capacity has the potential to allow traditional utilities to corner the market on capacity, leaving smaller independent QFs to provide only energy-only service.[265] PURPA does not direct the Commission to guarantee that QF sales make up some specified share of utilities' capacity needs nor does it require that each QF receive compensation for providing capacity. PURPA instead focuses on the purchasing electric utility's avoided costs and provides that the Commission cannot require that prices charged by a QF exceed the purchasing electric utility's avoided cost, if a purchasing electric utility has no need for additional capacity (and thus the purchasing utility's avoided cost for capacity would be zero),[266] the only service that QFs (and other suppliers) would need to provide that utility is energy. However, a utility's ability to ''corner the market'' on capacity depends not uniquely on the pricing of QF sales to the utility, but on a host of factors including the utility's analysis of its need for capacity and, without a specific inquiry into the circumstances of each utility, it cannot be concluded that any utility's decision will always be deficient or that it has been adversely and inappropriately affected by the Commission's action here.

172. Several commenters maintain that reliance on LMP will make it difficult for QFs to obtain financing.[267] This argument is addressed below in section IV.B.7 of this final rule.

ii. Requests for Modification or Clarification of the NOPR

173. We will not provide the clarifications requested by New England Small Hydro that the Commission require the use of the day-ahead LMP for QF rates set at LMP, or Southeast Public Interest Organizations' request to require the use of real-time LMP rather than average LMP. States that choose to use LMP will determine the LMP most representative of the avoided cost of the relevant purchasing utility.

174. While the Kentucky Commission requests that the Commission allow the use of the LMP at a delivery (load) node rather than a receipt (generator or QF) node, we find that this decision should be made by the state as it determines which particular LMP best reflects the avoided cost of the purchasing electric utility.

175. We grant APPA's request for clarification that, while the NOPR provides greater clarity as to states' entitlement to rely on competitively-set prices as a measure of avoided cost rates, nothing in the final rule is intended to call into question any particular state's existing implementation of PURPA's avoided cost requirements, such as their existing use of LMP.[268] While in the past a state

[261] New England Small Hydro Comments at 8–10.

[262] *Compare* ISO–NE, Transmission, Markets, and Services Tariff, LMPs and Real-Time Reserve Clearing Prices Calculation, § III.2.5 (describing how nodal real-time prices are calculated in ISO–NE at each node using energy offers and bids, transmission constraints, and other factors) *with* National Grid, Investigation as to the Propriety of Proposed Tariff Changes, Docket No. DPU 18–150, Exh. NG–HSG–1, Gorman Test. 3:18–4:6 (Nov. 15, 2018), *https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/10043215* (''The Company's filing is based on its investments and costs incurred to provide distribution service to its customers. An [Allocated Cost of Service Study] directly assigns or allocates each element of the revenue requirement, including plant and other investments, operating expenses, depreciation and taxes, among the rate classes, in order to determine the costs of providing service to each rate class. Each element of the total revenue requirement is analyzed and assigned to or allocated among the rate classes, so the utility can establish rates that, subject to assumptions such as kilowatt-hour ('kWh') delivery volumes and the number of customers, provide it with a fair opportunity to recover its costs and to earn an appropriate return.'').

[263] Southeast Public Interest Organizations Comments at 22.

[264] Biological Diversity Comments at 8–9.

[265] ENGIE Comments at 4.

[266] *See, e.g.,* NOPR, 168 FERC ¶ 61,184 at P 33 n.58; *see also 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.'').

[267] Biogas Comments at 2; BluEarth Renewables Comments at 2; Biological Diversity at 8; Covanta Comments at 9; Distributed Sun Comments at 1–2; New England Small Hydro Comments at 10; NIPPC, CREA, REC, and OSEIA Comments at 53.

[268] APPA Comments at 9.

may have been able to conclude that LMP was an appropriate measure of the avoided cost for energy, a state can now also rely on a rebuttable presumption that LMP is an appropriate measure of the as-available avoided cost for energy to be used in determining a QF's as-available avoided cost energy rate.

176. We provide the following clarification in response to the Solar Energy Industries' request that the Commission make clear that payments based on LMP do not relieve the purchasing utility of the requirement to compensate the QF for any values in addition to electricity (*e.g.,* RECs, etc.), and that the state's flexibility to allow utilities to set QF payment rates for as-available energy at the applicable LMP does not in any way limit QFs' rights to establish a LEO or contract for a longer-term sale at fixed, full avoided costs.[269] In *Windham Solar LLC,*[270] the Commission summarized its precedent concerning RECs. The Commission stated that the states have the authority to determine who owns RECs in the initial instance and how they are transferred, and that the automatic transfer of RECs within a sale of power at wholesale must find its authority in state law, not PURPA. But the Commission also held that a state may not assign ownership of RECs to utilities based on a logic that the avoided cost rates in PURPA contracts already compensate QFs for RECs in addition to compensating QFs for energy and capacity, because under PURPA the avoided cost rates are, in fact, compensation just for energy and capacity.[271] We see no reason to disturb that precedent in this final rule. With regard to the right of QFs to establish a LEO, that right is neither limited nor expanded by a state's choice of LMP as the measure of avoided costs for energy.

iii. Western EIM

177. We hereby find that the Western EIM prices, like other LMP prices, may presumptively be used as a measure of as-available energy avoided costs for utilities able to participate in the Western EIM market. As Xcel points out, ''prices in the EIM are calculated using the same methodology as LMPs'' since, ''in both cases, units are dispatched on a least-cost basis that respects applicable transmission constraints (*i.e.,* congestion),'' and ''[t]he formula for price calculation involves determination of the system marginal energy cost, which is the cost of providing the next increment of energy to the system, minus congestion costs, minus losses, and, in some cases, minus the cost of carbon.''[272] As with LMP, these Western EIM price components presumptively reflect the avoided cost of as-available energy incurred by purchasing electric utilities that are able to participate in the Western EIM region.

178. We reject arguments that Western EIM prices should not be used to establish as-available avoided cost energy rates for sales by QFs. With respect to the unit commitment and dispatch scheduling cost parameters ELCON refers to, it is true that the Western EIM is a real-time imbalance market built on a decentralized unit commitment that may not result in exactly the same real-time dispatch and LMP as would result from an RTO market with centralized day-ahead unit commitment and co-optimized energy and reserves. Nonetheless, Western EIM prices represent quite precisely the avoided cost of as-available energy for utilities operating in that market structure since those prices show the cost of obtaining an additional unit of energy at any particular place and time. With regard to the argument of Union of Concerned Scientists concerning the cost recovery mechanisms available to utility-owned and -affiliated generation,[273] as discussed above with respect to the rebuttable presumption that LMP may be used for avoided cost rate determination, we do not find these unproven allegations of use of retail cost recovery mechanisms to subsidize wholesale RTO/ISO market participation at a loss sufficient to make a blanket finding prohibiting the use of Western EIM prices to set as-available avoided cost energy rates for sales by QFs.

179. With regard to the argument concerning the ability to participate in the Western EIM raised by Solar Energy Industries,[274] for PURPA rate purposes, it is not relevant whether QFs are able to participate in the Western EIM. The rates at issue here are intended, per the statute, to reflect the costs of alternative electric energy that the purchasing utility is avoiding. In this context, all that matters is whether the Western EIM's prices accurately reflect a purchasing electric utility's avoided costs for energy. Thus, as long as the purchasing electric utility is able to participate in the Western EIM, a rebuttable presumption should apply that Western EIM prices reflect the purchasing electric utility's avoided costs for energy.

4. Use of Market Hub Prices as a Permissible Rate for Certain As-Available QF Energy Sales

a. NOPR Proposal

180. In the NOPR, the Commission recognized 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.[275] For the same reasons that LMPs could represent an appropriate avoided cost energy rate for QFs selling to electric utilities located in RTO/ISO markets, the Commission proposed to find that liquid market hubs 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. 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.[276]

181. Consequently, the Commission proposed in the NOPR 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 energy rates established at liquid market hubs. The Commission proposed 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

[269] Solar Energy Industry Comments at 27–28.

[270] 156 FERC ¶ 61,042 (2016).

[271] *Id.* P 4.

[272] Xcel Comments at 7–8.

[273] Union of Concerned Scientists Comments at 9.

[274] Solar Energy Industry Comments at 27.

[275] NOPR, 168 FERC ¶ 61,184 at P 52 (citing *Price Discovery in Nat. Gas and Elec. Mkts.,* 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 Elec. 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 ¶ 61,467, at 62,676 (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)).

[276] NOPR, 168 FERC ¶ 61,184 at P 53.

price. Such determination would require the state to find that the prices at such hub are competitive prices that reflect the costs an electric utility would avoid but for the purchase from the QF.[277]

b. Comments

i. Comments in Support

182. Arizona Public Service and El Paso Electric state that the Palo Verde/Hassayampa hub represents a regional liquid market hub that could be used to set as-available energy avoided costs.[278] Portland General likewise asserts that the Mid-C price hub should be approved as appropriate for use in establishing as-available energy avoided costs.[279]

183. Xcel provides two additional factors to support the liquid market hub proposal. First, Xcel cites to the 2018 State of the Market report issued by the Commission's Office of Enforcement's Division of Energy Market Oversight, which states that trading hub prices generally align with energy prices associated with competitive, market-based sales. Second, Xcel cites to wholesale power sales contracts providing for the purchase of excess energy based on a combination of day-ahead prices at Palo Verde and at Four Corners, which Xcel asserts demonstrates that prices at Palo Verde and Four Corners are reasonably representative of the value of energy.[280]

ii. Comments in Opposition

184. Several commenters argue that liquid market hubs are short-term spot markets and do not represent long-term energy rates or the other costs associated with that energy including, but not limited to, congestion, transmission, and capacity costs.[281] Other commenters express concern with setting QF prices at short-term liquid hub prices while allowing utilities to rate base and recover their long-term investments.[282]

185. Public Interest Organizations assert that the liquid market hub proposal is discriminatory because non-QF generators are not limited to the liquid market hub price and utilities can, and regularly do, pay effective prices for energy that exceed the price determined by regional trading.[283] Union of Concerned Scientists similarly asserts that liquid market hub prices are distorted by the participation of integrated utilities that submit bids below their total costs.[284]

186. Industrial Energy Consumers oppose the liquid market hub pricing proposal because such markets are not sufficiently competitive, nondiscriminatory, and transparent to be used as the basis for calculating a utility's avoided cost payment.[285] Industrial Energy Consumers urge the Commission not to assume that non-competitive markets are, in fact, competitive.[286] Southeast Public Interest Organizations state that no southeast state could credibly identify a particular market hub that is reasonably accessible and has competitive prices that actually relate to the costs an electric utility would avoid but for the purchase from the QF.[287] Southeast Public Interest Organizations also assert that the liquid market hub proposal does not require states to determine whether liquid market hub prices represent a utility's avoided costs, and therefore the proposal would allow liquid market hubs to set avoided energy prices even when they do not represent avoided energy costs.[288]

187. ELCON asserts that a liquid regional hub does not necessarily imply liquidity at a more granular level.[289] According to ELCON, the basis spread resulting from transmission congestion outside of RTO/ISOs is often opaque in real time and poorly documented in hindsight, and this is a clear indication that discriminatory treatment and barriers to the bulk transmission system persist under current conditions outside of RTO/ISOs.[290] ELCON states that for these and other reasons, bilateral markets alone are insufficient to serve as complete avoided cost measures.[291]

188. Allco states that prices at liquid market hubs would suffer from shortcomings with respect to small QFs connected to the distribution system, because purchases from such QFs also allow the purchasing utility to avoid transmission costs, including line losses.[292]

iii. Commission Determination

189. We adopt the proposal in the NOPR to give the states flexibility to set as-available avoided cost energy rates using prices from a liquid market hub to which the purchasing electric utility has reasonable access. For the reasons explained in the NOPR, we find that liquid market hubs can represent appropriate as-available avoided cost energy rates for QFs selling to electric utilities located outside of RTO/ISO markets. However, as the Commission also found in the NOPR, before relying on prices from liquid market hubs, a state must find that the liquid market hub price in question represents the purchasing utility's avoided cost for as-available energy.[293]

190. Examples of factors a state reasonably could consider in making this determination (in addition to the core finding that the liquid market hub represents the purchasing utility's avoided cost for as-available energy) are: (1) Whether the hub is sufficiently liquid that prices at the hub represent a competitive price;[294] (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; 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. These factors are not intended to be exhaustive, and states reasonably could consider other factors in identifying a relevant liquid market hub for setting as-available QF energy rates.

191. 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.[295] In addition, market prices in a region may be determined 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.[296] Such adjustments may be necessary to ensure that the

[277] *Id.* P 56.

[278] Arizona Public Service Comments at 6–8; El Paso Electric Comments at 2–3.

[279] Portland General Comments at 6–7.

[280] Xcel Comments at 8.

[281] IdaHydro Comments at 11; Southeast Public Interest Organizations Comments at 19.

[282] IdaHydro Comments at 11; Industrial Energy Consumers Comments at 12–13.

[283] Public Interest Organizations Comments at 64.

[284] Union of Concerned Scientists Comments at 8.

[285] Industrial Energy Consumers Comments at 12.

[286] *Id.*

[287] Southeast Public Interest Organizations Comments at 18.

[288] *Id.* at 19.

[289] ELCON Comments at 25.

[290] *Id.*

[291] *Id.*

[292] Allco Comments at 7–8.

[293] *See* NOPR, 168 FERC ¶ 61,184 at PP 53, 56.

[294] 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 Nat. Gas and Elec. Mkts.,* 109 FERC ¶ 61,184, at P 66.

[295] 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.

[296] NOPR, 168 FERC ¶ 61,184 at P 58.

competitive market price reflects a purchasing utility's actual avoided costs for as-available energy.

192. Arguments regarding the short-term nature of liquid market hubs and claims that use of such prices is discriminatory are addressed in Section IV.B.2 above.

193. We will not address in this final rule arguments about whether particular market hubs should be found to represent avoided costs or, to the contrary, that particular market hubs may be too illiquid or insufficiently granular, or that prices at particular market hubs may not reflect avoided costs. We are not making any determination in this final rule that the prices at any specific market hub do or do not represent the avoided costs of any specific utility. Rather, we are allowing the states the flexibility to rely on prices at liquid market hubs to set as-available avoided cost energy rates for QF sales in regions outside RTO/ISO markets upon a state finding that it is appropriate to do so given the specific circumstances governing a particular market hub and the purchasing utility involved. The aggrieved entity would be able to challenge the state's decision to use a liquid market hub price in the appropriate forum, which could include any one or more of the following: (1) Initiating or participating in proceedings before the relevant state commission or governing body; (2) filing for judicial review of any state regulatory proceeding in state court (under PURPA section 210(g)); or, alternatively (3) filing a petition for enforcement against the state at the Commission and, if the Commission declines to act, later filing a petition against the state in U.S. district court (under PURPA section 210(h)(2)(B)).[297]

194. With respect to Southeast Public Interest Organizations' assertion that the liquid market hub proposal in the NOPR does not require states to determine whether liquid market hub prices represent a utility's avoided costs, the Commission intended to impose such a requirement as a prerequisite before a liquid market hub may be relied on as a measure of a purchasing utility's avoided cost of as-available energy. However, we acknowledge that the regulatory text in the NOPR was ambiguous in that regard. Therefore, the regulatory text of 18 CFR 292.304(b)(7)(i) in the final rule has been revised to make this more clear.

c. Proposed Modifications

i. Comments

195. APPA requests that the Commission clarify that, in addition to liquid market hubs, as-available energy avoided costs could be determined based on prices of comparable competitive quality.[298] APPA states that amending the proposed regulation in this fashion would also enable utilities proximate to (or embedded within) RTO/ISO markets to reference prices in those markets as viable alternatives in establishing avoided costs.[299]

196. The California Commission requests that the Commission clarify that states previously were permitted to use liquid market hub prices under the current PURPA Regulations and that the proposed revisions simply codify and confirm the validity of this past practice.[300] The California Commission and Massachusetts DPU further request that the proposed rules be modified to permit states to use competitive prices to set both energy and capacity costs, and to not be limited to using such mechanisms only for as-available energy prices.[301]

197. EEI notes that some states may be located in regions with access to more than one market hub and those states should have the flexibility to use an average of market hub prices or develop a formula correlated to the appropriate market hubs to develop the electric utility's avoided cost.[302] EEI notes that this proposal is not new, but its inclusion in the Commission's regulations will provide certainty to states.[303]

198. NIPPC, CREA, REC, and OSEIA assert that the liquid market hub proposal should not be adopted without making significant changes.[304] For example, they argue, only long-term contract prices reported at market hubs should be used.[305] Even with respect to market-hub prices for long-term contracts, they assert that the Commission should include safeguards to ensure that prices are set based on liquid trading with a sufficient number of competitors to assure effective price discovery, that prices are not subject to manipulation, and that reported price indices are accurate and not subject to mis-reporting or other forms of manipulation.[306] Finally, they argue that the Commission should require avoided costs to include the costs of transmission to and from such hubs except in cases where the utility's system directly interconnects with that hub.[307] Resources for the Future makes similar arguments.[308]

199. In contrast, NorthWestern asserts that liquid market hub prices should be adjusted downward by a transmission differential to reflect the cost of getting energy from the market to load.[309] NorthWestern states that reliance on the market hub to establish avoided costs only remains a valid option if the prices are less than what it would cost a utility to build a resource to supply its customers' needs.[310]

ii. Commission Determination

200. We clarify that, in adopting a rule allowing states to use liquid market hubs to determine as-available avoided energy costs, we are not finding that the use of liquid market hubs for this purpose prior to the issuance of this final rule was not permitted. Depending on the specific circumstances, a state may appropriately have determined, prior to the final rule, that a liquid market hub price represented a purchasing utility's as-available avoided energy cost. After the effective date of this final rule, an aggrieved entity may seek review of a state's determination to use liquid market hubs in the appropriate forum.[311]

201. We confirm that: (1) States located in regions with access to more than one market hub have the flexibility to use an appropriate average of market hub prices or to develop an appropriate formula that relies on data from relevant market hubs to develop an electric utility's as-available avoided energy cost, so long as doing so yields a price that accurately reflects the purchasing electric utility's as-available avoided energy cost;[312] (2) states must determine that a liquid market hub is sufficiently liquid that its prices represent a competitive price;[313] and (3) the market hub price may need to be subject to adjustments to account for transmission costs the electric utility would incur.[314]

[297] *See Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978,* 23 FERC ¶ 61,304.

[298] APPA Comments at 13.

[299] *Id.* at 13.

[300] California Commission Comments at 24.

[301] California Comments at 25; Massachusetts DPU Comments at 8–10.

[302] EEI Comments at 26.

[303] *Id.* at 27.

[304] NIPPC, CREA, REC, and OSEIA Comments at 60.

[305] *Id.*

[306] *Id.*

[307] *Id.*

[308] Resources for the Future Comments at 8.

[309] NorthWestern Comments at 5.

[310] *Id.*

[311] *See Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978,* 23 FERC ¶ 61,304.

[312] NOPR, 168 FERC ¶ 61,184 at P 58.

[313] *Id.* P 57.

[314] *Id.* P 58.

202. Finally, we find that the general ruling requested by APPA regarding the use of ''prices of comparable competitive quality'' to set as-available avoided cost rates is beyond the scope of this rulemaking in that here we were proposing only particular discrete changes to our regulations for setting as-available avoided cost energy rates charged by QFs.

5. Use of Formulas Based on Natural Gas Prices To Establish a Permissible Rate for Certain As-Available QF Energy Sales

a. NOPR Proposal

203. The Commission observed in the NOPR that, in regions where there are no RTOs/ISO or liquid market hubs, 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.[315]

204. The Commission therefore proposed 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 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 a particular proposed natural gas price index 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. The Commission described the above factors as not exhaustive and proposed providing states the flexibility to apply other factors that also might be appropriate for consideration.[316]

205. The Commission stated that natural gas price indices coupled with the heat rate of an efficient natural gas combined-cycle generating facility may be a reasonably accurate measure of avoided cost, at least in those markets where natural gas-fired resources are commonly the marginal units. In such markets, the Commission stated that it 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 displace them economically. Thus, the Commission found preliminarily that using natural gas price indices and the heat rate of an efficient combined-cycle natural gas generating facility to establish an avoided cost energy rate relies on competitive market forces, in this case competitive forces in natural gas markets for the fuel used by natural gas combined-cycle generating facilities that the purchasing electric utility, but for the purchase from the QF, would generate itself or purchase from another source.[317]

b. Comments

206. Several entities oppose the NOPR's Combined Cycle Prices proposal.[318] Allco asserts that this is exactly the type of administrative avoided cost determination about which NARUC and utilities have complained.[319] Allco also argues that the only reason for including the Combined Cycle Prices proposal in the Commission's regulations is to create a menu of prices from which a state commission or unregulated utility can choose the lowest price, which Allco claims would not encourage QF generation, and would be inconsistent with the rules of economic dispatch and the language of PURPA.[320] Public Interest Organizations argue that the Combined Cycle Price proposal is discriminatory to QFs for all the same reasons that restricting QF rates to LMP is discriminatory (*i.e.,* because utilities can, and allegedly do, pay effective prices for energy that exceed the calculation from natural gas prices and assumed combined cycle heat rates).[321] Southeast Public Interest Organizations argue that the Combined Cycle Prices proposal does not require states to include variable O&M costs in the proxy combined cycle plant or an adjustment for natural gas transportation, even though a utility-owned combined cycle gas plant would be allowed to recover both types of costs.[322]

207. In contrast, R Street opposes the proposal because using natural gas combined cycle plants as the basis for QF rates in non-RTO/ISO regions could lead to the overpayment of a QF. R Street argues that regions without organized wholesale markets should instead price QF rates at the lowest cost resource based on an administratively determined avoidable cost.[323]

208. Similarly, ELCON argues that the proposal is complicated by the fact that natural gas units are not always marginal, especially in export-constrained subregions when renewables output is high. ELCON believes this proposal would be subject to extensive forecasting error, and therefore argues that careful assessment should precede its adoption.[324]

209. Other entities support the NOPR's Combined Cycle Price proposal.[325] The California Commission and EEI argue that states already had this flexibility under the current regulations, and request that the Commission acknowledge this fact in a final rule.[326] Similarly, other supporters of the Combined Cycle Price proposal argue that states should have the ability to develop as-available energy price formulas based on technologies other than combine cycle gas plants, if doing so would more accurately reflect the relevant purchasing utility's avoided cost.[327]

210. El Paso Electric argues that: (1) The gas index price should be adjusted to account for the basis differential between the price at the natural gas hub and the price of natural gas in or near the utility's service area; and (2) states should be allowed to update the formula periodically to reflect improved

[315] *Id.* P 59.

[316] *Id.*

[317] *Id.* P 54.

[318] Allco Comments at 8; BluEarth Comments at 1–2; ELCON Comments at 25–26; Industrial Energy Consumers Comments at 10–11; Public Interest Organizations Comments at 64; R Street Comments at 5; Southeast Public Interest Organizations Comments at 19–20.

[319] Allco Comments at 8.

[320] *Id.*

[321] Public Interest Organizations Comments at 64.

[322] Southeast Public Interest Organizations Comments at 19–20.

[323] R Street Comments at 5.

[324] ELCON Comments at 26.

[325] APPA Comments at 12–13; Arizona Public Service Comments at 6; California Commission Comments at 23; Chamber of Commerce Comments at 4; Duke Energy Comments at 9–10; EEI Comments at 27; El Paso Electric Comments at 3; Idaho Commission Comments at 3; Southern Comments at 9.

[326] California Commission Comments at 23; EEI Comments at 27–28.

[327] APPA Comments at 13; Duke Energy Comments at 10; EEI Comments at 27; Idaho Commission Comments at 3; Southern Comments at 9–11.

efficiencies in combined cycle generating facilities.[328]

c. Commission Determination

211. We adopt the NOPR proposal to revise 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 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. We also clarify that the formulas used to set as-available energy rates based on natural gas prices should include recovery of variable O&M costs.

212. While some commenters oppose allowing states to use Combined Cycle Prices (or other competitive prices) to set avoided energy cost rates, states already had the flexibility to determine avoided costs in this manner under the current regulations, as the California Commission and EEI observe.[329] If Combined Cycle Prices accurately represent a particular purchasing utility's avoided energy costs, their use would be consistent with the Commission's existing definition of avoided costs as ''the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.'' [330] Furthermore, as noted above in section IV.B.2, the use of competitive market prices, including Combined Cycle Prices, to set QF rates is explicitly subject to the requirement that such prices are equal to the purchasing utility's avoided energy costs. Therefore, this proposal merely codifies more explicitly an option for determining avoided cost rates that already existed, *i.e.,* where a state determines that a Combined Cycle Price is a measure of the purchasing electric utility's avoided cost for as-available energy.

213. The concerns of R Street, ELCON, and others that Combined Cycle Prices may not reflect a particular purchasing electric utility's avoided cost are addressed by the requirement that the state would need to determine that the Combined Cycle Price indeed represents the purchasing electric utility's avoided cost for as-available energy.

214. While some commenters requested that we expand the proposed regulation explicitly to include technologies other than combined cycle natural gas generating facilities, we decline to do so for two reasons. First, as already mentioned, the current regulations are already flexible enough to accommodate states calculating avoided costs based on the cost of the generating units or technology that accurately reflects the relevant purchasing utility's avoided cost.[331] Second, this proposal focused specifically on combined cycle technology, as opposed to other generating technologies, because combined cycle generation makes up such a large portion of the nation's generation fleet.[332] This relative ubiquity, coupled with the fact that combined cycle natural gas generation facilities are often the marginal units in many regions, justifies an elevated profile in the PURPA Regulations for combined cycle technology compared to other technologies. This final rule does not foreclose other technologies from being used for avoided cost determination, upon an appropriate finding by the state that they accurately measure a purchasing electric utility's avoided cost for as-available energy.

215. Southeast Public Interest Organizations support their opposition to Combined Cycle Prices in part by claiming that the Commission did not specifically require states to include variable O&M in the formula. We agree that variable O&M expenses are an appropriate cost component of formula rates and should be included in any Combined Cycle Price formulae in order to accurately reflect the relevant purchasing electric utility's avoided costs.

216. With respect to the arguments of Southeast Public Interest Organizations regarding natural gas transportation costs, the regulation we adopt in this final rule, 18 CFR 292.304(b)(7)(ii)(C), specifically requires that states consider whether there should be an adjustment to the natural gas price to appropriately reflect the cost of transporting natural gas to the relevant market. As to El Paso Electric's arguments regarding index price adjustments using basis differentials, and periodic formula updates to reflect efficiency improvements, we note that the revisions to the PURPA Regulations, which we adopt in this final rule, provide that states which choose to rely on Combined Cycle Prices must consider, when designing their formulae, whether and to what extent to include these costs, based on their assessment of how best to identify a relevant purchasing electric utility's avoided cost for as-available energy.[333]

6. 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

217. The NOPR noted that, 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. Accordingly, the NOPR suggested that 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 proposed to add a new option in 18 CFR 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.[334] In other words, states could rely on estimates of forecasted energy prices at the time of delivery over the anticipated life of the contract—such estimates are commonly referred to as forward price curves—to develop a fixed energy rate component for that contract when such estimates reflect the purchasing electric utility's avoided costs.

218. The NOPR stated that 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).[335] 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; however, the energy rate in the contract could be different from year-to-

[328] El Paso Electric Comments at 3–4.

[329] States could have used any of the competitive prices adopted in this final rule to set avoided cost energy rates as long as such prices met, to the extent practicable, the factors described 18 CFR 292.304(e).

[330] *See* 18 CFR 292.101(b)(6).

[331] *See* 18 CFR 292.101(b)(6).

[332] According to EIA data, the nameplate capacity of natural gas-fired combined cycle generation technology, exceeds the nameplate capacity of generation from any other fuel source. *See* EIA, *Electric Power Annual Table 4.7.A Net Summer Capacity of Utility Scale Units by Technology and by State, 2018 and 2017 (Megawatts), https://www.eia.gov/electricity/annual/html/epa_04_07_a.html,* and *4.7.C Net Summer Capacity of Utility Scale Units Using Primarily Fossil Fuels and by State, 2018 and 2017 (Megawatts), https://www.eia.gov/electricity/annual/html/epa_04_07_c.html.*

[333] *See* new 18 CFR 292.304(b)(7)(ii).

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

[335] *Id.* P 62 (noting that 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 (citing 18 CFR 292.304(e)(2)).

year (or some other period) and nevertheless comply with the current requirement in 18 CFR 292.304(d)(2)(ii) that the energy rate be fixed for the term of the contract.[336]

a. Comments

219. Two commenters oppose the NOPR proposal to add a new option in 18 CFR 292.304(d)(1)(iii) permitting fixed energy rates to be based on forecasted estimates of the stream of revenue flows during the life of the contract.[337] Southeast Public Interest Organizations and Mr. Mattson state that the NOPR proposal is a departure from past precedent.[338] Southeast Public Interest Organizations state that this proposal suffers the same deficiencies as the LMP and liquid market hub price proposals. Furthermore, according to Southeast Public Interest Organizations, the NOPR provides no analysis as to how or whether the forward price curves result in just and reasonable and non-discriminatory rates as required by PURPA.[339]

220. Other commenters support the NOPR proposal to add a new option in 18 CFR 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.[340] The South Dakota Commission and Pennsylvania Commission state that they support the NOPR proposal on forecasted values of the estimated stream of revenues because it forecasts a steady stream of revenue and provides built-in flexibility.[341] According to these commenters, the proposal also balances the QF's need for a steady stream of revenue with the purchasing electric utility's responsibility to have a prudent mix of supply contracts for its provider of last resort obligations.[342] The Chamber of Commerce states that, while future rates are not guaranteed to materialize, the projected rates will more accurately reflect those realized than a single avoided cost rate set at the inception of a QF contract.[343]

221. Arizona Public Service states that it supports the proposal because it grants states additional flexibility, which helps protect utilities' customers from over-paying for generation due to QFs need for sales guarantees and financing.[344] NRECA agrees that states must have flexibility in determining forecasted market prices including appropriate discounting to ensure that utilities and consumers are not locked into contracts with fixed prices that are higher than prevailing market prices.[345]

222. NRECA requests that the Commission clarify proposed revisions to 18 CFR 292.304(d)(1)(i), (ii), and (iii) to state that an electric utility is exempt from offering a stream of market revenue as payment, even if there is a market hub price that could be relevant.[346] The Connecticut Authority also suggests that the Commission modify 18 CFR 292.304(d)(1)(ii) to specify that a state may set a series of energy rates. For this option, Connecticut Authority argues, the regulatory text should provide greater regulatory and commercial certainty to QF developers, avoiding disputes with distribution utilities and states.[347]

223. Connecticut Authority supports revisions to 18 CFR 292.304(d)(2) because the rule would permit a state to limit a QF's option to select a preferred energy rate methodology.[348] Connecticut Authority also supports the proposed 18 CFR 202.304(d)(iii) that permits states to set a stated or fixed rate for energy that is calculated using the present value of the expected stream of revenue from as-available energy rates during the life of the contract or LEO.

224. EEI states that this proposal is not novel, and as an example notes that the Commission and a federal district court have already found that the Connecticut Authority could set avoided cost rates based on a forecast of future avoided costs.[349] According to EEI, the Commission has not ruled either that any form of forecasting is mandated or that any is unacceptable.[350]

225. Allco states that the proposed new option in 18 CFR 292.304(d)(1)(iii) permitting fixed energy rates to be based on forecasted estimates of the stream of revenue flows during the life of the contract is consistent with PURPA section 210 and is already permitted. Allco also states that forecasts need to be non-discriminatory. According to Allco, utilities and states frequently use one forecast when dealing with QFs and another when obtaining approval for their favored projects; Allco asserts that this practice is discriminatory.[351]

226. APPA states that the proposed change is a logical extension of the conclusion that market options are a legitimate alternative means of specifying avoided costs.[352] Distributed Sun states that it supports permitting states to set fixed energy rates with forward curves or through competitive solicitations.[353] NorthWestern supports the proposal to permit fixed energy rates to be on a forward price curve developed from prices in either the organized markets or liquid market hubs.[354]

b. Commission Determination

227. We adopt the proposal to add a new option in 18 CFR 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. The Commission has previously permitted the use of this method to establish energy and capacity rates over the term of a contract or LEO.[355] Nevertheless, given the flexibilities we adopt in this final rule with respect to competitive market prices and variable energy rates, we clarify here that a state may use competitive market prices and/or variable energy rates in the context of a more fixed estimated avoided cost energy rate (together with a fixed avoided capacity rate) that is determined at the time an LEO or contract is incurred. The fixed energy rate component of the contract could be

[336] *Id.* (noting that this is permissible under the Commission's existing PURPA Regulations (citing *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))).

[337] Southeast Public Interest Organizations Comments at 25; Mr. Mattson Comments at 26.

[338] Southeast Public Interest Organizations Comments at 25; Mr. Mattson Comments at 26.

[339] Southeast Public Interest Organizations Comments at 25.

[340] Allco Comments at 8; APPA Comments at 14; Arizona Public Service Comments at 2–3; Chamber of Commerce Comments at 4–5; Connecticut Authority at 13; Distributed Sun Comments at 2; EEI Comments at 28–30; Idaho Commission Comments at 4; NorthWestern Comments at 6; NRECA Comments at 8; Pennsylvania Commission Comments at 8; Resources for the Future Comments at 8; South Dakota Commission Comments at 3.

[341] Pennsylvania Commission Comments at 8–9; South Dakota Commission Comments at 3.

[342] Pennsylvania Commission Comments at 8–9.

[343] Chamber of Commerce Comments at 4–5.

[344] Arizona Public Service Comments at 2–3.

[345] NRECA Comments at 8.

[346] *Id.* at 9.

[347] Connecticut Authority Comments at 14.

[348] *Id.* at 13.

[349] EEI Comments at 28 (citing *Allco Renewable Energy Ltd.* v. *Mass. Elec. Co.,* 208 F. Supp. 3d. 390, 395 (D. Mass. 2016); *Windham Solar,* 157 FERC ¶ 61,134 at P 5.

[350] EEI Comments at 28–30.

[351] Allco Comments at 8.

[352] APPA Comments at 14.

[353] Distributed Sun Comments at 2.

[354] NorthWestern Comments at 6.

[355] *Windham Solar,* 157 FERC ¶ 61,134 at P 4 (citing 18 CFR 292.304(d)(2)).

a single rate, based on the amortized present value of forecast energy prices, or it could be a series of specified rates that change from year-to-year (or other periods) in future years. We also will allow the state to establish the applicable energy rate(s) for the QF for the entire term or the rate may change from year-to-year (or some other period) of the contract at the time the LEO is incurred.

228. Southeast Public Interest Organizations and Mr. Mattson state that the NOPR proposal is a departure from past precedent. The very purpose of a proceeding like this is to consider changes to our regulations and our doing so is not impermissible.

229. Southeast Public Interest Organizations also state that the proposal suffers the same deficiencies as the LMP and liquid market hub pricing proposals and that the NOPR provides no evidence as to how or if the forward price curves present just and reasonable and non-discriminatory rates as required by PURPA. Given that we find above that LMPs and liquid market hub prices may reflect avoided as-available energy costs and that estimates of such prices over the term of a contract can therefore reflect a purchasing electric utility's avoided as-available costs over time, we do not believe Southeast Public Interest Organizations and Mr. Mattson's concerns are justified.

230. Although, as described below, we allow states to require variable avoided cost energy rates, allowing forward price curves determined at the time an LEO is incurred provides an additional option for states to calculate avoided energy costs in advance while also using transparent metrics for those calculations. Use of the forward price curve does not deter the adoption of just and reasonable and non-discriminatory rates required by PURPA, moreover, and insofar as we require that states determine that the estimated stream of revenues reflects the purchasing electric utility's avoided energy, such pricing is fully consistent with the statute's requirements. With regard to forecasts, we acknowledge that the forecast used to set the avoided cost rate must meaningfully and reasonably reflect the utility's avoided costs over time.[356]

231. We decline to modify this proposal expressly either to permit or prohibit a state from setting a series of estimated avoided energy costs over time. Each state will be required to determine whether a particular estimated stream of revenues represents a purchasing electric utility's avoided costs over a specified term. Similarly, in order to provide states flexibility to use LMPs and other competitive market prices to establish as-available avoided energy costs, we will not require a state to use this option to guarantee a stream of revenues.

7. Providing for Variable Energy Rates in QF Contracts

a. Background

232. As explained above, if a QF chooses to sell energy and/or capacity pursuant to a contract, the PURPA Regulations currently provide the QF the option of receiving the purchasing electric utility's avoided cost calculated and fixed at the time the LEO is incurred.[357] The Commission's justification in Order No. 69 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.[358] 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." [359] Further, the Commission agreed with the "need for certainty with regard to return on investment in new technologies." [360] The Commission stated its belief that any overestimations or underestimations "will balance out." [361]

233. 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 have declined in recent 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.[362] Based on this concern, some 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 [QFs] 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.[363] 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.[364]

b. NOPR Proposal

234. In the NOPR, the Commission proposed to revise 18 CFR 292.304(d) 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 or LEO, and instead allow the state the flexibility to require QF energy

[356] *See* 18 CFR 292.304(b)(5). 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.

[357] 18 CFR 292.304(d)(2)(ii).

[358] 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").

[359] *Id.*

[360] *Id.*

[361] *Id.*

[362] *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 [percent] 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 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 [percent] 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 [percent] 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 (filed June 30, 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 [percent] from 2011 through 2015 (from approximately $60 per megawatt-hour to less than $30 per megawatt-hour).").

[363] EEI Supplemental Comments, attach. A at 4; *see also* Southern Company Comments, Docket No. AD16–16–000, at 7 (filed June 30, 2016) ("[T]he avoided energy cost payment to the QF should be based on actual avoided energy cost at the time the QF delivers energy.").

[364] *See* Technical Conference, Docket No. AD16–16–000, Tr. 26:22–25, 27:1–3 (June 29, 2016) (filed July 8, 2016) (Technical Conference Tr.) (Solar Energy Industries) ("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.").

rates to vary during the term of the contract. However, under the proposed revisions to 18 CFR 292.304(d), a QF would continue to be entitled to a contract with avoided *capacity* costs calculated and fixed at the time the contract or LEO is incurred. Only the *energy* rate in the contract or LEO could be required by a state to vary. Further, the NOPR did not propose to obligate states to require variable avoided cost energy rates—they would retain the ability to allow the QF's energy rate be fixed at the time the LEO is incurred.[365]

235. The Commission preliminarily found compelling the record evidence that overestimations have not been adequately balanced by underestimations in past years. Further, it appeared to the Commission that this trend may persist into the future with the continuing general decline in the cost of both wind and solar generation.[366] Consequently, the Commission found 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 to 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.'' [367]

236. The Commission acknowledged that the current PURPA Regulations allowing a QF to fix its rates for the life of a contract or LEO were based on the recognition that fixed rates are beneficial for obtaining financing for QF projects. The Commission also recognized that QF developers have continued to assert that they require fixed rates to finance new projects. However, the Commission stated that it did not view the proposed modification to the PURPA Regulations as materially affecting the ability of QFs to obtain financing for several reasons.[368]

237. First, the Commission expressed its understanding 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. The Commission stated that these fixed capacity and variable energy payments have been sufficient to permit the financing of significant amounts of new capacity in the RTOs and ISOs.[369] 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.[370] Other comments at the Technical Conference suggested that a fixed capacity charge likewise would be adequate for financing a QF project.[371]

238. The Commission further noted that there are financial products available, such as contracts for differences, which allow generation owners to hedge their exposure to fluctuating energy prices.[372] The Commission stated that 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.[373]

239. The Commission also explained that, 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. The Commission stated that the fact that owners of such facilities, which do not have recourse to the avoided cost rate provisions of PURPA, have been able to obtain financing for new projects is 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.[374]

240. For example, EIA data showed that, since 2005, QFs have made up only 10% to 20% 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.[375] EIA data also showed that net generation of energy by non-utility owned renewable resources in the United States escalated from 51.7 terawatt hours (TWh) in 2005 when EPAct 2005 was passed, to 340 TWh in 2018. The Commission further observed that, 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 [376] increased from 3.6 TWh in 2005 to 19.5 TWh in 2012, and to 42.5 TWh in 2018. 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.[377]

241. The Commission found that EIA data on independently-owned natural gas-fired generation capacity told 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 would not be within the scope of the PURPA avoided cost rate provisions. The Commission cited to EIA data showing that, in 2018,

[365] NOPR, 168 FERC ¶ 61,184 at P 67.

[366] *Id.* P 68 (citing EIA, Today in Energy, *Average U.S. construction costs for solar and wind continued to fall in 2016* (Aug. 8, 2018), *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 . . . .'')).

[367] *Id.* P 68 (internal quotations omitted) (citing 16 U.S.C. 824a–3(b)(1)).

[368] *Id.* P 69.

[369] *Id.* P 70 (citing Monitoring Analytics, LLC., *Third Quarter, 2018 State of the Market Report for PJM, January through September,* at 249, Table 5–6 (Nov. 8, 2018), *http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2018/2018q3-som-pjm.pdf* (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)).

[370] *Id.* (citing 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.''); *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.'')).

[371] *Id.* P 70 (citing Solar Energy Industries Comments, Docket No. AD16–16–000, at 3 (filed June 30, 2016) (''Developers need rates for such sales of *energy and/or capacity* to be fixed.'') (emphasis added)).

[372] *Id.* P 72 (citing *Elec. Storage Participation in Mrkts. Operated by Reg'l Transmission Org. and Independent Sys. 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'')).

[373] *Id.* P 72.

[374] *Id.* P 73.

[375] *Id.* P 74 (citing EIA, Today in Energy, *North Carolina has More PURPA-Qualifying Solar Facilities than any other State,* figure titled *PURPA qualifying facilities (1980–2015) percent of total renewable capacity* (Aug. 23, 2016), https://eia.gov/todayinenergy/detail.php?id=27632).

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

[377] NOPR, 168 FERC ¶ 61,184 at P 74.

approximately 44% of all energy produced by natural gas-fired generation in the United States was generated by independently-owned capacity.[378] The total amount of energy produced in 2018 by independently-owned natural gas-fired generation was 651 TWh, an increase of 13.7% from 2017.[379] 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 State region, 21.4% of the energy produced by natural gas-fired generation in 2018 was produced by independently-owned capacity, and in Oregon and Washington 45.4% of natural gas-fired energy was produced by independently-owned capacity.[380] From this, the Commission concluded that independent owners of non-QF generation have been, and continue to be, able to obtain financing for their facilities.[381]

242. The Commission did 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 Commission concluded that the evidence demonstrated 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. The Commission reasoned that QFs, which have the ability to take advantage of PURPA's mandatory purchase requirements, should be better positioned than non-QFs to negotiate the necessary contractual arrangements for financing. Moreover, the Commission noted that QFs are equally as well positioned as non-QF independent generators to take advantage of federal and state incentives designed to encourage the construction of renewable resources. [382]

243. Further, the Commission pointed to evidence that the desire to limit the effect of fixed QF contract rates had directly led to PURPA implementation issues that affected QF financing in other respects, particularly with respect to the length of QF contracts.[383] For example, a commissioner of the 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.[384] Similarly, Southern Company testified that the fixed rate requirement is ''resulting in . . . typically shorter contract term lengths.'' [385] Golden Spread Electric Cooperative recommended that, if the fixed rate requirement is not eliminated, the Commission permit shorter contract terms, ''as short as one-year or three years at most.'' [386]

244. Finally, the Commission addressed one particular standard form of QF contract rate currently employed by a number of utilities, which is a one-part rate, applicable to each MWh of energy delivered by the QF. This one-part rate is calculated to reflect both avoided capacity costs and avoided energy costs. Contracts employing such rates also typically impose a must purchase obligation on the purchasing utility. The Commission stated that its proposed rule was not intended to prevent states from implementing such an approach to setting QF contract rates in the future. The Commission proposed that, to the extent 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 18 CFR 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.[387]

c. General Comments on the NOPR Proposal

i. Comments in Support of NOPR Proposal

245. Several commenters support the NOPR proposal to allow energy rates to vary in QF contracts and other LEOs, arguing it will reduce overpayments and protect customers.[388] In that regard, Duke Energy asserts that the primary factor behind overpayment has been the requirement to offer fixed avoided cost energy rates during a period of rapidly declining energy prices.[389] Several other commenters similarly cite to the general decline of energy prices coupled with the fact that QFs have been able to lock in rates over the life of a contract or other LEO as reasons for their support of the NOPR proposal.[390]

246. Several commenters also support the NOPR's variable rate proposal because it will allow states greater flexibility to determine avoided cost rates accurately and to meet PURPA's consumer protection goals.[391] LG&E/KU states that such flexibility is appropriate and necessary to meet the statutory requirement that ratepayers not pay a rate that exceeds the electric utility's incremental cost of alternative energy.[392] NorthWestern argues that providing such flexibility will assist in guaranteeing that customers are held harmless by purchases of QF power.[393]

247. Supporters of the NOPR variable rate proposal also commented on specific aspects of the proposal. These comments are discussed in more detail in the following sections.

ii. Comments in Opposition to NOPR Proposal

248. Several commenters oppose the NOPR variable energy rate proposal.[394]

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[378] NOPR, 168 FERC ¶ 61,184 at P 75 (citing EIA, *Electric Power Monthly with Data for December 2018,* at tbl. 1.7.B, *https://www.eia.gov/electricity/monthly/current_month/epm.pdf.*).

[379] *Id.*

[380] *Id.*

[381] *Id.*

[382] *Id.* P 76.

[383] *Id.* P 65 (citing Natural Resources Defense Council Comments, Docket No. AD16–16–000, at 4 (filed June 30, 2016)).

[384] *Id.* P 65 (citing 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.'')).

[385] *Id.* P 65 (citing Technical Conference Tr. at 202 (Southern Company)).

[386] *Id.* P 65 (citing Golden Spread Electric Cooperative Comments, Docket No. AD16–16–000, at 10 (filed June 30, 2016)).

[387] *Id.* P 81.

[388] Conservative Action Comments at 1; Consumer Energy Alliance Comments at 2; EEI Comments at 30–31; Idaho Power Comments at 7–8; Idaho Commission Comments at 4; LG&E/KU Comments at 3; NextEra Comments at 5; *see also* Alaska Power Comments at 1; Arizona Public Service Comments at 3–4; Basin Comments at 6–8; Chamber of Commerce Comments at 4; Freedom Center Comments at 1–2; R Street Comments at 5; Tax Reform Comments at 1–2.

[389] Duke Energy Comments at 5–7.

[390] Consumer Energy Alliance Comments at 2; Idaho Power Comments at 7–8; Idaho Commission Comments at 4; LG&E/KU Comments at 3; Ohio Commission Energy Advocate Comments at 4.

[391] Alliant Energy Comments at 9; Duke Energy Comments at 8–9; LG&E/KU Comments at 4; MA DPU Comments at 1, 7; NorthWestern Comments at 6–7.

[392] LG&E/KU Comments at 4.

[393] NorthWestern Comments at 6–7.

[394] Allco Comments at 9–11; AllEarth Comments at 2; Biogas Comments at 2; BluEarth Comments at 2; CARE Comments at 3–5; Biological Diversity Comments at 8; ELCON Comments at 18, 21–23; EPSA Comments at 6–13; Massachusetts AG Comments at 8–9; North Carolina DOJ Comments at 2–6; North Carolina Commission Staff Comments at 2–4; New England Hydro Comments at 8; NIPPC, CREA, REC, and OSEIA Comments at 29–48; North American-Central Comments at 4–6; Public Interest Organizations Comments at 6–7, 27–51; Resources for the Future Comments at 4–7; Solar Energy Industries Comments at 28–38; SC Solar Alliance

Continued

In addition to objections as to specific aspects of that proposal, which are discussed in the following sections, some commenters raise threshold issues regarding this proposal.

249. NIPPC, CREA, REC, and OSEIA cite to the PURPA Conference Report as expressing Congress's intent that QFs be entitled to long-term fixed energy rates. Specifically, they cite to the statement in the Conference Report that ''the Commission and States should look to the reliability of that power to the utility and the cost savings to the utility which may result at some later date by reason of supply to the utility at that time of power from the cogenerator or small power producer.'' [395] According to NIPPC, CREA, REC, and OSEIA, this statement shows that ''Congress also recognized that attempts to set the rates based on the avoided costs at the time of delivery would likely be insufficient to encourage such facilities.'' [396]

250. Harvard Electricity Law asserts that the Commission may not authorize state regulators to change rates in existing contracts.[397] Harvard Electricity Law then asserts that the Commission: (1) Attempts to portray its agenda as consistent with Congressional intent by providing a skewed summary of the legislative history; (2) presents an unsupported statement that its rules will ''continue to encourage'' QF development, which ignores the administrative record and fails to account for regulatory changes since PURPA's enactment; (3) misreads its own rules in claiming that repeal is necessary to protect consumers; and (4) relies on a finding that fixed price energy contracts are not necessary to encourage QFs that is based on irrelevant data and questionable assumptions that are not grounded in reasoned decision making.

251. Harvard Electricity Law also asserts that allowing long-term contracts to include variable rates is contrary to PURPA.[398] In support of this assertion, Harvard Electricity Law cites to two decisions which it claims stand for the proposition that the Commission's proposed rule would impose forbidden utility-type regulation on QFs.[399]

252. NIPPC, CREA, REC, and OSEIA and Public Interest Organizations assert that it is unclear whether independent power producers that have obtained financing did so with short-term variable rate conditions.[400] North American-Central argues that, if a variable rate will preclude a QF from receiving financing in the first place, it is irrelevant that a state might be more willing to offer a longer-term contract.[401]

iii. Commission Determination

253. In this final rule, we adopt without modification the NOPR variable rate proposal. We find that setting QF energy avoided cost contract and other LEO rates at the level of the purchasing utility's avoided energy costs at the time the energy is delivered is consistent with PURPA, which limits QF rates to the purchasing utility's avoided costs. Indeed, a variable energy avoided cost approach is a more accurate way to ensure that payments to QFs equal, but do not exceed, avoided costs.[402] It is inevitable that, in contrast, over the life of a QF contract or other LEO a fixed energy avoided cost rate, such as that used in past years, will deviate from actual avoided costs.

254. As described in more detail in the following sections, the record overwhelmingly supports our conclusions that long-term forecasts of avoided energy costs are inherently less accurate, and that states should be given the flexibility to rely on a more accurate variable avoided cost energy rate approach. Further, there are numerous instances where overestimates and underestimates have not balanced out.[403] When that has occurred, consumers have borne the brunt of the overpayments, which subsidized QFs, in contravention of Congressional intent and the Commission's expectations.

255. Given that PURPA section 210(b) prohibits the Commission from requiring QF rates in excess of avoided costs,[404] this record evidence supports our decision to give the states the flexibility to require variable avoided cost energy rates in QF contracts and other LEOs to prevent QF rates from exceeding avoided costs. We discuss specific aspects of the variable energy rate provisions below, but at the outset address certain threshold issues raised in the comments.

256. We reiterate the points made in detail above in Section II. The variable energy avoided cost rate provision is not based on any determination that the Commission's rules no longer should encourage QF development. The question of whether QFs should continue to be encouraged is a question for Congress. Rather, we are revising the PURPA Regulations by giving states the flexibility to require variable avoided cost energy rates in QF contracts and other LEOs in order to better comply

Comments at 4–10; Southeast Public Interest Organizations Comments at 9–18; sPower Comments at 10–13; State Entities Comments at 2–3; Mr. Mattson Comments at 26–27; Two Dot Wind Comments at 11–13; Western Resource Councils Comments at 2.

[395] NIPPC, CREA, REC, and OSEIA Comments at 27 (quoting Conf. Rep. at 98–99).

[396] *Id.*

[397] Harvard Electricity Law Comments at 23 (citing *API,* 461 U.S. at 414).

[398] *Id.* at 28.

[399] *Id.* at 29 (citing *Freehold Cogeneration Assoc.* v. *Bd. of Regulatory Comm'rs. of N.J.,* 44 F.3d 1178, 1193 (3d Cir. 1995) (*Freehold Cogeneration*); *Smith Cogeneration Mgt.* v. *Corp. Comm'n.,* 863 P.2d 1227 (Okla. 1993) (*Smith Cogeneration*)).

[400] NIPPC, CREA, REC, and OSEIA Comments at 46.

[401] North American-Central Comments at 5–6.

[402] 16 U.S.C. 824a–3(b)(1).

[403] *See* Duke Comments at 6 (Duke's QF contracts cost $4.66 billion but its ''actual current avoided costs'' are $2.4 billion); Idaho Power Comments at 10–11 (''The cost of PURPA generation contained in Idaho Power's base rates, on a dollars per MWh basis, is not just greater than Mid-C market prices, it is greater than all the net power supply cost components currently recovered in base rates. Idaho Power's average cost of PURPA generation included in base rates is $62.49/MWh. At $62.49/MWh, the average cost of PURPA purchases is greater than the average cost of FERC Account 501, Coal at $22.79/MWh; greater than FERC Account 547, Natural Gas at $33.57/MWh; greater than FERC Account 555, Non-PURPA Purchases at $50.64/MWh; and significantly greater than what is being sold back to the market as FERC Account 447, Surplus Sales at $22.41/MWh.''); Portland General Comments at 5 (''for a typical 3 MW Solar QF project that incurred a LEO in 2016 and reaches commercial operations three years later, [Portland General's] customers would pay 67% more for the project's energy than if the 2019 avoided cost rate had been used. As a result of this lag, [Portland General's] customers would pay an additional $1.6 million more for the energy from the QF facility over the 15-year contract term.''); *see also* NOPR, 168 FERC 61,184 at P 64 n.101 (citing Alliant Energy, Comments, Docket No. AD16–16–000, at 5 (filed 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 incremental $17.54 million above market wind prices over the next 10 years.'') (emphasis in original); EEI Supplemental, Comments, attach. A at 3–4 (''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 (filed June 30, 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).'').

[404] This prohibition is described in Section IV.A.

with Congress's clear instruction in PURPA that the Commission may not require QF rates in excess of a purchasing utility's avoided costs.

257. By its very nature, the question of fixed versus variable energy rates is a question of how risk from increases in avoided energy costs over the life of a QF contract or other LEO should be allocated. Answering this question requires the Commission to allocate this risk either to (i) customers of electric utilities, or (ii) QFs and their investors and lenders. But the Commission does not have unlimited discretion in how it resolves the question. Congress in PURPA section 210(b) provided guidance to the Commission in how it should perform that allocation—by mandating that the Commission cannot adopt a rule that provides for a rate that exceeds the incremental cost of alternative electric energy.[405]

258. Opponents of variable avoided cost energy rates urge the Commission to continue placing this risk on the customers of electric utilities, as it did in the past, by retaining the option for QFs to fix their avoided cost energy rates in their contracts or LEOs notwithstanding record evidence, discussed elsewhere in this final rule, that fixed energy rates compared to actual avoided costs have not balanced out over time. But, after consideration of the record, the Commission has decided instead to allow states to reduce the risk to customers by giving states the flexibility to require variable avoided cost energy rates in QF contracts and LEOs. The Commission's determination ensures that the PURPA Regulations continue to be consistent with the statutory avoided cost rate cap in PURPA section 210(b), coupled with the directive in the Conference Report that customers of utilities not be required to subsidize QFs.[406]

259. Third, there is no merit to the contention that the PURPA Conference Report expresses Congressional intent that QFs are entitled to long-term fixed energy rates. The statement in the Conference Report cited by NIPPC, CREA, REC, and OSEIA does not support this contention.[407] The example provided in the PURPA Conference Report was of a utility owning a hydroelectric generating facility. Congress hypothesized that this utility might be able to avoid drawing down its reservoir as a result of a purchase from a QF, and thereby be able to generate electricity from the hydroelectric facility at a later date rather than running a more expensive fossil fuel unit at that later date. Congress stated that the avoided cost in its example should be based on the cost of the more expensive fossil unit whose operation was avoided at a later date rather than the avoided cost at the time the QF delivered its energy.[408]

260. While Congress recognized that the better measure of avoided cost in that scenario might be the cost of the alternative fossil fuel unit that would not be run at that later date,[409] nothing in the quoted section of the PURPA Conference Report suggests that Congress intended the Commission to require that all avoided cost energy rates be fixed at the outset for the life of a QF contract or other LEO. And nothing in the revision being implemented in this final rule would prohibit a state from calculating a QF's avoided cost energy rate for a QF contract or LEO in the manner suggested in the PURPA Conference Report or, indeed, in the manner the Commission has long allowed, if a state determined that such an approach best reflects the purchasing electric utility's avoided costs.

261. Fourth, the variable avoided cost energy rate provision adopted herein does not run afoul of the *Freehold Cogeneration* and *Smith Cogeneration* cases cited by Harvard Electricity Law.[410] Those decisions, which overturned state avoided cost determinations allowing for changes in QF rates, were based on the provision in the original PURPA Regulations giving QFs the option to select contracts with long-term fixed avoided cost rates.[411] Indeed, the *Smith Cogeneration* decision quotes at length from the explanation in Order No. 69 of the Commission's justification for its requiring in its regulations fixed avoided cost rates in QF contracts and LEOs.[412] Neither decision suggests that PURPA would prevent the Commission from revising its regulations to allow states the flexibility to require variable avoided cost energy rates, as the Commission is doing here.

262. Harvard Electricity Law also relies on *Freehold Cogeneration* and *Smith Cogeneration* to assert that the Commission is imposing ''utility-type'' regulation in violation of Congressional intent as expressed in the PURPA Conference Report.[413] However, those holdings do not address the changes the Commission is implementing here. By adopting a provision that allows states the option to require variable avoided cost energy rates, we are not mandating ''utility-type'' regulation. The PURPA Conference Report states that: ''It is not the intention of the conferees that [QFs] become subject . . . to the type of examination that is traditionally given to electric utility rate applications to determine what is the just and reasonable rate that they should receive for their electric power.'' [414] Our action today is consistent with that statement; we are not subjecting QFs to the same type of examination that is traditionally given to electric utility rate applications (*e.g.,* cost-of-service rate regulation).

263. Indeed, the regulation adopted today does not subject QF rates to any examination whatsoever of the costs incurred by QFs in producing and selling power. Rather, the variable avoided cost energy rate provision applicable to QF contracts and other LEOs that is adopted in this final rule sets QF rates based on the avoided costs

[405] 16 U.S.C. 824a–3(b); *see also* 16 U.S.C. 824a–3(d); 18 CFR 292.101(b)(6), 292.304(b)(2).

[406] Conf. Rep. at 98 (''The provisions of this section *are not intended to require the rate payers of a utility to subsidize* cogenerators or small power produc[er]s.'') (emphasis added).

[407] *See* NIPPC, CREA, REC, and OSEIA Comments at 27 (quoting Conf. Rep. at 98–99).

[408] *Id.* at 98–99 (''In interpreting the term 'incremental cost of alternative energy,' the conferees expect that the Commission and the states may look beyond the cost of alternative sources which are instantaneously available to the utility. Rather, the Commission and states should look to the reliability of that power to the utility and the cost savings to the utility which may result at some later date by reason of supply to the utility at that time of power from the cogenerator or small power producer; for example an electric utility which owns a source of hydroelectric power and which is offered the sale of electric energy from a cogenerator or small power producer might, if measured over the short term, have a low incremental cost of alternative power because of its access to hydropower; however, it may be the case that by purchasing from the cogenerator or small power producer and saving hydropower for later use, the utility can avoided the use of expensive electric energy generated by fossil fired units during later months of its seasonal generation cycle. Thus, viewed over the longer period of time, the incremental cost of alternative electric energy might be substantially higher than that measured by the instantaneously available hydropower.'').

[409] Under the approach adopted in this final rule, with the flexibility granted to states to adopt—but not a mandate directing states to adopt—variable avoided cost energy rates for QF contracts and other LEOs, states can adopt a pricing approach that best fits their circumstances, including adopting the pricing approach described by the Conference Report to address the circumstances described by the Conference Report.

[410] Harvard Electricity Law Comments at 29 (citing *Freehold Cogeneration,* 44 F.3d at 1193; *Smith Cogeneration,* 863 P.2d at 1227).

[411] *See Smith Cogeneration,* 863 P.2d at 1241 (holding that allowing reconsideration of established avoided costs ''makes it impossible to comply with PURPA *and FERC regulations requiring established rate certainty for the duration of long term contracts* for qualifying facilities that have incurred an obligation to deliver power'') (emphasis added); *Freehold Cogeneration,* 44 F.3d at 1193 (relying on *Smith Cogeneration* analysis that ''that PURPA *and FERC regulations* preempted the State Commission rule'') (emphasis added).

[412] *Smith Cogeneration,* 863 P.2d at 1240.

[413] Harvard Electricity Law Comments at 30.

[414] Conf. Rep. at 97.

of the purchasing utility. In no sense can this variable avoided cost energy rate provision be characterized as imposing utility-style regulation on the QFs themselves.

264. Finally, we agree with Harvard Electricity Law that state regulators may not change rates in existing QF contracts or other existing LEOs.[415] By its terms, the variable energy avoided cost provision adopted in this final rule applies only prospectively to new contracts and new LEOs entered into after the effective date of this final rule. Nothing in the final rule, including in this preamble, should be read as sanctioning the modification of existing fixed-rate QF contracts and LEOs.

d. Whether the Current Approach Has Resulted in Payments to QFs in Excess of Avoided Costs

i. Comments in Support of NOPR Proposal

265. Duke Energy states that its experience shows the Commission's original assumption that overestimations and underestimations will balance out over time was incorrect. From 2012 to 2017, Duke Energy states that it experienced explosive growth in solar QF contracts, and entered into at a time of rapidly declining natural gas prices—which drove down Duke Energy's avoided costs. Duke Energy states that, as of July 1, 2019, it has almost 4,000 MW of QF power under contract and in commercial operation. Duke Energy claims the total estimated financial obligation on Duke Energy's retail and wholesale customers to pay for this QF power is approximately $4.66 billion over the next approximately 15 years. If the contracts had been permitted to contain rates that mirrored the utilities' declining incremental costs either to generate that electric energy itself or to purchase alternative electric energy, *i.e.,* Duke Energy's ''actual current avoided costs,'' Duke Energy asserts that the contracts would be valued at $2.4 billion. Duke Energy claims that, among the factors contributing to this overpayment of $2.26 billion for the remainder of these QF contracts, the primary factor has been the requirement to offer fixed avoided cost energy rates during a period of rapidly declining energy prices.[416]

266. EEI argues that relying on certain avoided cost methods, such as the costs of a proxy unit at a fixed point in time, may result, and has resulted, in the over estimation of future energy prices, leaving customers saddled with uneconomic PURPA contracts. According to EEI, the Commission's variable rate proposal will help ensure that the variable energy rate more accurately reflects the electric utility's actual avoided cost of energy so that rates for customers are just and reasonable. EEI describes this change as important for states, especially those in RTO/ISO markets, that elect to have the avoided cost rate set at LMP.

267. EEI also submitted with its comments a study performed by Concentric Energy Advisors showing that the avoided cost rates in the sample of solar and wind QF contracts they reviewed generally exceeded rates that are realized in competitive markets for solar and wind energy. According to that report, the total overpayment ranged between $2.7 billion and $3.9 billion. Several other commenters also cited the Concentric Energy Advisors report for the proposition that consumers nationwide have overpaid for QF contracts between 2009–2018.[417] Berkshire Hathaway represents that PURPA contracts held by PacifiCorp will cost customers more than $1.2 billion above projected market costs over the next 10 years.[418]

268. Massachusetts DPU argues that a 10-year, fixed energy rate based on current New England wholesale energy market prices is highly likely to diverge from actual energy market prices over the ten-year contract term and could significantly harm ratepayers.[419] Mr. Transeth represents that Consumers Energy's QF contracts are priced between 30 to 50% higher than their current market value.[420]

269. APPA supports the variable energy rate proposal because the discrepancy between administratively set, locked-in, long-run avoided costs and actual market prices for the purchase of equivalent energy can be enormous, as demonstrated by the evidence submitted in the Technical Conference. According to APPA, were continued development of the IPP and renewable industries in jeopardy, the Commission might have grounds to conclude that enabling QFs to lock in energy payments over the course of their agreement is needed in order to bolster these resources, but the growth in the IPP and renewables industries in RTOs/ISOs indicate otherwise.[421]

270. Commissioner O'Donnell asserts that the Montana Public Service Commission has addressed concerns about overpayments by shortening QF contract length from 25 years to 15, which has resulted in litigation currently pending before the Montana Supreme Court. Commissioner O'Donnell asserts that, because the energy component of an avoided cost rate reflects the price at which the purchasing electric utility could purchase power on the open market, there is no need to fix that fluid energy component for as long as 25 years.[422]

271. Competitive Enterprise asserts that long-term fixed price rates ''serve only to reward certain financial investors at the expense of consumers, who are forced to pay inflated rates for electricity'' and insists that utilities should only be required to purchase from resources that are needed and competitively priced.[423]

ii. Comments in Opposition to NOPR Proposal

272. Harvard Electricity Law observes that the Commission's examples of contract rates that exceed avoided costs calculated years prior illustrate the general proposition that ''energy forecasts have a manifest record of failure.''[424] Harvard Electricity Law notes, however, that in issuing Order No. 69, the Commission recognized that industry changes are difficult to forecast, but the Commission nonetheless concluded in Order No. 69 that the possibility that consumers would be harmed by high rates was outweighed by the Commission's duty to encourage QFs.[425] Harvard Electricity Law further claims that the repeal of the fixed-price rule is not necessary to protect consumers from rates in future contracts.[426] Harvard Electricity Law argues that the Commission's rules do not require an annual matching between avoided costs and rates, nor prevent states from setting declining avoided costs (which Order No. 69 explicitly condones).[427]

273. Several commenters argue that the NOPR's assertion of artificially high avoided cost rates is unsupported or

[415] Harvard Electricity Law Comments at 23 (citing *API,* 461 U.S. at 414).

[416] Duke Energy Comments at 6.

[417] Alliant Energy Comments at 7–8; Conservative Action Comments at 1; Duke Energy Comments at 5–7; Mr. Moore Comments at 2; Mr. Transeth Comments at 2.

[418] Berkshire Hathaway Comments at 5.

[419] Massachusetts DPU Comments at 7 (citing NOPR, 168 FERC ¶ 61,184 at 40).

[420] Mr. Transeth Comments at 2.

[421] APPA Comments at 16.

[422] Commissioner O'Donnell Comments at 2.

[423] Competitive Enterprise Comments at 2.

[424] Harvard Electricity Law Comments at 24 (citing Vaclav Smil, *Energy at the Crossroads: Global Perspectives and Uncertainties,* Mass. Inst. Tech., 2003, at 121, 145–149).

[425] Harvard Electricity Law Comments at 24.

[426] *Id.* at 23.

[427] *Id.* at 23–24 (citing Order No. 69, FERC Stats. & Regs. ¶ 30,128 at 30,881).

relies on flawed data and analysis.[428] For example, NIPPC, CREA, REC, and OSEIA argue that the Commission relied on flawed data and analysis by using actual market prices that resulted after substantial QF penetration (which they assert has reduced power prices).[429]

274. Public Interest Organizations claim that the NOPR's evidence of overestimations is based on a selective choice of years reflecting general wholesale price declines, in which QF contracts were executed just before unforeseen natural gas price declines.[430] Public Interest Organizations argue that these recent electricity price overestimations are not unique to QFs and can be explained by general declines in natural gas prices since the adoption of hydraulic fracturing and the 2007–2009 recession.[431]

275. Public Interest Organizations dispute Alliant's asserted overestimation by claiming that Alliant likely would have procured non-QF energy at the same price and further point out that Alliant does not disclose the data upon which it relies.[432] Public Interest Organizations assert that the Commission similarly erred in relying on EEI's description of overestimations of avoided costs in PacifiCorp's QF contracts because PacifiCorp only compares those prices to the Mid-C hub and does ''not contain an analysis of the long-term balancing of its forecasted avoided energy rates with actual avoided energy costs.'' [433] Public Interest Organizations contend that this comparison implies that PacifiCorp would have relied entirely on the Mid-C hub for all of its needs but for the QF contracts.[434]

276. SC Solar Alliance contests Duke Energy's estimate of $2.26 billion in overpayments for QF power. According to SC Solar Alliance, ''an expert witness for South Carolina's Office of Regulatory Staff, which represents the interests of the using and consuming public in proceedings before the South Carolina Commission, recently testified that Duke's estimation of 'overpayments' to QFs was not reliable and that he 'wouldn't put a whole lot of weight in [Duke's estimate].' '' [435]

277. GridLab attacks the conclusions of the Concentric Report, raising two principal arguments. First, according to GridLab, QF contracts are executed in non-competitive markets where utilities do not perform competitive solicitations. If QF avoided cost pricing is higher than prices set through competitive bidding, GridLab asserts that is because the utility's production costs are higher than competitive prices.[436] Second, GridLab asserts that Concentric has compared two datasets that are different in several ways, most notably project size—with larger projects enjoying economies of scale that result in lower costs. According to GridLab, the difference in project size and its impact on cost is a significant factor that could account for the whole of the reported increase on price.[437]

278. NIPPC, CREA, REC, and OSEIA argue that it was unreasonable for the Commission in the NOPR to assume that electricity price declines are permanent, given recent integrated resource plans (IRP) in the Northwest predicting significantly increased electricity demand and market prices at the Mid-C and Palo Verde hubs.[438] NIPPC, CREA, REC, and OSEIA represent that electricity prices will climb significantly in the Northwest. NIPPC, CREA, REC, and OSEIA also assert that 100% renewable or non-emitting generation mandates and increased electrification of transportation could substantially increase electricity demand. NIPPC, CREA, REC, and OSEIA contend that fixed-price QF contracts protect consumers from the potential for future rising prices, market volatility, market risk, and project risk.[439]

279. Resources for the Future reasons that ''while fixed prices determined [five to ten] years ago would likely exceed current average market prices, that may not be true for fixed prices determined either more recently or in the future.'' [440] Resources for the Future states that, contrary to the NOPR, there is no consensus that wind and solar generation costs will continue to decline because any capital cost declines will be relatively modest and will be offset by declining federal tax credits.[441] Furthermore, Resources for the Future attributes these cost declines to the recent U.S. natural gas boom and points out that this decline is therefore not likely to continue.[442] sPower similarly argues that recent energy price declines will not necessarily continue, especially given expiring tax credits and additional tariffs.[443]

280. Several commenters assert that the risk of overpayments to QFs should be compared to the alternative generation sources used by the utility.[444] For example, ELCON claims that critics who assert that QFs are ''locking-in'' consumers to artificially high rates must acknowledge that utility procurement does exactly the same via the pre-approval process, sometimes for even longer durations. ELCON argues that QFs can only benefit consumers by competing on a level playing field with comparable terms and conditions.[445] North Carolina Commission Staff similarly asserts that the risk of overpayment to QFs should be considered in the context of a utility's long-term commitment to build plants where ''generation decisions are based upon uncertain forecasts that could result in ratepayers bearing the same type of forecast risk from utility plants as they do from QFs.'' [446]

281. According to Solar Energy Industries, the risk from utility generation construction is allocated to ratepayers for the life of these assets regardless of ongoing changes in energy prices, while PURPA was designed to shift this risk away from ratepayers. Solar Energy Industries state that there is no evidence that ratepayers are harmed by long-term QF contracts any more than other long-term contracts or utility recovery of generation assets in their rate base. Solar Energy Industries state that, even though solar prices have declined over time, solar QFs should not be penalized for utility failures to update their avoided cost calculations to keep pace with such declines.[447]

282. The DC Commission states that, with respect to the fact that long-term contracts (*e.g.,* 20 years) using fixed avoided energy costs could create stranded costs potentially due to

[428] NIPPC, CREA, REC, and OSEIA Comments at 30; Public Interest Organizations Comments at 39–40; Public Interest Organizations Comments at 43; Solar Energy Industries Comments at 34–36.

[429] NIPPC, CREA, REC, and OSEIA Comments at 30–31.

[430] Public Interest Organizations Comments at 39–40.

[431] *Id.* at 47–50.

[432] *Id.* at 40–41.

[433] *Id.* at 41 (citing NOPR, 168 FERC ¶ 61,184 at P 64 n.101 (citing EEI Supplemental Comments, Docket No. AD16–16–000, attach. A at 3–4 (June 25, 2018))).

[434] *Id.*

[435] SC Solar Alliance Comments at 7 (quoting Public Service Commission of South Carolina, Docket No. 2019–185 & 186–E, Hearing Transcript Vol. 2 at 596, lines 6–21 (Horii Test.)) (attached as Appendix 1 to SC Solar Alliance Comments).

[436] GridLab Comments at 1–2.

[437] *Id.* at 4.

[438] NIPPC, CREA, REC, and OSEIA Comments at 33–34.

[439] *Id.* at 34–36.

[440] Resources for the Future Comments at 4.

[441] *Id.* at 5.

[442] *Id.* at 4.

[443] sPower Comments at 10–11.

[444] ELCON Comments at 22; North Carolina Commission Staff Comments at 2–3; NIPPC, CREA, REC, and OSEIA Comments at 31; Public Interest Organizations Comments at 40, 43; Solar Energy Industries Comments at 36–38.

[445] ELCON Comments at 22.

[446] North Carolina Commission Staff Comments at 2–3.

[447] Solar Energy Industries Comments at 36–38.

inaccurate projections, the chance of creating stranded costs is substantially reduced when the most up-to-date data regarding avoided energy costs is used. The DC Commission states that, if the contract length is permitted to be flexible, the possibility of stranded costs would be significantly reduced for shorter term contracts.[448] The DC Commission states that, without the worry of stranded costs, there is no need to eliminate the fixed price contract option for QFs.[449]

iii. Commission Determination

283. As explained above, the NOPR proposal to give states the flexibility to require variable energy pricing in QF contracts and other LEOs, instead of providing QFs the right to elect fixed energy prices, was based on the Commission's concern that, at least in some circumstances, long-term fixed avoided cost energy rates have been well above the purchasing utility's avoided costs for energy—a result prohibited by PURPA section 210(b). And the record evidence demonstrates just that, *i.e.,* that QF contract and LEO prices for energy can exceed and have exceeded avoided costs for energy without any subsequent balancing out. In addition to the examples presented in the record of the Technical Conference that were cited in the NOPR, commenters have provided additional examples of such overpayments, as described above.[450] Such evidence has persuaded us that it is necessary to give states the flexibility to address QF contract and LEO rates for energy that exceed avoided costs for energy, while at the same time still allowing states the flexibility to continue requiring long-term fixed avoided cost energy rates in QF contracts and other LEOs when such treatment is appropriate.

284. As Harvard Electricity Law concedes, the examples of QF contract rates that exceed avoided costs that are in the record illustrate the general proposition that ''energy forecasts have a manifest record of failure.'' [451] It is this ''manifest record of failure'' including evidence in the record that the failure has been at the expense of consumers, that drives us to make the change adopted in the final rule.[452]

285. While some commenters challenge the idea that avoided cost energy rates in QF contracts and other LEOs have exceeded actual avoided costs, their arguments largely either concede that overestimations have occurred while arguing that such overestimations impacted purchasing electric utilities just as much as QFs, or attempt to argue that such overestimations were temporary or unusual. For these reasons, they assert that the Commission should not conclude that historical overestimations of avoided cost require a change to the current PURPA Regulations requiring states to allow QFs to fix their avoided costs energy rates for the term of their contracts. These arguments do not cause us to reconsider our determination, for the reasons explained below.

286. First, Harvard Electricity Law's citation to the Commission's original determination in Order No. 69 that it was not necessary to provide for variable avoided cost energy rates carries little weight.[453] The purpose of the NOPR was to reconsider the Commission's determinations made in Order No. 69 in light of changes in circumstances and additional evidence that was not available to the Commission when it issued Order No. 69 in 1980. The record evidence cited above demonstrates that, contrary to the Commission's finding in 1980, overestimations and underestimations of future avoided costs may not even out.[454] Consequently, the Commission's determination in 1980 does not preclude the Commission from changing the rule adopted at that time.

287. We agree with Public Interest Organizations that the recent electricity price overestimations were not unique to QFs and can be explained by general declines in natural gas prices since the adoption of hydraulic fracturing and the 2007–2009 recession.[455] But that is precisely why the estimates of avoided costs reflected in the QF contracts and LEOs were incorrect and why the resulting fixed avoided cost energy rates reflected in such QF contracts and other LEOs resulted in QF rates well above utility avoided costs in violation of PURPA section 210(b); the precipitous decline in natural gas prices caused a corresponding reduction in utilities' energy costs, and thus in their energy avoided costs but this decline was not reflected in the QFs' fixed contract rates that remained at their previous levels.

288. Similarly, arguments from commenters that electric utilities also based resource acquisitions on incorrect forecasts of natural gas prices [456] ignore a key distinction between utility rates and fixed QF rates. Electric utilities may have relied on incorrect natural gas price forecasts to justify the timing and type of their resource acquisitions, as commenters assert. But once an electric utility resource decision was made, their cost-based rate regimes typically obligated the electric utility eventually to pass through to customers any energy cost savings realized as a result of declining natural gas and other fuel prices, as well as any energy cost savings due to lower purchased power rates resulting from the decline in natural gas prices. By contrast, once QF avoided cost energy rates were fixed based on now-incorrect (and now-high) natural gas price forecasts, those energy rates remained fixed for the term of the QFs' contracts and LEOs. Therefore, unlike fixed avoided cost energy rates in QF contracts and LEOs, cost-based electric utility energy rates declined as the cost of natural gas and other fuels and purchased power declined.

289. We also disagree with Public Interest Organizations' assertions that it was improper to have used competitive market hub prices to determine whether fixed QF contract and LEO prices resulted in overpayments as compared to electric utilities' actual avoided costs.[457] We recognize that the competitive market hub prices used in the comparisons may not have precisely reflected the avoided energy costs of all electric utilities located in the same region as the competitive market hub. However, as explained above in the discussion of the use of Market Hub Prices to determine avoided energy costs, competitive market prices in general should reflect the marginal avoided energy costs of utilities with access to such markets. Certainly, those markets generally reflect the marginal cost of energy in the region.[458] The

[448] DC Commission Comments at 8.

[449] *Id.*

[450] *See* Duke Comments at 6; Idaho Power Comments at 10–11; Portland General Comments at 5; NOPR, 168 FERC ¶ 61,184 at P 64 n.101.

[451] Harvard Electricity Law Comments at 24 (citing Vaclav Smil, *Energy at the Crossroads: Global Perspectives and Uncertainties,* Mass. Inst. Tech., 2003, at 121, 145–149).

[452] *See, e.g., supra* P 254 & note 403.

[453] *Id.* at 23–24 (citing Order No. 69, FERC Stats. & Regs. ¶ 30,128, at 30,881).

[454] *See* Duke Comments at 6; Idaho Power Comments at 10–11; Portland General Comments at 5; NOPR, 168 FERC ¶ 61,184 at 64 n.101.

[455] Public Interest Organizations Comments at 47–50.

[456] ELCON Comments at 22; North Carolina Commission Staff Comments at 2–3; NIPPC, CREA, REC, and OSEIA Comments at 31; Public Interest Organizations Comments at 40, 43; Solar Energy Industries Comments at 36–38.

[457] Public Interest Organizations Comments at 40–41.

[458] A review of recent Mid-C Hub daily spot prices (from Intercontinental Exchange (ICE) *https://www.eia.gov/electricity/wholesale/,* indicates that they reflect the marginal cost of energy in that area since they are usually the result of a significant number of trades (averaging 54 per day), counterparties (averaging 16 per day), and trading volume (averaging 26,714 MWh/day), which usually exceed those of the NP–15 trading hub, an active Western trading hub in Northern California

magnitude of the differences between the market hub prices and the QF contract and LEO prices provides solid evidence that the QF contract and LEO prices used in the comparison were well above actual avoided energy costs at the time the energy was delivered by the QFs, even if the exact magnitude is unclear.

290. We acknowledge that energy prices may increase in the future, as several commenters point out.[459] However, as noted by Harvard Electricity Law, ''energy forecasts have a manifest record of failure.'' [460] Moreover, the fact that energy prices may increase in the future does not eliminate the risk that fixed avoided cost energy rates could still be above actual avoided costs. That is, if the actual increase in energy prices is still lower than the forecasted increase that would form the basis of the fixed avoided cost energy rate, then the fixed avoided cost energy rate will be above actual avoided energy costs. Giving states the flexibility to require variable avoided cost energy rates in QF contracts and in other LEOs will allow states to better ensure that avoided cost energy payments made to QFs will more accurately reflect the purchasing utility's avoided costs regardless of whether energy prices are increasing or declining. We also note that, if energy prices do in fact increase, variable avoided cost energy pricing would protect and even benefit the QF itself, as it would not be locked into a fixed energy rate contract or LEO that would be below the purchasing electric utility's avoided energy cost.

291. Although many commenters agreed that fixed QF energy rates were higher than actual avoided energy costs in at least some instances, challenges were raised against both Duke Energy's estimate that its fixed QF contract rates were $2.6 billion above market costs, and the Concentric Report's comparison of QF fixed rates for wind and solar facilities with the cost of wind and solar projects with competitive, non-PURPA contracts.

292. However, the expert testimony cited by the SC Solar Alliance, that the witness ''wouldn't put a whole lot of weight in [Duke's estimate],'' [461] does not address Duke's calculation of past overpayments. Rather, the witness was answering a question regarding the potential for overpayments ''[f]or going forward solar,'' *i.e.,* future overpayments as a result of the new fixed avoided cost rates being considered by the South Carolina Commission that were the subject of the expert witness' testimony.[462] The same witness acknowledged the past overpayments made by Duke Energy, which he attributed to ''drops in natural gas prices that no one could've foreseen.'' [463] It is these overpayments due to unforeseen declines in natural gas prices that form an important basis for the Commission's determination in this final rule to now give states the flexibility to require variable avoided cost energy rates in QF contracts and LEOs.

293. With respect to the criticisms of the Concentric Report, we emphasize that we have not relied on that report to support the variable energy avoided cost provision adopted in the final rule. It is not clear that the lower cost of the competitively priced renewable resources identified in the report represents the avoided costs of the purchasing utilities that entered into the QF contracts at fixed rates for renewable resources under PURPA. Therefore, it is not clear that the difference in costs identified by Concentric can be ascribed to the fixed rates in the QF contracts or rather to the fact that the avoided cost rates in the QF contracts were based on more expensive non-renewable capacity that was avoided by the purchasing utilities.

e. Whether the Proposed Change Would Violate the Statutory Requirement that the PURPA Regulations Encourage QFs

i. Comments

294. Several commenters argue that the NOPR's variable rate proposal is inconsistent with PURPA's mandate that the PURPA Regulations ''encourage'' the development of QFs.[464] Southeast Public Interest Organizations state that removing QFs' right to a fixed energy rate would flout Congressional intent that PURPA encourage QF development because fixed rates are necessary to attract QF financing.[465] Harvard Electricity Law states that Congress's mandate to encourage QFs is not contingent on industry conditions and does not expire.[466]

ii. Commission Determination

295. As explained above in Section IV.A.1, the statutory requirement that the Commission's PURPA Regulations encourage QFs remains, but it is bounded by the statutory provision in PURPA section 210(b) that QF rates may not exceed a purchasing utility's avoided costs. Further, as explained above, we have determined, based on the record evidence, that it is not necessarily the case that overestimations and underestimations of avoided energy costs will balance out. Consequently, a fixed energy rate in a QF contract or LEO potentially could violate the statutory avoided cost cap on QF rates.

296. The Commission's PURPA Regulations continue to encourage the development of QFs by, among other things, allowing a state to vary the rate paid to the QF over time but in a way that satisfies the rate cap established in PURPA section 210(b). In this way, the QF can obtain a higher rate when the utility's avoided costs increase, and ratepayers are not paying more than the utility's avoided costs when prices decrease. Furthermore, as discussed above, allowing the use of variable energy rates may promote longer contract terms, which would help encourage and support QFs.[467] It therefore is consistent with PURPA section 210(b), as well as the obligation imposed by PURPA section 210(a) to revise the Commission's PURPA Regulations ''from time to time,'' to provide the states the flexibility to require that QF contracts and other LEOs implement variable avoided cost energy rates in order to prevent payments to QFs in excess of the purchasing electric utility's avoided energy costs. PURPA section 210(b) prohibits the Commission from requiring QF rates above avoided costs even if, according to some commenters, a fixed avoided cost energy rate would provide greater encouragement to QFs than a variable avoided cost energy rate.

in the CAISO footprint (averaging 6 trades per day, 4 counterparties per day, and 2,756/MWh per day). The prices for Mid-C ranged between an average of approximately $16/MWh high price and $13/MWh low price during the recent spring (Mar 19–Jun 20, 2020). During this period the index was reported for 65 trading days for Mid-C and 9 trading days for NP–15.

[459] NIPPC, CREA, REC, and OSEIA Comments at 33–36; Resources for the Future Comments at 4; sPower comments at 10–11.

[460] Harvard Electricity Law Comments at 24 (citing Vaclav Smil, *Energy at the Crossroads: Global Perspectives and Uncertainties,* Mass. Inst. Tech., 2003, at 121, 145–149).

[461] SC Solar Alliance Comments at 7 (quoting, Public Service Commission of South Carolina, Docket No. 2019–185 & 186–E, Hearing Transcript Vol. 2, Tr. at 596: 6–21 (Horii Test)) (attached as Appendix 1 to SC Solar Alliance Comments).

[462] Public Service Commission of South Carolina, Docket No. 2019–185 & 186–E, Hearing Transcript Vol. 2, Tr. 596: 3–4 (Horii Test)) (attached as Appendix 1 to SC Solar Alliance Comments).

[463] *Id.* at 593:21–22.

[464] Allco Comments at 9; Con Edison at 3, 4; Harvard Electricity Law Comments at 1; North American-Central Comments at 4–6; Southeast Public Interest Organizations at 9–11.

[465] Southeast Public Interest Organizations Comments at 9–10.

[466] Harvard Electricity Law Comments at 1.

[467] *See infra* P 349.

f. Discrimination

i. Comments in Support of NOPR Proposal

297. Alliant Energy observes that utility-owned generation and traditional power purchase agreements (PPAs) are subject to a demonstration of need and that traditional PPAs are subject to re-evaluation during their term to determine whether they continue to be cost-competitive and in the best interests of customers. Alliant Energy asserts that, by contrast, QFs are not required to demonstrate that their projects are needed and that, once a contract is executed, it is not subject to re-evaluation.[468]

ii. Comments in Opposition to NOPR Proposal

298. Several commenters assert that the NOPR's variable avoided cost energy rate proposal is discriminatory.[469] For example, EPSA argues that PURPA requires the Commission to implement regulations that, for rates for electric utility purchases from QFs, ''shall not discriminate against qualifying cogenerators or qualifying small power producers.'' EPSA describes this standard as more restrictive than the FPA's prohibition against ''unduly discriminatory'' rates. According to EPSA, the fact that long-term QF contracts are substantially above prevailing market prices due to declining wholesale prices over the long-term does not justify the variable rate proposal because electric utility-owned generation is similarly based on imperfect long-term forecasts of energy prices that oftentimes prove to be too high. EPSA therefore argues that the NOPR variable rate proposal should not be adopted unless utility-owned assets are also subject to a similar cost recovery regime.[470]

299. sPower describes the NOPR proposal to allow variable rates as providing a significant advantage to electric utilities over QFs, given that electric utilities themselves, according to sPower, have not had to lower rates to consumers as energy prices have declined.[471] ELCON asserts that pushing more market risk to QFs while utility assets remain insulated from markets creates an investment risk asymmetry. ELCON claims this puts QFs at a competitive disadvantage and shifts the consumer burden to more utility builds, which have generally been higher cost than merchant builds.[472]

300. SC Solar Alliance states that utilities often rely on fuel price forecasts over time to justify rate base approval for generation assets that might run beyond price forecasts. SC Solar Alliance argues that allowing utilities this right, but not QFs, holds QFs to a much higher standard than utilities and therefore is discriminatory.[473]

301. Commissioner Slaughter argues that, by removing the fixed, long-term contract option for independent power producers, the NOPR threatens to hamper the competitiveness of renewable-based energy firms challenging vertically integrated utilities in many localities across the country.[474]

iii. Commission Determination

302. The discrimination claims are based on the incorrect assumption that electric utilities have not been required to lower their energy rates as prices have declined. To the contrary, as explained above, utilities typically charge their customers cost-based rates, and as their fuel and purchased power costs have declined, they typically have been required to provide corresponding reductions in the energy portion of their rates to their customers.[475] Requiring QF avoided cost energy rates to likewise change as purchasing electric utilities' avoided energy costs change does not create a discriminatory difference, but rather puts QF rates on par with utility rates.

303. Further, we are not changing the requirement that QF avoided cost energy rates be set at the purchasing utility's full avoided energy costs. As the Supreme Court held in *API,* ''the full-avoided-cost rule plainly satisfies the nondiscrimination requirement.''[476] Rather, we are allowing the states the option to now choose to require QF avoided cost energy rates that vary with the purchasing utility's avoided costs of energy, rather than QF avoided cost rates that are fixed for the life of the QF's contract or LEO, to ensure the rates comply with PURPA.

g. Effect of Variable Energy Rates on Financing

i. Comments in Support of the NOPR Proposal

304. Several commenters state that fixed energy payments are not necessary for QFs to obtain financing.[477] Alliant states that it is on track to be the third largest utility owner-operator of wind facilities in the United States, with 1.9 GW on its system and in addition is increasing the pace of solar resource development in its Wisconsin territory. Alliant states it therefore does not believe that the proposed change will slow renewable deployment and adoption.[478]

305. Several commenters assert that PURPA's must-purchase requirement itself should necessarily afford QF developers a degree of certainty and enables developers to attract capital at advantageous terms.[479] The Idaho Commission states that, even if modified as proposed, QF contract terms would remain superior to competitively bid renewable projects where the energy is not ''must take'' and curtailment and other reliability parameters are imposed.[480]

306. Finadvice and APPA argue that maintaining a fixed capacity rate, as proposed by the Commission, will help attract capital and ameliorate any negative effect that the variable energy rate proposal may impose.[481] Ohio Commission Energy Advocate argues, as evidence that QFs can still flourish under a variable energy rate, that the PJM market has successfully attracted new supplies and ensured resource adequacy through fixed capacity and variable energy rates.[482]

307. The Idaho Commission states that variable energy prices protect the ratepayer while allowing the QF to ensure a stream of revenue through a longer-term contract. The Idaho Commission affirms that the rapid growth of non-QF renewable projects and their ability to obtain financing should quell any concerns about a QF's ability to obtain financing as long as PURPA's ''must take'' provision remains.[483] Commissioner O'Donnell asserts that QFs should bear some market risk as energy prices rise and fall in a way that balances risks to all parties.[484]

308. EEI argues that PURPA does not require the Commission or the states to implement regulations that guarantee a

[468] Alliant Energy Comments at 6–7.

[469] ELCON Comments at 21–22; SC Solar Alliance Comments at 5–10; sPower Comments at 13; *see also* ELCON Comments at 22; North Carolina Commission Staff Comments at 2–3; NIPPC, CREA, REC, and OSEIA Comments at 31; Public Interest Organizations Comments at 40, 43; Solar Energy Industries Comments at 36–38.

[470] EPSA Comments at 8–9.

[471] sPower Comments at 13.

[472] ELCON Comments at 21–22.

[473] SC Solar Alliance Comments at 5–10.

[474] Commissioner Slaughter Comments at 4.

[475] *See supra* PP 40, 122, 288.

[476] *API,* 461 U.S. at 413.

[477] APPA Comments at 16–17; Indiana Commission Comments at 6.

[478] Alliant Energy Comments at 6.

[479] APPA Comments at 16–17; Finadvice Comments at 2; Idaho Commission Comments at 4; Commissioner O'Donnell Comments at 3.

[480] Idaho Commission Comments at 4.

[481] APPA Comments at 16–17; Finadvice Comments at 2.

[482] Ohio Commission Energy Advocate Comments at 3–4.

[483] Idaho Commission Comments at 4.

[484] Commissioner O'Donnell Comments at 3.

QF's financeability. EEI represents that Congress intended QFs to be treated similarly to merchant generation and simply required QFs to have non-discriminatory access. According to EEI, because QFs are not subjected to the oversight or regulatory responsibilities applicable to electric utilities, it was not expected or intended that QFs be treated the same as electric utilities.[485] Similarly, Duke argues that the central design criteria for PURPA rates and terms should be customer indifference, just and reasonableness, and non-discrimination. Duke Energy states that a design that requires QF financeability as a criterion will inevitably lead to a QF boom and customer harm.[486] Duke Energy further asserts that several factors affect financeability and that, therefore, claims by QFs that they require fixed energy payments for financing purposes should be rejected.[487]

309. EEI claims QFs that require third-party financing will still be able to obtain financing if the Commission adopts the proposals in the NOPR, because they are additional options, in addition to those currently being used by states, that will be available to determine avoided costs. EEI maintains that a QF developer will be able to obtain financing under any of the options, provided it can build a cost-efficient plant that can profit at an avoided cost rate.[488] EEI claims that independent power producers lacking the certainty of the mandatory purchase obligation are building most renewable generation today because merchant power plants may be developed and financed using a variety of hedging and risk management tools, such as commodity hedges, that lock in cash flows and facilitate construction at the outset.[489]

310. APPA states that much of the renewable development that has occurred over the past 20 years has taken place within RTO/ISO footprints and therefore is largely unaided by PURPA obligations.[490]

311. Duke Energy states that concern about the potential for fixed avoided cost contract rates exceeding actual avoided costs at the time of delivery have led both North Carolina and South Carolina to enact laws placing limits on the length of QF contracts.[491] The Idaho Commission states that there is no evidence that variable energy prices would be fatal to QF development.[492] The Idaho Commission states that it reduced contract length on large projects to two years because it did not interpret the Commission's current rules to allow for a variable energy rate inside a long-term contract. The Idaho Commission states that, because its experience dictated that the longer the contract term, the more inflated the avoided cost rate, the Idaho Commission set parameters to balance QF interests against utility ratepayer interests. The Idaho Commission states that an energy rate established at the time of contract formation that provides for ''revisions to the energy rate at regular intervals, consistent with, for example, a purchasing electric utility's [integrated resource planning (IRP)] to reflect updated avoided cost calculations'' would allow states to consider longer term contracts without putting ratepayers at risk.[493] NorthWestern represents that the Montana Commission has lowered the length of QF contracts from 25 to 15 years in response to the current requirement that QFs are entitled to fixed avoided cost rates for energy in their contracts and a concern that rates calculated at the time a contract is signed are likely to change over the life of that contract.[494]

ii. Comments in Opposition to the NOPR Proposal

312. Many commenters assert that the NOPR's variable energy rate proposal will result in QFs being unable to obtain financing.[495] Several commenters also assert that it is discriminatory that utilities and non-QF generators can rate-base long-term investments and recover actual operating costs, while the NOPR's proposed rules would deprive QFs of a reasonable ability to forecast their cost recovery with no guarantees.[496]

313. Several commenters assert that the NOPR lacks evidence on the record to conclude that the variable rate proposal would not affect the ability of QFs to obtain financing.[497] NIPPC, CREA, REC, and OSEIA argue that the NOPR contained no record evidence demonstrating how this proposal would continue to encourage QFs in a non-discriminatory manner,[498] and lacks evidence on how QF generation can be financed without a fixed energy rate.[499] Similarly, Harvard Electricity Law asserts that repealing the fixed-price PPA requirement is premised on irrelevant data and ignores the record, and disagrees with the Commission's demonstration of information on non-QF capacity to show that QF development no longer relies on contracts with fixed energy rates.[500]

314. Public Interest Organizations assert that testimony from Southern Company, American Forest and Paper Association, and Solar Energy Industries, upon which the NOPR relies, states that non-QF renewable PPAs generally entail fixed energy rates rather than variable energy rates.[501] In particular, Public Interest Organizations state that testimony from Solar Energy Industries, refers to reliance on fixed rates for energy and/or capacity without describing them as alternatives but rather ''an acknowledgement that a [power purchase agreement] may provide fixed capacity in addition to fixed energy revenue, not a suggestion that a QF can be developed without a predictable energy revenue stream.'' [502]

315. Allco describes programs in California, Massachusetts, Connecticut, and Vermont that offer standard QF contract programs with variable energy rates, none of which, according to Allco, have led to the construction of solar projects.[503] Allco claims that these programs prove that, without the ability to obtain a fixed long-term forecasted rate, QF solar energy development will

[485] EEI Comments at 35.

[486] Duke Energy Comments at 17–18.

[487] *Id.* at 13.

[488] EEI Comments at 35–36.

[489] *Id.* at 36.

[490] APPA Comments at 16–17.

[491] Duke Energy Comments at 9; LG&E/KU Comments at 4.

[492] Idaho Commission Comments at 4.

[493] *Id.* (citing NOPR, 168 FERC ¶ 61,184 at P 5 n.5).

[494] NorthWestern Comments at 6–7.

[495] Allco Comments at 9; AllEarth Comments at 2; Biogas Comments at 2; BluEarth Comments at 2; Biological Diversity Comments at 8; Commissioner Slaughter Comments at 4; Con Edison Comments at 3, 4; Covanta Comments at 7–8; DC Commission Comments at 6–8; Distributed Sun Comments at 1; EPSA Comments at 2; Energy Recovery at 4; Harvard Electricity Law Comments at 5; Massachusetts AG Comments at 8–9; New England Hydro Comments at 8; NIPPC, CREA, REC, and OSEIA Comments at 37–38; North Carolina DOJ Comments at 3, 6; North American-Central Comments at 4–6; Public Interest Organizations Comments at 6–7; Resources for the Future Comments at 6–7. SC Solar Alliance Comments at 5–7; Southeast Public Interest Organizations Comments at 9–11; State Entities Comments at 2–3; Two Dot Wind Comments at 11–13.

[496] Allco Comments at 9; Commissioner Slaughter at 4; Harvard Electricity Law Comments at 5; NIPPC, CREA, REC, and OSEIA Comments at 36–37; Public Interest Organizations Comments at 6–7; Solar Energy Industries at 29–30.

[497] NIPPC, CREA, REC, and OSEIA Comments at 29, 46; Harvard Electricity Law Comments at 22, 25–27; Public Interest Organizations Comments at 6–7, 33–35.

[498] NIPPC, CREA, REC, and OSEIA Comments at 29.

[499] *Id.* at 46–48.

[500] Harvard Electricity Law Comments at 22, 25 (citing NOPR, 168 FERC ¶ 61,184 at PP 69–70, 76).

[501] Public Interest Organizations Comments at 33–35 (citing NOPR, 168 FERC ¶ 61,184, at P 70 n.114 (citing Tech. Conference, Docket No. AD16–16–000, Tr. at 153, 200 (filed June 30, 2016))).

[502] *Id.* at 35 (citing NOPR, 168 FERC ¶ 61,184, at P 70 n.115 (citing Solar Energy Industries Comments, Docket No. AD16–16–000, at 3 (filed June 30, 2016))).

[503] Allco Comments at 10.

not exist.[504] Southeast Public Interest Organizations assert that Southeastern states with fixed QF energy rates have seen vigorous QF development, while Southeastern states with variable energy rates have seen virtually no QF development, undermining the Commission's assertion that QFs can be financed without fixed energy rates.[505]

316. Covanta and Energy Recovery state that the NOPR's variable rate proposal would have an especially negative effect on Waste to Energy facilities.[506] Covanta states that, because Waste to Energy depends on finite local tax resources, a loss in energy revenue due to price variability cannot be easily replaced.[507] Covanta states that, without adequate QF pricing and multi-year contracts (and consistent, predictable pricing throughout the life of the contract), local governments may be forced to close their Waste to Energy facilities prematurely, to minimize loss and stranding that investment.[508] Energy Recovery states that the inability to secure suitable rates through a long-term contract has closed seventeen Waste to Energy facilities in the last fifteen years.[509]

317. NIPPC, CREA, REC, and OSEIA state that the NOPR's anecdotal reliance on tax incentives to encourage QF development is irrelevant because these incentives are declining or disappearing, thereby requiring QFs to rely even more on energy rates.[510] NIPPC, CREA, REC, and OSEIA predict that the NOPR's proposed rules would make QF development riskier and would thereby slow the development of new technologies such as energy storage, hydrogen fuels, and other advanced renewable energy technologies.[511]

318. Solar Energy Industries states that financing for QFs differs from financing for fossil fuel generators because ''much of the cost of installation is incurred up-front, but once installed, the generation has little, if any, variable cost.'' [512] Likewise, Harvard Electricity Law observes that wind and solar QFs, for example, have higher capital costs, lower operating costs, and provide energy intermittently, and therefore have characteristics that may present different financing challenges as compared to non-QF natural gas fired capacity.[513] Similarly, Public Interest Organizations argue that, unlike independent power producer natural gas generators with fixed capacity payments and variable energy costs, renewable QFs rely on fixed energy payments to cover their capital costs given their own nominal variable energy costs.[514]

319. NIPPC, CREA, REC, and OSEIA state that the financeability of generation with fixed capacity prices and variable energy prices inside RTOs/ISOs is irrelevant to regions that lie outside of RTOs/ISOs.[515] NIPPC, CREA, REC, and OSEIA criticize the NOPR's reliance on an independent power producer natural gas turbine's financeability outside the RTO/ISO context as irrelevant to QFs because these natural gas turbines receive fixed capacity payments and variable energy payments to account for the fluctuating price of fuel; whereas a QF would need a sufficient fixed capacity payment to support financing and an energy rate that removes market risk.[516]

320. NIPPC, CREA, REC, and OSEIA state that the NOPR's reference to hedging instruments to reduce risks from fluctuating prices is irrelevant.[517] NIPPC, CREA, REC, and OSEIA state that hedging makes projects less financeable because it increases transaction and compliance costs for small power producer QFs that cannot afford large legal divisions and trading floors to employ such hedges.[518]

321. Resources for the Future states that wind projects have used bank hedges, synthetic PPAs, and proxy revenue swaps.[519] Resources for the Future claims, however, that these products would be inaccessible to most wind QFs if fixed energy payments are eliminated. Resources for the Future argues that solar QFs would have even less access to such hedging given their smaller size and high transaction costs. Resources for the Future states that QFs under 5 MW in RTO/ISOs and QFs outside of RTO/ISOs thus would be unable to obtain financing.[520]

322. Solar Energy Industries states that QFs in RTO/ISO markets without a fixed energy rate would require a hedging instrument to finance their projects. Solar Energy Industries further states that QFs outside RTO/ISO markets without a fixed energy rate would be unable to finance their projects because they would have no access to such hedging mechanisms.[521] Solar Energy Industries states that the NOPR failed to consider which markets offer financial products, whether these financial products are available to QFs outside RTOs/ISOs, and whether these products will be sufficient to provide financing to QFs.[522]

323. Solar Energy Industries states that financing for QFs differs from financing for fossil fuel generators because much of the cost of installation is incurred up-front, with virtually no variable costs. Solar Energy Industries states that, because of this difference, financiers ''examine the QF's projected revenue stream to ensure that the revenue stream is sufficient to recover the installed costs plus a competitive return.'' [523] Solar Energy Industries reasons that QFs must therefore know in advance their facility's energy and capacity values and obtain a legally enforceable contract that fits into common underwriting models.[524]

324. North Carolina DOJ asserts that allowing avoided cost energy prices to fluctuate could eliminate fixed-price power sales contracts, thereby making compensation to QFs more volatile and discouraging renewable energy financing.[525]

325. Distributed Sun agrees with Commissioner Glick's dissent on the NOPR that revoking the fixed energy price requirement would halt the construction of most distributed energy resources.[526] Solar Energy Industries states that it is not aware of a meaningful number of QFs that have been constructed using capacity rates alone or capacity rates with variable energy rates.[527]

326. Mr. Mattson argues that a variable rate or a rate based on a projected stream of revenues during the contract are not long-term contracts. Mr. Mattson argues that this violates legislative intent and precedent and is not viable, suggesting that PURPA requires avoided cost data to be kept by a utility for public inspection.[528]

327. Western Resource Councils represents that PURPA, in the rural

[504] *Id.* at 9–11.

[505] Southeast Public Interest Organizations Comments at 9–11, 15–16.

[506] Covanta Comments at 7–8; Energy Recovery Comments at 1, 4.

[507] Covanta Comments at 7–8.

[508] *Id.* at 8.

[509] Energy Recovery Comments at 3.

[510] NIPPC, CREA, REC, and OSEIA Comments at 40–41.

[511] *Id.* at 41–42.

[512] Solar Energy Industries Comments at 30.

[513] Harvard Electricity Law Comments at 26.

[514] Public Interest Organizations Comments at 33–34.

[515] NIPPC, CREA, REC, and OSEIA Comments at 42–43.

[516] *Id.*

[517] *Id.* at 44–45 (citing NOPR, 168 FERC ¶ 61,184 at P 72 & n.117).

[518] *Id.* at 45–46.

[519] Resources for the Future Comments at 6.

[520] *Id.* at 6–7.

[521] Solar Energy Industries Comments at 30.

[522] *Id.* at 31.

[523] *Id.*

[524] *Id.*

[525] North Carolina DOJ Comments at 3.

[526] Distributed Sun Comments at 3.

[527] Solar Energy Industries Comments at 28.

[528] Mr. Mattson Comments at 26.

Northern Plains and Rocky Mountain West, is the only vehicle for small businesses to obtain project financing and that variable rates undermine the certainty of QFs obtaining financing.[529]

328. Public Interest Organizations assert that the NOPR has no basis to speculate that the Idaho Commission shortened contract lengths to two years because of the fixed rate requirement or that it would provide longer contracts if it could require variable energy rates.[530] According to Public Interest Organizations, the fact that no solar and wind QFs have been developed since the Idaho Commission set a two year contract length, even while they are currently entitled to fixed rates, shows that allowing variable rates will further discourage wind and solar QF development.[531]

329. sPower argues that, even with long-term contracts, QFs will not be viable without fixed energy rates and explains that, if the Commission seeks to encourage states to offer longer contract terms, it should just require longer terms.[532]

330. The DC Commission states that, in the jurisdictions where the contract length has been adjusted to ''short-term,'' such as Idaho's two-year contract,[533] further elimination of the QF fixed price contract option would discourage or eliminate new small renewable energy facilities entering the markets, which is not consistent with PURPA's objective of encouraging the construction of renewable generation.[534]

331. NIPPC, CREA, REC, OSEIA, and Public Interest Organizations argue that the fact that states have shortened the length of QF contracts in response to fixed energy prices means that the Commission should require a minimum contract length.[535] Green Power supports the creation of longer-term standard contract lengths for both cogeneration and small power production facilities.[536] Green Power recommends that cogeneration developers are offered 5, 8, or 10-year contracts and that small power producers developers are offered 10, 15, or 20-year contracts.[537] Mr. Mattson proposes that long-term contracts, defined as 20 years or longer, be available to QFs at their discretion.[538]

332. CARE notes that a purchasing utility's fixed capacity value may be zero if the state determines that the electric utility has no need for additional capacity resources. In that circumstance, there would be no fixed element in an avoided cost contract, which CARE believes would be inconsistent with the Commission's rationale justifying variable energy rate contracts.[539] EPSA similarly argues that, as noted in the NOPR, an electric utility is not required to pay for QF capacity that the state has determined is not needed. EPSA claims that the variable rate proposal therefore would create substantial uncertainty for QF developers and investors in non-ISO/RTO regions.[540]

333. American Biogas argues that LMP prices are not sufficient to sustain existing biogas projects or to increase their number.[541] Several commenters state that LMP cannot sustain QFs in general.[542]

334. NIPPC, CREA, REC, and OSEIA argue that the NOPR proposal to base QF pricing on LMP or Western EIM will limit competition, because QFs will be stuck with no long-term assurance of investment recovery, and thus with no means to finance their projects, while regulated incumbent utilities will be able to rate-base their generation assets, thus guaranteeing long-term recovery of their investments.[543] NIPPC, CREA, REC, and OSEIA maintain that prices for long-term QF contracts should be set by reference to long-term price indices or other indicators that, unlike highly-variable LMP and Western EIM prices, genuinely reflect the long-term costs of generation avoided by the purchasing utility.[544]

iii. Commission Determination

335. As an initial matter, the Commission agrees with commenters that PURPA does not guarantee QFs a rate that guarantees financing. PURPA only requires the Commission to adopt rules that encourage the development of QFs; it does not provide a guarantee that any particular QF will be developed or profitable. This is evident from the structure of PURPA, which caps QF rates at the purchasing utility's avoided costs rather than providing for rates that guarantee the recovery of a QF's costs. The legislative history confirms that Congress did not intend to guarantee QF financing. As stated in the PURPA Conference Report, ''the Conferees recognize that [QFs] are different from electric utilities, *not being guaranteed a rate of return* on their activities generally or on the activities vis-a-vis the sale of power to the utility *and whose risk in proceeding forward in the [QF] enterprise is not guaranteed to be recoverable*.'' [545]

336. Notwithstanding that PURPA does not guarantee QF financeability, the Commission believes that the variable avoided cost energy rate option implemented by this final rule will still allow QFs to obtain financing.

337. Before addressing specific comments on this issue, however, we reiterate that we are not eliminating fixed rate pricing for QFs. Under this final rule, QFs will continue to be able to require fixed avoided cost capacity rates in their contracts and LEOs. Capacity costs, as relevant here, include the cost of constructing the capacity being avoided by purchasing utilities as a consequence of their purchases from QFs. As will be discussed below, a combination of fixed avoided cost capacity rates and variable energy rates can provide important revenue streams that can support the financing of QFs.

338. Furthermore, merely because QFs have had access to fixed avoided cost energy rates does not mean that QFs must have access to such rates to obtain future financing. Up to now, QFs have had the right under the PURPA Regulations to both fixed capacity and fixed energy rates, and we understand that most QFs executing long-term contracts have exercised this right. Commenters insisting that the Commission cannot allow states the option to impose variable avoided cost energy rates without evidence that QFs have obtained financing under such contract structures [546] are attempting to impose a standard that could never be satisfied.

339. In any event, there is ample evidence outside of the PURPA context demonstrating that generation projects with fixed capacity rate-variable energy contracts are financeable. As the Commission explained in detail in the NOPR, since the time of the passage of PURPA a large new independent power production industry has developed in

[529] Western Resource Councils Comments at 2.

[530] Public Interest Organizations Comments at 36.

[531] *Id.* at 35–38.

[532] sPower Comments at 11.

[533] DC Commission Comments at 8 (citing NOPR, 168 FERC ¶ 61,184 at P 77).

[534] *Id.*

[535] NIPPC, CREA, REC, and OSEIA Comments at 47–48; Public Interest Organizations Comments at 6–7.

[536] Green Power Comments at 2, 10.

[537] *Id.* at 10.

[538] Mr. Mattson Comments at 7–9.

[539] CARE Comments at 4 n.7.

[540] EPSA Comments at 12.

[541] Biogas Comments at 2.

[542] BluEarth Renewables Comments at 2; Biological Diversity at 8; Covanta Comments at 9; Public Interest Organization Comments at 43–44.

[543] NIPPC, CREA, REC, and OSEIA Comments at 55–56.

[544] *Id.* at 53.

[545] Conf. Rep. at 97–98 (emphasis added).

[546] *See* Solar Energy Industries Comments at 28; NIPPC, CREA, REC, and OSEIA Comments at 29, 46; Harvard Electricity Law Comments at 22, 25–27; Public Interest Organizations Comments at 6–7, 33–35.

the United States. Like QFs, independent power producers sell power at wholesale, and have no ability to rate-base their facilities or to otherwise recover their costs through regulated rates to retail customers, unlike traditional utilities with franchised service territories and retail customers. Unlike QFs, however, independent power producers have had no right to require utilities to purchase their power or to impose fixed energy cost pricing in their power sales contracts.[547]

340. The record shows that, even without the right to require long-term fixed energy rates, non-QF independent power producers nevertheless have been able to obtain financing for large amounts of generation capacity, including from renewables. EIA data shows that, in 2019, approximately 44% of all energy produced by natural gas-fired generation in the United States was generated by independently owned capacity.[548] Furthermore, EIA data demonstrates that net generation of energy by non-utility owned renewable resources in the United States grew by almost 700% between 2005 and 2018, which speaks to the reality that renewable resources are able to acquire financing even without the right to require long-term fixed energy rates.[549] Based on this data, we find that the right to require counterparties to pay fixed energy rates is not essential for the financing of independent power generation capacity.

341. We acknowledge that a number of different financing mechanisms were used for this independent power generation capacity, not all of which will be available to QFs. Nevertheless, we understand that a standard rate structure employed in the electric industry is a fixed capacity rate-variable energy rate structure, and that many independent power production facilities have been financed based on this structure.[550] Accordingly, record evidence and historical data regarding the financing and construction of significant amounts of independent power production facilities supports the Commission's conclusion that a fixed capacity rate-variable energy rate structure—which will apply in those states choosing the variable avoided cost energy rate option—also will support financing of QFs.

342. For the reasons described below, we do not find compelling the concerns expressed by some commenters that a fixed capacity rate-variable energy rate construct may not work for solar and wind resources, which have high fixed capacity costs and minimal variable energy costs.[551] Similarly, we are not persuaded by comments that point out that energy rates in typical independent power production contracts are designed to recover the cost of a facility's fuel, whereas variable energy rates would provide no such guarantee.[552]

343. As an initial matter, as we have noted, the record demonstrates that the amount of renewable resources being developed outside of PURPA greatly exceeds the amount of renewable resources developed as QFs.[553] Renewable resources developed outside of PURPA may not have a legal right to long-term contracts with fixed energy rates, yet nevertheless have been able to obtain financing.

344. The Commission also disagrees with those commenters who assert that, as a consequence of the above factors, the Commission should ''require[] the variable energy component to be structured in a way that removes market risk from the QF.'' [554] This argument runs directly counter to one of the fundamental premises of PURPA, which is that QFs must accept the market risk associated with their projects by being paid no more than the purchasing utility's avoided cost, thereby preventing utility retail customers from subsidizing QFs.[555] PURPA does not allow the Commission to require QFs to be paid rates above avoided costs in order to make certain types of QF technologies financeable. If a state determines that it is necessary to require variable avoided cost energy rates in order to avoid paying QFs an above-avoided cost rate, which is a bedrock requirement of PURPA, then the impact this may have on facilities not financeable with a fixed capacity rate-variable energy rate contract structure is a direct result of the requirements of PURPA itself.[556] Concerns regarding the alleged mismatch between avoided costs and the costs of renewable technologies therefore are collateral attacks on the requirements of PURPA itself, not our proposed implementation of it.

345. In the NOPR, the Commission noted the availability of various hedging devices that would allow QFs to fix or limit the variability of a variable avoided cost energy rate.[557] We acknowledge those comments explaining that hedging tools increase project expense and may not be available to all QFs.[558] However, the Commission never intended to suggest that hedging is cost-free or that it would be appropriate for all QFs. The commenters all agree that hedging is available for at least some QFs.[559] For such QFs, hedging can help provide energy rate certainty if such certainty is required for financing. To the extent that certainty is required, then the cost of hedging is a part of the cost of financing the project that PURPA requires QFs to bear.

346. Public Interest Organizations cite testimony from the Technical Conference stating that Southern Company has negotiated non-QF renewable contracts with fixed energy rates rather than variable energy rates.[560] However, that testimony does not support the contention that the Commission must provide for fixed avoided cost energy rates for QF contracts and other LEOs. As the cited testimony notes, Southern agreed to contracts with longer terms and with fixed energy rates only because the

[547] *See* NOPR, 168 FERC ¶ 61,184 at P 76.

[548] EIA, *Electric Power Monthly with Data for December 2018,* at tbl. 1.7.B (February 2020), *https://www.eia.gov/electricity/monthly/archive/february2020.pdf*).

[549] *Id.* P 74 (explaining that net generation of energy by non-utility owned renewable resources in the United States escalated from 51.7 TWh in 2005 when EPAct 2005 was passed, to 340 TWh in 2018) (citing EIA, Electricity Data Browser, *www.eia.gov/electricity/data/browser*).

[550] American Public Power Association, *How New Generation is Funded* (Aug. 29, 2018), *https://www.publicpower.org/blog/how-new-generation-funded* (''Beginning in 2015, merchant generation [in RTOs/ISOs markets] began to increase dramatically from prior years, amounting to 19.3 percent of new capacity in 2015, 7.2 percent in 2016, and 29.1 percent in 2017.''). In RTOs and ISOs with capacity markets, merchant generators are compensated through variable energy rates and fixed capacity rates, along with whatever ancillary service revenues they can earn.

[551] *See* Harvard Electricity Law Comments at 26; Public Interest Organizations Comments at 33–34; Solar Energy Industries Comments at 30.

[552] NIPPC, CREA, REC, and OSEIA Comments at 42–43.

[553] *See supra* P 240.

[554] NIPPC, CREA, REC, and OSEIA Comments at 43.

[555] *See* Conf. Rep. at 97–98 (stating that the ''risk in proceeding forward in the [QF] enterprise is not guaranteed to be recoverable''); *accord API,* 461 U.S. at 416 (holding that QFs ''would retain an incentive to produce energy under the full-avoided-cost rule so long as their marginal costs did not exceed the full avoided cost of the purchasing utility'').

[556] *See* Connecticut Authority Comments at 14 (''[C]ontracted QF rates that take into account New England market conditions would not deter lenders and investors. Many QFs have no fuel costs and low variable costs of production; therefore, it is reasonable to find that these QFs would earn substantial inframarginal rents on energy sales. Further, QFs may be able to sell RECs and/or participate in other Connecticut programs.'').

[557] NOPR, 168 FERC ¶ 61,184 at P 72.

[558] NIPPC, CREA, REC, and OSEIA Comments at 45–46; Resources for the Future Comments at 6–7; Solar Energy Industries Comments at 30.

[559] *Id.*

[560] Public Interest Organizations Comments at 33–34 (citing NOPR, 168 FERC ¶ 61,184 at P 70 n.114 (citing Tech. Conference, Docket No. AD16–16–000, Tr. 200 (filed June 30))).

renewable energy developers agreed to a rate that was 50 to 60 percent of the projected long-term avoided cost.[561]

347. Certain commenters expressed concern that, when a purchasing electric utility is not avoiding the construction or purchase of capacity as a consequence of entering into a contract with a QF, under the NOPR's proposed rules a state could limit the QF's contract rate to variable energy payments.[562] 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.[563] Nothing in PURPA or the legislative history of PURPA suggests that the Commission should set QF rates so as to facilitate the financing of new QF capacity in locations where no new capacity is needed.

348. In the NOPR, the Commission also observed that the variable avoided cost energy rate proposal might cause states to make other changes to their administration of PURPA in ways that would improve the financeability of QF projects. Most notably, states that had limited the length of contract terms because of concerns about overpayments for energy might be willing to allow longer term contracts if the contracts have variable avoided cost energy rates. Longer term contracts with fixed avoided cost capacity rates, in turn, would provide greater revenue assurance to QFs.[564] The comments submitted in response to the NOPR support our analysis.

349. Further, there is some evidence that variable avoided cost energy rates in contracts and LEOs could result in longer-term contracts.[565] To be clear, we are not finding that the variable avoided cost energy rate provision in this final rule will necessarily lead to longer term contracts and LEOs in every state, nor does our decision to adopt this provision rely on such a finding.[566] However, the record supports the conclusion that the variable avoided cost energy rate provision could lead to longer term contracts in at least some states, and that likelihood provides support for the conclusion that QFs will be able to obtain financing for their projects under this provision if their costs are indeed below the purchasing utility's avoided costs.

h. Other Claimed Benefits of Fixed Avoided Cost Energy Rates

i. Comments

350. Public Interest Organizations assert that maintaining the requirement to pay QFs fixed rates serves as a hedge for consumers because QFs, unlike utilities, bear their own risks and have provided ''billions of dollars'' in benefits to consumers. Public Interest Organizations assert that eliminating QFs' rights to fixed rate contracts ignores these benefits to consumers and puts them at risk.[567] Likewise, Solar Energy Industries portrays a fixed energy rate as providing a hedge to a utility that the purchasing electric utility may use as a revenue stream in connected markets. Solar Energy Industries nevertheless argues that, in order to encourage QF development, the Commission must ensure that QFs know the energy price at the time of contracting and that utilities publish rates stating the energy, capacity, and environmental attributes of the QF rate.[568]

ii. Commission Determination

351. Fixed and variable energy rates each can provide benefits to electric utility customers. These benefits are the converse of each other: Variable avoided cost energy rates provide protection to customers when energy costs decline, and fixed avoided cost energy rates provide protection to customers when energy costs increase. By giving the states the flexibility to choose either variable or fixed avoided cost energy rates in QF contracts and LEOs, the Commission is giving each state the ability to choose the protection that is best suited for electric customers in their state, based on each state's view of what the future may hold and the likelihood that variable energy avoided costs will exceed fixed energy avoided costs during the life of a QF contract or LEO.

352. We acknowledge that fixed avoided energy cost rates can serve as a hedge against future fuel price increases in a way that protects ratepayers, assuming such price increases actually occur. Given that PURPA both places an avoided cost cap on QF rates, and requires that such rates must be just and reasonable to the electric consumers of the electric utility, we find it is appropriate to provide flexibility to states to decide how to apportion such risks to their ratepayers in a way that ensures QF avoided energy cost rates are consistent with PURPA's requirements (*i.e.,* by using either fixed or variable avoided cost energy rates to best meet those requirements).

353. We caution, though, that having made that choice, a state is not free to toggle a QF's contractual rate structure back and forth unilaterally from one to the other as circumstances change; QFs are entitled to the certainty that once a state has made its choice with respect to a particular QF's contract or LEO, that QF's contract or LEO is not subject to change during the term of that contract or LEO except by mutual consent.

i. Potential Modifications to NOPR Proposal

i. Comments

354. The California Commission, Connecticut Authority, and Massachusetts DPU support the variable energy rate proposal and suggest that, in addition, states be given the discretion

[561] Tech. Conference, Docket No. AD16–16–000, Tr. at 200 (filed June 30). The Commission notes that the PURPA Regulations specifically permit QFs and utilities to agree to rates that differ from what the PURPA Regulations require. 18 CFR 292.301(b). As the testimony cited by the Public Interest Organizations suggests, QFs that believe fixed energy avoided cost rates are required to obtain financing are free to offer rate and/or other contractual concessions in exchange for a fixed rate.

[562] CARE Comments at 4 n.7; EPSA Comments at 12.

[563] *See, e.g., City of Ketchikan,* 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.'').

[564] NOPR, 168 FERC ¶ 61,184 at P 65. Contrary to assertions by some commenters, the Commission's conclusion in the NOPR about the possible positive effects of the variable avoided cost energy rate proposal was not based on speculation. *See* Public Interest Organizations Comments at 36. Rather, the Commission relied on testimony presented at the Technical Conference. *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.'').

[565] Idaho Commission Comments at 4 (allowing states to set variable QF energy avoided costs ''would allow states to consider longer term contracts without putting ratepayers at risk'') (citing NOPR, 168 FERC ¶ 61,184 at 5 n.5).

[566] We are not finding that variable avoided cost energy rates would be appropriate only if they cause states to require longer term contracts, and we are not adopting the suggestion made by certain commenters that the Commission order states to require longer contract terms. *See* NIPPC, CREA, REC, and OSEIA Comments at 47–48; Public Interest Organizations Comments at 6–7; sPower Comments at 11.

[567] Public Interest Organizations Comments at 45–46 (citing S. Rep. No. 95–442, at 9, 22–23, 33 (1977), *as reprinted in* 1978 U.S.C.C.A.N. 7903, 7906, 7919–21, 7930; Public Interest Organizations, Comments, Docket No. AD16–16–000, at 5, 19–21 (Oct. 17, 2018)). In earlier comments in Docket No. AD16–16–000, cited by Public Interest Organizations in response to the NOPR, Public Interest Organizations asserted that long-term fixed QF contracts often act as a hedge that lowers QF financing expenses, which benefits ratepayers, and insulates ratepayers from fuel price fluctuations. Public Interest Organizations, Comments, Docket No. AD16–16–000, at 20–21 (Oct. 17, 2018).

[568] Solar Energy Industries Comments at 31–32.

to require the avoided capacity rate to vary.[569]

355. In contrast, NIPPC, CREA, REC, and OSEIA urge the Commission, if it allows variable energy rates, to adopt strict parameters for setting capacity rates in order to provide some predictability to QFs to allow them to obtain financing. NIPPC, CREA, REC, and OSEIA recommend that the Commission require forecasted capacity rates be ''offered in a long-term contract of at least 20 years after commencement of sales under the agreement'' for ''[a]ll years during the term of the QF's long-term contract after which the utility forecasted to be capacity deficit in its load and resource balance, as forecasted in its resource plan in effect at the time of the legally enforceable obligation'' and ''[a]ny time the utility is planning or undertaking actions to acquire a major generation resource or a major capital investment at an aging facility at the time of creation of the legally enforceable obligation.'' [570]

356. Commissioner O'Donnell urges the Commission to provide additional guidance to states on the minimum required contract duration that would enable a QF to obtain financing from investors while providing sufficient ratepayer protections.[571]

ii. Commission Determination

357. We decline to adopt the California Commission's, Connecticut Authority's, and Massachusetts DPU's requests to permit a state to require variable avoided cost capacity rates in addition to variable avoided cost energy rates. There is a fundamental difference between avoided energy costs and avoided capacity costs. Unlike avoided energy costs, which fluctuate with changes in the variable cost of the purchasing utility's marginal energy resource, a purchasing utility's avoided capacity cost is determined at the time the utility incurs the obligation to purchase capacity from a QF rather than self-build a capacity resource or enter into a power purchase agreement with a third party. Although a purchasing utility's avoided capacity cost may later change as additional capacity acquisitions are avoided, the cost of the capacity avoided by the purchasing utility as a consequence of purchasing capacity from a particular QF at a particular moment in time does not change.

358. As a simple illustrative example, if a utility is able to avoid constructing a new generation facility with a capacity cost of $10/MW-month as a result of purchasing power from a QF, its avoided capacity cost is the $10/MW-month capacity cost that it would have been incurred to construct the new facility. Once the utility commences its purchases from the QF, it may not need additional capacity, and its avoided capacity cost for the next QF would drop to $0/MW-month. It would not be appropriate to then reduce the original QF's avoided capacity charge to $0/MW-month, however, because the only reason that the utility does not need additional capacity is because it already purchased capacity from the original QF in order to avoid the $10/MW-month capacity cost. That is, without the purchase from the original QF, the utility would have incurred a capacity cost of $10/MW-month, and that is the utility's avoided capacity cost for the term of its contract with the original QF. It would be inappropriate, in other words, for avoided cost capacity rates to change after they are first set at the time a LEO (such as a contract) is established.

359. We also decline to adopt the suggestion of NIPPC, CREA, REC, and OSEIA to adopt additional criteria for establishing avoided capacity costs, including minimum contract lengths. We believe that the existing rate-setting provisions adequately set out the criteria that should be considered by a state in determining avoided capacity costs.[572] To the extent that any party believes a state has not appropriately applied these criteria, that party has recourse to the enforcement provisions of PURPA sections 210(g) and (h).[573]

360. We decline to specify a minimum required contract length given that it is up to states to decide appropriate contract lengths in a way that accurately calculates avoided costs so as to meet all statutory requirements.

8. Consideration of Competitive Solicitations To Determine Avoided Costs

a. NOPR Proposal

361. The Commission in the NOPR proposed 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 cost energy and/or capacity rates using competitive solicitations (*i.e.,* requests for proposals or RFPs), conducted pursuant to appropriate procedures.

362. The Commission recognized that one way to enable the industry to move toward more competitive QF pricing is to allow states to establish QF avoided cost rates through a competitive solicitation process. 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.[574] That rulemaking proceeding, along with several related proceedings, ultimately was withdrawn as overtaken by events in the industry.[575]

363. Since then, the Commission held in a 2014 order addressing the specific facts of the particular competitive solicitation 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 competitive solicitation.[576] In a separate proceeding involving a different competitive solicitation, the Commission declined to initiate an enforcement action where the state competitive solicitation was an alternative to a PURPA program.[577]

364. Given this precedent, the Commission proposed to amend its regulations to clarify that a state could establish QF avoided cost rates through an appropriate competitive solicitation process. Consistent with its general approach of giving states flexibility in the manner in which they determine

[569] California Commission Comments at 27–28; Connecticut Authority Comments at 14–15; Massachusetts DPU Comments at 8–10.

[570] NIPPC, CREA, REC, and OSEIA Comments at 51.

[571] Commissioner O'Donnell Comments at 3.

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

[573] *See also Policy Statement Regarding the Commission's Enforcement Role Under Section 210 of the Public Utility Regulatory Policies Act of 1978,* 23 FERC ¶ 61,304.

[574] *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, Sales of Power to Qualifying Facilities, and Interconnection Facilities,* FERC Stats. & Regs. ¶ 32,457 (1988) (cross-referenced at 42 FERC ¶ 61,324) (*ADFAC NOPR*).

[575] *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, Sales of Power to Qualifying Facilities, and Interconnection Facilities,* 84 FERC ¶ 61,265 (1998) (terminating *ADFAC NOPR* proceeding).

[576] *See, e.g., Hydrodynamics, Inc.,* 146 FERC ¶ 61,193, at PP 31–35 (2014) (*Hydrodynamics*).

Competitive solicitation processes have been used more recently in a number of states, including Georgia, North Carolina, and Colorado. Georgia's competitive solicitation process is described at Ga. Comp. R. & Regs. 515–3–4.04(3) (2018). North Carolina's competitive solicitation process is described at 4 N.C. Admin. Code 11.R8–71 (2018). Colorado's competitive solicitation process is described at *sPower Development Co., LLC* v. *Colorado Pub. Utils. Comm'n,* 2018 WL 1014142 (D. Colo. Feb. 22, 2018).

[577] *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).

avoided costs, the Commission did not propose in the NOPR to prescribe detailed criteria governing the use of competitive solicitations as tools to determine rates to be paid to QFs, as well as to determine other contract terms. The Commission stated that 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.

365. Nevertheless, in considering what constitutes proper design and administration of a competitive solicitation, the Commission found it was appropriate to establish certain minimum criteria governing the process by which competitive solicitations are to be conducted in order for a competitive solicitation to be used to set QF rates. In that regard, the Commission noted that it 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,[578] the Bidding NOPR, and the *Hydrodynamics* case[579] all suggest factors that could be considered in establishing an appropriate competitive solicitation that is conducted in a transparent and non-discriminatory manner.

366. These factors, as proposed in the NOPR, include, among others: (a) An open and transparent process; (b) solicitations should be open to all sources to satisfy the purchasing electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity;[580] (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 proposed that a state may use a competitive solicitation to set avoided cost energy and capacity rates, provided that such competitive solicitation process is conducted pursuant to procedures ensuring the solicitation is transparent and non-discriminatory. The Commission proposed that such a competitive solicitation must be conducted in a process that includes, but is not limited to, the factors identified above which would be set forth in proposed subsection (b)(8).

367. In addition, the Commission sought comment on whether it should provide further guidance on whether, and under what circumstances, a competitive solicitation can be used as a utility's exclusive vehicle for acquiring QF capacity.[581]

b. Comments

i. Comments in Opposition

368. Several commenters oppose the NOPR proposal to allow states the ability to set avoided cost energy and capacity rates through a competitive solicitation such as an RFP.[582]

369. Allco states that allowing a state commission to use a competitive solicitation price is simply giving another tool to a state commission to eliminate QF projects.[583] Allco also contends that this proposal creates an apples and oranges scenario where a competitive solicitation could be won by solar projects of 80 MWs at a low, steeply discounted price that may never get built, resulting in a state commission publishing that as an avoided cost for a 1 MW solar project connected to the distribution system.[584] Allco points to California's Renewable Marketing Adjustment Tariff program as an example of a competitive solicitation price failure.[585]

370. CA Cogeneration states that relying on a competitive solicitation violates PURPA's mandatory purchase obligation, and the regulations must always preserve the right of a QF to negotiate a contract for the purchase of its output at an avoided cost rate.[586] CA Cogeneration states that reliance on a competitive solicitation also fails to provide the necessary financial and operational encouragement for combined heat and power.[587]

371. Covanta asserts that the Commission's proposed competitive solicitation process would disadvantage technologies like Waste to Energy that are not growing, or are closing facilities.[588]

372. Southeast Public Interest Organizations argue that, in the states that currently require some form of competitive solicitation, many utilities do not regularly hold competitive solicitations, do not make competitive solicitations open to all QFs, or do not provide QFs the ability to sell to the utility outside of a competitive solicitation process.[589] Southeast Public Interest Organizations maintain that the competitive solicitation process can be overly burdensome and costly for smaller facilities. Southeast Public Interest Organizations assert that no state requires, and no utility conducts, a competitive solicitation to determine how best to meet the ongoing energy needs that it currently meets through the operation of its existing generation fleet and market purchases.[590] In particular, Southeast Public Interest Organizations represent that: (1) Florida does not require an independent evaluator as part of its competitive solicitation process; (2) Colorado and Oklahoma allow utilities to apply for waivers of the competitive solicitation requirement; and (3) North Carolina allows the incumbent utility to participate in the competitive bidding process and to receive preferential treatment in the form of waiving post bid security required for any independently owned projects.[591] Southeast Public Interest Organizations conclude that, while a well-designed and well-implemented competitive solicitation process could be an appropriate procurement and rate-setting tool in some cases, competitive solicitations should never be the only way to set rates or for QFs to sell their output, and close consideration should be given to determinations of utility capacity needs that could be manipulated to limit renewable energy procurements.[592]

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

[579] *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 competitive solicitation would retain their existing PURPA right to sell energy as available to the electric utility, if the state has concluded that such QF capacity puts tendered after an competitive solicitation 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,* 94 FERC ¶ 61,293 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.'')).

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

[581] The Commission proposed that, even if a competitive solicitation were used as an exclusive vehicle for an electric utility to obtain QF capacity, QFs that do not receive an award in the competitive solicitation would be entitled to sell energy to the electric utility at an as-available avoided cost energy rate.

[582] Allco Comments at 12; Blue Earth Comments at 1–2; Boulder Comments at 6; CA Cogeneration Comments at 10–11; Green Power Comments at 1–3; Industrial Energy Consumers Comments at 13.

[583] Allco Comments at 12.

[584] *Id.*

[585] *Id.*

[586] CA Cogeneration Comments at 10.

[587] *Id.* at 11.

[588] Covanta Comments at 9.

[589] Southeast Public Interest Organizations Comments at 26.

[590] *Id.* at 26–27.

[591] *Id.* at 27.

[592] *Id.* at 25–26.

373. Mr. Mattson states that precedent and legislative intent remove competitive solicitations from being a PPA option.[593] Both Mr. Mattson and Two Dot Wind point to the Commission's ruling in *Hydrodynamics* that ''requiring a QF to win a competitive solicitation as a condition to obtaining a long-term contract imposes an unreasonable obstacle to obtaining a legally enforceable obligation.'' [594] Two Dot Wind also states that competitive solicitations have not worked in Montana, and that the NOPR's suggestion that competitive bidding can replace PURPA is not supported by the factual record in Montana.[595]

374. Industrial Energy Consumers expresses concern that the parameters for competitive solicitations are not sufficiently developed to ensure a well-structured, fairly administered, transparent, and non-discriminatory process for procurement, and therefore opposes allowing a competitive solicitation process to determine avoided costs at this time.[596]

ii. Comments in Support

375. Several commenters support the NOPR proposal to allow states the ability to set energy and capacity rates through a competitive solicitation such as an RFP.[597]

376. Multiple commenters, including EEI, NRECA, and the Oregon Commission, support the notion that the states are in the best position to tailor the competitive solicitation process to their needs, and that the Commission should not provide detailed criteria governing the use of competitive solicitations.[598] EEI states that the fact that competitive solicitations may be used to set avoided costs is an idea nearly as old as PURPA.[599] EEI also supports the Commission's proposal for a state to allow a competitive solicitation to be used as the exclusive vehicle for acquiring QF capacity.[600] NRECA notes that numerous NRECA members have already had success using competitive solicitations to establish both energy and capacity rates in states where competitive solicitations are permitted.[601]

377. Growth and Opportunity Center states that competitive solicitation processes, in place of avoided cost calculations, provide better signals to investors of where their electricity is most valuable because competitive solicitations reflect more informed estimates of the real-time needs of electricity consumers. Growth and Opportunity Center contends that the proposed rule changes, by giving states more latitude to use competitive solicitations in complying with PURPA, should result in prices for consumers that more accurately reflect market costs for electricity.[602] Growth and Opportunity Center also asserts that in states using competitive solicitation processes, nondiscrimination rules should be enforced to ensure that solicitations are competitive and that no providers receive preferential treatment.[603]

378. The Michigan Commission states that it recently approved using competitive solicitations to determine avoided capacity costs for a large electric utility in Michigan.[604] The Michigan Commission states that it believes that that recently approved structure aligns with the Commission's proposal in the NOPR.[605]

379. Portland General asserts that, because the output of an competitive solicitation represents a resource's true market costs, a competitive solicitation is the correct method to determine avoided cost.[606] Portland General states that, given the competitive nature of competitive solicitations, bidders are highly motivated, which results in the procurement of resources with high benefit-to-cost ratios. Portland General cites as an example its recent competitive solicitation, which resulted in a $40.70-levelized price and reflects a combination of technologies (wind, solar, and battery), whereas QFs, which Portland General asserts provide lower capacity, are currently offered at a $45.19 levelized price for solar energy.[607]

380. Xcel urges the Commission's to give the states the option of procuring all needed capacity through competitive bidding processes.[608] Xcel strongly believes that states must have the ability to control capacity additions to ensure that customer needs and state policy goals are met.[609] Xcel explains that in many states, including some in which the Xcel operating companies operate, resource procurement is accomplished largely through state-administered IRP processes, which are utilized to ensure a resource mix that meets the overall public interest in affordable and clean energy. Xcel states that these carefully calibrated processes can be upset when QFs bring capacity on to a utility's system that does not align with the state's vision of its optimal resource mix and when those QFs also attempt to collect above-market payments from utilities and therefore customers. Xcel states that Colorado's procurement efforts have been so successful that in 2016 more than 400 bids for 238 distinct projects were submitted for Public Service Company of Colorado alone, and that this process resulted in some of the lowest prices for renewables seen as of that date, with a median wind price of $19.30/MWh and a median solar price of $30.96/MWh. Xcel argues that unsolicited puts by QFs, in contrast, can impede the ability of states to meet their resource planning goals and can undermine the competitive markets that states like Colorado have already created or are striving to create.[610]

381. North Carolina Commission Staff states that North Carolina has implemented a competitive solicitation process for solar energy that complements the PURPA reforms adopted by the state, with the first solicitation concluding in April 2019.[611] North Carolina Commission Staff states that an independent administrator estimated the initial nominal savings for the competitive solicitation with a 20-year contract versus traditional avoided cost pricing to exceed $370 million for the utilities involved.[612]

382. Duke Energy shares its state-specific experience with North Carolina's competitive solicitation for renewable energy as a positive example.[613] Duke Energy states that Duke Energy Carolinas, LLC and Duke Energy Progress, LLC recently completed their Tranche 1 Competitive Procurement of Renewable Energy RFP and procured approximately 550 MW of new solar capacity for 20-year fixed price contract terms at a projected savings of approximately $261 million relative to administratively determined

[593] Mr. Mattson Comments at 23.

[594] *Id.;* Two Dot Wind Comments at 10 (citing *Hydrodynamics,* 146 FERC ¶ 61,193).

[595] Two Dot Wind Comments at 9–10.

[596] Industrial Energy Consumers Comments at 13.

[597] Alaska Power Comments at 1; Distributed Sun Comments at 2; EEI Comments at 32–33; El Paso Electric Comments at 4; NARUC Comments at 3; NRECA Comments at 11; South Dakota Commission Comments at 2–3.

[598] EEI Comments at 32–33; NRECA Comments at 11; Oregon Commission Comments at 3–4.

[599] EEI Comments at 32.

[600] *Id.* at 33.

[601] NRECA Comments at 11.

[602] Growth and Opportunity Center Comments at 9.

[603] *Id.* at 10.

[604] Michigan Commission Comments at 4.

[605] *Id.* at 5.

[606] Portland General Comments at 11.

[607] *Id.*

[608] Xcel Comments at 10.

[609] *Id.* at 8.

[610] *Id.* at 9.

[611] North Carolina Commission Staff Comments at 3–4.

[612] *Id.* at 4.

[613] Duke Energy Comments at 10–12.

forecasts of avoided costs over this same period.[614]

iii. Comments Requesting Modifications/Clarifications

(a) Requests for Clarification and/or Separate Proceedings

383. NIPPC, CREA, REC, and OSEIA argue that the NOPR fails to explain (1) whether the Commission is proposing to merely clarify that a state could use the lowest offer prices submitted in a competitive solicitation to set the avoided costs of energy and capacity on a prospective basis for any QF seeking a contract until the next competitive solicitation, or (2) whether the Commission is proposing a radical change in its precedent by revising its rules to provide that a QF may only sell under a long-term contract if that QF wins a competitive solicitation, which NIPPC, CREA, REC, and OSEIA assert would be contrary to the *Hydrodynamics*[615] and *Winding Creek*[616] cases.[617]

384. NIPPC, CREA, REC, and OSEIA request that any requirement to win a competitive solicitation to obtain a long-term PURPA contract should exempt small facilities.[618] NIPPC, CREA, REC, and OSEIA further state that the Commission should: (1) Require that the competitive solicitation include no utility-ownership options; or (2) if utility-owned generation may result, the competitive solicitation must be: (i) Administered and scored (not just overseen) by a qualified independent party, not the utility; (ii) any utility or utility-affiliate ownership bid must be capped at its bid price and not allowed traditional cost-plus ratemaking treatment; and (iii) the product sought, minimum bidding criteria, and detailed scoring criteria must be made known to all parties at the same time.[619] Additionally, NIPPC, CREA, REC, and OSEIA contend that an option for long-term contracts should remain available for both small QFs and existing QFs outside of a competitive solicitation.[620]

385. The Michigan Commission states that it would welcome guidance on whether, and under what circumstances, a competitive solicitation can be used as a utility's exclusive vehicle for acquiring QF capacity.[621] Similarly, the Montana Commission recommends that the Commission provide as much guidance to states as possible regarding the requirements for transparency and non-discrimination.[622]

386. The California Commission states that the NOPR does not provide states any more flexibility than they already have, and the Commission's final order adopting revised regulations should clearly state this.[623]

387. Several commenters suggest that the Commission should conduct focused additional processes on this topic.[624] Advanced Energy Economy suggests that the Commission conduct one or more workshops or technical conferences, to explore in detail the specific factors that would make a utility competitive solicitation process a truly competitive process of a ''comparative quality'' to competitive wholesale energy and capacity markets.[625] Advanced Energy Economy contends that such workshops or technical conferences could ultimately be the basis for developing proposed regulations better guiding the states and electric utilities in implementing open and competitive solicitation processes to obtain relief from the mandatory purchase obligation under PURPA section 210(m)(1)(C).[626] Industrial Energy Consumers argues that, if the Commission seeks to allow states to rely on competitive solicitation processes, the Commission should undertake a separate inquiry, with necessary technical conferences, to develop specific parameters to govern such processes.[627] If the Commission relies directly on competitive solicitation processes in the final rule, Industrial Energy Consumers states that if, after undertaking the competitive solicitation, the utility rejects all offers and decides to self-build, then the all-inclusive price of the self-build option should at least establish the avoided cost rate for QFs seeking to develop in that area.[628] EPSA argues that the Commission should require further proceedings, including another technical conference, to discuss the protections that would be necessary in order to have a genuinely level playing field for competitive solicitations.[629]

388. Commissioner Slaughter states that PURPA sits at the intersection of competition and regulatory policy in an area of vital and urgent interest, and that the Commission should establish fair, non-discriminatory guidelines for competitive solicitations that would help states and other stakeholders maximize the benefits of competition from low-cost energy sources, particularly utility-scale renewable energy facilities.[630] Commissioner Slaughter states that such guidelines could form the basis for transitioning many local markets from administratively determined prices to environments of dynamic price discovery in which the rapidly decreasing cost of utility-scale renewable energy can put maximum pressure on both new and pre-existing fossil fuel-based sources of electricity.[631]

389. EPSA states that the Commission should ensure that competitive solicitations are properly designed to ensure that QFs have meaningful opportunities to compete against resources owned by incumbent utilities on a level playing field.[632] EPSA states that the Commission should use this opportunity to do a full assessment of how competitive solicitations are working and could be enhanced, while providing continued protections to prevent discrimination against QFs.[633] EPSA also emphasizes that, regardless of whatever competitive solicitation rules the Commission ultimately adopts, the Commission must continue to exercise its ''backstop'' oversight and enforcement authority to ensure that any requirements are implemented in a consistent and appropriate manner by individual states.[634]

(b) Requests Regarding Proposed Criteria

390. Several commenters requested that the Commission clarify the criteria that solicitations be conducted at regular intervals.[635] Several commenters request that the Commission reconsider or remove that criteria.[636] sPower argues that the Commission should require that such competitive solicitations be conducted at a minimum every two years.[637] Colorado Independent Energy

[614] *Id.* at 12.

[615] *Hydrodynamics,* 146 FERC ¶ 61,193.

[616] *Winding Creek Solar LLC* v. *Peterman,* 932 F.3d 861.

[617] NIPPC, CREA, REC, and OSEIA Comments at 62–63.

[618] *Id.* at 67.

[619] *Id.*

[620] *Id.* at 67–68.

[621] Michigan Commission Comments at 5.

[622] Montana Commission Comments at 3.

[623] California Commission Comments at 23.

[624] Advanced Energy Economy Comments at 13; EPSA Comments at 15–16; Industrial Energy Consumers Comments at 13–14.

[625] Advanced Energy Economy Comments at 13.

[626] *Id.*

[627] Industrial Energy Consumers Comments at 13–14.

[628] *Id.* at 14.

[629] EPSA Comments at 16.

[630] Commissioner Slaughter Comments at 1–2.

[631] *Id.* at 3.

[632] EPSA Comments at 3.

[633] *Id.* at 14.

[634] *Id.* at 16–17.

[635] APPA Comments at 17–18; Basin Comments at 9; Montana Commission Comments at 3; sPower Comments at 9–10.

[636] NorthWestern Comments at 7–8.

[637] sPower Comments at 9–10.

asserts that competitive solicitations should be held at regular intervals to test the market, and that the Commission should consider the entire market, not just projects 80 MW and under, in evaluating whether there are full and competitive opportunities.[638]

391. Several commenters oppose the requirement for an independent administrator.[639] APPA argues that the entire PURPA administrative construct is designed to entrust to state regulatory authorities the responsibility to carry out the duties they are assigned under the Commission's regulations.[640] NRECA believes that states are in the best position to determine the need for ''oversight by an independent administrator'' and recommends this criterion be deleted.[641] NRECA requests that, if the Commission retains the requirement that competitive solicitation processes include some type of oversight, instead of requiring oversight by an independent administrator, the Commission should allow states the flexibility to allow electric utilities to retain a third-party consultant for this purpose.[642] NRECA contends that many cooperatives have long-standing relationships with third-party consultants that assist the cooperatives in evaluating power supply options, and requiring those cooperatives to now use some other entity (*i.e.,* the independent administrator) would be disruptive and costly.[643] Colorado Independent Energy notes that, while independent evaluators are helpful, they are often employed by utilities and thus sometimes reluctant to offer third party criticism of the bid evaluation process.[644]

392. The Montana Commission requests clarification of the term ''independent administrator'' and ''certified'' as those terms are used in the proposed revisions to § 292.304(b).[645]

393. sPower disagrees that a competitive solicitation should ''take into account the required operating characteristics of the needed capacity'' in order to produce accurate avoided cost rates and recommends that a final rule remove that language from condition (ii) in the Commission's list of conditions that a competitive solicitation must meet.[646]

394. Colorado Independent Energy states that, in addition to the guidelines provided in the NOPR, the Commission should include additional guidelines, including that fairness of an ''all-source'' competitive solicitation must also be determined based on bid evaluation and not just on a competitive solicitation. Colorado Independent Energy asserts that competitive solicitation *submissions* can be technology-specific, but not the evaluation or the analysis of the need to be met by a competitive solicitation. Colorado Independent Energy asserts that a true all-source selection process must allow resource planning models to optimize among all bids received without bias toward QF-eligible technologies such as renewable generation or cogeneration.[647]

395. Several commenters stated that competitive solicitations must be assessed using the criteria set forth in *Allegheny*.[648] EPSA further states that, while the *Allegheny* principles provide a good starting point, additional protections will be required to level the playing field between independent generators and utilities.[649] R Street asserts that, if an auction can meet the *Allegheny* standard, then generators in that state would not be eligible for QF designations. R Street suggests that QFs should not be able to force their power on utilities if they lose such fairly administered auctions.[650]

396. Solar Energy Industries asserts that the Commission should require a purchasing electric utility to provide the state commission, and make available for public inspection, a post-solicitation report that: (1) Identifies the winning bidders; (2) includes a copy of any reports issued by the independent evaluator; and (3) demonstrates that the solicitation program was implemented without undue preference for the interests of the purchasing utility or its affiliates. Solar Energy Industries further assert that the solicitation program should include clear details regarding the manner in which the bids will be scored and clearly specify price and non-price criteria under which bids are evaluated including: (1) Acceptable delivery points and any scoring deductions for delivery to other points; (2) credit evaluation criteria and development securing requirements; and (3) performance requirements.[651]

397. Public Interest Organizations argue that the Commission's proposal does not require that state competitive solicitation procedures meet the statutory floor established through PURPA that rates both (1) encourage small power producers and (2) not discriminate relative to the utility's own generation and other non-QF generators.[652] To ensure competitive solicitations actually meet the statutory criteria, the Commission must ensure that competitive solicitations meet four minimum standards.[653] First, Public Interest Organizations state that solicitations must account for utility-owned and non-QF generation and cannot be a limited competition between QFs without the ability to displace non-QF generation.[654] As an example of an incorrectly-conducted, and unlawfully-discriminatory, bidding process, Public Interest Organizations cite the Nevada competitive solicitation process that is limited to QFs to meet a small, segregated portion of the utility's energy and unmet capacity requirements.[655] Second, to ensure that QFs receive the same price that other generation receives, Public Interest Organizations state that all sources of supply must compete in the competitive solicitation— including the utility's own generation.[656] Third, Public Interest Organizations state that the solicitation process cannot be used in any way to curtail or delay a utility's obligation to purchase from QFs.[657] Fourth, the ''required operating characteristics of the needed capacity'' factor suggested in the NOPR cannot be used as a surrogate to define characteristics of only non-QF generation or to allow a utility to pick among favored generators.[658]

398. Biogas states that, if QFs are to enter into competitive solicitations as a vehicle for PURPA, then there must be some correcting for the inequitable tax and regulatory provisions afforded to incumbent utilities and select renewable

[638] Colorado Independent Energy Comments at 9–12.

[639] APPA Comments at 18; NRECA Comments at 11.

[640] APPA Comments at 18 (citing 16 U.S.C. 824a–3(f) (expressly calling for state regulatory authorities and nonregulated electric utilities to implement Commission-issued PURPA regulations)).

[641] NRECA Comments at 11.

[642] *Id.* at 12.

[643] *Id.*

[644] Colorado Independent Energy Comments at 8.

[645] Montana Commission Comments at 3.

[646] sPower Comments at 8.

[647] Colorado Independent Energy at 2.

[648] EPSA Comments at 14–15 (citing *Allegheny,* 108 FERC ¶ 61,082); R Street Comments at 3–4; Solar Energy Industries Supplemental Comments, Docket No. AD16–16–000, at 32–37 (filed Aug. 28, 2019).

[649] EPSA Comments at 15.

[650] R Street Comments at 3–4.

[651] Solar Energy Industries Supplemental Comments, Docket No. AD16–16–000, at 21 (filed August 28, 2019).

[652] Public Interest Organizations Comments at 69–70.

[653] *Id.* at 70.

[654] *Id.*

[655] *Id.* at 71–72.

[656] *Id.* at 72.

[657] *Id.* at 72–73.

[658] *Id.* at 73.

technologies, in order to ensure a fair market opportunity.[659]

399. American Dams requests that QFs competing against a utility that can rate base the cost of new generation should be entitled to similar valuation provided that QF costs are at or less than those of the utility.[660]

(c) Other Requests

400. In their comments to the NOPR, Solar Energy Industries reference their August 28, 2019 comments in Docket No. AD16–16–000,[661] in which they describe the ''SEIA Counterproposal.'' That document proposes that, where a utility seeks to meet identified capacity needs through an open, fairly designed, and independently administered competitive solicitation: (i) The purchasing electric utility would only have to pay QFs for capacity to the extent that the purchasing electric utility failed to meet identified need through the competitive solicitation; and (ii) the QF would be paid for its output (energy and capacity) at the market rate established through the competitive solicitation process.[662]

401. Solar Energy Industries request that the Commission supplement proposed 18 CFR 292.304(b)(5) to require that: (1) Participants are provided with complete and transparent information regarding transmission constraints, levels of congestion, and interconnections; and (2) the solicitation is linked with the purchasing utility's IRP and is conducted for the entirety of a utility's anticipated capacity needs.[663]

402. Solar Energy Industries request that the Commission expressly implement safeguards to prevent utility self-dealing and affiliate abuse, with regard to both price and non-price terms.[664] Solar Energy Industries reference their previous comments in this proceeding, which they state describe practices of PacifiCorp,[665] NorthWestern,[666] Duke,[667] and Xcel[668] purportedly showing that these utilities have attempted to reduce QFs' ability to sell while simultaneously seeking to build and rate base their own substantial renewable resources.[669]

403. ELCON states that it continues to see shortcomings in competitive procurement practices across regions.[670] A current example ELCON provides is Dominion Energy Virginia's 2019 RFP which, ELCON argues, limited competition in a manner that all but guarantees that a Dominion self-build option will prevail because it restricts participation to new resources only and does not permit an independent third party to evaluate bids.[671] Another example ELCON provides is a recent Entergy Louisiana solicitation through which a natural gas generating facility was approved despite opposition from Louisiana industrial consumers who argued that the competitive solicitation was improperly designed to limit resource options to new construction comparable to a self-build.[672]

404. ELCON asserts that, to be competitive, a competitive solicitation must be transparent, face independent oversight, have safeguards against affiliate abuse involving transactions between franchised utilities and their market-based affiliates, and have well-defined technical parameters.[673] ELCON states that experiences with competitive solicitations thus far expose the challenges of achieving a workably competitive process. ELCON urges the Commission to set a high bar, with enforcement to verify that a process is sufficiently competitive.[674]

405. NorthWestern states that it supports the Commission's proposal to use competitive solicitations or RFPs to establish avoided *capacity* costs, but not avoided *energy* costs, because NorthWestern believes that an energy-only competitive solicitation has no relation to the market whereas a capacity competitive solicitation does.[675] NorthWestern believes that use of a competitive solicitation should be the preferred vehicle for setting avoided capacity rates for QFs because this will ensure that the capacity is acquired at the least cost thereby benefiting customers.[676]

406. Institute for Energy Research states that it would go even further than the NOPR proposal and require that competitive solicitations be the default whenever possible, with states having to justify case-by-case why a non-competitive solicitation is needed, because solicitation is the best expression of the Congressional mandate to encourage competition.[677]

407. Harvard Electricity Law states that the NOPR's proposed 18 CFR 292.304(b)(8)(ii), requiring solicitations must be open to ''all sources''—could be read as inconsistent with the Commission's *CPUC* orders[678] and the 2019 *CARE* v. *CPUC* decision.[679] Harvard Electricity Law argues that, if the Commission amends its avoided cost rules to allow states to set avoided cost rates based on competitive solicitations, it should clarify that states may set tiered rates, as the Commission and the U.S. Court of Appeals for the Ninth Circuit has allowed in the above cases.[680]

408. The Oregon Commission recommends that the Commission emphasize the need for states to have adequate safeguards to protect bidders' confidential and commercially sensitive proprietary information when using competitive solicitations to determine or inform avoided cost rates.[681]

409. sPower states that the issue of using a competitive solicitation process to establish avoided cost rates has sometimes been conflated with using a competitive solicitation process to establish a LEO, and sPower encourages the Commission to continue to analyze these distinct issues separately.[682]

410. Resources for the Future stresses that competitive solicitations alone would minimize QF costs but would not establish avoided cost rates, which depend on much more than the cost of QF generation.[683] However, used in concert with forward curves, Resources for the Future states that competitive solicitations could provide an effective complementary method.[684]

c. Commission Determination

411. In this final rule, we affirm the NOPR proposal to revise the PURPA Regulations to explicitly permit a state the flexibility to set avoided energy and/or capacity rates using competitive solicitations (*i.e.,* RFPs), conducted

[659] Biogas Comments at 2.

[660] American Dams Comments at 3.

[661] Solar Energy Industries Supplemental Comments, Docket No. AD16–16–000, at 17–40 (filed Aug. 28, 2019).

[662] Solar Energy Industries Comments at 38.

[663] *Id.* at 39.

[664] *Id.*

[665] Solar Energy Industries Supplemental Comments, Docket No. AD16–16–000, at 25–28 (filed August 28, 2019).

[666] *Id.* at 28–29.

[667] *Id.* at 29–31.

[668] *Id.* at 21.

[669] Solar Energy Industries Comments at 40.

[670] ELCON Comments at 27.

[671] *Id.*

[672] *Id.* at 28.

[673] *Id.* at 28–29.

[674] *Id.*

[675] NorthWestern Comments at 7.

[676] *Id.*

[677] Institute for Energy Research Comments at 1.

[678] *Cal. Pub. Utils. Comm'n,* 133 FERC ¶ 61,059, *clarification and reh'g denied,* 133 FERC ¶ 61,059 (2010), *reh'g denied,* 134 FERC ¶ 61,044 (2011) (*CPUC*) .

[679] *Californians for Renewable Energy* v. *Cal. Pub. Utils. Comm'n,* 922 F.3d 929, 937 (9th Cir. 2019) (*CARE* v. *CPUC*) (holding that ''where a state has [a renewable portfolio standard (RPS)] and the utility is using a QF's energy to meet the RPS, the utility cannot calculate avoided costs based on energy sources that would not also meet the RPS[,]'' which ''comports with PURPA's goal to put QFs on an equal footing with other energy providers'').

[680] Harvard Electricity Law Comments at 31.

[681] Oregon Commission Comments at 4.

[682] sPower Comments at 3.

[683] Resources for the Future Comments at 8–9.

[684] *Id.* at 9.

pursuant to appropriate procedures in a transparent and non-discriminatory manner. A primary feature of a transparent and non-discriminatory competitive solicitation is that a utility's capacity needs are open for bidding to all capacity providers, including QF and non-QF resources, on a level playing field. This level playing field ensures that any QF's capacity rates that result from the competitive solicitation are just and reasonable and non-discriminatory avoided cost rates.

412. Consistent with our general approach of giving states flexibility in the manner in which they determine avoided costs, we do not prescribe detailed criteria governing the use of competitive solicitations as tools to determine rates to be paid to QFs, as well as to determine other contract terms. States arguably are 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.

413. In considering what constitutes proper design and administration of a competitive solicitation, however, we find it appropriate to establish certain minimum criteria governing the process by which competitive solicitations are to be conducted in order for an competitive solicitation to be used to set QF rates. These factors, which we proposed in the NOPR and adopt here, 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; (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.

414. We affirm that such competitive solicitations must be conducted in a process that includes, but is not limited to, the factors identified above that will be set forth in 18 CFR 292.304(b)(8). This rule does not undo any competitive solicitations conducted prior to the effective date of this final rule that may not have met these criteria. This rule applies only to competitive solicitations conducted after the effective date of the final rule. We also provide modifications and clarifications to the NOPR proposal, as described below.

i. Requests for Clarification and/or Separate Proceedings

415. As an initial matter, in the NOPR, the Commission addressed competitive solicitations in two related but distinct contexts. The first, to be discussed in this section, relates to the proposal to explicitly permit a state the flexibility to set avoided cost energy and/or capacity rates using competitive solicitations (*i.e.,* RFPs), conducted pursuant to appropriate procedures. The second, to be discussed below, in section IV.G.2 of this final rule, concerns the NARUC proposal that urged the Commission to give meaning to PURPA section 210m(1)(C) by establishing a ''yardstick'' by which a vertically integrated utility outside of an RTO or ISO could apply to terminate the mandatory purchase obligation if it conducts sufficiently competitive RFPs for energy or capacity.

416. More generally, we support the use of competitive solicitations as a means to foster competition in the procurement of generation and to encourage the development of QFs in a way that most accurately reflects a purchasing utility's avoided costs. We believe that allowing QFs to compete to provide capacity and energy needs, through a properly administered competitive solicitation, may help ensure an accurate determination of the purchasing electric utility's avoided cost, and therefore result in prices meeting the PURPA's statutory requirements. We also believe that it is reasonable for states to choose to require QFs to be responsive to price signals as to where and when capacity is needed.

We believe that a properly administered competitive solicitation can help provide such price signals.

417. Furthermore, we believe that competitive solicitations may be an especially appropriate tool for developing competition in the markets outside of RTOs and ISOs, where there are no organized competitive markets in place where QFs can make sales.

418. We emphasize, however, that neither the Commission's current regulations, nor those adopted in this final rule, *require* a state or a purchasing electric utility to use a competitive solicitation to determine avoided cost rates for QFs. Consistent with other changes in our regulations discussed above, we give states the flexibility to use a properly structured competitive solicitation for this purpose, but we do not mandate that they do so.

419. Furthermore, in light of the substantial experience the industry has with competitive solicitations within and outside of the PURPA context, and the voluminous comments the Commission has received regarding competitive solicitations, we find that there is not currently a need for a separate proceeding or additional procedures to address competitive solicitation issues, such as holding workshops or technical conferences. Should further procedures appear beneficial in light of actual competitive solicitation experience under PURPA and the regulations adopted today, such a proceeding may be appropriate in the future.

ii. Proposed Criteria

420. We continue to find that competitive solicitations as discussed in this final rule may accurately reflect a purchasing electric utility's avoided costs and ensure that the resulting rates for winners of such competitive solicitations are consistent with PURPA. A competitive solicitation may more accurately value QF capacity over time by subjecting it to competition with other sources. Such competitive solicitations may provide more certainty both to QFs regarding when and how often they will be eligible to compete and to purchasing utilities regarding how they may expect to fulfill their capacity needs.

421. The Commission clarifies that, if a utility acquires all of its capacity through properly conducted competitive solicitations (using the factors described above), and does not add capacity through self-building and purchasing power from other sources outside of such solicitations, the competitive solicitations could be the exclusive vehicle for the purchasing electric utility to pay avoided capacity costs from a QF. In this situation, using properly conducted competitive solicitations as the exclusive vehicle to determine the purchasing electric utility's avoided cost capacity rates would allow QFs a chance to compete to provide the utility's capacity needs on a level playing field with the utility. We clarify that it is up to the states to determine whether to require that a utility's total planned self-build and power purchase options must compete in the competitive solicitations, and we will not direct such a requirement here.

422. If a state decides to require utility self-build and power purchase options to participate in competitive solicitations, then a QF that does not obtain an award in a competitive solicitation would have no right to an avoided cost capacity rate more than zero because the utility's full capacity needs would have been met by the competitive solicitation.[685] However,

[685] This would be consistent with *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.'').

QFs would continue to have the right to put energy to the utility at the as-available avoided cost energy rate because the purchasing utility will still be able to avoid incurring the cost of generating energy even when it does not need new capacity.

423. If the state does not require utility self-build and purchase options to participate in competitive solicitations, then QFs that lose in a competitive solicitation still may have the right to avoided cost capacity rates more than zero if the state determines that the utility still has capacity needs after the competitive solicitation that otherwise could be met through the utility's self-build or purchase options.

424. The Commission has held and we reaffirm here that, when capacity is not needed, the avoided capacity cost rate can be zero.[686] Competitive solicitations conducted pursuant to the rules adopted in this final rule that are held whenever capacity is needed provide QFs a level playing field on which to compete to sell capacity. This approach further shields purchasing electric utilities from situations like those explained by Xcel, where QFs could simply sit out the competitive solicitation process (or participate but not have their bids accepted), but then seek to sell capacity to the purchasing electric utility and to receive a separate higher administratively-determined avoided cost rate including an avoided cost capacity rate, and even potentially displace non-QF competitive solicitation winners.[687] This approach benefits ratepayers because allowing QFs to compete in properly conducted, competitive solicitations that are held whenever capacity is needed allows the purchasing utility to obtain needed capacity efficiently. To be clear, the competitive solicitation is not to be a means to determine a QF's right to put as-available energy to the utility. But the competitive solicitation can be the means to determine what, if any, rate the QF will be paid for capacity.

425. Multiple commenters point out that using competitive solicitations could be a beneficial way to carry out the Congressional intent behind PURPA. However, many of these same commenters claim that the competitive solicitations carried out to date do not live up to this standard. In other words, commenters assert that the competitive solicitations conducted to date have often not been properly conducted and instead have been unfair. As described above, assertions about specific states' competitive solicitation processes include that:

—The competitive solicitations conducted in Florida are unfair because they do not require an Independent Evaluator as part of the competitive solicitation process;[688]

—the competitive solicitations conducted in Colorado and Oklahoma are unfair because purchasing electric utilities are allowed to apply for waivers of the competitive solicitation requirement;[689]

—The competitive solicitations conducted in North Carolina are unfair because the incumbent purchasing electric utility can receive preferential treatment in the form of waivers of the post bid security otherwise required for any independently owned projects;[690] and

—The competitive solicitations conducted in Nevada are unfair because the process is limited to QFs to meet a small, segregated portion of the utility's energy and unmet capacity requirements.[691]

426. Commenters also make assertions about unfair practices of purchasing electric utilities, including that the purchasing electric utilities have attempted to reduce QFs' ability to sell while the purchasing electric utilities are simultaneously seeking to build and rate base their own substantial renewable resources.

427. The criteria proposed in the NOPR were aimed at ensuring that competitive solicitations are conducted fairly. In this final rule, the Commission finds that, in order to use the results of a competitive solicitation to set avoided cost rates, the competitive solicitation must be conducted in a transparent and non-discriminatory manner. Such a competitive solicitation must be conducted in a process that includes, but is not limited to, the following factors: (i) The solicitation process is an open and transparent process that includes, but is not limited to, providing equally to all potential bidders substantial and meaningful information regarding transmission constraints, levels of congestion, and interconnections, subject to appropriate confidentiality safeguards; (ii) solicitations must 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 through a post-solicitation report.

428. Without judging the competitive solicitations conducted to date, we find that henceforth any competitive solicitation that does not comply with these factors will be viewed as not transparent and discriminatory, and not a basis for either setting the avoided cost capacity rate that a QF may charge the purchasing electric utility or limiting which generators can receive a capacity rate. Phrased differently, we will presume that any future competitive solicitation that does not comply with the factors adopted in this final rule does not comply with the Commission's regulations implementing PURPA.

429. In addition, to further promote fairness, the Commission makes several clarifications, as described below.

430. We clarify that competitive solicitations must also be conducted in accordance with the *Allegheny* principles under which the Commission evaluates a competitive solicitation: (1) Transparency, a requirement that the solicitation process be open and fair; (2) definition, a requirement that the product, or products, sought through the competitive solicitation be precisely defined; (3) evaluation, a requirement that the evaluation criteria be standardized and applied equally to all bids and bidders; and (4) oversight, a requirement that an independent third party design the solicitation, administer bidding, and evaluate bids prior to selection.[692] While the NOPR's proposed guidelines for competitive solicitations were generally inclusive of the *Allegheny* principles, in order to more precisely define what is and what is not a properly conducted competitive solicitation that can be used to determine what generators will be entitled to an avoided cost capacity rate, and what that rate will be, we specifically clarify here that the *Allegheny* principles apply as well.

431. We also revise the proposed language in 18 CFR 292.304(d)(8)(i) to clarify that participants must be provided with substantial and meaningful information regarding transmission constraints, levels of congestion, and interconnections, subject to appropriate confidentiality

[686] *Id.* 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.").

[687] *See* Xcel Comments at 2–3, 9–10.

[688] Southeast Public Interest Organizations Comments at 27.

[689] *Id.*

[690] *Id.*

[691] Public Interest Organizations Comments at 71–72.

[692] *Allegheny,* 108 FERC ¶ 61,082 at P 18.

safeguards. We believe that it is important that all participants in the competitive solicitation have access to these data as a necessary predicate for a nondiscriminatory competitive solicitation process, and we find that requiring that this information be provided will help ensure that a competitive solicitation is open and transparent. We acknowledge the risk that competitive solicitation participants could use this information to gain a competitive advantage that could be used outside of the competitive solicitation, but find that this risk can be minimized through the use of non-disclosure agreements and placing reasonable limits on those persons permitted to review the information, just as is done in other Commission proceedings where this issue arises.

432. We also clarify that the requirement that the competitive solicitation process be open and transparent includes that the electric utility provide the state commission, and make available for public inspection, a post-solicitation report that: (1) Identifies the winning bidders; (2) includes a copy of any reports issued by the independent evaluator; and (3) demonstrates that the solicitation program was implemented without undue preference for the interests of the purchasing utility or its affiliates. We find this consistent with the requirement that competitive solicitations be open and transparent, to not only ensure that utilities are not discriminating against QFs, but also to help all stakeholders and the public at large better understand the utility's competitive solicitation processes and thus to be confident in the fairness of the process and of the results.

433. Regarding the requirement that solicitations must be open to all sources to satisfy the purchasing electric utility's capacity needs, taking into account the required operating characteristics of the needed capacity, we decline to remove the phrase ''taking into account the operating characteristics of the needed capacity.'' There may be times when a utility needs capacity with specific attributes, such as specific ramping capability, that cannot be filled by certain types of generators. However, we agree with Public Interest Organizations that this phrase may not be used to define characteristics of only non-QF generation or to allow a utility to select favored generators.[693]

434. We decline to be overly prescriptive as to what constitutes ''regular intervals.'' In general, utilities should be reviewing their capacity needs frequently, and the state or nonregulated electric utility is in the best position to determine the frequency of that review. However, there may be times when a utility's review of capacity needs reveals that no capacity is needed, and it would not make sense for a competitive solicitation to be mandated at such a time.

435. We similarly decline to be overly prescriptive as to what constitutes an ''independent administrator.'' Commenters argue on both sides whether the NOPR proposal goes too far or not far enough. On the one hand, NRECA argues that states are in the best position to determine the need for oversight by an independent administrator and recommends this criterion be deleted.[694] On the other hand, Colorado Independent Energy notes that independent administrators are often employed by utilities and thus sometimes reluctant to offer third party criticism of the bid evaluation process.[695] We clarify that the independent administrator, who is responsible for administering the competitive solicitation, must be an entity independent from the purchasing electric utility in order to help ensure fairness. Whether the entity is called an independent administrator or a third-party consultant, the substantive requirement of this factor is that the competitive solicitation not be administered by the purchasing electric utility itself or its affiliates, but rather by a separate, unbiased, and unaffiliated entity not subject to being influenced by the purchasing utility. We recognize, however, that such an independent administrator will need to be selected and paid. Though we are not directing a process, we note that the selection and payment could be done under the auspices of a state regulatory authority or by mutual agreement between the utility and the competitive solicitation participants.

436. In response to the Montana Commission's request for clarification as to what ''certified'' means within the guideline that requires certification of the competitive solicitation by the state regulatory authority or nonregulated electric utility as fulfilling the above criteria, we clarify that, after a thorough review of the competitive solicitation procedures used and the competitive solicitation results, certification of the competitive solicitation requires a written, formally-issued finding by the state that the competitive solicitation and its results comply with PURPA and this Commission's PURPA regulations—and must include the independent administrator's report to the same effect.

437. We decline at this time to add any additional requirements for competitive solicitations. We continue to believe that states may be in the best position to consider their particular local circumstances. We think that the guidelines adopted here, in conjunction with the *Allegheny* principles and other clarifications made here, provide an adequate framework for competitive solicitations to be conducted efficiently, transparently and in a nondiscriminatory manner.

438. We also clarify that, if a competitive solicitation is not conducted fairly and in accordance with the guidelines here, then an aggrieved entity may challenge the state's competitive solicitation in the appropriate forum, which could include any one or more of the following: (1) Initiating or participating in proceedings before the relevant state commission or governing body; (2) filing for judicial review of any state regulatory proceeding in state court (under PURPA section 210(g)); or, alternatively (3) filing a petition for enforcement against the state at the Commission and, if the Commission declines to act, later filing a petition against the state in U.S. district court (under PURPA section 210(h)(2)(B)).

iii. Other Requests

439. We decline to grant Solar Energy Industries request to require that solicitations be linked with the purchasing electric utility's IRP. Where a state has an IRP,[696] it may make sense to link the competitive solicitation processes with the IRP so that the competitive solicitation is conducted for the entirety of a utility's anticipated capacity needs. On the other hand, IRPs may come in a variety of forms. For example, an IRP may merely be a general projection of short- and long-term load growth and potential resources to meet such growth, and each generation project may be subject to specific approval based on actual specific need. In order to provide states flexibility in conducting these

[693] Public Interest Organizations Comments at 73.

[694] NRECA Comments at 11. In this final rule, we note, for ease of readability we have used the word ''state'' to refer to both state regulatory authorities and to nonregulated electric utilities. Thus, in the context of nonregulated electric utilities in particular, to say that the ''state'' can fairly administer the competitive solicitation is to say that the nonregulated electric utility can, essentially, be both the purchasing electric utility and potentially the independent administrator of its own competitive solicitation. That is a result we cannot countenance.

[695] Colorado Independent Energy Comments at 8.

[696] 16 U.S.C. 2621(a), (d)(7) (requiring states to consider whether to employ integrated resource planning).

processes, we will not require such links between competitive solicitations and IRPs, although such links certainly are permitted if a state deems it to be appropriate.

440. Regarding facilities not designed primarily to sell electricity to the purchasing electric utility, such as waste to power small power production facilities and cogeneration facilities, we find that an exemption from competitive solicitation processes is unnecessary. We do not exempt small power production facilities from the competitive solicitation process; we are not persuaded that such an exemption is appropriate given that exempting large classes of small power producers could frustrate the price discovery function of the competitive solicitation. A large number of exempted small facilities could disrupt the competitive solicitation process. We clarify, however, that QFs whose capacity is 100 kW or less already are entitled to standard rates regardless of whether they compete in a competitive solicitation and we do not change that regulation in this final rule.[697] Given that we view competitive solicitations as an important price discovery tool and that states already are required to establish standard rates for such entities, there is no need to determine prices for QFs at 100 kW or less through a competitive solicitation.

441. The Commission clarifies that any competitive solicitation conducted may not force alteration of existing QF contracts. A QF receiving a capacity payment is entitled to that payment for the duration of the term of its contract, and a competitive solicitation is necessarily forward looking based on the results of that auction.

C. Relief From Purchase Obligation in Competitive Retail Markets

1. NOPR Proposal

442. The Commission in the NOPR proposed to add regulatory text at the end of § 292.303(a) of the PURPA Regulations to provide that a utility's 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 stated that it was reasonable for electric utilities' PURPA capacity purchase obligations to be reduced to the extent retail choice reduces their supply obligations. To the extent Provider of Last Resort (POLR) supplies are obtained through solicitations having a particular contract term such as one year, the Commission proposed that 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.

443. The Commission proposed, 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 intended that this proposal would apply prospectively from the effective date of a final rule and would not disturb contracts in effect at the time the utility's supply obligation is reduced.

2. Comments

444. APPA, DTE Electric, EEI, Institute for Energy Research, NorthWestern, NRECA, Pennsylvania Commission, Portland General, and We Stand for Energy filed comments in support of the Commission's proposal 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.[698]

445. New England Small Hydro, NIPPC, CREA, REC, and OSEIA, and Public Interest Organizations filed opposing comments arguing that the Commission lacks the statutory authority to implement this proposal because the Commission lacks discretion to reduce an electric utility's mandatory purchase obligation except through PURPA section 210(m).[699] New England Small Hydro claims that PURPA section 210(a) clearly states that electric utilities must purchase the electric energy from QFs, and that the Commission does not have the authority to deviate from the statute.[700] NIPPC, CREA, REC, and OSEIA argues that the Commission's existing regulations adequately address the concern at issue because any reduction in the long-term capacity needs of the utility due to retail access should be reflected in avoided capacity rates offered to QFs.[701] Public Interest Organizations claim that the Commission proposes to remove state authority by requiring QF contracts with a POLR to match the term of the POLR's other supply contracts.[702] Public Interest Organizations also state that even if the Commission had such authority, there is no evidence in the record to support matching QF contract lengths with a POLR's other supply contracts. Public Interest Organizations also assert that the Commission's proposal unlawfully discriminates against QFs to the extent that it fails to treat QF contracts in parity with any of a POLR's other supply contracts.[703]

446. Biogas and Covanta argue that the rationale for this proposal is unclear and that the NOPR fails to justify the reduction of a utility's obligation to purchase QF power based on the amount of any non-utility generator's supply into the utility's service territory.[704] Covanta states that the NOPR incorrectly concludes that all public power is renewable power.[705] Biogas and Covanta assert that the existence of a competitive retail market does not mean there is a competitive retail market for biogas or waste-to-energy QFs.[706] Biogas and Covanta also argue that the NOPR would reduce that already limited market by providing greater leverage to the purchasing electric utility, and urge the Commission to remove barriers to local government options for energy purchase rates.

447. Ohio Commission Energy Advocate states that under Ohio law, an electric distribution utility is required to provide consumers within its certified territory a standard service offer of all competitive retail electric services necessary to maintain essential electric services to customers, including a firm supply of electric generation services.[707] Ohio Commission Energy Advocate claims that all PUCO-regulated electric distribution utilities satisfy this obligation through competitive solicitation for default service within the context of an electric security plan.[708] Ohio Commission Energy Advocate believes that the electric distribution utility should retain the full purchase obligation because the regulated utility maintains the obligation to serve as the POLR for all

[697] *See* 18 CFR 292.304(c).

[698] APPA Comments at 20; DTE Electric Comments at 4–5; EEI Comments at 41–42; Institute for Energy Research Comments at 1–2; NorthWestern Comments at 8; NRECA Comments at 13–14; Pennsylvania Commission Comments at 6–7; Portland General Comments at 12–13; and We Stand Comments at 1.

[699] New England Small Hydro Comments at 15–16; NIPPC, CREA, REC, and OSEIA Comments at 68–69; and Public Interest Organizations Comments at 74–75.

[700] New England Small Hydro at 16 (citing *Chevron U.S.A., Inc.* v. *Nat. Res. Def. Council,* 467 U.S. 837 (1984)).

[701] NIPPC, CREA, REC, and OSEIA Comments at 69.

[702] Public Interest Organizations Comments at 74.

[703] *Id.* at 75.

[704] Biogas Comments at 2; Covanta Comments at 9.

[705] Covanta Comments at 9.

[706] Biogas Comments at 2; Covanta Comments at 9–10.

[707] Ohio Commission Energy Advocate Comments at 5.

[708] *Id.* at 6.

''wires-connected'' customers.[709] Ohio Commission Energy Advocate also states that it is concerned by the lack of alternatives to the mandatory purchase obligation and would question any interpretation of PURPA that contemplates a scenario where no entity has a purchase obligation for a QF.[710]

448. ELCON, California Utilities, Chamber of Commerce, Connecticut Authority, and Michigan Commission request further clarification on how the Commission's proposal will be implemented. ELCON states that industrial customers conditionally support the reduction in obligation to purchase based on a state retail choice program, subject to the development of clear and enforceable criteria that exclude mandatory purchase obligation relief for default supply obligations that utilities meet with their own generation.[711]

Similarly, California Utilities state that because of the various ways states have developed restructured retail markets, the Commission should provide additional guidance as to the various ways that state commissions can address load reductions due to retail choice while protecting legacy utilities.[712] California Utilities explain that they need Commission guidance to ensure that cost recovery for past and future mandated QF purchases is equitable to the remaining retail customers in the legacy utilities' distribution service areas and that future PURPA mandates or costs are fairly allocated consistent with cost-causation principles.[713] Chamber of Commerce states that the Commission should clarify that the reduction in a utility's QF purchase obligation is measured against the amount of a utility's load that has elected an alternative supplier, as opposed to eligible load.[714] Chamber of Commerce claims that in certain states, only a portion of an electric utility's load is eligible to select an alternative electricity supplier and that such percentage would serve as the limit for any corresponding reduction in a utility's QF purchase obligation. Michigan Commission states that its retail choice program caps retail choice at 10 percent of an electric utility's retail customer demand, and seeks clarification on (1) whether the reduction in a utility's purchase obligation would equal the reduction in its supply obligation, be based on the percentage of its customer demand participating in the state's retail choice program, or some other metric; and (2) how fluctuations in the state's retail choice program and resulting purchase obligation should be addressed.[715]

449. Connecticut Authority supports the proposal to modify distribution utilities' must-purchase obligations.[716] Connecticut Authority states that since Connecticut's electric industry restructuring, distribution utilities' purchases of QF output have not been used to serve retail customers, rather the distribution utility acts as an intermediary selling output into the New England markets. Connecticut Authority asserts that the Commission should clarify that the state regulatory authority is responsible for determining the appropriate adjustment to the distribution utility's must-purchase obligation and providing notice of such determination to the Commission.[717]

450. Connecticut Authority claims that QF output is different from, and cannot be substituted in for, distribution utility-provided default standard or last resort services. Connecticut Authority explains that standard service is procured in six-month tranches, last resort service is procured in three-month tranches, and that distribution utilities do not self-manage their default service supply portfolios.[718]

451. Connecticut Authority states that while it agrees that matching the contract terms for default service supply and QF supply could potentially reduce the burden of over-estimated avoided costs and give states flexibility to respond quickly to changes to a distribution utility's default supply obligation, the Commission should not mandate any term length for the mandatory purchase obligation.[719] Instead, Connecticut Authority asserts that the Commission should allow the state to establish the term based on state-specific circumstances.

452. California Utilities request that the Commission reaffirm that all alternative retail suppliers, including Electric Service Providers (ESP) and Community Choice Aggregators (CCA), are electric utilities subject to the PURPA purchase obligation.[720] California Utilities explain that ESPs and CCAs are the two types of entities that California allows to sell power to retail customers in the distribution service territories of CPUC-regulated utilities, and argues that such entities meet the definition of electric utility used in PURPA.[721]

453. California Utilities state that the Commission should clarify that a state has no authority to exempt any traditional or alternative retail supplier from the PURPA mandatory purchase obligation in order to ensure QFs that there is a robust market to sell their energy and capacity to entities that actually serve load in the event a legacy utility is relieved of all or part of its PURPA obligations.[722] California Utilities also state that the Commission should clarify that alternative retail suppliers must make avoided cost information publicly available to allow QFs to locate and identify potential buyers that may have higher avoided costs than legacy utilities that have lost load and may no longer have capacity needs.

454. California Utilities argue that for states such as California that allow alternative retail suppliers to opt out of procuring capacity and require legacy utilities to provide capacity on their behalf, it would be unfair for legacy utilities to pay a QF any amount for energy greater than the LMP unless the price differential for which the legacy utility can sell the energy in the market is paid for by the alternative retail supplier that was short on capacity.[723] California Utilities explain that this would prevent cost shifts to customers who remain with the legacy utility such that all costs associated with the mandatory PURPA purchases made by the legacy utility on behalf of the alternative retail supplier would be borne by customers of the alternative retail supplier.[724] California Utilities also argue that the Commission should clarify that if legacy utilities are required to procure capacity from QFs on behalf of alternative retail suppliers, states must require alternative retail suppliers to pay for such QF purchases at the avoided cost rate set by the state for the legacy utility for capacity.

455. California Utilities urge the Commission to adopt a stranded cost regulation addressing PURPA obligations incurred by legacy utilities that lose load to retail competition consistent with the cost recovery guarantee in PURPA section 210(m)(7)(A).[725] California Utilities argue that such regulation should be clear that prudently incurred costs include any costs associated with a

[709] *Id.* at 6–7.

[710] *Id.*

[711] ELCON Comments at 19.

[712] California Utilities Comments at 5.

[713] *Id.* at 7.

[714] Chamber of Commerce Comments at 5.

[715] Michigan Commission Comments at 5–6.

[716] Connecticut Authority Comments at 16.

[717] *Id.* at 17.

[718] *Id.*

[719] *Id.* at 18.

[720] California Utilities at 9.

[721] *Id.* at 9–10.

[722] *Id.* at 11.

[723] *Id.* at 12.

[724] *Id.* at 13.

[725] *Id.* at 14.

purchase under a state-mandated contract. California Utilities propose new language to § 292.304(g) regarding implementation of the cost recovery mandate in section 210(m)(7)(A) of PURPA stating, in part, that ''[a] state commission may not find any costs associated with any legally enforceable obligation that it has imposed on an electric utility imprudent.'' [726]

3. Commission Determination

456. In this final rule, we decline to adopt the proposed regulation permitting states with retail competition to allow relief from the purchase obligation. We instead clarify that the Commission's existing PURPA Regulations already require that states, to the extent practicable, must account for reduced loads in setting QF rates.

457. Specifically, 18 CFR 292.304(e)(3) already does and will continue to allow states, when setting avoided cost rates, to take into account ''the ability of the electric utility to avoid costs, including the deferral of capacity additions.'' We regard this existing regulation as allowing a state to consider reductions in a purchasing electric utility's supply obligations given retail competition and the purchasing electric utility's POLR obligations under state law. We further clarify that this clarification is not intended to be reflected as a MW-for-MW reduction (or increase) based on yearly changes in load and therefore does not and may not serve to terminate a purchasing utility's mandatory purchase obligation under PURPA section 210(a).[727]

D. Evaluation of Whether QFs Are at Separate Sites

1. Rebuttable Presumption of Separate Sites

a. NOPR Proposal

458. The Commission proposed 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 proposed that this change would be effective as of the date of the 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.

459. The Commission proposed that an entity can seek to rebut the presumption only for those facilities that are located more than one mile apart and less than 10 miles apart. The Commission believed 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.[728] That latter distance, the Commission believed, is 10 miles or more apart. Thus, if two affiliated facilities are one mile or less apart, they would continue to be irrebuttably presumed to be a single facility at a single site. If affiliated facilities are 10 miles or more apart, they would be irrebuttably presumed to be separate facilities at separate sites.

460. The Commission proposed that if affiliated facilities are more than one mile apart and less than 10 miles apart, there would still be a presumption, but it would 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 10 miles apart and argue that they should be treated as a single facility. The Commission could also act *sua sponte.* The Commission proposed that self-certifications will remain effective after a protest has been filed, until such time as the Commission issues an order revoking the certification.

461. The Commission proposed allowing an entity seeking QF status to provide further information in its certification (both self-certification and application for Commission certification), to preemptively defend against rebuttal by asserting factors that affirmatively show that the affiliated facilities are indeed separate facilities at separate sites.[729] Anyone challenging the QF certification would be allowed to assert factors to show that the facilities are actually part of the same, single facility.

462. The Commission proposed 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 proposed 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.

463. The Commission proposed that physical and ownership factors may be asserted to rebut or defend against rebuttal. Noting that no single factor would be dispositive, the Commission proposed the following factors: (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 solicited 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.

464. The Commission stated that it will continue to rely on its definition of ''affiliate'' provided in 18 CFR 35.36(a)(9), and noted that subsection (iii) provides that the Commission may determine, after appropriate notice and

[726] *Id.* at 15.

[727] 18 CFR 292.304(e)(3).

[728] NOPR, 168 FERC ¶ 61,184 at P 101. As discussed in detail in section IV.D.1.d below, this final rule will change the references to ''separate facilities'' or ''the same facility'' to ''at separate sites'' or ''at the same site.''

[729] 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 a self-certification or application for Commission certification), if the QF's status is later challenged (*i.e.,* by a petition for declaratory order), 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.

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.[730] The Commission intended, 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 stated that it could take into consideration many of the same factors that would reasonably be considered in evaluating whether facilities located over one and less than 10 miles apart are a single facility or separate facilities.

465. The Commission believed that this change, together with the proposed definition of ''electrical generating equipment'' and revision to the FERC Form No. 556, would more closely align with Congress's requirement that QFs seeking to certify as small power production facilities are in fact below the 80 MW statutory limit for such facilities.[731]

b. Commission Determination

466. As further discussed and revised in the following sections, we adopt the NOPR proposal. Henceforth, if a small power production facility seeking QF status is located one mile or less from any affiliated small power production QFs that use the same energy resource, it will be irrebuttably presumed to be at the same site as those affiliated small power production QFs. If a small power production facility seeking QF status is located ten miles or more from any affiliated small power production QFs that use the same energy resource, it will be irrebuttably presumed to be at a separate site from those affiliated small power production QFs. If a small power production facility seeking QF status is located more than one mile but less than ten miles from any affiliated small power production QFs that use the same energy resource, it will be rebuttably presumed to be at a separate site from those affiliated small power production QFs.

467. We adopt the proposal to allow a small power production facility seeking QF status to provide further information in its certification (both self-certification and application for Commission certification) or recertification (both self-certification and application for Commission recertification), to preemptively defend against anticipated challenges by identifying factors that affirmatively show that its facility is indeed at a separate site from affiliated small power production QFs that use the same energy resource and that are more than one but less than 10 miles from its facility. We will correspondingly allow any interested person or entity to challenge a QF certification (both self-certification and application for Commission certification) or recertification (both self-recertification or application for Commission recertification) that makes substantive changes to the existing certification as further described below).[732]

468. As explained in section IV.D.1.f below, we adopt the NOPR's proposed factors, with certain additions.

469. We adopt the proposal to clarify that challenges to QF status require that the interested person or entity filing a protest must specify facts that make a prima facie demonstration that the facility described in the certification (both self-certification and application for Commission certification) or recertification (both self-recertification and application for Commission recertification) does not satisfy the requirements for QF status. Additionally, any protest must be adequately supported, with supporting documents, contracts, or affidavits, as appropriate. General allegations or unsupported assertions will not provide a basis for denial of certification or recertification. We additionally limit protests, as described more fully in section IV.E below, by clarifying that protests may be made to an initial certification (both self-certification and application for Commission certification) filed on or after the effective date of this final rule, but only to a recertification (both self-recertification and application for Commission recertification) filed on or after the effective date of this final rule that makes substantive changes to the existing certification. We adopt the proposal to limit protests by requiring that once the Commission has affirmatively certified an applicant's QF status in response to a protest opposing a self-certification or self-recertification, or in response to an application for Commission certification or recertification, any later protest to a recertification (self-recertification or application for Commission recertification) making substantive changes to a QF's existing certification must demonstrate changed circumstances from the facts on which the Commission acted on the certification filing that call into question the continued validity of the earlier certification.[733] Finally, the Commission retains the discretion to summarily reject protests where a protest reiterates arguments already made against the same QF that the Commission previously denied or otherwise rejected.

c. Need for Reform

i. Comments

470. Multiple parties have expressed concern 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 slightly more than one mile apart in order to qualify as separate small power production facilities.[734] Several commenters state that the NOPR-proposed changes will reduce the opportunity for gaming.[735]

471. Several commenters argue, to the contrary, that there is no evidence of

[730] 18 CFR 35.36(a)(9)(iii).

[731] *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'').

[732] We note that a protester must separately file for intervention seeking to be made a party to the proceeding; the filing of a protest does not make that person or entity a party. 18 CFR 385.102(c), 385.211(a)(2).

[733] An interested person or entity can choose to file a petition for declaratory order, with fee, at any time (that is, not only within 30 days from the date of the filing of the Form No. 556). However, if the Commission has affirmatively certified an applicant's QF status in response to a protest opposing a self-certification or self-recertification, or in response to an application for Commission certification or recertification, any later petition for declaratory order protesting the QFs existing certification must demonstrate changed circumstances from the time the Commission acted on the certification that call into question the continued validity of the earlier certification.

[734] *See* APPA Comments at 21; Center for Growth and Opportunity Comments at 5–6; Consumers Energy Comments at 4; East River Comments at 1–2; EEI Comments at 43; ELCON Comments at 35; Governor of Idaho Comments at 1; Idaho Commission Comments at 5–7; Idaho Power Comments at 13; Missouri River Energy Comments at 5; Mr. Moore Comments at 2; Northern Laramie Range Alliance Comments at 2; NorthWestern Comments at 9; NRECA Comments at 14–15; Portland General Comments at 14.

[735] APPA Comments at 21; Center for Growth and Opportunity Comments at 5–6; Consumers Energy Comments at 4; East River Comments at 1–2; EEI Comments at 43; ELCON Comments at 35; Governor of Idaho Comments at 1; Idaho Commission Comments at 5–7; Idaho Power Comments at 13; Missouri River Energy Comments at 5; Mr. Moore Comments at 2; Northern Laramie Range Alliance Comments at 2; NorthWestern Comments at 12; NRECA Comments at 14–15; Portland General Comments at 14.

gaming of the current one-mile rule.[736] Con Edison argues that utilities are not overwhelmed with QFs using the one-mile rule and there is little to no evidence to the contrary.[737] sPower states that it is difficult to see how developers that comply with this clear bright-line rule could be said to be circumventing.[738] New England Small Hydro argues that the Commission is attempting to address perceived abuses of the 80 MW limitation by burdening projects that do not abuse the system.[739]

ii. Commission Determination

472. The record shows that, since the establishment of the one-mile rule in the PURPA Regulations in 1980, the development of large numbers of affiliated renewable resource facilities, requires a revision of the one mile-rule. We find that the final rule will reduce the opportunity for developers of small power production facilities to circumvent the current one-mile rule by strategically siting small power production facilities that use the same energy resource slightly more than one mile apart.[740] While such circumvention may not be an everyday occurrence, we agree with commenters that the record demonstrates it is still a sufficient possibility under the current regulations that the Commission is justified in addressing it in order to comply with the statute.[741] The final rule, as adopted, still retains the presumption that small power production QFs more than one mile apart are located at separate sites, but simply makes the presumption rebuttable for small power production QFs located more than one mile but less than 10 miles apart, allowing the Commission the ability to address those circumstances.

[736] Solar Energy Industries Comments at 51; Southeast Public Interest Organizations Comments at 31; SC Solar Alliance Comments at 19.

[737] Con Edison Comments at 5.

[738] sPower Comments at 5.

[739] New England Small Hydro Comments at 17.

[740] The regulation, in practice, is only of consequence if the facilities located ''at the same site'' would exceed a power production capacity of 80 MW, as that is the size limit for a small power production facility to qualify as a QF. 16 U.S.C. 796(17)(A)(ii).

[741] *See* APPA Comments at 21; Center for Growth and Opportunity Comments at 5–6; Consumers Energy Comments at 4; East River Comments at 1–2; EEI Comments at 43; ELCON Comments at 35; Governor of Idaho Comments at 1; Idaho Commission Comments at 5–7; Idaho Power Comments at 13; Missouri River Energy Comments at 5; Mr. Moore Comments at 2; Northern Laramie Range Alliance Comments at 2; NorthWestern Comments at 9; NRECA Comments at 14–15; Portland General Comments at 14.

d. Site Definition

i. Comments

473. Solar Energy Industries state that, in *El Dorado County Water Agency,* the Commission found that ''the critical test under PURPA relates to whether the facilities are located at one site rather than whether they are integrated as a project.'' [742] Solar Energy Industries argue that the proposed rule, as drafted, abandons the focus on whether the facilities are located at one site and transforms it into an analysis as to whether affiliated QFs are part of the same project. Solar Energy Industries similarly contend that it is arbitrary to change from a ''same site'' to an ''integrated project'' standard.[743]

474. NIPPC, CREA, REC, and OSEIA state that the existing rule is a reasonable means of implementing the statutory phrase ''same site,'' particularly given the statutory directive to encourage QF development, and state that they prefer the current bright line rule.[744] Allco argues that the proposed rule is divorced from the statutory use of ''site.'' Allco asserts that the Commission lacks authority to define the term ''site'' in a manner other than one reasonably related to its ordinary meaning and argues that the Commission's definition of site arbitrarily limits QF development for no apparent reason.[745] The DC Commission would like the Commission to leave the resolution of certain disputes over whether QFs are separate to state commissions.[746] Idaho also requests that states be given as much discretion as possible.[747]

475. EEI states that the interpretation of ''same site'' is determined by the Commission, and that there is nothing in the statute that prevents the Commission from modifying its interpretation of the term ''same site.'' [748]

ii. Commission Determination

476. We modify the NOPR proposal to change terminology relating to the determination of whether small power production facilities are separate facilities to focus not on whether they are *separate facilities,* but rather to mirror the statutory language and thus focus on whether they are at ''*the same site.*'' In that regard, we change references to ''separate facilities'' or ''the same facility'' to ''at separate sites'' or ''at the same site.''

477. The NOPR refers to determining whether affiliated facilities are ''separate facilities'' or ''a single facility.'' However, both the statute and the existing regulations contemplate that the Commission will determine what is ''the same site,'' [749] and do not require the Commission to determine whether two facilities are a single facility. The statute defines a small power production facility as an eligible facility, which, together with other facilities located at the same site (as determined by the Commission), has a power production capacity no greater than 80 MW,[750] and the Commission's regulations have long approached the matter as defining how to determine ''the same site.'' [751] We find that the Commission's determination of whether or not a small power production facility is a QF (*i.e.,* exceeds a power production capacity of 80 MW) should continue to be focused on whether the small power production facility seeking QF status and other nearby affiliated small power production QFs are at the same site or at separate sites.

478. We also modify the NOPR proposal to change the irrebuttable and rebuttable presumptions regarding affiliated facilities to instead apply to affiliated *small power production* qualifying facilities. As noted, the NOPR refers to determining whether *affiliated facilities* are ''separate facilities'' or ''a single facility.'' We find that only *affiliated small power production QFs* are relevant to the determination of whether the small power production facility seeking QF status and other nearby facilities are at the same site or separate sites.[752] Correspondingly, as further detailed below, we will allow entities challenging a QF certification (both self-certification and application for Commission certification) or recertification (both self-recertification and application for Commission recertification) to rebut the presumption that a small power production facility seeking QF status is at a separate site from any affiliated small power production QFs that use the same energy resource and that are located

[742] Solar Energy Industries Comments at 60 (quoting *El Dorado Cty. Water Agency,* 24 FERC ¶ 61,280, at 61,578 (1983)).

[743] *Id.* at 61–62.

[744] NIPPC, CREA, REC, and OSEIA Comments at 70.

[745] Allco Comments at 16.

[746] DC Commission Comments at 9.

[747] Idaho Comments at 1.

[748] EEI Comments at 42.

[749] 16 U.S.C. 796(17)(A)(i); 18 CFR 292.204(a).

[750] 16 U.S.C. 796(17)(A)(i).

[751] 18 CFR 292.204(a).

[752] We note, however, that, in the context of a PURPA section 210(m) proceeding, *all* affiliates are relevant in evaluating whether a QF has nondiscriminatory access to a competitive market.

more than one but less than 10 miles from it.[753]

479. We therefore modify the language proposed in the NOPR. In sum, we find that if a small power production facility seeking QF status is located one mile or less from any affiliated small power production QFs that use the same energy resource, it will be irrebuttably presumed to be ''at the same site'' as those affiliated small power production QFs (rather than a single facility at a single site, as proposed in the NOPR). The Commission finds that if a small power production facility seeking QF status is located ten miles or more from any affiliated small power production QFs that use the same energy resource, it will be irrebuttably presumed to be at a separate site from those affiliated small power production QFs (rather than separate facilities at separate sites, as proposed by the NOPR). We find that if a small power production facility seeking QF status is located more than one but less than ten miles from any affiliated small power production QFs that use the same energy resource, it will be rebuttably presumed to be at a separate site from those affiliated small power production QFs (rather than separate facilities at separate sites, as proposed in the NOPR).

480. Purchasing electric utilities and others will be able to file a protest and identify factors attempting to rebut the presumption for a small power production facility seeking QF status that has an affiliated small power production QF that uses the same energy resource more than one but less than 10 miles from it, and argue that the small power production facility seeking QFs status should be treated as ''at the same site'' as the affiliated small power production QF located more than one but less than 10 miles from it (rather than as a single facility, as proposed in the NOPR). We will allow a small power production facility seeking QF status to provide further information in its certification (both self-certification and application for Commission certification) or recertification (both self-recertification and application for Commission recertification) to preemptively defend against rebuttal by identifying factors that affirmatively show that its facility is indeed at a separate site from an affiliated small power production QF located more than one but less than 10 miles from it (rather than separate facilities at separate sites, as proposed in the NOPR).

481. Regarding the requests to allow states to decide whether affiliated small power production QFs are located at separate sites, we note that, in PURPA section 201, now codified in section 3 (17) of the FPA, Congress authorized the Commission to determine whether the applicant and other facilities are located at the same site. This Commission will therefore continue to make these determinations.

e. Distance Between Facilities

i. Comments

482. Several commenters contend that the proposal to institute a rebuttable presumption for facilities that are more than one mile but less than 10 miles apart is arbitrary and lacks sufficient supporting evidence.[754] ELCON notes that the choice of 10 miles as the threshold is not supported by any evidence.[755]

483. Regarding the proposed rebuttable presumption for QFs more than one but less than 10 miles apart, Terna Energy argues that the NOPR effectively increases the ''exclusion zone'' around a QF's electrical generating equipment from approximately three square miles (3.1415 square miles, the circle with one-mile radius around the QF's electrical generating equipment, assuming a point generating source) to over 300 square miles (*i.e.* a 10-mile radius circle), a 100-times increase to the ''exclusion area'' for a single QF.[756]

484. New England Small Hydro notes that hydroelectric generators are located where river conditions are ideal for generating and that, while they are not generally located within one mile, there may be some projects owned by affiliates that are within 10 miles of each other.[757]

485. Borrego Solar opposes applying the proposed changes to the one-mile rule to distributed generation and finds that it would restrict the ability of developers to follow market signals when locating projects and significantly increase the regulatory burden. Borrego Solar notes that there are several reasons that otherwise different projects from the same company would be within 10 miles of each other, including land zoning restrictions, available substation capacity, and optimal topology or insolation.[758] Borrego Solar notes that it is common for projects on the distribution system to be within two miles of a substation or three-phase lines to reduce interconnection costs. Borrego Solar states that it is also common for multiple unaffiliated developers to site their projects in a single area within just a few miles of each other, and later sell those projects to a single entity much later in the process, inadvertently violating the Commission's rules.[759] Borrego Solar would like the Commission to exclude projects directly interconnected to the distribution system or initially developed by different entities from any presumption of common development. Borrego Solar urges the Commission to, at a minimum, establish a streamlined, low-cost option for challenging any presumption of common development, to avoid casting a chill over project development and driving developers and long-term owners out of the market due to the risks of having the projects disqualified.[760]

486. North Carolina DOJ argues that the proposed rule, by discouraging facilities from being placed close to one another, also runs counter to a North Carolina policy based on efficient use of electric resources.[761] North Carolina DOJ and North Carolina Commission Staff state that the rules in North Carolina incentivize the installation of production facilities close to substations so projects naturally appear in clusters surrounding transmission and distribution infrastructure.[762] North Carolina DOJ says that the proposed rule fails to take into account the complex and regionally specific factors driving the siting, financing, operation, and maintenance of production facilities.[763]

487. Industrial Energy Consumers state that the NOPR does not distinguish between merchant small power production QFs built to sell electricity to third parties and self-supply QFs built primarily to support manufacturing or industrial processes. Industrial Energy Consumers state that there are many manufacturing company sites that are of a 10-mile length. Industrial Energy Consumers state that the Commission's proposed changes to the one-mile rule should be clarified to exclude ''self-supply'' QFs.[764]

488. Solar Energy Industries believes that for facilities less than one mile

[753] Though not at issue here, we also note that the facilities need to use the same energy resource. 18 CFR 292.204(a)(1).

[754] Allco Comments at 16; Ares Comments at 7; Borrego Solar Comments at 4; ELCON Comments at 19; Public Interest Organizations Comments at 93; SC Solar Alliance Comments at 17; Solar Energy Industries Comments at 60, 62.

[755] ELCON Comments at 35–36.

[756] Terna Energy Comments at 4.

[757] New England Small Hydro Comments at 17.

[758] Borrego Solar Comments at 3–4.

[759] *Id.* at 4.

[760] *Id.* at 5.

[761] North Carolina DOJ Comments at 8.

[762] *Id.;* North Carolina Commission Staff Comments at 6.

[763] North Carolina DOJ Comments at 6.

[764] Industrial Energy Consumers Comments at 16.

apart the Commission should continue to waive the rule where appropriate.[765]

489. Regarding the proposed irrebuttable presumption that facilities located more than 10 miles apart are separate facilities, NorthWestern urges the Commission to consider increasing the distance. NorthWestern explains that its operations in Montana are geographically very expansive and 10 miles in Montana is not a substantial distance, especially when compared to other states that are geographically much smaller. NorthWestern states that Montana's electric system has more than 24,450 miles of electric transmission and distribution lines to serve approximately 374,000 customers, and that its electric operations are very rural and cover more than 97,500 square miles.[766] NorthWestern therefore recommends that the Commission consider expanding this distance to accommodate utilities in the West that have very large service territories.[767]

ii. Commission Determination

490. We adopt the NOPR proposal that an entity can seek to rebut the presumption of separate sites only for an entity seeking small power production QF status with an affiliated small power production QF or QFs that are located more than one and less than 10 miles from it.

491. We recognize, as we have previously for the one-mile rule,[768] that it is debatable as to where exactly these thresholds are most appropriately set. PURPA requires that no small power production facility, together with other facilities located ''at the same site,'' exceed 80 MWs, and Congress has tasked the Commission with defining what constitutes facilities being at the same site for purposes of PURPA. We find that providing set geographic distances will limit unnecessary disputes over whether facilities are at the same site, and therefore must choose reasonable distances at which small power production facilities will be considered irrebuttably at the same site or irrebuttably at separate sites. There are some affiliated small power production facilities using the same energy resource that are so close together that it is reasonable to treat them as irrebuttably at the same site. The Commission finds that one mile or less is a reasonable distance to treat such facilities as irrebuttably at the same site. Likewise, there are some small power production facilities that are affiliated and may use the same energy resource but that are sufficiently far apart that it is reasonable to treat them as irrebuttably at separate sites. The Commission finds that 10 miles or more is a reasonable distance to treat such facilities as irrebuttably at separate sites. For affiliated small power production facilities using the same resource that are more than one mile but less than 10 miles apart, the Commission finds that the distinction between same site or separate site is not as clear, and therefore finds that it is reasonable to treat them as rebuttably at separate sites, and to allow interested parties to provide evidence to attempt to rebut that presumption. The Commission finds that establishing these reasonable distances, and particularly establishing the ability to rebut the presumption of separate sites for affiliated small power production facilities more than one mile but less than 10 miles apart, better allows the Commission to address the evolving shape and configuration of resources, such as modular solar or wind power plants, that are being developed as QFs, and provides for improved administration of PURPA. The Commission therefore finds that the one-mile and 10-mile limits are reasonable inflection points for differentiating between the same site and separate sites.

492. The Commission understands that there may be many reasons that guide developers' decisions on where to site facilities, and for siting them near to (or far from) each other. The Commission reiterates that for affiliated small power production QFs that are more than one and less than 10 miles apart, there is still a presumption that they are at separate sites, though the Commission today makes that presumption a rebuttable presumption.[769] We also adopt today the proposal to allow an entity seeking QF status to provide further information in its certification (both self-certification and application for Commission certification) or recertification (both self-recertification and application for Commission recertification) to preemptively defend against rebuttal by identifying factors that affirmatively show that its facility is indeed at a separate site from affiliated small power production QFs more than one but less than 10 miles from it. Additionally, we note that we are retaining waiver provision in 18 CFR 292.204(a)(3), allowing the Commission to waive the method of calculation of the size of the facility for good cause.[770]

493. Borrego Solar raises the concern that unaffiliated developers may site their projects within a few miles of each other, and later sell those projects to a single entity much later in the process, inadvertently violating the Commission's rules. The Commission finds that it is reasonable to expect the single purchasing entity in the example to be on notice about the size and locations of its QF acquisitions and the requirements of both PURPA and the Commission's regulations, just as it would need to consider other regulatory requirements associated with its acquisition. Moreover, ownership by a single entity of multiple small power production QFs in close proximity to each other that together exceed a power production capacity of 80 MW, and whether this improperly circumvents the Commission's regulations, is precisely what the new rebuttable presumption is seeking to address.

494. Regarding Industrial Energy Consumers' request that the Commission's changes be clarified to exclude ''self-supply'' QFs, the Commission declines to do so. PURPA limits the power production capacity of a small power production QF, together with any other facilities located at the same site (as determined by the Commission), to 80 MW.[771] The Commission finds that Industrial Energy Consumer's argument that ''self-supply'' QFs are built primarily to support manufacturing and industrial processes does not negate the fact that the ''self-supply'' QFs in question are small power production facilities limited to 80 MW. Similarly, its argument also does not justify different application of the same site determination. The Commission will therefore apply the same site determinations to all small power production QFs. The Commission notes that, as with other small power production QFs, an individual ''self-supply'' QF may assert relevant factors to show why it should not be considered to be at the same site as an affiliated small power production QF that is more than one but less than 10 miles away from it. For example, if a self-supply facility seeking QF status was within 10 miles of an affiliated

[765] Solar Energy Industries Comments at 60–61 (citing *Windfarms, Ltd.*, 13 FERC ¶ 61,017, at 61,032 (1980) (*Windfarms*)).

[766] NorthWestern Comments at 10.

[767] *Id.*

[768] *See Windfarms*, 13 FERC at 61,032.

[769] For hydroelectric generating facilities, the regulations currently provide that the same energy resources essentially means ''the same impoundment for power generation,'' *see* 18 CFR 292.204(a)(2)(i), and it is unlikely that hydroelectric generating facilities located more than a mile apart would rely on the same impoundment. Should that circumstance arise, though, the applicant facility could seek waiver, arguing that the facilities should not be considered to be at the same site. *See* 18 CFR 292.204(a)(3).

[770] *See* 18 CFR 292.204(a)(3).

[771] 16 U.S.C. 796(17)(A)(ii).

small power production QF, but the energy from each facility was used primarily to supply different end users, the self-supply facility seeking QF status could argue that this fact supports that it is at a separate site from the affiliated small power production QF, and the Commission would consider this fact in its evaluation.

495. Regarding Terna Energy's contention that the new rule causes a 100-times increase to the ''exclusion zone'' around a QF's electrical generating equipment, we believe that the rule providing for a rebuttable presumption for affiliated small power production QFs located more than one but less than 10 miles apart, as promulgated today, is necessary to address allegations of improper circumvention of the one-mile rule that both previously and in comments have been presented to the Commission.

496. We reject NorthWestern's request to increase the distance of the irrebuttable presumption of separate sites to more than 10 miles. Northwestern argues that 10 miles is not a significant distance compared to the geographic expansiveness of its system. We believe this is an irrelevant comparison; what matters is not how large or small the purchasing electric utility's service territory is or how rural it may be or how many miles of transmission lines it may have, but the question presented by the statute, *i.e.,* whether or not the affiliated small power production QFs are located at the same site. As described above, we have decided that 10 miles is a reasonable and appropriate distance at which to apply the irrebuttable presumption of separate sites, irrespective of how expansive, or diminutive, the purchasing electric utility's system may be.

f. Factors

i. Comments

497. Several commenters state that they support the factors for evaluating whether or not facilities are at the same site, which are described in the NOPR.[772] SC Solar Alliance and the Southeast Public Interest Organizations support considering a common point of interconnection or a single real estate parcel or owner as factors weighing towards a determination that multiple projects are a single facility.[773]

498. Several commenters offer additional factors for consideration.[774] North Carolina Commission Staff states that the Commission should also consider whether the QF is attempting to game the system by getting rates for which they would otherwise be ineligible, as well as where the facilities were constructed and when common ownership commenced.[775] Northern Laramie Range Alliance suggests that relevant factors could include, for example, direct or indirect ownership by the same party or parties, interconnection at a single substation, simultaneous site acquisition and/or state and local permitting.[776] Allco proposes that the criteria to determine if sites are separate should be whether they share infrastructure, private roads or interconnection agreements in common.[777] NRECA proposes that the types of evidence could include evidence of contemporaneous construction, shared interconnection, common communication and control, use of the same step-up transformer, and common permitting and land leasing.[778] The Idaho Commission proposes that relevant factors include whether they share an interconnection agreement, obtained local, state or federal permits under the same application or as the same entity, and if they have a revenue sharing agreement.[779]

Portland General suggests that the Commission include past ownership of projects as a factor.[780]

499. Regarding the relative weight of the factors, the Southeast Public Interest Organizations would like the Commission to identify which factors would be definitive in a QF being able to proactively demonstrate that their site is separate.[781] Both Basin and EEI would like the Commission to clarify that the list of factors to be considered is not exhaustive or weighted.[782] NorthWestern contends that the Commission should specify that a showing of any one factor is sufficient to rebut the presumption. NorthWestern argues that the Commission should have the flexibility to deal with this issue on a case-by-case basis and expand or modify the list of factors where appropriate.[783]

500. NorthWestern states that it has concerns about the Commission's reliance on 18 CFR 35.36(a)(9), because, according to NorthWestern, developers carefully structure the ownership of their companies to ensure that they are not, technically, legal affiliates when, in fact, considering the totality of the circumstances, they are affiliates. For these reasons, NorthWestern strongly urges the Commission to consider the physical characteristic factors identified for determining the distance between facilities in order to also determine if facilities are owned by affiliates.[784] NorthWestern states that, for example, if one facility only owns five percent voting interest in another facility, but the two facilities have one interconnection request and use the same collector system, the Commission should be able to find that there are sufficient facts so that they are treated as affiliates for purposes of the one-mile rule.[785]

501. Several commenters opposed the Commission's proposed factors.[786] SC Solar Alliance states that the range of factors included under the categories of ''ownership/other characteristics'' and ''physical characteristics'' is overly broad and could be subject to inconsistent or problematic interpretation. For example, SC Solar Alliance states that the term ''infrastructure'' is undefined and ambiguous, and ''control facilities,'' ''access and easements,'' ''collector systems or facilities,'' and ''property leases'' are all vague and imprecise.[787] SC Solar Alliance agrees with Solar Energy Industries' emphasis that under no scenario should common financing be relevant, as unquestionably distinct facilities are frequently financed as part of a bundled portfolio.[788]

502. NIPPC, CREA, REC, and OSEIA strongly oppose use of common interconnection facilities as a factor because separately owned facilities are likely to share interconnection facilities to reduce costs and build off of existing infrastructure. NIPPC, CREA, REC, and OSEIA state that, given that there are only a limited number of qualified

[772] APPA Comments at 21–22; Connecticut Authority Comments at 19–20; Idaho Commission Comments at 6–7; NARUC Comments at 5; Portland General Comments at 15.

[773] SC Solar Alliance Comments at 17; Southeast Public Interest Organization Comments at 34.

[774] Allco Comments at 16; Idaho Commission Comments at 6–7; North Carolina Commission Staff Comments at 6; Northern Laramie Range Alliance Comments at 3; NRECA Comments at 15–16.

[775] North Carolina Commission Staff Comments at 6.

[776] Northern Laramie Range Alliance Comments at 3.

[777] Allco Comments at 16.

[778] NRECA Comments at 15–16.

[779] Idaho Commission Comments at 6–7.

[780] Portland General Comments at 15.

[781] Southeast Public Interest Organization Comments at 34.

[782] Basin Comments at 12; EEI Comments at 45.

[783] NorthWestern Comments at 11.

[784] *Id.* at 12.

[785] *Id.*

[786] Ares Comments at 5–7; Borrego Solar Comments at 3–4; NIPPC, CREA, REC, and OSEIA Comments at 73; Solar Energy Industries Comments at 62; SC Solar Alliance Comments at 16–18; Southeast Public Interest Organizations Comments at 34.

[787] SC Solar Alliance Comments at 17.

[788] *Id.* at 16 (citing Solar Energy Industries Supplemental Comments, Docket No. AD16–16, at 55–56 (August 28, 2019)).

maintenance providers and other service contractors, the fact that two facilities use the same contractors should not be relevant to common ownership and control of two facilities. NIPPC, CREA, REC, and OSEIA state that the fact that two facilities are constructed within 12 months of each other could merely be evidence that the market conditions at the time favored construction of the facilities, not that the facilities are intended to be one facility.[789]

503. SC Solar Alliance states that the extensive list of ''ownership/other characteristics'' as written is highly problematic. Control and maintenance, particularly in North and South Carolina where there are a substantial number of distributed solar facilities, is often contracted for by a limited number of solar maintenance companies. Allowing the existence of a common maintenance company to in any way dictate QF status is entirely unreasonable and bears no relationship to the question at hand.[790] Similarly, other factors included in the NOPR, including the sale of electricity to a common utility, a common financing lender, the use of a mutual contractor for project construction, the timing of contract execution, and the timing of facilities being placed into service do not provide relevant evidence as to common ownership requiring facilities to be considered a single QF. Applying these factors would create an unnecessary and undue burden on QFs, particularly smaller distribution-connected QFs that have been constructed relatively nearby and which often rely on a limited number of local contractors and partners to complete this necessary work.[791]

504. The Southeast Public Interest Organizations are concerned that the use of common contractors, financing entity, maintenance companies, or sales to the same entity and such could be used against QFs that are built in the same area but are otherwise separate sites.[792]

505. SC Solar Alliance states that the Commission's statement that ''no single factor would be dispositive'' is troubling, and that it is inconceivable that QF ownership would not be dispositive in any such rebuttable presumption. SC Solar Alliance states that it would be wholly unjust and unreasonable to consider a solar facility owned by one solar developer to be considered part of a solar facility owned by a distinct and unaffiliated solar developer. SC Solar Alliance states that any rebuttable presumption should include ''separate ownership'' as a dispositive indication of separate facilities.[793]

506. North Carolina DOJ states that the element of common control is a challenging question because of the limited number of companies available to operate renewable energy facilities. North Carolina DOJ asserts that a handful of firms are responsible for the operation and maintenance work for close to half of the country's solar energy production facilities.[794]

507. NIPPC, CREA, REC, and OSEIA state that the Commission should include substantially more specific parameters about what evidence a project would need to submit to demonstrate single-project status and should make clear that this test has no applicability unless generators within one to 10 miles are owned by the same company or affiliates of the same company. NIPPC, CREA, REC, and OSEIA assert that ''the decisive factors are the 'stream of benefits' from the project and control of the venture,'' which the Commission defined ''to include entitlement to profits, losses, and surplus after return of initial capital contribution.'' [795] These criteria could be used to objectively evaluate whether two QFs within 10 miles are commonly owned or controlled, as opposed to also putting two separately owned and controlled facilities at risk of violating the rule based solely on physical characteristics.[796]

ii. Commission Determination

508. We adopt the physical and ownership factors proposed in the NOPR, including as noted above the ability of a QF to preemptively identify the factors in its filing in anticipation of protests to its filing. As explained above in section IV.D.1.d we are modifying the NOPR proposal to change terminology relating to the determination of whether facilities are separate facilities to focus not on whether they are *separate facilities,* but rather to mirror the statutory language and thus focus on whether they are at ''*the same site.*'' Accordingly, we adopt these factors as relevant indicia of whether affiliated small power production facilities are ''at the same site.'' In addition, we modify the NOPR proposal to identify the following additional physical factors as indicia that small power production facilities should be considered to be located at the same site: (1) Evidence of shared control systems; (2) common permitting and land leasing; and (3) shared step-up transformers.

509. Specifically, we adopt the factors listed below as examples of the factors the Commission may consider in deciding whether small power production facilities that are owned by the same person(s) or its affiliates are located ''at the same site'': (1) *Physical characteristics,* including such common characteristics as: Infrastructure, property ownership, property leases, control facilities, access and easements, interconnection agreements, 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, connections to the electrical grid, evidence of shared control systems, common permitting and land leasing, and shared step-up transformers; 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),[797] 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 small power production qualifying facility in the same location, placed into service within 12 months of an affiliated small power production QF project's commercial operation date as specified in the power sales agreement, or sharing engineering or procurement contracts.

510. We adopt the NOPR proposal to allow a small power production facility seeking QF status to provide further information in its certification (both self-certification and application for Commission certification) or recertification (both self-recertification and application for Commission recertification) to preemptively defend against rebuttal, by identifying factors that affirmatively show that its facility is indeed at a separate site from

[789] NIPPC, CREA, REC, and OSEIA Comments at 73–74.

[790] SC Solar Alliance Comments at 17–18.

[791] *Id.*

[792] Southeast Public Interest Organizations Comments at 34.

[793] SC Solar Alliance Comments at 17.

[794] North Carolina DOJ Comments at 8.

[795] NIPPC, CREA, REC, and OSEIA Comments at 73 (citing *CMS Midland, Inc.,* 50 FERC ¶ 61,098, at 61,278–279 (1990), *aff'd Mich. Municipal Coop. Group* v. *FERC,* 990 F.2d 1377 (D.C. Cir. 1993)).

[796] *Id.*

[797] Definitionally, if the facilities are not owned by the same person(s) or its affiliates, then the issue of compliance with the one-mile rule, even as revised in this final rule, becomes irrelevant. *See* 18 CFR 292.204(a)(1). That is, two facilities owned by two different persons are definitionally not located at the same site.

affiliated small power production QFs more than one but less than 10 miles away from it. Any party challenging the QF certification (both self-certification and application for Commission certification) or recertification (both self-recertification and application for Commission recertification) that makes substantive changes to the existing certification would, in its protest, be allowed to correspondingly identify factors to show that the small power production facility seeking QF status and affiliated small power production QFs more than one but less than 10 from that facility are actually at the same site.

511. We reiterate that, as a general matter, no one factor is dispositive.[798] Rather, we will conduct a case-by-case analysis, weighing the evidence for and against, and the more compelling the showing that affiliated small power production QFs should be considered to be at the same site as the small power production facility seeking QF status in a specific case, the more likely the Commission will be to find that the facilities involved in that case are indeed located ''at the same site.''

g. Exemptions

i. Comments

512. Ares notes that small power producers have certain exemptions from utility regulation, including exemptions from FPA sections 203 and 204 if under 30 MW and exemptions from FPA sections 205 and 206 if under 20 MW (or 30 MW in special cases), as well as exemptions from some state utility laws and PUHCA if under 30 MW.[799] Ares is concerned that the rebuttable presumption and the factors will make many small power QFs ineligible for these exemptions.[800] Ares argues that the aggregation of small power QFs may result in many required applications for market-based rate authority for sales that are minor. Ares argues that the Commission has no basis for, did not consider, and has sought no comments on the removal of regulatory obligations when small power QFs are aggregated under the new ten-mile proposal.[801]

513. Solar Energy Industries note that many facilities could lose their FPA and PUHCA exemptions if there are multiple facilities within 10 miles, which is particularly harmful to QFs that are not selling to their host utility. Solar Energy Industries state that PURPA section 210(e)(1) instructs that the Commission shall exempt QFs from regulation if such exemption ''is necessary to encourage cogeneration and small power production.''[802]

ii. Commission Determination

514. The Commission's current one-mile rule is a rule used to measure, ultimately, whether or not small power production facilities are within PURPA's limit on small power production QFs of 80 MW, and thus whether such facilities are QFs, and the Commission has consistently applied the one-mile rule generally to the regulations issued pursuant to PURPA.[803] There is no persuasive reason it should not be equally applied in the context of the regulations implementing section 210(e) of PURPA. That being said, we are not removing or amending the exemptions provided by the regulations implementing PURPA section 210(e). If a QF qualifies for exemptions pursuant to PURPA section 210(e) and the Commission's implementing regulations,[804] then that QF is entitled to those exemptions. But, if a small power production facility does not meet the 80 MW limit for whatever reason, including because an affiliated small power production QF is located at the same site, then it does not qualify for such exemption because it would not be a QF.[805] There is nothing inappropriate about this consequence; a facility that is not a QF is not entitled to the exemptions available to QFs. We further note that there will now be a rebuttable presumption that affiliated small power production QFs located more than one but less than 10 miles apart are indeed located at separate sites. That is no different than the one-mile rule as it has long existed. What is different is that, with this final rule, the presumption will be rebuttable while before it was irrebuttable; the presumption that the facilities are at separate sites, though, remains unchanged. Only if a party rebuts that presumption and shows that the small power production facility seeking QF status and affiliated small power production QFs should be viewed as located at the same site will the capacity of such facilities be counted together. In that event, if the small power production facility seeking QF status and affiliated small power production QFs located at the same site have a combined power production capacity that exceeds 80 MW, the entity seeking QF status would not qualify as a QF and would properly not be entitled to the exemptions that are available to QFs.

2. Electrical Generating Equipment

a. NOPR Proposal

515. The Commission proposed 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 expected 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. The Commission sought comments on this approach, and on what equipment—if not individual wind turbines and solar panels—should be considered ''electrical generating equipment'' for wind and solar plants.

516. The Commission also proposed specifying how to measure the distance between facilities that have multiple, separate sets of ''electrical generating equipment'' such as wind farms and solar facilities. The Commission proposed measuring the distance between the nearest ''electrical generating equipment'' of any two facilities such that, for the facilities to be presumed irrebuttably separate, all such equipment of one QF must be at least 10 miles away from all such equipment of another QF. The Commission believed 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.

517. The Commission sought comment on this approach, and whether alternative approaches would be more appropriate. For example, some parties had 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.''[806] The Commission was concerned these approaches could be easily gamed, but sought comment on whether they may be constructed in a way that would prevent gaming, and whether such

[798] *But see supra* note 797.

[799] Ares Comments at 4–5.

[800] *Id.* at 5–6.

[801] *Id.* at 11–12.

[802] Solar Energy Industries Comments at 55.

[803] *SunE B9 Holdings LLC,* 157 FERC ¶ 61,044, at P 16 & n.24 (2016) (citing *Windfarms,* 13 FERC ¶ 61,017 at 61,031).

[804] 18 CFR 292.601, 292.602.

[805] *See* 16 U.S.C. 796(17)(A)(ii).

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

formulations would be preferable to the proposed approach.

b. Comments

518. Many commenters support the definition of ''electrical generating equipment'' proposed in the NOPR.[807] However, ELCON objects to both the proposed definition of ''electric generating equipment'' and the approach to measuring distance.[808]

519. Many commenters support the method for measuring distance between sites proposed in the NOPR, which would require measuring the distance between the nearest ''electrical generating equipment'' of any two affiliated facilities.[809] Several commenters note their opposition to measuring the distance between sites using the geographic center of the plant or a weighted average of the locations of individual pieces of ''electrical generating equipment,'' both methods the Commission sought comment on in the NOPR.[810] The Southeast Public Interest Organizations request clarification of whether to measure from the edge of a solar panel or the center of a solar array.[811]

520. Several commenters request that the Commission discuss how energy storage (sometimes referred to as battery storage) would be considered in relation to the proposed definition of electrical generating equipment.[812] The California Commission requests that a battery storage facility be excluded from consideration as electrical generating equipment provided the storage is charged solely by the small power production facility, and that energy stored by the storage facility be considered to be of the same energy source of that energy before it was stored.[813] The California Commission also requests that the Commission affirm that storage does not permit a facility to exceed the maximum size criteria of a small power production facility.[814] EEI requests that the Form 556 collect data on storage resources as well as electrical generating equipment for purposes of measuring distance to an affiliated small power production QF.[815]

c. Commission Determination

521. We adopt the NOPR proposal that ''electrical generating equipment'' refers to all boilers, heat recovery steam generators, prime movers (any mechanical equipment driving an electric generator), electrical generators, photovoltaic solar panels, 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. Each wind turbine at a wind facility 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.

522. We require the distance between the facility seeking small power production QF status and any affiliated small power production QFs using the same energy resource to be measured by the distance between the nearest ''electrical generating equipment'' of each such facility, such that, for the entity seeking QF status to be presumed irrebuttably at a separate site from any affiliated small power production QF, all such equipment of the affiliated small power production QF must be at least 10 miles away from all such equipment of the entity seeking small power production QF status. The Commission finds that this is the most appropriate way to measure the distance between affiliated sets of ''electrical generating equipment'' at small power production facilities because this reflects the distance between the components directly tied to producing electric energy.

523. The point used in the distance calculation will always be from the edge of the electrical generating equipment closest to the affiliated small power production QF's nearest electrical generating equipment. Thus, we clarify that for a solar facility, the measurement should be from the edge of the small power production facility seeking QF status' solar panel or inverter that is closest to the edge of the nearest ''electrical generating equipment'' of that affiliated small power production QF. For a wind facility, the measurement should similarly be from the edge of the small power production facility seeking QF status' wind turbine or inverter closest to the edge of the nearest ''electrical generating equipment'' of the affiliated small power production QF. For a wind facility, we clarify that the relevant point for measuring distance of an individual wind turbine is the tower (not the projection of the blade's wingspans onto the ground). We also clarify that only horizontal distances are taken into consideration for purposes of this rule (such that elevation changes have no effect on facility distance).

524. We find that the role of battery storage in QFs, including with regard to the distance between QFs, is beyond the scope in this proceeding.

E. QF Certification Process

1. NOPR Proposal

525. In the NOPR, the Commission proposed to revise 18 CFR 292.207(a) to allow interested persons to intervene in, 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 with which it is interconnected and those to which it will be selling) as well as the relevant state regulatory authorities, the Commission proposed to 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).[816]

526. 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. 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-

[807] Alliant Energy Comments at 19; APPA Comments at 23; Basin Comments at 11; Connecticut Authority Comments at 19–20; EEI Comments at 49; Idaho Commission Comments at 6; Kentucky Commission Comments at 7; NRECA Comments at 17; Portland General Comments at 16–17; Southeast Public Interest Organizations Comments at 37–38.

[808] ELCON Comments at 36.

[809] Alliant Energy Comments at 19; APPA Comments at 23; Basin Comments at 11; Connecticut Authority Comments at 19–20; EEI Comments at 49; Kentucky Commission Comments at 7; NARUC Comments at 4–5; Portland General Comments at 16–17; Southeast Public Interest Organizations Comments at 37–38.

[810] Connecticut Authority Comments at 21; Kentucky Commission Comments at 7; NorthWestern Comments at 12–13; NRECA Comments at 18; Portland General Comments at 18.

[811] Southeast Public Interest Organizations Comments at 38.

[812] Alliant Energy Comments at 19; EEI Comments at 46–47; Energy Storage Comments at 3; NorthWestern Comments at 13.

[813] California Commission at 16–17.

[814] *Id.* at 15.

[815] EEI at 51–52.

[816] 18 CFR 292.207(c)(1).

recertification to demonstrate that the claims raised in the protest are incorrect and that certification is, in fact, warranted.

527. QF self-certification is effective upon filing and would remain effective if a protest is filed, until such time as the Commission rules that certification is revoked. The Commission proposed that it would issue an order within 90 days of the date the protest is filed. The Commission also reserved the right to request more information from the protester, the entity seeking QF status, or both.[817] If 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.

528. There may be instances, however, when the Commission may need additional time to review the record in light of the nature of the protests. In those cases, the Commission proposed 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 within one additional 60-day period. The Commission proposed to delegate to the Commission's Secretary, or the Secretary's designee, the authority to toll the 90-day period for this purpose.

529. The Commission believed these procedures would allow for timely but thorough review of protested self-certifications and self-recertifications. The Commission sought comment on whether these procedures impose an undue burden on the QF even though the QF remains certified pending the review.

2. Comments

530. Many commenters raise the issue of granting legacy treatment, colloquially known as ''grandfathering,'' to existing QF certifications and their future recertifications.[818] Most of these comments support granting legacy treatment to current QFs and their future recertifications.[819] Several commenters note that the application of the rule to existing or recertifying QFs will create uncertainty and cause disruptions of the sale of these QFs.[820]

531. New England Small Hydro warns that applying the proposed rule to existing QFs could trigger financing defaults if those QFs lose their status.[821] The Southeast Public Interest Organizations state that the proposed rebuttable presumption has implications for existing solar QFs in the Southeast, noting that QFs would be required to seek recertification as their existing PPAs expire, adding a significant burden.[822] The Southeast Public Interest Organizations provide maps showing the ten-mile radius of utility-scale projects could lead to many overlapping affiliated territories under the new rules.[823] SC Solar Alliance also notes the large number of small solar QFs overlapping within a ten-mile radius across North Carolina and South Carolina and finds that the application of the more-than-one-but-less-than-10-miles rebuttable presumption to recertifications will be burdensome and unwieldy.[824] NIPPC, CREA, REC, and OSEIA warn that the application of the new rule to existing QFs will effectively bar the transfer or sale (or potentially any number of less significant changes) of existing assets that were lawfully qualified under the one-mile rule but would pass the 80 MW aggregate threshold under the new rule. NIPPC, CREA, REC, and OSEIA find this to be a violation of the existing QFs contractual and constitutional rights.[825]

532. Terna Energy states that granting legacy treatment to existing QFs and their recertifications is necessary to protect investment decisions and contracts made under the long-standing one-mile rule.[826] Terna Energy contends that, without clarification on the legacy treatment of recertifications, QFs could lose their status even for non-substantive revisions to their FERC Form No. 556s such as contact information, street address, ownership or operation.[827] Terna Energy warns that absent the clarification of legacy treatment for existing QF recertifications, QFs might go to extremes to avoid updating their FERC Form No. 556s with information changes.[828]

533. Solar Energy Industries state that retroactively applying a more-than-one-but-less-than-10-miles rebuttable presumption to physical facilities that were developed based on the original one-mile rule will inject instability, will erode trust from the investment community, and will discourage the development of QFs as well as investment in the industry in general.[829] Ares notes that not granting legacy treatment to existing QFs is inconsistent with past Commission actions on PURPA, such as the granting of legacy treatment to existing QF contracts in Order No. 671 or other QF related proceedings.[830]

534. New England Small Hydro supports granting legacy treatment to existing QFs to avoid upsetting the settled expectations of existing generation.[831] New England Small Hydro gives the example of three hypothetical projects, each located nine miles apart that, when capacities are totaled, exceed 80 MW. If there is an ownership change that triggers the need for a recertification but the entities remain affiliates, under the Commission's proposed rule, all three projects would lose QF status. According to New England Small Hydro, this could trigger defaults under financing documents and the utility might be able to terminate the power contract, because many PPAs for QFs require the project to remain a QF for the term of the PPA. New England Small Hydro states that, as a result, a minor ownership change could have cascading negative effects to QFs.[832]

535. Terna Energy requests that existing QFs be granted legacy treatment as long as they do not make changes to electrical generating equipment of the facility, because that is the equipment that determines compliance with the one-mile rule. Terna Energy argues that otherwise an existing QF could be subject to challenge anytime it makes a non-substantive revision to its FERC Form No. 556, including a change to contact information, street address, ownership, or operator, effectively

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

[818] Ares Comments at 12; Basin Comments at 11; BluEarth Comments at 2; DC Commission at 9; New England Small Hydro Comments at 17; Industrial Energy Consumers Comments at 17; NIPPC, CREA, REC, and OSEIA Comments at 74; Solar Energy Industries Comments at 61–63; SC Solar Alliance Comments at 18; Southeast Public Interest Organizations Comments at 29–31; Terna Energy Comments at 16–18.

[819] Ares Comments at 12; BluEarth Comments at 2; New England Small Hydro Comments at 17; Industrial Energy Consumers Comments at 17; NIPPC, CREA, REC, and OSEIA Comments at 74; Solar Energy Industries Comments at 61–63; SC Solar Alliance Comments at 18; Southeast Public Interest Organizations Comments at 29–31; Terna Energy Comments at 16–18.

[820] New England Small Hydro Comments at 17; NIPPC, CREA, REC, and OSEIA Comments at 74; Terna Energy Comments at 16–18.

[821] New England Small Hydro Comments at 17.

[822] Southeast Public Interest Organizations Comments at 29.

[823] *Id.* at 30–31.

[824] SC Solar Alliance Comments at 18.

[825] NIPPC, CREA, REC, and OSEIA Comments at 75.

[826] Terna Energy Comments at 1–2.

[827] *Id.* at 2.

[828] *Id.* at 7.

[829] Solar Energy Industries Comments at 62.

[830] Ares Comments at 12.

[831] New England Small Hydro Comments at 17.

[832] *Id.*

eliminating legacy treatment.[833] Terna Energy states that granting legacy treatment is necessary to protect the sanctity of investments and contracts made in reliance upon the Commission's current PURPA regulations and the one-mile rule.[834] Terna Energy submits revised language for 18 CFR 292.204(a)(2) and (3) to clarify that existing QF recertifications, unless they change the electrical generating equipment, should not be subject to the new rules.[835]

536. Basin, on the other hand, asks the Commission to be clear that recertifications filed by QFs will trigger application of the proposed rule.[836] Basin also recommends the Commission allow petitions seeking de-certification of QFs that have previously filed self-certifications because some QFs self-certify at an early stage of project development and ultimately never proceed to development.[837]

537. The DC Commission would like the Commission to clarify whether the changes to the one-mile rule will apply to QFs under construction when the rule goes into effect.[838] The DC Commission would like the Commission to leave the issue of legacy treatment of existing QFs up to the states.[839]

538. Several commenters oppose the NOPR proposal 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 pay the associated filing fee.[840] Several commenters argue that this proposal will lead to a flood of challenges that will discourage the growth of QFs.[841] Several commenters state that there will be substantial costs associated with this proposal that will fall on ratepayers and QFs.[842] Several commenters state that the proposed changes will lead to increased administrative burden and expense[843] or litigation risk.[844] Several commenters state that the proposed changes will lead to uncertainty[845] and deter development.[846]

539. Solar Energy Industries state that the proposed changes to the one-mile rule will substantially increase the regulatory burden on QFs and the self-certification process will no longer be quick.[847] Solar Energy Industries is concerned that QFs may need to defend numerous self-certifications over a facility's lifetime, and assert that QFs could be forced to recertify any time the information represented in the Form No. 556 changes, including ownership changes to affiliated facilities located within 10 miles.[848] Solar Energy Industries state that the burden will be increased exponentially if the one-mile rule is expanded in a ten-mile rule.[849] Solar Energy Industries state that the NOPR's estimate of an additional eight hours and $632 per docket for each QF self-certification or re-certification is a substantial underestimation.[850] Solar Energy Industries estimate that it would require an additional approximately 90 to 120 hours per year to comply with the new requirements. Solar Energy Industries state that a QF could be forced to recertify any time the information represented changes, including ownership changes to affiliated facilities located within 10 miles. Solar Energy Industries note that a QF may have to engage in multiple defenses of its status, each time needing to engage legal counsel and devote internal company resources to preserve the status of its already-installed plant.[851] Solar Energy Industries assert that the flood of self-certification filings and updates would be a substantial burden on Commission staff and provide little value to the Commission or the public.[852] Solar Energy Industries also state that, unless and until the Commission makes a determination on the burden associated with collecting, reporting, and updating the Connected Entity[853] information, it would be unjust and unreasonable for the Commission to impose similar burdens on QF entities through the FERC Form No. 556.[854] Solar Energy Industries state that the increased regulatory burden that will arise for these entities is similar in scope and the Commission has not provided a rationale for the increased information collection requirements.[855]

540. Allco describes the Commission's Regulatory Flexibility Act (RFA) analysis of the proposed rules' effect on small businesses as improperly limited to proposed paperwork changes, ignoring the impact on small QFs' abilities to construct facilities.[856] Allco states that the Commission did not attempt to minimize the impacts on small renewable energy producers, consider alternative structures, or describe these steps or considerations in a mandatory final RFA analysis.[857] Allco asserts that the Commission failed to support its finding that the NOPR's proposed revisions will not significantly impact a substantial number of small entities (specifically, solar energy QFs); Allco therefore claims that the Commission violated the Small Business Regulatory Enforcement Fairness Act.[858]

541. Solar Energy Industries state that the NOPR lacks important details such as whether the Commission's determination is subject to rehearing, and whether a final decision can be appealed under the FPA to an appellate court.[859] Solar Energy Industries state that an adverse determination by the Commission could impose upwards of $100 million in harm on a QF, and it is unclear whether the QF would have a path to relief if the Commission erred in its determination. Solar Energy

[833] Terna Energy Comments at 2.

[834] *Id.* at 1–2.

[835] *Id.* at 8–9.

[836] Basin Comments at 11.

[837] *Id.*

[838] DC Commission Comments at 9.

[839] *Id.*

[840] Allco Comments at 21; BluEarth Comments at 3; CARE Comments at 7; Con Edison Comments at 5; Distributed Sun Comments at 3; ENGIE Comments at 4; Public Interest Organizations Comments at 9, 97–98; Western Resource Councils Comments at 144; Solar Energy Industries Comments at 57–59.

[841] Allco Comments at 21; BluEarth Comments at 3; Distributed Sun Comments at 3; Public Interest Organizations Comments at 97; Western Resource Councils Comments at 144.

[842] Con Edison Comments at 5; ENGIE Comments at 4; Public Interest Organizations Comments at 97; Solar Energy Industries Comments at 58.

[843] Ares Comments at 6; Borrego Solar Comments at 4; Con Edison Comments at 5; Public Interest Organizations Comments at 97–98; Solar Energy Industries Comments at 51–52, 54, 57–58; SC Solar Alliance Comments at 15–18; Southeast Public Interest Organizations Comments at 29, 35; sPower Comments at 14.

[844] Con Edison Comments at 5; Distributed Sun Comments at 3; ELCON Comments at 19–20; NIPPC, CREA, REC, and OSEIA Comments at 71–72; Public Interest Organizations Comments at 97–98; Solar Energy Industries Comments at 58–60; SC Solar Alliance Comments at 16, 18; Southeast Public Interest Organizations Comments at 29,35; sPower Comments at 14.

[845] Ares Comments at 9; Distributed Sun Comments at 3; ELCON Comments at 19–20, 38; NIPPC, CREA, REC, and OSEIA Comments at 69–72; Public Interest Organizations Comments at 97–98; Solar Energy Industries Comments at 58–60, 62–63; SC Solar Alliance Comments at 16, 18; Southeast Public Interest Organizations Comments at 29, 35, 38, 93, 97–98; sPower Comments at 14.

[846] Allco Comments at 16; Borrego Solar Comments at 4–5; Biological Diversity Comments at 9; Con Edison Comments at 4–5; Distributed Sun Comments at 3; NIPPC, CREA, REC, and OSEIA Comments at 72–73; North Carolina DOJ Comments at 8; Public Interest Organizations Comments at 93, 99; Solar Energy Industries Comments at 51–52, 59–63; SC Solar Alliance Comments at 2, 18; Southeast Public Interest Organizations Comments at 31–36, 38, 93.

[847] Solar Energy Industries Comments at 52.

[848] Solar Energy Industries at 57.

[849] *Id.* at 53.

[850] *Id.* at 52.

[851] *Id.* at 58.

[852] *Id.* at 53–54.

[853] *Id.* at 54 (citing *Data Collection for Analytics and Surveillance and Market-Based Rate Purposes,* Order No. 860, 168 FERC ¶ 61,039, at P 183 (2019)).

[854] *Id.* at 54, 57.

[855] *Id.* at 54.

[856] Allco Comments at 33.

[857] *Id.*

[858] *Id.*

[859] *Id.* at 58.

Industries state that the current practice, where the challenger bears the responsibility of seeking declaratory relief, strikes an appropriate balance.[860]

542. Several commenters, on the other hand, support the NOPR proposal 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.[861] Several commenters argue that the proposed amendment would strike the right balance and distribute the burdens of proof appropriately.[862] Several commenters also state that this proposal would increase the efficiency of the process, reduce administrative costs, and could solve potential certification problems before they even begin.[863]

543. Other commenters support the NOPR proposal, but with caveats or extra requests.[864] Golden Valley recommends that the 30-day clock to challenge QF self-certification or self-recertification begins when the QF serves notice to the interested electric utility, not when the QF makes its filing with the Commission.[865] NIPPC, CREA, REC, and OSEIA state that the Commission should provide a 60-day deadline after the filings are complete by which time a failure of the Commission to rule results in the objection being denied by operation of law.[866]

544. NorthWestern requests the QFs be subject to various discovery requests when they self-certify or self-recertify.[867] Two commenters argue that any challenging party should be required to include an affidavit from a company official.[868]

545. NorthWestern and Northern Laramie Range Alliance request that QF developers seeking certification with the Commission should be required to publish notice in local newspapers in the states in which the development would be located, in order to alert affected parties so they could intervene in the certification process.[869] El Paso Electric is concerned by the proposal to limit the ability to challenge QF status once it has been certified in a Commission certification proceeding or in response to a challenge unless the new challenger can demonstrate a change in the facility circumstances that threaten the validity of the previous finding. El Paso Electric states that sometimes QFs fail to provide utilities with their QF application and so the utility does not know to protest.[870]

546. Ares notes that small power production QFs could be aggregated under the more-than-one-but-less-than-10-miles rebuttable presumption and not even be aware of the other small power production QFs because of a lack of information.[871]

3. Commission Determination

547. We adopt the NOPR proposal to revise 18 CFR 292.207(a) to allow an interested person or entity to seek to intervene and to file a protest of a self-certification or self-recertification of a QF, and not have to file a petition for declaratory order and pay the filing fee for petitions.[872] We also adopt the other changes to the QF certification process proposed in the NOPR, with the additions detailed below. We find that any increased administrative burden or litigation risk imposed by the new rule is justified by the need to ensure that QFs meet the statutory criteria for QF status.

548. The ability to intervene and to file a protest of a self-certification or self-recertification of a QF without having to file a petition for declaratory order and pay the filing fee for petitions is effective as of the effective date of the final rule. However, we will grant legacy treatment to existing QFs under certain circumstances, as we explain below. With the exceptions noted below, protests pursuant to this final rule will not be allowed to QF certifications and recertifications (including self-certifications and self-recertifications) that are submitted before the effective date of the final rule, although entities may still challenge by filing a petition for declaratory order and submitting the required fee. Conversely, protests *can* be made to QF certifications (both self-certification and application for Commission certification) or recertifications (both self-recertification and application for Commission recertification) that are submitted on or after the effective date of this final rule. We note here that it is the date of filing for certification or recertification, and not the date of construction, that determines whether our new protest rule applies to the certification or recertification.

549. Many commenters have argued for expansive legacy treatment for recertification of existing projects. They have noted that QFs need to recertify when property is transferred, PPAs expire, or even for non-substantive changes, such as changes in contact information or street address.[873] Commenters argue that, if the new protest rules apply to recertifications, existing QFs could lose their QF status, even if their configuration or other relevant factors do not materially change, when they file their recertifications, upsetting the settled expectations under which the QFs built their facilities.

550. We agree that QF recertifications to implement or address non-substantive changes should not be subject to our new protest rule; the settled expectations of the QFs should be respected in such instances. Accordingly, we find that protests may be filed to an initial certification (both self-certification and application for Commission certification) filed on or after the effective date of this final rule, but only to a recertification (both self-recertification and application for Commission recertification) that makes substantive changes to the existing certification and that are filed on or after the effective date of this final rule. Substantive changes that may be subject to a protest may include, for example, a change in electrical generating equipment that increases power production capacity by the greater of 1 MW or 5 percent of the previously certified capacity of the QF, or a change in ownership in which an owner increases its equity interest by at least 10% from the equity interest previously reported. We find that recertifications (both self-recertifications and applications for Commission recertifications) making ''administrative only'' changes should not be subject to

[860] *Id.* at 59.

[861] Alaska Power Comments at 2; Alliant Energy Comments at 22–23; APPA Comments at 31–35; Duke Energy Comments at 23–24; Indiana Municipal Comments at 10; NRECA Comments at 21–22; Portland General Comments at 21–22; Ohio Commission Energy Advocate Comments at 10; Chamber of Commerce Comments at 8; We Stand Comments at 3.

[862] APPA Comments at 31–35; NRECA Comments at 21–22; Ohio Commission Energy Advocate Comments at 10.

[863] Indiana Municipal Comments at 10; NRECA Comments at 21–22; Portland General Comments at 21–22.

[864] DTE Electric Comments at 9–10; Golden Valley Electric Comments at 1–2, 3–7; Industrial Energy Consumers Comments at 14; Northern Laramie Range Alliance Comments at 3; NorthWestern Comments at 17–18; ELCON Comments at 19–20, 37–38.

[865] Golden Valley Electric Comments at 2.

[866] NIPPC, CREA, REC, and OSEIA Comments at 74.

[867] NorthWestern Comments at 17–18.

[868] Industrial Energy Consumers Comments at 14; ELCON Comments at 20, 38.

[869] NorthWestern Comments at 3; Northern Laramie Range Alliance Comments at 3.

[870] El Paso Electric Comments at 5.

[871] Ares Comments at 6.

[872] We amend the proposed regulation in the NOPR to move the sections referring to protests and interventions from 18 CFR 292.204 to 18 CFR 292.207.

[873] NIPPC, CREA, REC, and OSEIA Comments at 75; Terna Energy Comments at 1–2, 7.

a protest pursuant to this final rule.[874] We believe that excepting from protests QF recertifications making non-substantive changes will allow QFs to make such changes and recertify without potentially losing their QF status.

551. Solar Energy Industries asserts that the certification process will no longer be quick, and estimates that it would require an additional approximately 90 to 120 hours per year to comply with these new requirements. Solar Energy Industries is concerned that QFs may need to defend numerous self-certifications over a facility's lifetime, and asserts that QFs could be forced to recertify any time the information represented in the Form No. 556 changes.[875]

552. We do not agree with Solar Energy Industries' estimates. First, we note that 18 CFR 292.207(d) (which we are not altering in this rule except to renumber as 18 CFR 292.207(f)) already states that if a QF fails to conform with any material facts or representations presented in the certification, the QF status of the facility may no longer be relied upon,[876] and hence it is long-standing practice that a QF must recertify when material facts or representations in the Form No. 556 change.

553. Second, certifications and recertifications are already subject to protests, albeit in the form of petitions for declaratory order, and therefore dealing with objections to a certification or recertification is not new. Although the new procedures may result in more protests being filed than the number of petitions that have been filed, we believe that the conditions we impose in this final rule will limit the number of protests filed. The Commission anticipates that most, though not all, of the protests filed pursuant to the new 18 CFR 292.207(a) will relate to the new more-than-one-but-less-than-10-miles rebuttable presumption.[877] Such protests will necessarily be limited because not all certifications and recertifications will be subject to the new more-than-one-but-less-than-10-miles rebuttable presumption. Only small power production facilities seeking QF status that have an affiliated small power production QF more than one but less than 10 miles away and that uses the same energy resource are subject to the rebuttable presumption. Small power production facilities that do not have multiple small power production facilities or affiliates will not be affected by the new rebuttable presumption. Nor will cogeneration QFs be affected by the new rebuttable presumption.[878] Additionally, in general as described above, protests may only be made to an initial certification (both self-certification and application for Commission certification) filed on or after the effective date of this final rule, and only to a recertification (self-recertification or application for Commission recertification) that makes substantive changes to the existing certification that are filed after the effective date of this final rule.

554. Third, we are also instituting time limits on protests that may be filed under this final rule. We adopt the NOPR proposal that interested parties will have 30 days from the date of the filing of the Form No. 556 at the Commission to file a protest (without paying a fee).[879] Additionally, a protestor must concurrently serve its protest on the Form No. 556 applicant pursuant to 18 CFR 385.2010.

555. Fourth, regarding Solar Energy Industries' concern that a QF may have to engage in multiple defenses of its status, in addition to the above limits on protests, once the Commission has affirmatively certified an applicant's QF status in response to a protest opposing a self-certification or self-recertification, or in response to an application for Commission certification or Commission recertification, any later protest to a recertification (self-recertification or application for Commission recertification) making substantive changes to a QF's existing certification, *e.g.,* asserting that the entity seeking QF status is at the same site as affiliated small power production QFs more than one but less than 10 miles from it, must demonstrate changed circumstances from the facts on which the Commission acted on the certification filing that call into question the continued validity of the earlier certification.

556. Finally, even if it indeed takes *some* small power production facilities an additional 90 to 120 hours (and we think that unlikely), that is not an unreasonable burden to impose to ensure that a generating facility that seeks to be a QF is, in fact, entitled to QF status and complying with PURPA.[880]

557. Turning to the requirements for a protest, as proposed in the NOPR, we will require any person or entity filing a protest to specify facts that make a prima facie demonstration that the facility described in the certification (both self-certification and application for Commission certification) or recertification (both self-recertification or application for Commission recertification) does not satisfy the requirements for QF status. We will also require any protest to be adequately supported with any supporting documents, contracts, or affidavits, as appropriate. Just as public utilities are typically not subject to discovery with regard to their rate filings under section 205 of the FPA prior to the Commission's instituting trial-type evidentiary hearings,[881] we similarly decline to make QFs subject to discovery requests when they self-certify or self-recertify.

558. The Commission also orders here that an applicant's response to a protest will be allowed under 18 CFR 385.213(a)(2). By this final rule, we are consistent with that regulation, ''otherwise order[ing]'' that such answers may be filed. They will be due no later than 30 days after the filing of the protest.

559. Rooftop solar developers frequently finance the initial development of rooftop solar photovoltaic (PV) systems of individual homeowners, and then retain ownership of such PV systems for extended periods of time until the ownership is

[874] As noted elsewhere in this final rule, our allowing protests does not eliminate the ability to file a petition for declaratory order seeking revocation of qualifying status.

[875] Solar Energy Industries at 57.

[876] 18 CFR 292.207(d), which this final rule will renumber to 18 CFR 292.207(f).

[877] While we anticipate that most protests will involve interested persons or entities attempting to rebut the presumption of separate sites for affiliated small power production qualifying facilities that are more than one and less than 10 miles apart, we note that protesters may also protest any fact or representation in the Form No. 556, or other aspect of a QF's filing they believe is inconsistent with PURPA or our PURPA Regulations.

[878] The 80 MW limit and same site determination only apply to small power production facilities, not cogeneration facilities. *See* 16 U.S.C. 796(17)(A).

[879] We note that section 292.207(c) of the PURPA Regulations requires the applicant to concurrently with its filing serve a copy of the filing on each applicable electric utility as well as the applicable State regulatory authority. We expect an applicant seeking QF status (or recertifying its status) to timely comply with that regulation. Therefore, a utility should also receive the filing at the same time that the filing is made at the Commission.

[880] The regulations adopted in this final rule explicitly make self-certifications and self-recertifications effective upon filing and allow them to remain effective even if challenged until such time as the Commission finds that a facility does not qualify to be a QF. Additionally, entities seeking QF status can file self-certifications years in advance of facility operation, such that the few months contemplated by the new process should not cause delay. Finally, with regard to the time it may take to fill in the Form No. 556, we note that while an entity seeking QF status *may choose* to preemptively defend against claims that it should be considered to be at the same site as affiliated small power production qualifying facilities located more than one but less than 10 miles from it, this is optional, not required.

[881] 18 CFR 385.401(a).

eventually transferred to the relevant homeowners. While these rooftop solar PV systems are owned by the developer, each individual rooftop solar PV system would be considered affiliated electrical generating equipment of every other rooftop solar PV system owned by that developer. When there are multiple co-owned rooftop solar PV systems within a mile, and thus at the same site, they may exceed 1 MW and therefore be required to file for certification or recertification unless they receive a waiver.[882] Moreover, whenever they add an additional rooftop solar PV system to their portfolio, or alternatively transfer the ownership of such a rooftop solar PV system to the relevant homeowner, their facility could be viewed as no longer conforming with the material facts in their prior certification or recertification; thus they would need to recertify.

560. Due to the unique nature of rooftop solar PV developers, the Commission finds the recertification requirement for PV developers could be unduly burdensome. Therefore, to lessen the burden on such developers when recertifying, we will permit rooftop solar PV developers an alternative option to file their recertification applications. That is, rather than be required to file for recertification each time the rooftop solar developer adds or removes a rooftop facility, a rooftop solar PV developer may recertify on a quarterly basis. The filing would be due within 45 days after the end of the calendar quarter. However, if in any quarter a rooftop solar PV developer either has no changes or only has changes of power production capacity of 1 MW or less, then it would not be required to recertify until it has accumulated changes greater than 1 MW total over the quarters since its last filing.[883] Additionally, we note that rooftop solar PV developers, like all small power production facilities, will not be subject to protests when they file recertifications that are ''administrative only'' in nature, but would be subject to such protests when they make substantive changes to the existing certification as detailed above in this section.

561. We take this opportunity to clarify that, when the Commission issues an order revoking QF certification, such order is subject to rehearing and appeal pursuant to the FPA.[884] The Commission's authority to determine whether or not a facility is a qualifying small power production facility stems from PURPA section 201, which amended FPA section 3 to add paragraph (17).[885] Similarly, FPA section 3(18) grants the Commission authority to determine whether a cogeneration facility meets the Commission's requirements.[886] Because the Commission's authority is grounded in the FPA, the Commission's order revoking QF certification is subject to rehearing and appeal pursuant to FPA section 313.[887]

562. El Paso Electric states that sometimes the utility does not know to protest, because sometimes QFs fail to provide utilities with their QF application, and El Paso Electric is therefore concerned by the Commission's proposal to limit protests by requiring that once the Commission has affirmatively certified an applicant's QF status, any later protest must demonstrate changed circumstances. We note that a QF that is filing a FERC Form No. 556 is currently required by 18 CFR 292.207(c) (which we are not altering in this rule except to renumber as 18 CFR 292.207(e)) to serve a copy on each electric utility with which it expects to interconnect, transmit or sell electric energy to, or purchase supplementary, standby, back-up or maintenance power from, and the state regulatory authority of each state where the facility and each affected utility is located. This final rule does not change that requirement and we expect applicants to timely comply with that regulation. Should an issue arise, though, the Commission can address it on a case-by-case basis as the circumstances warrant. Additionally, we note that, if a self-certification or self-recertification is not protested within the 30 day-period permitted for protests, then, just as it could prior to this final rule, a challenger still has the ability to file a petition for declaratory order, with the filing fee, without being required to show changed circumstances to do so.

563. Regarding Basin's request to allow petitions seeking de-certification of QFs that have previously filed self-certifications and ultimately never proceed to development,[888] as we note above we limit the ability to file a protest (rather than a petition for declaratory order, with the accompanying filing fee) to within 30 days of the date of the filing of the self-certification or self-recertification. If an interested party would like to contest a self-certification or self-recertification later than 30 days after the date of its filing, then the interested party may file a petition for declaratory order with the accompanying filing fee, just as they could prior to the effective date of this final rule.

564. We decline to adopt the requests that QF developers seeking certification with the Commission be required to publish notice in local newspapers in the states in which the development would be located. We find that the service requirement already in our regulations cited above should serve to provide adequate notice to affected entities.

565. We decline to impose a 60-day deadline after which a failure of the Commission to rule on the protest results in the protest being denied by operation of law. Self-certification will be effective upon filing and we adopt the NOPR proposal that the self-certifications will remain effective after a protest has been filed, until such time as the Commission issues an order revoking certification. We also clarify that self-recertifications will likewise remain effective after a protest has been filed, until such time as the Commission issues an order revoking certification.

566. We also will adopt the NOPR's proposed timeline for issuance of an order following protests to a QF self-certification and self-recertification. The

[882] *See Sunrun, Inc.,* 167 FERC ¶ 61,059 (2019).

[883] For example, if a rooftop solar QF increases its power production capacity by 0.9 MW in a quarter, it would not need to file to recertify for that quarter. However, if in the next quarter the rooftop solar QF increased its power production capacity by 0.9 MW, it would need to recertify for that quarter because cumulatively over the quarters since its last filing it has changed its power production capacity by more than 1 MW (*i.e.,* under this example the rooftop solar QF changed its power production capacity since its last recertification filing by 1.8 MW).

[884] Similarly, when the Commission issues an order affirmatively certifying an applicant's QF status (in response to a protest opposing a self-certification or self-recertification, or in response to an application for Commission certification or recertification), any party to that proceeding aggrieved by the order, including the protestant, may seek rehearing and appeal pursuant to the FPA.

[885] 16 U.S.C. 796(17). Section 3(17) of the FPA mandates a size requirement for a small power production facility: It must have ''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.''

[886] 16 U.S.C. 796(18).

[887] 16 U.S.C. 825*l.* The Commission has previously entertained rehearing of an order revoking QF status, *Golden Valley Elec. Ass'n, Inc.,* 167 FERC ¶ 61,208 (2019), *reh'g denied,* 170 FERC ¶ 61,025 (2020), and of an order denying petitions to revoke QF status, *N. Laramie Range All.,* 138 FERC ¶ 61,171, *reh'g denied,* 139 FERC ¶ 61,190 (2012), *appeal dismissed,* 733 F.3d 1030. There have also been appeals of orders denying petitions to revoke QF status. *N. Laramie Range All.* v. *FERC,* 733 F.3d 1030 (10th Cir. 2013) (dismissing appeal on other grounds); *Brazos Elec. Power Coop. Inc.,* v. *FERC,* 205 F.3d 235 (5th Cir. 2000) (denying petition for review). Unlike PURPA section 210, PURPA section 201 amends the FPA and is therefore subject to FPA section 313. *See Portland Gen. Elec. Co.* v. *FERC,* 854 F.3d 692, 700 (2017); *Midland Power Coop.* v. *FERC,* 774 F.3d 1, 3 (2014).

[888] Basin Comments at 11.

Commission will issue an order within 90 days of the filing of a protest. However, if 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. 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. We clarify, however, that, absent Commission action by the date of the expiration of the tolling period, a protest will be deemed denied, and the self-certification or self-recertification will remain effective. We find that this timeline provides both QFs and other interested persons with certainty about the QFs' status within a reasonable amount of time.

567. Regarding Ares' concern that small power production QFs could be aggregated under the new rule without being aware of the other small power production QFs with which they are aggregated, the Commission notes that this concern would only apply to small power production facilities owned by the same person or its affiliates; it is unlikely that the owner(s) of one facility would not be aware of other, affiliated QFs. Furthermore, the presumption continues to be that a small power production facility seeking QF status that is located more than one but less than 10 miles from any affiliated small power production QFs is at a separate site from those affiliated small power production QFs, and the Commission here is simply making this presumption rebuttable. If an entity challenges that presumption, the applicant seeking QF status would necessarily be served with the protest[889] and thus informed of the challenge, and given the opportunity to defend against the challenge.

568. Regarding Solar Energy Industries contention regarding the currently pending Connected Entity proceeding, that is a separate proceeding and beyond the scope of this proceeding. Moreover, the data collection at issue in that proceeding does not eliminate the need for the Commission to collect the data required by the FERC Form No. 556 so that the Commission has the information it needs to determine whether a facility qualifies to be a QF consistent with the standards laid out in the statute. In any event, we note that the Connected Entity rulemaking was about market-based rate sellers, not QFs, and it is likely that the Connected Entity rulemaking would not apply to many QFs in the first place since they often nether seek nor have the authority to sell at market-based rates.

569. Regarding Allco's concerns about the RFA, we discuss the RFA issue in section VII.

F. Corresponding Changes to the FERC Form No. 556

1. NOPR Proposal

570. The Commission proposed changes to the FERC Form No. 556, corresponding to the new rules discussed above regarding whether QFs are at separate sites. Currently, item 8a of FERC 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:

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**

571. The Commission proposed adding a new item 8b,[890] 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.

572. The Commission proposed 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 10 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,[891] considering the relevant physical and ownership factors. The Commission further proposed to provide reference, in the instructions to the new item 8b, to the paragraphs of this final rule which discuss the relevant physical and ownership factors that may be asserted to defend against rebuttal.

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

[889] 18 CFR 385.211(b).

[890] Subsequent items in that section of the FERC Form No. 556 would be retained but re-numbered and moved down accordingly.

[891] As discussed in detail in section IV.D.1.d, this final rule will change the references to ''separate facilities'' or ''the same facility'' to ''at separate sites'' or ''at the same site.''

in calculating the distance(s) between the facilities.

574. The Commission noted that item 8a currently requires applicants to list all affiliated ''facilities.'' Under this requirement, an applicant would have to list all affiliated QFs as well as affiliated *non*-QFs. We requested comment on whether such a requirement is more burdensome than necessary. It was 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.*

575. The Commission also sought comment on whether item 3c (geographic coordinates) and the Geographic Coordinates instructions on page 4 of the current FERC 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 has been the case). We believed such information may provide more transparency in measuring 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.

576. The Commission noted, as it did in Order No. 732,[892] and as in the general form instructions on page 4 of the FERC 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. The Commission also noted that the Commission has a link on its QF web page (*https://www.ferc.gov/industries-data/electric/power-sales-and-markets/purpa-qualifying-facilities*) which provides assistance with determining geographic coordinates of facilities. As such, the Commission believed that the burden that would be created by requiring every QF to provide geographic coordinates would be limited. Even so, the Commission sought comment on whether the value of the information to the public and the Commission would outweigh the limited burden.

2. Comments

577. A few commenters oppose the changes to FERC Form No. 556 as proposed in the NOPR.[893] Solar Energy Industries and the Southeast Public Interest Organizations contend that the proposed new item 8b that requests a list of all affiliated facilities within one to 10 miles from the certifying QF would be a significant increase in information collection, time, effort, and cost of QF certification.[894]

578. The Southeast Public Interest Organizations further object that the obligation to show how distances are calculated and to identify electrical generating equipment and their associated geographic coordinates are overly burdensome for facilities that are presumed to be separate and contradicts the rebuttable presumption of separate facilities, which usually places the burden on the challenger.[895]

579. The Southeast Public Interest Organizations also assert it would be reasonable to ask for only affiliated QFs and to exclude non-QF affiliates from the questions in item 8.[896]

580. Several commenters support changes to FERC Form No. 556 as proposed in the NOPR.[897] A few commenters support the proposed changes to item 8a and proposed new item 8b and argue that the additional information might be otherwise difficult to find and will be useful to clarify if the assumption of separate facilities is appropriate.[898] Some commenters support requiring all applicants to supply geographic coordinates in item 3c, regardless of whether they have a street address.[899]

581. Two commenters support the collection of information for all affiliated facilities, not just QF affiliates, within the one or ten-mile radius requested in item 8a and proposed item 8b, respectively, because they believe it will be needed to identify QFs not complying with the proposed rule.[900]

582. Solar Energy Industries assert that the proposed item 8b to the Form No. 556, requiring a listing of all affiliated facilities whose nearest electrical generating equipment is greater than one mile and less than 10 miles from the electrical generating equipment of the certifying QF, is a substantial expansion of the information collection requirements and goes against the Commission's previously-granted blanket exemptions for QFs to relieve the burden of public utility regulation. Solar Energy Industries argue that this is not a mere information collection requirement, but a request for information that is not otherwise publicly available and is inconsistent with the Commission's finding on the burden of collecting Connected Entity information. Solar Energy Industries argue that collecting such information from QFs is unwarranted discriminatory treatment and is arbitrary and capricious.[901]

583. A few commenters requested additional changes to FERC Form No. 556.[902] North American-Central would like the Commission to create separate Form No. 556 forms for small power producers and cogeneration QFs for a more distinct and simplified application process.[903] EEI would like Form No. 556 to explicitly include battery storage.[904] EEI requests that the Form No. 556 collect information on the rated capacity and notes that net capacity may not be the appropriate measure of power production. Solar Energy Industries also noted that the Commission stated in Order No. 732 that future changes to Form No. 556 would not go through a rulemaking and would instead be reviewed by the Office of Management and Budget with a period for public comments.[905]

3. Commission Determination

584. We adopt the NOPR proposals regarding changes to the FERC Form No. 556, with the further clarifications and additions described below. The revised Form No. 556 will be attached to this rule in eLibrary, but will not be published in the **Federal Register** or Code of Federal Regulations. The Commission finds that the added information collected by these changes

[892] *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).

[893] Solar Energy Industries Comments at 8; Southeast Public Interest Organizations Comments at 36–37.

[894] Solar Energy Industries Comments at 56; Southeast Public Interest Organizations Comments at 36–37.

[895] Southeast Public Interest Organizations Comments at 37–38.

[896] *Id.*

[897] APPA Comments at 23; EEI Comments at 50; Portland General Comments at 17–18; Subsurface Engineering Association Comments at 1.

[898] APPA Comments at 23–24; EEI Comments at 50.

[899] EEI Comments at 50; Idaho Commission Comments at 7; Subsurface Engineering Association Comments at 1.

[900] EEI Comments at 50–51; Portland General Comments at 18.

[901] Solar Energy Industries Comments at 56–57.

[902] EEI Comments at 51; El Paso Electric Comments at 5–6; North American-Central Comments at 7.

[903] North American-Central Comments at 7.

[904] EEI Comments at 51–52.

[905] Solar Energy Industries Comments at 56.

is necessary to implement the changes made to the regulations in this final rule, and thus justifies the increase in reporting burden.

585. The currently effective Form No. 556 contains a ''Who Must File'' section which specifies when an applicant seeking QF status or recertification of QF status must file a self-certification, and when such applicant is exempt from the filing requirement. We will revise the ''Who Must File'' section to clarify that the exemption from the requirement to complete or file a Form No. 556 applies to an applicant seeking QF status for a small power production facility that, together with any affiliated small power production QFs within one mile of the entity seeking small power production QF status, has a net power production capacity of 1 MW or less. While we did not seek comment on this corrective change in the NOPR, this change is consistent with the Commission's determination in *SunE B9 Holdings LLC,* [906] and serves to make the Form No. 556 more transparent in its application.

586. We also revise the ''Who Must File'' section to include a ''Recertification'' section which provides the text of revised 18 CFR 292.207(f), (previously 18 CFR 292.207(d)) which states that a QF must file for recertification whenever the QF ''fails to conform with any material facts or representation presented . . . in its submittals to the Commission.'' [907]

This addition does not alter our recertification requirements, and we include it here simply to make the Form No. 556 clearer in its application.

587. The total burden estimates in the ''Paperwork Reduction Act Notice'' section of FERC Form No. 556 will be updated based on the changes in this final rule, to provide the following estimates: 1.5 hours for self-certifications of facilities of 1 MW or less; 1.5 hours for self-certifications of a cogeneration facility over 1 MW; 50 hours for applications for Commission certification of a cogeneration facility; 3.5 hours for self-certifications of small power producers over 1 MW and less than a mile or more than 10 miles from affiliated small power production QFs that use the same energy resource; 56 hours for an application for Commission certification of a small power production facility over 1 MW and less than a mile or more than 10 miles from affiliated small power production QFs that use the same energy resource; 9.5 hours for self-certifications of small power producers over 1 MW with affiliated small power production QFs more than one but less than 10 miles that use the same energy resource; 62 hours for an application for Commission certification of a small power production facility over 1 MW with affiliated small power production QFs more than one but less than 10 miles that use the same energy resource.

588. We find that an explanatory ''Protest to the Filing'' section should be added to the FERC Form No. 556 to note that, pursuant to 18 CFR 292.207, an interested person or entity has 30 days from the date of the filing of the FERC Form No. 556 to intervene or file a protest. The ''Protest to the Filing'' section will state that the protestor must concurrently serve a copy of such filing, pursuant to 18 CFR 385.211(b), on the Form No. 556 applicant. The ''Protest to the Filing'' section will also state that the Form No. 556 applicant will have 30 days to file any answer to a protest. The ''Protest to the Filing'' section will also state that protests may be made to any initial certification, and any recertifications on or after the effective date of this final rule making substantive changes to the existing certification, which may include, for example, a change in electrical generating equipment that increases power production capacity by the greater of 1 MW or 10 percent of the previously certified capacity of the QF, or a change in ownership in which an owner increases their equity interest by at least 10% from the equity interest previously reported. The ''Protest to the Filing'' section will note that ''administrative only'' changes will not be subject to protests.

589. The Commission finds that item 3c (geographic coordinates) and the Geographic Coordinates instructions on page 4 of the current FERC Form No. 556 will be revised to require all applicants to report the applicant facility's geographic coordinates, rather than only for applications where there is no street address (as was the case previously). We find that such information will provide more transparency regarding the location of each site, and that such transparency may be useful for both the public and Commission staff in monitoring compliance with the Commission's QF regulations.

590. The Commission will change item 8a, which currently requires applicants to list all affiliated facilities within one mile, to instead require that the applicant only list affiliated *small power production QFs using the same energy resource* within one mile.

591. We modify the NOPR's proposal to add the collection of information for affiliated facilities whose nearest electrical generating equipment is more than one but less than 10 miles from the electrical generating equipment of the applicant's facility to instead add the collection of information for affiliated small power production QFs using the same energy resource located more than one mile but less than 10 miles from the electrical generating equipment of the applicant's facility. However, rather than adding a separate item 8b to the Form No. 556 specifically for such QFs, as proposed in the NOPR, we are expanding the existing item 8a to require the applicant to list all affiliated small power production QFs using the same energy resource whose nearest electrical generating equipment is *less than 10 miles* from the electrical generating equipment of the entity seeking small power production QF status.

592. We determine that the revised item 8a will require the applicant to list the geographic coordinates of the nearest ''electrical generating equipment'' of both its own facility and the affiliated small power production QF in question based on the definitions adopted in this final rule. The distance between the entity seeking small power production QF status and each affiliated small power production QF will be automatically calculated based on these coordinates. For any affiliated small power production QFs that cannot be described in item 8a due to space limitations, the instructions will direct applicants to provide the required information for such small power production QFs in the Miscellaneous section of the form. To facilitate the uniform calculation of distances for facility data that are entered into the Miscellaneous section of the form, a distance calculator will be added to the form, and the form instructions will direct applicants to use the calculator to convert their facilities' geographic coordinates into distance.

593. The Commission also adopts the NOPR proposal to allow applicants with affiliated small power production QFs *greater than one mile and less than 10 miles* from the electrical generating equipment of the entity seeking small power production QF status identified under item 8a to, if they choose, explain why the affiliated small power production QFs *greater than one mile and less than 10 miles* from the nearest electrical generating equipment of the entity seeking QF status identified

[906] 157 FERC ¶ 61,044 at P 16 (''the one-mile rule of section 292.204(a)(2) is a size determination which the Commission has consistently applied generally to the regulations pursuant to PURPA, and which applies here to determining the applicability of the less-than-1–MW exemption of section 292.203(d)'') (internal citations omitted).

[907] 18 CFR 292.207(d).

under item 8a should be considered to be at separate sites from the entity seeking QF status, considering the relevant physical and ownership factors. The instructions will provide references to the relevant physical and ownership factors, as defined in this final rule, that may be asserted to defend against rebuttal.

594. Regarding Solar Energy Industries' concern regarding the expansion of the information collection requirements, we find that the added information collected by item 8a of the Form No. 556 is necessary to implement the changes made to the regulations in this final rule, and thus justifies the increase in reporting burden. As noted in section IV.E, the currently pending Connected Entity proceeding is a separate proceeding and beyond the scope of this proceeding. Moreover, the data collection at issue in that proceeding does not eliminate the need for the Commission to collect the data required by the FERC Form No. 556 so that the Commission has the information it needs to determine whether a facility qualifies to be a QF consistent with the standards laid out in the statute.

595. We note that these changes and any future changes to Form No. 556 will continue to be reviewed by the Office of Management and Budget following solicitation of comments from the public, as described in Order No. 732.[908]

596. We find the requests for additional changes to FERC Form No. 556 beyond the scope of this proceeding.

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

1. PURPA Section 210(m) Implementation

a. NOPR Proposal

597. 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, fourteen years later, the markets are more mature, and the mechanics of participation in such markets are improved and better understood. Consequently, in the NOPR, the Commission determined that small power production facilities below 20 MW should now be able to participate in such markets under most circumstances. The Commission therefore proposed to revise 18 CFR 292.309(d) 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.

598. The Commission determined that, in light of the maturation of organized electric markets, such a reduction was consistent with Congress's intent to relieve electric utilities of their obligation to purchase when a QF has nondiscriminatory access to competitive markets.

599. The Commission noted that, in establishing the original 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, it had acknowledged that "there is no unique and distinct megawatt size that uniquely determines if a generator is small." [909] The Commission noted that, in using 20 MW to separate the presumption that large QFs had nondiscriminatory access and small QFs lacked such access, the Commission had 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–A's setting 20 MW as the demarcation for different interconnection standards between small and large generators.[910] The NOPR stated that, while the Commission had not (and likewise did not in the NOPR) propose to revise the exemptions for QFs from sections 205 and 206 of the FPA, the Commission had elsewhere taken steps to ease both interconnection and market access for generation resources with small capacities since it first implemented section 210(m) of PURPA.

600. For example, the Commission noted that it had 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),[911] and had 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.[912] While both of these changes do not apply only to generation types that could become QFs or only to RTOs/ISOs, the Commission stated that it believed 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. The Commission also stated that, under the NOPR proposal and like QFs over 20 MW today, small power production facilities over 1 MW would still be able to rebut the presumption of access due to operational characteristics or transmission constraints.[913]

601. The Commission did not propose to make the same reduction applicable to cogeneration facilities. The Commission stated that, 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.[914] Consequently, the production and sale of electricity is a byproduct of these thermal processes, and owners of cogeneration facilities might not be as familiar with energy markets and the technical requirements for such sales. The Commission stated that retention of the existing 20 MW level for the presumption of access to markets therefore would be appropriate for cogeneration facilities.

b. Comments in Opposition

602. Numerous commenters oppose the NOPR proposal to revise 18 CFR 292.309(d) to reduce the net power production capacity level at which the presumption of nondiscriminatory

[908] Order No. 732, 130 FERC ¶ 61,214.

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

[910] *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) ("[S]ales 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, *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).

[911] *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).

[912] Order No. 841, 162 FERC ¶ 61,127 at P 265.

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

[914] *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).

access to a market attaches for small power production facilities, but not cogeneration facilities, from 20 MW to 1 MW.[915]

i. Insufficient Evidentiary Support

603. Several commenters argue that the record does not support the proposal.[916]

604. Advanced Energy Economy asserts that, when an agency reverses course on a policy issue, and the ''new policy rests upon factual findings that contradict those which underlay'' the previous policy, then the agency must ''provide a more detailed justification than what would suffice for new policy created on a blank slate.'' [917] Advanced Energy Economy argues that the NOPR falls short of that standard.[918]

605. Public Interest Organizations and NIPPC, CREA, REC and OSEI argue that the Commission fails to cite any evidence supporting the premise that the markets are more mature, and that the mechanics of participation in such markets are improved and better understood. Public Interest Organizations and NIPPC, CREA, REC, and OSEIA state that the Commission asserts that QFs smaller than 20 MW can now participate in markets on a nondiscriminatory basis ''under most circumstances,'' but that the Commission does not explain what those ''circumstances'' are, or whether they apply as a general matter to most small QFs.[919]

606. Several commenters state that, in Order No. 688–A, the Commission, rejected utility proposals to set the threshold at 1 MW, and confirmed that 20 MW was an appropriate threshold.[920] Advanced Energy Economy states that the Commission's explanation in Order No. 688–A, which stated that the rebuttable presumptions were based on the Commission's experience of implementing non-discriminatory open access transmission over the past 11 years, dealing with QF issues over the past 29 years and its experience with RTO/ISO markets for almost 10 years, contradicts the Commission's justification in the NOPR of limited experience with organized electric markets.[921] Advanced Energy Economy and Southeast Public Interest Organizations assert that, since Order No. 688, the Commission has repeatedly found that utilities in organized markets have failed to rebut the presumption of nondiscriminatory access to QFs, instead finding that QFs 20 MW and under do not have sufficient access.[922]

607. Public Interest Organizations and NIPPC, CREA, REC, and OSEIA argue that the Commission fails to explain the relevance of its Fast-Track interconnection process or energy storage order or which barriers these developments alleviate for small QFs' access to markets.[923] Advanced Energy Economy asserts that the expansion of the Fast-Track procedures only applied to a narrow slice of inverter-based resources under 20 MW and is insufficient to support a rebuttable presumption that all QFs under 20 MW have nondiscriminatory access.[924]

608. Solar Energy Industries and New England Hydro argue that, just because some small QFs participate in energy markets, that is not sufficient justification to find that all small QFs meet the statutory standard required for granting waiver for all QFs 20 MW or less.[925] Public Interest Organizations assert that proper implementation of section 210(m) requires that exemption from the mandatory purchase obligation only applies where QF development will be stimulated by market forces; otherwise Congress intended QF development to continue to be encouraged by the mandatory purchase obligation.[926] Protesters assert that the record does not provide evidence that could reasonably allow the Commission to conclude that small QF development will be stimulated by market forces. On the contrary, the Public Interest Organizations assert that the Commission's proposal placing the burden on small QFs to rebut the presumption of access is itself a barrier to QF development.[927]

609. Solar Energy Industries argue that, along with the energy markets, the capacity markets in the RTO/ISO regions have not evolved to provide a meaningful opportunity for any QF to sell long-term capacity.[928] Solar Energy Industries argue that PURPA section 210(m) requires the Commission to find that a QF has nondiscriminatory access to a market for long-term sales of capacity prior to relieving the purchase obligation. Solar Energy Industries provide several examples such as MISO's Planning Resources Auction that only provides a one-year purchase agreement, PJM not purchasing capacity since the Commission's July 2019 Order, and that SPP does not have a centralized capacity market. Solar Energy Industries argue that without a specific finding that RTO/ISO markets provide QFs with an opportunity to sell long-term capacity, the Commission is statutorily required to maintain utilities' obligation to purchase output from QFs 20 MWs or less.[929]

610. Mr. Mattson asserts, without elaboration, that FPA sections 205 and 206 disallow the Commission from lowering the nondiscriminatory access threshold from 20 MW to 1 MW, and, therefore, claims it would amount to a violation of state-jurisdictional rights and a taking of property.[930]

ii. Administrative Burden and Complex Market Rules

611. The DC Commission state that QFs 20 MW or less lack the capability

[915] Allco Comments at 2, 17–19; Advanced Energy Economy Comments at 1–12; AllEarth Comments at 2; Biogas Comments at 2–3; Biological Diversity Comments at 8–9; California Commission Comments at 31–33; CARE Comments at 5–6; Con Edison Comments at 5; Covanta Comments at 10–12; DC Commission Comments at 4–5; Distributed Sun Comments at 2–3; ELCON Comments at 18, 31–35; Energy Recovery Comments at 4–5; ENGIE Comments at 3–4; Commissioner Slaughter Comments at 2, 4; Green Power Comments at 3; Industrial Energy Consumers Comments at 6–10; Massachusetts AG Comments at 6–8; Michigan Commission Comments at 6–7; North American-Central at 2–4; One Energy Comments at 2; South Dakota Commission Comments at 5; Solar Energy Industries Comments at 44–51; State Entities Comments at 5–6; Western Resource Councils Comments at 1–144.

[916] AllEarth Comments at 2; Advanced Energy Economy Comments at 5–9; Biological Diversity Comments at 9; ELCON Comments at 31–32; Industrial Energy Consumers Comments at 8; New England Hydropower Comments at 11–12; NIPPC, CREA, REC, and OSEIA Comments at 77; Public Interest Organizations Comments at 76–78; SC Solar Alliance Comments at 12; Solar Energy Industries Comments at 45–48; Southeast Public Interest Organization Comments at 39–40.

[917] Advanced Energy Economy Comments at 6 (citing *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. at 515).

[918] *Id.* at 7.

[919] Public Interest Organizations Comments at 78; NIPPC, CREA, REC, and OSEIA Comments at 77 (citing NOPR, 168 FERC ¶ 61,184 at P 126).

[920] Advanced Energy Economy Comments at 5–6; ELCON Comments at 31–32.

[921] Advanced Energy Economy Comments at 8–9.

[922] *Id.* (citing, *e.g., PPL Elec. Utils Corp.,* 145 FERC ¶ 61,053, at P 24 (2013); *City of Burlington,* 145 FERC ¶ 61,121, at P 36 (2013); *Fitchburg Gas and Elec. Light Co.,* 146 FERC ¶ 61,186, at PP 32–33 (2014); *Va. Elec. & Power Co.,* 151 FERC ¶ 61,038, at P 21 (2015); *N. States Power Co.,* 151 FERC ¶ 61,110 (2015)); Southeast Public Interest Organizations Comments at 39–40.

[923] NIPPC, CREA, REC, and OSEIA at 77; Public Interest Organizations Comments at 78 (citing *Motor Vehicle Mfrs. Ass'n of U.S., Inc.* v. *State Farm Mut. Auto. Ins. Co.,* 463 U.S. 29, 43 (1983) (explaining that an agency's failure to consider the relevant factors and supply a ''rational connection between the facts found and the choice made'' renders its decision arbitrary and capricious)).

[924] Advanced Energy Comments at 7–8.

[925] Solar Energy Industries Comments at 46; New England Hydro Comments at 11–12.

[926] Public Interest Organizations Comments at 76 (citing *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities,* Order No. 688, 117 FERC ¶ 61,078, at P 6 (2006), *order on reh'g,* Order No. 688–A, 119 FERC ¶ 61,305 (2007), *aff'd sub nom. Am. Forest and Paper Ass'n* v. *FERC,* 550 F.3d 1179).

[927] *Id.*

[928] Solar Energy Industries Comments at 45.

[929] *Id.* at 49.

[930] Mr. Mattson Comments at 10.

to participate in a complicated wholesale market such as PJM where there is a need to understand membership obligations and rules in order to appropriately execute transactions.[931]

612. Allco argues that, in retail choice states, PURPA is the only way small QFs can sell to utilities. Allco asserts that in retail choice states there is a shifting retail customer base, therefore utilities want obligations reduced and contracts limited to a year. Allco asserts that utilities and state commissions cannot limit contracts due to a potentially disappearing customer base and then argue that a sufficient wholesale market exists for long-term sales of electric energy and capacity to support nondiscriminatory access for small QFs under 20 MW.[932]

613. Public Interest Organizations argue that giving special exemptions to cogeneration facilities is discriminatory against small power producer QFs.[933] Two commenters also assert that small QFs are at an inherent disadvantage compared to larger QFs because smaller QFs are often engaged in other business enterprises, such as governmental units distributing irrigation water or local companies unfamiliar with energy markets.[934]

c. Comments in Support

614. Numerous commenters support the proposal to revise 18 CFR 292.309(d) for small power production facilities but not cogeneration facilities, to reduce the net power production capacity level at which the presumption of nondiscriminatory access to a market applies from 20 MW to 1 MW.[935] DTE Electric argues that RTO/ISOs can now provide smaller resources non-discriminatory access, and therefore electric utilities should no longer be required to purchase electric energy from them.[936] EEI supports the proposal because resource diversity has improved and markets have evolved as smaller resources, including QFs, are increasingly participating in the RTO/ISO markets. RTOs/ISOs have also increasingly adjusted their bidding rules, forecasts, and operations to better accommodate variable resources.[937] Alliant and the Ohio Commission Energy Advocate state that small resources have increased access to wholesale markets and that RTO/ISO rule flexibility allows for the non-discriminatory participation of very small resources and the aggregation of even smaller resources in the markets, therefore the 20 MW threshold is no longer appropriate.[938]

615. Consumer Alliance and EEI argue that reducing the threshold will reduce costs to customers because currently some QFs with access to markets are foregoing the opportunity to participate in those markets and electing to contract with electric utilities under state-implemented PURPA programs, which EEI argues compensate QFs at an above-market rate.[939]

616. The Ohio Commission Energy Advocate argues that the rebuttable presumption process for QFs provides an appropriate safety valve for the lower threshold.[940]

d. Comments Requesting Modifications/Clarifications

617. Institute for Energy Research requests that the Commission expand the rebuttable presumption of non-discriminatory access to QFs 1 MW and below if the market structure in a given state is appropriate. Institute for Energy Research gives the example of Texas's open market model, where generation is open to all comers of all sizes. Institute for Energy Research also suggests that the Commission should include some threshold now such that when other states achieve similar open access market designs QFs 1 MW and below could be rebuttably presumed to have non-discriminatory access to those markets, without the need to undertake, at that time, a separate rulemaking on QFs 1 MW and below.[941]

618. The Connecticut Commission suggests reducing the threshold at which the presumption of nondiscriminatory access attaches to 0 MW because the markets are more mature, the mechanics of participating in the markets are improved and the law requires nondiscriminatory access to the markets for all resources.[942] Missouri River Energy recommends lowering the threshold to 500 kW.[943] FirstEnergy recommends the Commission treat both small power production resources and cogeneration resources consistently by lowering the rebuttable presumption threshold from 20 MW to 1 MW for all QFs.[944] Indiana Municipal requests that the Commission automatically apply the 1 MW threshold to utilities that have already been granted waiver for QFs over 20 MW to promote the efficient use of the Commission's resources and savings to utilities.[945]

619. The Michigan Commission requests clarification on the NOPR proposal specifically regarding: (1) How existing contracts with QFs greater than 1 MW but below 20 MWs are to be treated under the NOPR, and if they would be subject to early termination or would be granted legacy treatment indefinitely or until the end of the existing contract term; (2) whether utilities that have already received relief from the mandatory purchase obligation from the Commission for operating within the footprint of an organized wholesale electricity market automatically qualify for relief under the 1 MW threshold; and (3) how interconnection requirements would be considered for QFs between 1 MW and 20 MWs—specifically whether these projects would need to interconnect at transmission level voltages to be considered as having access to the wholesale electricity market.[946] The Michigan Commission notes that there is some tension between the proposal and the market rules for MISO and PJM.[947]

620. Several commenters request that the Commission expand the exemption for cogeneration to small power QFs whose primary purpose is to self-supply but still rely on PURPA when making occasional sales to the interconnected utility when QF output exceeds on-site consumption.[948] Industrial Energy

[931] DC Commission Comments at 4–5.

[932] Allco Comments at 18.

[933] Public Interest Organizations Comments at 74.

[934] NIPPC, CREA, REC, and OSEIA Comments at 18–19, 24–25; Mr. Mattson Comments at 15.

[935] Alliant Energy Comments at 13–16; Tax Reform Comments at 2; APPA Comments at 24–26; Arizona Public Service Comments at 8–10; Basin Comments at 12–13; Freedom Center Comments at 2; Colorado Independent Energy Comments at 14; Connecticut Commission Comments at 21–22; Conservative Action Comments at 2; Consumers Alliance Comments at 1–2; Consumers Energy Comments at 4–5; DTE Electric Comments at 4–5; East Kentucky Comments at 3; East River Comments at 2; EEI Comments 54–59; FirstEnergy Comments at 2–3; Idaho Power comments at 14; Indiana Municipal Comments at 6–9; Institute for Energy Research Comments at 2; Kentucky Commission Comments at 8; Missouri River Energy Comments at 3–4; NorthWestern at 14; TAPS Comments at 4; Ohio Commission Energy Advocate Comments at 8; Taxpayers Protection Alliance Comments at 2; Chamber of Commerce Comments at 7; We Stand Comments at 1–144; Taxpayer Protection Alliance Comments at 2; TAPS Comments at 4.

[936] DTE Electric Comments at 5–6.

[937] EEI Comments at 56–58.

[938] Alliant Energy Comments at 13–14; Ohio Commission Energy Advocate Comments at 7–8.

[939] EEI Comments at 58–59; Consumers Alliance Comments at 1–2.

[940] Ohio Commission Energy Advocate Comments at 8.

[941] Institute of Energy Research Comments at 2.

[942] Connecticut Commission Comments at 21–23.

[943] Missouri River Energy Comments at 3.

[944] FirstEnergy Comments at 2–3.

[945] Indiana Municipal Comments at 8–9.

[946] Michigan Commission Comments at 6–7

[947] *Id.* at 7 (commenting that MISO, for example, utilizes a 5 MW threshold as the cut off point for Network Modeling purposes and that resources less than 5 MW are modeled on a case-by-case basis only).

[948] ELCON Comments at 32–33; Industrial Energy Consumers Comments at 6–8; Chamber of Commerce Comments at 7.

Consumers suggest that small power producers seeking a 20 MW self-supply exemption meet the ''fundamental use test'' which currently applies to cogeneration facilities.[949] Other commenters assert that behind-the-meter distributed energy resources,[950] Waste to Energy resources,[951] and baseload renewables [952] are similar to cogeneration facilities and should be included in the exemption.

621. Public Interest Organizations request that the Commission clarify that utilities are required to petition to eliminate the must-purchase obligation for small QFs, even for those utilities that have previously made such a showing for QFs larger than 20 MW.[953] NRECA, concerned over a potential change in aggregation for distributed energy resources in RTOs/ISOs, requests that the Commission clarify that the presumption will only apply to those facilities having sufficient transmission access to the RTO/ISO markets.[954]

622. Hydropower Association asserts that, despite their potential, hydropower resources do not receive the same tax treatment and eligibility for state RPSs and therefore have not enjoyed the same growth rate as other renewable energy small power producers. Hydropower Association urges the Commission to retain the 20 MW rebuttable presumption for hydropower resources, as would be the case for cogenerators, because hydropower resources are required by the FPA section 10(a) to be best adapted for comprehensive uses, including non-power generation purposes such as irrigation, flood control, navigation, recreation, environmental restoration, and wildlife preservation. Hydropower Association states that non-powered dams by definition were not constructed to generate power. Because power generation is therefore a secondary use of these facilities, Hydropower Association asserts that subjecting these facilities to new avoided cost calculations will necessarily burden hydropower resources more than other small power production facilities. Hydropower Association also asserts that there is almost 5 GW of potential non-power dams that could be developed and that the 20 MW exemption should be retained for these resources.[955]

623. Ohio Consumers Counsel states that lowering the rebuttable presumption could permit electric utilities and state policies to deny QFs and distributed energy resources under 20 MW from having unrestricted and nondiscriminatory access to wholesale markets. For example, Ohio Consumers Counsel states that the NOPR would permit electric distribution utilities to limit the availability of after-the-meter generation and storage from PJM's markets, such as through restrictive net metering requirements, unreasonably low compensation for distributed energy resources, or other state regulatory and policy restrictions. Ohio Consumers Counsel urges the Commission to require that investor-owned electric distribution utilities demonstrate that they have not restricted market access to QFs and distributed energy resources rated between 1 MW and 20 MW.[956]

e. Commission Determination

624. We agree with commenters that, in Order Nos. 688 and 688–A, given conditions at the time, the Commission established the rebuttable presumption at QFs 20 MW or less. Furthermore, as commenters noted in reviewing several individual cases in 2013–2015, the Commission continued to find that those individual small power production facilities 20 MW or less still needed the additional protections and encouragement.[957] However, since Order Nos. 688 and 688–A the Commission has recognized multiple examples of small power production facilities under 20 MW participating in RTO/ISO energy markets. The Commission found that the electric utilities in those proceedings rebutted the presumption of no market access and therefore terminated the mandatory purchase obligation.[958]

625. We adopt the proposal to revise 18 CFR 292.309(d) 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 for cogeneration facilities. However, recognizing some of the challenges that QFs near 1 MW have in participating in such markets that have been identified by commenters, in this final rule we lower the rebuttable presumption from 20 MW to 5 MW, rather than from 20 MW to 1 MW as proposed in the NOPR. Under the final rule, small power production facilities with a net power production capacity at or below 5 MW will be presumed *not* to have nondiscriminatory access to markets, and, conversely, small power production facilities with a net power production capacity over 5 MW will be presumed to have nondiscriminatory access to markets.

626. A number of commenters oppose the reduction below 20 MW, arguing the lack of a record to support the proposal. We disagree. In Order Nos. 688 and 688–A, the Commission determined that small QFs may not have nondiscriminatory access to wholesale markets and, therefore, it was reasonable to establish a presumption for small QFs. At that time, the Commission found that it was ''reasonable and administratively workable'' to define ''small'' for purposes of this regulation to be QFs below 20 MW.[959] We also note that a number of commenters, including state entities which are charged with applying PURPA in their jurisdictions,[960] supported a reduction in the 20 MW threshold.

627. The Commission acknowledged that there is no unique number to draw a line for determining what is a small entity.[961] In establishing 20 MW presumption as the line between large and small QFs for purposes of section 210(m), the Commission looked at other non-QF rulemaking orders in which it considered what was a small entity and those orders showed 20 MW was a reasonable number at which to draw the line.[962] But, as explained below, the Commission has since determined, based on changed circumstances since the issuance of Order Nos. 688 and 688–A, that entities with capacity lower than 20 MW have nondiscriminatory access to the markets and, therefore, capacity

[949] Industrial Energy Consumers Comments at 9–10.

[950] One Energy Comments at 2.

[951] Industrial Energy Consumers Comments at 9–10.

[952] Renewable Baseload Coalition Comments at 2.

[953] Public Interest Organizations Comments at 76.

[954] NRECA Comments at 18–19.

[955] Hydropower Association Comments at 2–7 (citing 16 U.S.C. 803).

[956] Ohio Consumers Counsel Comments at 2–5.

[957] *PPL Elec. Utilities Corp.,* 145 FERC ¶ 61,053 at P 24; *Va. Elec. & Power Co.,* 151 FERC ¶ 61,038, at P 21; *N. States Power Co.,* 151 FERC ¶ 61,110.

[958] *See, e.g., Fitchburg Gas and Elec. Light Co.,* 146 FERC ¶ 61,186, at P 33 (2014); *City of Burlington, Vt.,* 145 FERC ¶ 61,121, at P 33 (2013).

[959] *See* Order No. 688, 117 FERC ¶ 61,078 at PP 74–78 (establishing rebuttable presumption); Order No. 688–A, 119 FERC ¶ 61,305 at P 95 (''There is no perfect bright line that can be drawn and we have reasonably exercised our discretion in adopting a 20 MW or below demarcation for purposes of determining which QFs are unlikely to have nondiscriminatory access to markets.'').

[960] *See* Connecticut Commission Comments at 20–21; Kentucky Commission Comments at 8.

[961] Order No. 688–A, 119 FERC ¶ 61,305 at P 97 (''Although there is no unique and distinct megawatt size that uniquely determines if a generator is small, in other contexts the Commission has used 20 MW, based on similar considerations to those presented here, to determine the applicability of its rules and policies.'').

[962] *See* Order No. 688, 117 FERC ¶ 61,078 at P 76; Order No. 688–A, 119 FERC ¶ 61,305 at PP 96–97.

level of 20 MW may no longer be a reasonable place to establish the presumption on what constitutes a smaller entity under our regulations.

628. Similar to our analysis in Order No. 688, we have determined that entities below 20 MW now can participate in RTO/ISO markets.[963] Here, we are updating the rebuttable presumption based on industry changes since Order No. 688. Moreover, it is reasonable to update the rebuttable presumption as markets defined in PURPA section 210(m)(1)(A), (B), and (C) evolve because that statute itself does not establish a presumption and we are updating the rules, as PURPA provides we will do from time to time, to ensure we comply with PURPA. However, because the revised presumption established in this final rule is a rebuttable presumption, QFs can seek to overcome it.

629. Over the last 15 years, the RTO/ISO markets have matured, market participants have gained a better understanding of the mechanics of such markets, and, as a result, we find that it is reasonable to presume that access to the RTO/ISO markets has improved and that it is appropriate to update the presumption for smaller production facilities. As we did in Order No. 688, we have looked to indicia in other orders to determine where the presumption should be set.

630. We find that at this time, market rules are inclusive of power producers below 20 MW participating in markets. For example, since the issuance of Order No. 688, the Commission has required public utilities to increase the availability of a Fast-Track interconnection process for projects up to 5 MW.[964] That the Commission chose a 5 MW cut-off for eligibility for the fast-track procedures represents an implicit judgment by the Commission that facilities larger than 5 MW do not need such procedures to be able to interconnect to the grid.

631. While the existence of Fast-Track interconnection processes does not on its own demonstrate nondiscriminatory access for resources under 20 MW, it does indicate that entities smaller than 20 MW have access to the market. Presuming that QFs above 5 MW have such access is therefore a reasonable approach to identifying a capacity level at which to update the rebuttable presumption of nondiscriminatory market access.

632. Additionally, since the issuance of Order No. 688 the Commission has required each RTO/ISO to update its tariff to include a participation model for electric storage resources that established a minimum size requirement for participation in the RTO/ISO markets that does not exceed 100 kW.[965] These proposals require RTO/ISOs to revise their tariffs to provide easier access for smaller resources. Requiring markets to accommodate storage resources to as low as 100 kW also supports that resources smaller than 20 MW have nondiscriminatory access to those RTO/ISO markets. The Commission believes that these developments support updating the 20 MW presumption to a lower number.

633. Commenters argue that individually each of these changes in circumstances, standing alone, may not support the reduction of the threshold below 20 MW. But when the changes are viewed together, we find that their cumulative effect demonstrates that it is reasonable for the Commission to maintain a small entity rule but update its determination of what is a small entity under this presumption under the PURPA regulations. Additionally, the prospect of increased participation of distributed energy resources in energy markets further supports the proposition that wholesale markets are accommodating resources with smaller capacities.[966]

634. The Commission recognizes that certain of these precedents would support reducing the presumption below 5 MW, and perhaps even lower than 1 MW. However, the Commission has carefully considered the comments detailing the problems that QFs have had in participating in RTO/ISO markets, problems that necessarily are more acute for smaller QFs at or near the 1 MW threshold proposed in the NOPR.[967] The Commission therefore has determined that a 5 MW is a more reasonable threshold of non-discriminatory access to RTO/ISO markets.

635. Based on the foregoing, we find it reasonable to update the presumption under these regulations as to what constitutes a small entity that has non-discriminatory access to RTO/ISO markets and markets of comparable competitive quality below 20 MW, and that 5 MW represents a reasonable new threshold that accounts for the change of circumstances indicating that 20 MW no longer is appropriate but also accommodates commenters' concerns that a 1 MW threshold would be too low. We acknowledge that ''there is no unique and distinct megawatt size that uniquely determines if a generator is small.'' [968] We find that a 5 MW threshold accords with PURPA's mandate to encourage small power production facilities, recognizes the progress made in wholesale markets as discussed above, and balances the competing claims of those seeking a lower threshold and those seeking a higher threshold.

636. Individual small power production QFs that are over 5 MW and less than 20 MW can seek to make the case, however, that they do not truly have nondiscriminatory access to a market and should still be entitled to a mandatory purchase obligation.

637. Regarding Advanced Energy Economy's argument that the Commission failed to sufficiently justify its change in policy, we disagree.[969] In *FCC* v. *Fox Television,* the court stated that, when an agency makes a change in policy, the agency must show that there are good reasons for the change, ''[b]ut it need not demonstrate to a court's satisfaction that the reasons for the new policy are better than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency *believes* it to be better, which the conscious change of course adequately indicates.'' [970]

638. To be clear, we are maintaining our determination from Order No. 688 that small entities potentially may not have non-discriminatory access for purposes of PURPA section 210(m). However, as explained above, the Commission has determined that using 20 MW as an indicator of what constitutes a small entity is no longer valid. Entities below 20 MW increasingly have access to the markets, become familiar with practices and procedures, and that markets have since

[963] In fact, when the Commission established the rebuttable presumption of 20 MW, commenters in that proceeding cited instances where QFs at 1 MW or above had already had nondiscriminatory access to RTOs/ISOs. *See* Order No. 688, 117 FERC ¶ 61,078 at PP 64–66.

[964] Order No. 792, 145 FERC ¶ 61,159, at P 103, *clarified,* Order No. 792–A, 146 FERC ¶ 61,214.

[965] Order No. 841, 162 FERC ¶ 61,127 at P 265.

[966] *See, e.g., Elec. Participation in Mkts Operated by Reg'l Transmission Orgs and Independent Sys. Operators,* 157 FERC ¶ 61,121, P 129 (2016) (''The costs of distributed energy resources have decreased significantly, which when paired with alternative revenue streams and innovative financing solutions, is increasing these resources' potential to compete in and deliver value to the organized wholesale electric markets.'' (footnote omitted)).]

[967] *See, e.g.,* Allco Comments at 17–19; Advanced Energy Economy Comments at 10–11; DC Commission Comments at 5; Public Interest Organizations Comments at 89–90; SEIA Comments at 45–49.

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

[969] Advanced Energy Economy Comments at 6 (citing *FCC* v. *Fox Television,* 556 U.S. at 515).

[970] *FCC* v. *Fox Television,* 556 U.S. at 515.

implemented several changes to provide easier access to smaller facilities, including small power production QFs, storage facilities, and distributed energy resources. These changes demonstrate a change in facts since the time we issued Order No. 688 which supports our updating of what constitutes a small entity for purposes of PURPA section 210(m).

639. Accordingly, we decline to adopt Ohio Consumers Counsel's suggestion that electric utilities continue to have the burden to demonstrate that certain small power production QFs under 20 MW have nondiscriminatory access to markets like PJM before being relieved of the mandatory purchase obligation for such QFs.

640. While we find that it is reasonable to update the rebuttable presumption from 20 MW to 5 MW, we recognize commenters' concerns regarding specific barriers to participation in RTO markets that may affect the nondiscriminatory access to those markets of some individual small power production facilities between 5 MW and 20 MW.

To address these concerns, we additionally are revising 18 CFR 292.309(c)(2)(i)–(vi) to include factors that small power production facilities between 5 MW and 20 MW can point to in seeking to rebut the presumption that they have nondiscriminatory access. These factors are in addition to the existing ability, pursuant to 18 CFR 292.309(c), to rebut the presumption of access to the market by demonstrating, *inter alia,* operational characteristics or transmission constraints.

641. Specifically, the Commission adds to 18 CFR 292.309(c) the following five factors: (1) Specific barriers to connecting to the interstate transmission grid, such as excessively high costs and pancaked delivery rates; (2) the unique circumstances impacting the time/length of interconnection studies/queue to process small power QF interconnection requests; (3) a lack of affiliation with entities that participate in RTO/ISO markets; (4) a predominant purpose other than selling electricity which would warrant the small power QF being treated similarly to cogenerators (*e.g.,* municipal solid waste facilities, biogas facilities, run-of-river hydro facilities, and non-powered dams); (5) the QF has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; and (6) the QF lacks access to markets due to transmission constraints, including that it is located in an area where persistent transmission constraints in effect cause the QF not to have access to markets outside a persistently congested area to sell the QF output or capacity. This is not intended to be an exhaustive list of the factors that a QF could rely upon in seeking to rebut the presumption. These factors, among other indicia of lack of nondiscriminatory access, will be assessed by the Commission on a case-by-case basis in considering a claim that the presumption of nondiscriminatory access to the defined markets should be considered rebutted for a specific QF.

642. The addition of these factors addresses commenters' concern that not all small power production facilities between 5 and 20 MW may have nondiscriminatory access to competitive markets, and facilitates the ability of small power production facilities facing barriers to participation in RTO markets to demonstrate their lack of access. For example, while a small power production facility between 5 MW and 20 MW does not need to be physically interconnected to transmission facilities to be considered as having access to the statutorily-defined wholesale electricity markets, we recognize there are some small power production facilities between 5 MW and 20 MW that may face additional barriers, such as excessively high costs and pancaked delivery rates, to access wholesale markets.

643. For example, several commenters express concern over the resources or administrative burden for some small power QFs that lack the necessary experience or expertise to participate in energy markets. Recognizing these concerns, we have added consideration of both the fact that some small power production facilities will face additional difficulties due to costs, administrative burdens, length of the interconnection study process and the size of the queues, and the fact that some small power production QFs do not have access to the expertise of affiliated entities.

644. We agree with commenters that some small power production facilities are similar to cogeneration facilities because their predominant purpose is not power production. Like cogeneration facilities, the sale of electricity from these small power production facilities is a byproduct of another purpose and these facilities might not be as familiar with energy markets and the technical requirements for such sales. Therefore, we will allow the small subset of small power production facilities that are between 20 MW and 5 MW to rebut the presumption of access to markets where the predominant purpose of the facility is other than selling electricity, and the sale of electricity is simply a byproduct of that purpose. Finally, like all QFs over 20 MW, we recognize that there may be particular small power production facilities with certain operational characteristics or that are located in an area where persistent transmission constraints in effect cause the QF not to have access to markets outside a persistently congested area to sell the QF output or capacity.

645. While we appreciate Indiana Municipals' concern over preserving Commission resources, we will deny its request to automatically apply the lower threshold to utilities that have already been granted termination for QFs over the 20 MW threshold. We find that it is appropriate to require utilities that were previously granted termination of the mandatory purchase obligation for new contracts and obligations for QFs above 20 MW, but are now seeking to terminate the mandatory purchase obligation for new contracts and obligations for small power production facilities between 5 and 20 MW to follow the procedures in 18 CFR 292.310, including procedures for providing notice to those potentially affected QFs within their footprint. That is, those utilities for which the Commission has already granted relief from the mandatory purchase obligation for small power production facilities over 20 MW must reapply with the Commission requesting relief from the mandatory purchase obligation for small power production facilities between 5 MW and 20 MW.

646. Among other factors, the regulation's notice provision mentioned above will allow small power production facilities between 5 MW and 20 MW an opportunity, if applicable, to present evidence that their facility does not have nondiscriminatory access to defined markets based on the factors discussed above.[971] In the proceeding in which the utility seeks to terminate the mandatory purchase obligation between 5 MW and 20 MW, we will not entertain arguments that the utility should lose its previously granted termination of purchase obligation at 20 MW and above; our regulations provide how a mandatory purchase obligation can be reinstated. We do not, in this final rule, change a QF's right to seek reinstatement of the mandatory purchase obligation where the conditions set forth in 18 CFR 292.309(a), (b), or (c) are no longer met.[972]

647. Regarding the Michigan Commission's questions, this final rule

[971] 18 CFR 292.310.

[972] *See* 18 CFR 292.311.

preserves the rights or remedies of any party under existing contracts or obligations, in effect or pending approval before the appropriate state regulatory authority or non-regulated electric utility on or before December 31, 2020 with QFs between 5 MW and 20 MW. Consistent with Commission precedent, this final rule defines the term ''obligations'' broadly to encompass any existing legally enforceable obligation.[973]

2. Reliance on RFPs and Liquid Market Hubs To Terminate Purchase Obligation Under PURPA Section 210(m)

a. NOPR Discussion

648. In the NOPR, the Commission noted that NARUC had 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).[974] After describing generally how such a proposal might be structured, NARUC suggested 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).'' [975]

649. The Commission stated that, 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).[976] The Commission further noted that 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).

650. The Commission then stated that it believed 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 that it would consider such proposals on a case-by-case basis. Although the Commission did not propose additional criteria a utility or utilities may rely on to satisfy PURPA section 210(m)(1)(C), the Commission sought 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).[977]

b. Comments

i. Comments in Opposition

651. A few commenters do not support allowing competition to be an alternative to the mandatory purchase obligation.[978] ELCON is concerned that no state competitive procurement is robust enough to replace avoided capacity costs.[979] Solar Energy Industries supports using RFPs to set avoided cost rates, but does not support using RFPs to vitiate utilities' mandatory purchase obligations.[980]

652. Public Interest Organizations contend that RFPs are not comparable in quality to PURPA section 210(m)(1)(A) or (B) markets because there is only a single buyer and there are no safeguards against the anti-competitive behavior of that buyer, such as favoring its own or an affiliate's generation.[981] NIPPC, CREA, REC, and OSEIA state that, while they agree in principle that competition should be the motivating force in energy markets, their experience shows that utility-sponsored RFP programs often fall far short of genuine competition.[982]

653. Public Interest Organizations state that Order No. 688–A specifies that demonstrating that a market offers ''a meaningful opportunity to sell'' usually requires evidence of QF transactions, which is not possible with a market hub.[983] Public Interest Organizations argue that market hubs are not equivalent to PURPA section 210(m)(1)(A) or (B) markets because, unlike an independently administered auction, there is no guarantee that a QF will be able to sell their energy even if it is the lowest cost resource.[984]

654. Public Interest Organizations further contend that the Commission does not have the authority to approve RFPs or liquid market hubs as PURPA section 210(m)(1)(C) wholesale markets because they are not of comparable qualify to Day 1 or Day 2 markets, *i.e.,* to PURPA section 210(a)(1)(A) or (B) markets.[985]

ii. Comments in Support

655. Several commenters support allowing competition to be an alternative to the mandatory purchase obligation.[986] ELCON supports competitive procurements that exempt industrial self-supply.[987]

656. APPA supports the Commission reviewing factors that would determine if a market is competitive and comparable to PURPA sections 210(m)(1)(A) and (B).[988] Xcel proposes that the PURPA section 210(m)(1)(C) test should evaluate whether market players have a reasonable opportunity to participate in the market, rather than whether the type of market is similar to PURPA section 210(m)(1)(A) and (B) markets.[989] A few commenters requested a technical conference to identify the criteria for determining what processes are competitive.[990] Colorado Independent Energy would like the RFP standard for PURPA section 210(m)(1)(C) status to be higher than for QF pricing and include evaluation of bid data and the modeling process to show the absence of bias against renewable and cogeneration

[973] *See Cedar Creek Wind LLC,* 137 FERC ¶ 61,006, at PP 35–36 n.62 (2011) (stating that courts have recognized negotiations regarding terms that parties to the negotiations intend to become finalized or written contract, may in some circumstances result in legally enforceable obligations on those parties notwithstanding the absence of a writing). *See generally Burbach Broadcasting Co. of Delaware* v. *Elkins Radio Corp.,* 278 F.3d 401, 407–09 (4th Cir. 2002); *Adjustrite Systems, Inc.* v. *GAB Business Serv., Inc.,* 145 F.3d 543, 550 (2d Cir. 1998); *Miller Constr. Co.* v. *Stresstek,* 697 P.2d 1201, 1202–04 (Idaho 1985).); *see also JD Wind 1, LLC,* 129 FERC ¶ 61,148 at P 25; *Grouse Creek Wind Park, LLC,* 142 FERC ¶ 61,187 at PP 40–41.

[974] NOPR, 168 FERC ¶ 61,184 at P 131 (citing NARUC Supplemental Comments, Docket No. AD16–16–000 (filed Oct. 17, 2018)).

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

[976] *Id.* P 132 (citing 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)).

[977] *Id.* P 133.

[978] Allco Comments at 17–19; Public Interest Organizations Comments at 90.

[979] ELCON Comments at 19.

[980] Solar Energy Industries Comments at 24 (citing Solar Energy Industries, Supplemental Comments, Docket No. AD16–16–000, at 10–37, 40–58 (filed Aug. 28, 2019)).

[981] Public Interest Organizations Comments at 93.

[982] NIPPC, CREA, REC, and OSEIA Comments at 66.

[983] Public Interest Organizations Comments at 92 (citing Order No. 688–A, 119 FERC ¶ 61,305 at P 38).

[984] *Id.*

[985] *Id.* at 90–91.

[986] Advanced Energy Economy Comments at 12; APPA Comments at 29; Colorado Independent Energy Comments at 7; Xcel Comments at 11.

[987] ELCON Comments at 19.

[988] APPA Comments at 26–29.

[989] Xcel Comments at 11.

[990] Advanced Energy Economy Comments at 13; ELCON Comments at 19.

projects and likewise the absence of bias for utility self-build projects.[991]

657. Arizona Public Service agrees with NARUC that the Commission should allow utilities to rely on RFPs to establish eligibility to terminate the utility's purchase obligation pursuant to PURPA section 210(m)(1)(C). Arizona Public Service believes this proposal is one way a utility could demonstrate that a market is of comparable competitive quality to the markets described in PURPA sections 210(m)(1)(A) and (B).[992]

658. APPA argues that market hubs should be considered as possibly comparable, particularly to PURPA section 210(m)(1)(B), which requires that QFs have access to Commission-approved transmission service and competitive wholesale markets for long and short-term capacity and energy sales.[993] APPA highlights the Commission finding that the Mid-Columbia and Palo Verde hubs have sufficient liquidity to find just and reasonable rates and adds that an empirical test of market liquidity could be created.[994]

c. Commission Determination

659. In this final rule, we affirm that we will consider utility proposals to terminate the purchase obligation pursuant to PURPA section 210(m)(1)(C) on a case-by-case basis, including utility proposals based on competitive solicitations or liquid market hubs.

660. In response to Public Interest Organizations, as explained above in Section IV.A.1, PURPA section 210(m) obligates the Commission to grant any request to terminate a utility's obligation to purchase from a QF with nondiscriminatory access to the specified markets that satisfy that provision. Whether any particular market is of comparable quality to a Day 1 or Day 2 market necessarily must be determined in the context of an individual case.

661. We refrain from outlining here an exhaustive list of factors that will be used in any such case-by-case evaluation, but at a minimum we will be guided by the important criteria discussed previously in this rule in section IV.B.8 on the use of competitive solicitations to determine avoided costs.

662. Consistent with our findings and discussion in section IV.B.4 on the use of market hubs to determine avoided cost, the Commission finds that competitive market prices in general should reflect the avoided cost energy rates of utilities with access to such markets in a given region. We will therefore consider, on a case-by-case basis, whether a properly run RFP or competitive acquisition process may also justify termination of the PURPA purchase obligation pursuant to PURPA section 210(m)(1)(C).

H. Legally Enforceable Obligation

1. NOPR Proposal

663. The Commission proposed to add regulatory text in 18 CFR 292.304(d)(3) to require QFs to demonstrate that a proposed project is commercially viable and that 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 proposed to provide that states have flexibility as to what constitutes an acceptable showing of commercial viability and financial commitment.

664. The Commission stated that its objective in requiring a showing of commercial viability and the QF's financial commitment to construct the project was 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. The NOPR proposed that 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. The NOPR stated that these proposed indicia were not intended to be exhaustive and the Commission sought comment on these indicia and others that also might be appropriate for consideration.

665. The Commission stated that it believed requiring QFs to demonstrate their commercial viability and financial commitment to construct the facilities based on such indicia before obtaining a LEO would allow electric utilities to reliably plan their systems while ensuring resource adequacy. Additionally, the development and definition of objective and reasonable factors to determine commercial viability and financial commitment to construct a facility would encourage the development of QFs by providing QFs with more certainty as to when they will obtain a LEO.[995]

2. Comments

a. Comments in Opposition

666. Several commenters oppose the Commission's proposal 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 and that states have flexibility as to what constitutes an acceptable showing of commercial viability and financial commitment, arguing it undermines PURPA's intent to promote QF development.[996]

667. NIPPC, CREA, REC, and OSEIA argue that developers cannot obtain financing without the financial commitment of a PPA or LEO from the utility and therefore requiring financial viability as a condition precedent to obtain a LEO is problematic.[997] Western Resource Councils argues that the NOPR proposal represents an onerous financial and bureaucratic barrier that will lead to a substantial reduction in the number of QFs.[998]

668. Southeast Public Interest Organizations argue that the proposal does not sufficiently narrow the range of divergent LEO tests that have already been adopted by the states and opposes allowing states additional flexibility in establishing criteria up to a fully executed agreement.[999] sPower requests that the Commission establish specific criteria and prohibit states from imposing any additional criteria.[1000] Solar Energy Industries requests that the Commission develop a concrete baseline

[991] Colorado Independent Energy Comments at 6, 11–12.

[992] Arizona Public Service Comments at 8–10.

[993] APPA Comments at 27.

[994] *Id.* at 28.

[995] Because QFs already in operation have necessarily demonstrated a commitment to construct the project, the Commission stated that it 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.

[996] NIPPC, CREA, REC, and OSEIA Comments at 81; Public Interest Organizations Comments at 98; Western Resource Councils Comments at 144.

[997] NIPPC, CREA, REC, and OSEIA Comments at 81.

[998] Western Resource Councils Comments at 144.

[999] Southeast Public Interest Organizations Comments at 43

[1000] sPower Comments at 14.

in determining when a QF is entitled to a purchase contract.

669. Solar Energy Industries and Public Interest Organizations argue that requiring developers to invest additional capital prior to obtaining a LEO will prevent smaller companies who are unable to invest heavily in early state development activity from participating.[1001] Solar Energy Industries argue that it is unjust and unreasonable to require QFs to invest millions of dollars in site control, permit acquisition and interconnection costs in order to secure the opportunity to negotiate with the purchasing utility. For those states that do not willingly disclose their avoided cost rates or methodology, the NOPR's LEO proposal requires QFs to incur substantial expense to establish their commercial viability without a reasonable understanding of what their rate may be.[1002]

670. In striking a balance between interconnection and development risk, Solar Energy Industries proposes that the first prerequisite to a LEO formation be either: (a) The completion of the System Impact Study (or the equivalent in the state interconnection process); or (b) where the utility cannot complete the System Impact Study within a reasonable period of time, one year after tendering an interconnection request to the host utility.[1003] Where a QF has obtained site control, initiated state permitting processes, submitted an interconnection request and associated study deposit, and has been certified through the submission of a Form No. 556, the Commission should find that the QF is eligible to establish a LEO to sell to the purchasing utility, provided that: (1) The QF has received a System Impact Study report (or equivalent) or one year has elapsed since the QF's interconnection request was tendered to the host utility; and (2) the QF commits to achieving commercial operation within 180 days of the completion of all interconnection facilities and network upgrades by the utility.[1004] Solar Energy Industries asserts that QFs would, upon satisfaction of these criteria, be legally entitled to negotiate with the purchasing utility to develop a PPA setting forth the terms and conditions of the purchase, including liability if the QF fails to perform. Projects that reach agreement will proceed according to the terms of the PPA and the purchasing utility can establish milestones with enough financial protection to ensure that ratepayers will not be harmed if the QF fails to begin operations.[1005]

671. American Dams argues that Interconnection Agreements are generally processed far too slowly, a problem that should be addressed by the Commission.[1006]

672. Southeast Public Interest Organizations support the requirement of demonstrating site control, but state that requiring permits can be time-consuming and costly such that pre-financing QFs may not have the resources for the lengthy permitting process, and it is unreasonable to expect a QF to incur these expenses until it has secured a price for its output so that it can in turn secure financing for the project.[1007]

b. Comments in Support

673. Numerous commenters support the NOPR's LEO proposal, asserting that state agencies are better positioned to develop criteria that reflect their unique operational circumstances, resource planning needs and risk appetite.[1008] Several commenters note that the proposed factors provide a reasonable balance between the planning needs of the connecting utility and certainty to QF developers.[1009] Several commenters assert that requiring QFs to demonstrate commercial viability and financial commitment will reduce the reliability or other risks a utility faces by having to plan for its system needs or resource adequacy around a QF that is never developed.[1010]

674. Several commenters agree that the proposed regulations will provide certainty to host utilities and state commissions while decreasing systems impact and associated costs.[1011]

675. Connecticut Authority supports the proposal arguing that the factors included in the NOPR will provide greater certainty and less risk to QF developers and purchasing utilities which is consistent with PURPA's goal of developing renewable resources.[1012] The Chamber of Commerce argues that the proposed factors indicate a developer's good-faith intention to ultimately develop its proposed QF.[1013] The Michigan Commission states that it supports the proposal, currently has a rulemaking and several cases pending regarding LEOs, and appreciates any additional clarity the Commission could provide.[1014]

c. Comments Requesting Modification

676. NIPPC, CREA, REC, and OSEIA request that the Commission: (1) Further define the terms ''commercial viability'' and ''financial commitment'' to avoid litigation; (2) clarify that any changes to the LEO rules will not affect the viability of any executed contract between a developer and utility, regardless of the facility's development status; and (3) clarify that the LEO rules will not preclude nor bar any utility from executing a PPA before the QF may be able to demonstrate compliance with the implementation of LEO rules.[1015]

i. Studies

677. NorthWestern requests that the Commission require more than just the submission of an interconnection application prior to obtaining a LEO in order to demonstrate that the proposal is more than a speculative paper project.[1016] Portland General requests that the Commission allow states to require developers to have completed the first interconnection study.[1017] The South Dakota Commission states that developers should be required to have completed a transmission feasibility study or system impact study with a determination of the interconnection costs the QF would be required to pay prior to obtaining a LEO.[1018] Portland General requests that off-system QFs be required to have completed the first study milestone of the transmission service request.[1019]

678. SC Solar Alliance requests that the Commission adopt a recent South Carolina Commission ruling that a QF should be able to establish a LEO after

[1001] Solar Energy Industries Comments at 41; Public Interest Organization Comments at 80–82.

[1002] Solar Energy Industries Comments at 41.

[1003] *Id.* at 43.

[1004] *Id.*

[1005] *Id.*

[1006] American Dams Comments at 5–6.

[1007] Southeast Public Interest Organization Comments at 43–44.

[1008] Alaska Power Comments at 1–2; APPA Comments at 30; Chamber of Commerce at 8; Colorado Independent Energy Comments at 13; Connecticut Authority Comments at 24–25; Consumer Alliance Comments at 2; Consumers Energy Comments at 5; East Kentucky Comments at 3–4; East River at 2; El Paso Electric Comments at 6–7; Golden Valley Comments at 7–8; Indiana Municipal Comments at 11–12; Institute for Energy Research Comments at 2; Massachusetts DPU Comments at 10; NARUC Comments at 7–8; NIPPC, CREA, REC, and OSEIA Comments at 81; NRECA Comments at 21; North Carolina Commission Staff Comments at 6; Northern Laramie Range Alliance Comments at 3–4; Ohio Commission Energy Advocate Comments at 10; Oregon Commission at 6.

[1009] Alliant Energy Comments at 21; Industrial Energy Consumers Comments at 14–16.

[1010] Duke Energy Comments at 19; EEI Comments at 37.

[1011] Alliant Energy Comments at 21–22; NRECA at 21; Northern Laramie Range Alliance Comments at 3–4.

[1012] Connecticut Authority Comments at 24–25.

[1013] Chamber of Commerce Comments at 8.

[1014] Michigan Commission Comments at 7–8.

[1015] NIPPC, CREA, REC, and OSEIA Comments at 81–83.

[1016] NorthWestern Comments at 15–16.

[1017] Portland General Comments at 20.

[1018] South Dakota Commission Comments at 2.

[1019] Portland General Comments at 20.

receiving a System Impact Study or within one year if a System Impact Study is not provided in a timely manner and that PPA in-service dates must be extended based on interconnection delays.[1020]

ii. Commercial Viability

679. Alliant Energy requests that the Commission consider requiring QF developers to have contracts in place with equipment suppliers and an analysis of interconnections needed.[1021]

680. North Carolina Commission Staff requests that the Commission adopt a North Carolina Commission standard that QFs must (1) commit to sell their power via a written notice of commitment by the earlier of 105 days after submission of an interconnection request or upon receipt of the system impact study, (2) have filed a report of proposed construction, and (3) submitted an interconnection request under the state's interconnection protocol which requires the QF to demonstrate site control.[1022] sPower argues that option contracts should be sufficient to demonstrate site control.[1023]

iii. Financial Viability

681. Portland General and sPower suggest requiring developers to pay a deposit to state commissions to demonstrate financial viability with the amount based on the capacity of the QF and released upon project completion.[1024] Portland General asserts that having to post a deposit encourages developers to perform sufficient due diligence prior to claiming a LEO.[1025]

682. North Carolina Commission Staff argues that, in order to protect ratepayers from QFs gaming the process, any project that backs out of its notice of commitment should only receive as-available rates for two years.[1026]

iv. Rejecting QF Purchases and Expanded Curtailment Rights

683. North Carolina Commission Staff suggests that the Commission update its regulations to allow curtailing QFs when it would be uneconomic for the utility to make such purchases.[1027] The Institute for Energy Research argues that the Commission should allow a utility to reject purchases from QFs if the utility has no need for additional capacity. The Institute for Energy Research states that such need could be determined separately, on an annual basis, a stand-alone basis, or as part of an IRP process.[1028]

3. Commission Determination

684. In this final rule, we adopt the NOPR proposal to require QFs to demonstrate that a proposed project is commercially viable and that 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.[1029] We also affirm that the states have flexibility as to what constitutes an acceptable showing of commercial viability and financial commitment, albeit subject to the criteria being objective and reasonable. We find that requiring a showing of commercial viability and financial commitment, based on objective and reasonable criteria, will 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. At the same time, the criteria ensure that the purchasing utility does not unilaterally and unreasonably decide when its obligation arises. We believe this strikes the right balance for QF developers and purchasing utilities and should encourage development of QFs.

685. Examples of factors a state could reasonably require are that a QF demonstrate that it is in the process of at least some of the following prerequisites: (1) Taking meaningful steps to obtain site control adequate to commence construction of the project at the proposed location and (2) filing an interconnection application with the appropriate entity. The state could also require that the QF show that it has submitted all applications, including filing fees, to obtain all necessary local permitting and zoning approvals. We note that the factors that the state requires must be factors that are within the control of the QF. Thus, we clarify that it is appropriate for states to require a QF to demonstrate that it is in the process of obtaining site control or has applied for all local permitting and zoning approvals, rather than requiring a QF to show that it has obtained site control or secured local permitting and zoning.

686. We agree with Southeast Public Interest Organizations' concerns regarding requiring QFs to obtain permits in order to determine commercial viability. In some regions the permitting and zoning process can be lengthy and expensive, making obtaining the permits and zoning changes a condition to a LEO unreasonable. Therefore, instead of requiring a QF to have secured local permitting and zoning, states can require QFs to have applied for all of the necessary permits and zoning variances, including the payment of all necessary fees, as a factor in demonstrating the QF's commercial viability. States may require a showing that such applications have been submitted to the relevant regulatory bodies (including payment of the application fees).

687. Several commenters argue that requiring QFs to demonstrate financial viability prior to obtaining a LEO is problematic because QFs need a LEO to obtain financing.[1030] However, demonstrating the required financial commitment does not require a demonstration of having obtained financing. Requiring QFs to, for example, apply for all relevant permits, take meaningful steps to seek site control, or meet other objective and reasonable milestones in the QF's development can sufficiently demonstrate QF developers' financial commitment in the QF development and allows utilities to reasonably rely on the LEO in planning for system resource adequacy. Obtaining a PPA or financing cannot be required to show proof of financial commitment.

688. The intent of these factors is to provide a reasonable balance between providing QFs with objective and transparent milestones up front that are needed to obtain a LEO, allowing states the flexibility to establish factors that address the individual circumstances of each state, and increasing utilities' ability to accurately plan their systems.[1031] Establishing objective and reasonable factors is intended to limit the number of unviable QFs obtaining LEOs and unnecessarily burdening utilities that currently have to plan for QFs that obtain a LEO very early in the process but ultimately are never developed.[1032] In adopting this provision, the Commission is raising the bar to prevent speculative QFs from obtaining LEOs, and the associated burden on purchasing utilities, but is

[1020] SC Solar Alliance Comments at 15.

[1021] Alliant Energy Comments at 22.

[1022] North Carolina Commission Staff Comments at 6.

[1023] sPower Comments at 15.

[1024] Portland General Comments at 15–16; sPower Comments at 14–15.

[1025] Portland General Comments at 20–21.

[1026] North Carolina Commission Staff Comments at 6.

[1027] *Id.* at 8.

[1028] Institute for Energy Research Comments at 2–3.

[1029] NOPR, 168 FERC ¶ 61,184 at P 140.

[1030] NIPPC, CREA, REC, and OSEIA Comments at 81; Western Resource Council Comments at 144.

[1031] Alliant Energy Comments at 21; Industrial Energy Consumers Comments at 14–16.

[1032] Duke Energy Comments at 19; EEI Comments at 37.

not establishing a barrier for financially committed developers seeking to develop commercially viable QFs.

689. We disagree that establishing reasonable, transparent factors is an onerous barrier or will cause a substantial reduction of QFs. The objective and reasonable criteria we have established will protect QFs against onerous requirements for a LEO that hinder financing, such as a requirement for a utility's execution of an interconnection agreement [1033] or power purchase agreement,[1034] or requiring that QFs file a formal complaint with the state commission,[1035] or limiting LEOs to only those QFs capable of supplying firm power,[1036] or requiring the QF to be able to deliver power in 90 days.[1037] We find that, by making clear that such conditions are not permitted, and by providing objective criteria to clarify when a LEO commences, the LEO provisions we have adopted will encourage the development of QFs.

690. For those commenters that requested that the Commission establish specific factors for the states to apply, or to establish a baseline for eligible factors, or to otherwise limit states' flexibility, we decline to do so. Since its inception, the Commission's PURPA Regulations have established rules and defined boundaries allowing states flexibility within those boundaries in implementing PURPA as appropriate for each state. As commenters noted, this allows states to address their unique circumstances and best address each states' needs. Furthermore, existing precedent establishes a baseline [1038] and this final rule's requirement that states adopt objective and reasonable criteria for determining when a QF has obtained a LEO provides additional safeguards (in addition to that baseline) applicable to both QFs and utilities. Similarly, regarding Solar Energy Industries' proposed pre-requisites and factors, for the reasons stated above, we find that states are in the best position to determine what specific factors would best suit the specific circumstances of that state, so long as they are objective and reasonable, and we provide the suggested prerequisites above as examples of objective and reasonable factors.[1039] While Solar Energy Industries' proposed criteria may be reasonable, we decline to mandate specific terms for the entire country.

691. Contrary to Solar Energy Industries' assertions, nothing in this final rule limits a QF developer's or utility's ability to negotiate rates, terms or conditions.[1040]

692. With regard to the argument that the NOPR's LEO proposal is unreasonable in states that do not disclose their avoided cost rate because it would require QFs to incur substantial expense to establish commercial viability without a reasonable understanding of the purchase rate, we find that such state-specific implementation issues can be addressed case-by-case. To the extent that entities believe that a particular state's avoided cost rates or rate setting methodologies do not provide sufficient transparency to support a QF's ability to make reasonable commercial viability investment decisions, such entities could file a petition for enforcement against the state at the Commission and, if the Commission declines to act, later file a petition against the state in U.S. district court (pursuant to PURPA section 210(h)(2)(B)).

693. NIPPC, CREA, REC, and OSEIA request that we further define the terms commercial viability and financial commitment. We decline. As discussed above, we believe the best course is to allow states the flexibility (employing objective and reasonable factors) to determine what constitutes commercial viability and financial commitment relative to the unique conditions or circumstances in each state but also recognizing that existing Commission precedent establishes boundaries of what would be considered reasonable and not discriminatory limits for requirements in establishing a LEO.[1041]

694. Additionally, we clarify that any changes to the LEO rules adopted herein do not affect the viability of any executed contract or LEO between a QF developer and utility in place as of the effective date of this final rule, regardless of the facility's development status. Further we clarify that nothing in the LEO rules adopted herein precludes any utility from choosing to execute a PPA before a QF has demonstrated compliance with the LEO rules adopted here.

Several commenters requested that the Commission require QFs to do more than just file an interconnection application; instead, for example, suggesting requiring completion of system impact study, interconnection or transmission feasibility study.[1042] We disagree. The approach taken here recognizes the need for a QF to demonstrate that its project is more than mere speculation, such that it is reasonable for a utility to consider the resource in its planning projections. A QF that has submitted an application for interconnection, as well as having taken meaningful steps to obtain site control and has applied for all relevant permits, while not a guarantee that the project will be completed, are all objective and reasonable indicators that the QF developer is seriously pursuing the project and has spent time and resources in developing the project to show a financial commitment. As numerous commenters have explained, QFs need a LEO in order to obtain financing to complete the project, and we find that, as an illustrative example, requiring the submission of an interconnection request (as opposed to the completion of a system impact study or transmission feasibility study) as one criteria strikes an appropriate balance between the competing needs.

695. Moreover, it bears remembering that the concept of a LEO was specifically adopted to prevent utilities from circumventing the mandatory purchase requirement under PURPA by refusing to enter into contracts.[1043] The Commission thus has found that requiring a QF to have a utility-executed contract or interconnection agreement, or requiring the completion of a utility-controlled study places too much control over the LEO in the hands of the utility and defeats the purpose of a LEO and is inconsistent with PURPA.[1044] When reviewing factors to demonstrate commercial viability and financial commitment, states thus should place emphasis on those factors that show that the QF has taken meaningful steps to

[1033] *See, e.g., FLS Energy, Inc.,* 157 FERC ¶ 61,211, at P 26 (2016) (*FLS*) (stating that requiring signed interconnection agreement as prerequisite to LEO is inconsistent with PURPA Regulations).

[1034] *See, e.g., 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 LEO is inconsistent with PURPA Regulations.

[1035] *See, e.g., Grouse Creek Wind Park, LLC,* 142 FERC ¶ 61,187, at P 40 (2013).

[1036] *Exelon Wind 1, L.L.C.* v. *Nelson,* 766 F.3d 380, 400 (5th Cir. 2014).

[1037] *Power Resource Group, Inc.* v. *Public Utility Com'n of Texas,* 422 F.3d 231, (5th Cir. 2005).

[1038] For example, 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. *See FLS,* 157 FERC ¶ 61,211 at P 26; *Cedar Creek Wind LLC,* 137 FERC ¶ 61,006 at P 35.

[1039] *See supra* P 685.

[1040] *See* 18 CFR 292.301(b).

[1041] *See FLS,* 157 FERC ¶ 61,211 at P 26; *Cedar Creek Wind LLC,* 137 FERC ¶ 61,006 at P 35.

[1042] NorthWestern Comments at 15–16, Portland General Comments at 20, South Dakota Commission Comments at 2.

[1043] *JD Wind 1, LLC,* 129 FERC ¶ 61,148 at P 25, *reh'g denied,* 130 FERC ¶ 61,127 (citing Order No. 69 FERC Stats. & Regs. ¶ 30,128 at 30,880; *see also Midwest Renewable Energy Projects, LLC,* 116 FERC ¶ 61,017 (2006).

[1044] *FLS,* 157 FERC ¶ 61,211 at P 23 (finding such requirements ''allows a utility to control whether and when a legally enforceable obligation exists—*e.g.* by delaying the facilities study.'').

develop the QF that are within the QF's control to complete, and not on those factors that a utility controls. For example, requiring a QF to make a deposit as Portland General and sPower proposed or whether the QF has applied for system impact, interconnection or other needed studies are the types of factors that may show that the QF has taken meaningful steps to develop the QF that are within the QF's control and the type of objective and reasonable standards that states can consider in their implementation.[1045]

696. Requests by parties to expand utilities' rights to curtail QF sales are outside the scope of this proceeding. Additionally, requests to allow a utility to reject purchases from QFs if a utility has no need for additional capacity are outside the scope of this proceeding.

V. Information Collection Statement

697. The Paperwork Reduction Act [1046] 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 10 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).[1047] 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: The Commission is revising its regulations implementing PURPA. At the Notice of Proposed Rulemaking (NOPR) stage, the Commission stated the principal changes that affect information collection involved the FERC Form No. 556.[1048] In response to comments arguing that the NOPR proposals would cause additional reporting burdens, in this final rule we have analyzed whether there are additional incremental reporting burdens that result from other aspects of this final rule. As described further below, we find that there is one additional potential reporting burden arising from this final rule. It relates to reducing the PURPA section 210(m) rebuttable presumption regarding small power production QFs' nondiscriminatory access to certain markets from 20 MW to 5 MW. Specifically, this reporting burden would arise from electric utilities located in markets who choose to submit to the Commission a PURPA section 210(m) petition for termination of the PURPA mandatory purchase obligation (affecting information collection FERC–912) for small power production QFs between 20 MW and 5 MW.

698. With respect to the FERC Form No. 556, the Commission affirms that the relevant burdens derive from the change from the Commission's current "one-mile rule" for determining whether generation facilities should be considered to be at the same site for purposes of determining qualification as a qualifying small power production facility, to allowing an interested person or other entity challenging a QF certification the opportunity to file a protest, without a fee, to rebut the presumption that affiliated small power production QFs using the same energy resource and located more than one mile and less than 10 miles from the applicant facility are considered to be at separate sites.

Specifically, as more fully explained in section IV.F above, and as demonstrated by the revised Form No. 556 attached to this final rule (but not published in the **Federal Register** or Code of Federal Regulations),[1049] the Commission makes the following changes to the FERC Form No. 556 which affect the burden of the information collection:

- Allow an interested person or other entity challenging a QF certification the opportunity to file a protest, without a fee, to an initial certification (both self-certification and application for Commission certification) filed on or after the effective date of this final rule, or to a recertification (self-recertification or application for Commission recertification) that makes substantive changes to the existing certification that is filed on or after the effective date of this final rule.
- Require *all* applicants to report the applicant facility's geographic coordinates, rather than only for applications where there is no street address.
- Change the current requirement to identify *any* affiliated facilities with electrical generating equipment within one mile of the applicant facility's electrical generating equipment to instead require applicants to list only affiliated small power production QFs using the same energy resource one mile or less from the applicant facility.
- Additionally require applicants to list affiliated small power production QFs using the same energy resource whose nearest electrical generating equipment is greater than one mile and less than 10 miles from the electrical generating equipment of the applicant facility.
- Require the applicant to list the geographic coordinates of the nearest "electrical generating equipment" of both its own facility and the affiliated small power production QF in question based on the definitions adopted in this final rule.
- Provide space for the applicant to explain, if it chooses to do so, why the affiliated small power production QFs using the same energy resource, that are more than one mile and less than 10 miles from the electrical generating equipment of the applicant facility, should be considered to be at separate sites from the applicant's facility, considering the relevant physical and ownership factors identified in this final rule.

As explained in the body of this final rule, these changes in burden are appropriate because they are necessary to meet the statutory requirements contained in PURPA.

699. In this final rule, the Commission is revising its regulations implementing PURPA, which will affect the information collections for the FERC Form No. 556 and FERC–912. Below, the first table includes estimated changes to the burden and cost of the FERC Form No. 556 due to the final rule. As demonstrated by the table, we believe that QFs will spend more time to identify any affiliated small power production QFs that are less than one mile, between one and 10 miles, and more than 10 miles, apart. The Commission expects that there will be an increase due to the revisions to the Commission's regulations, and that the changes to the "one-mile rule" and the ability to protest without a fee will affect self-certifications and applications for Commission certification.

[1045] Portland General Comments at 15–16; sPower Comments at 14–15.

[1046] 44 U.S.C. 3501–21.

[1047] *See* 5 CFR 1320.11.

[1048] The change to the FERC–556 described by the NOPR was submitted under a temporary interim information collection no., FERC–556A (OMB Control No. 1902–0316) because another item for FERC–556 was pending OMB review at the time and only one item per OMB Control No. can be pending OMB review at a time. The final rule is being submitted to OMB under FERC–556.

[1049] The Form 556 and instructions will be available in the Commission's eLibrary.

FERC–556, CHANGES DUE TO FINAL RULE IN DOCKET NOS. RM19–15–000 AND AD16–16–000 [1050]

Facility type	Filing type	Number of respondents (1)	Annual number of responses per respondent (2)	Total number of responses (1) * (2) = (3)	Increased average burden hours and cost per response ($) (4)	Increased total annual burden hours and total annual cost ($) (3) * (4) = (5)	Increased annual cost per respondent ($) (5) ÷ (1 = (6)
Cogeneration and Small Power Production Facility ≤ 1 MW [1051].	Self-certification ...	no change (692) ..	no change (1.25)	no change (865) ..	no change (1.5 hrs.); $0.	no change (1,297.5 hrs.); $0.	0
Cogeneration Facility > 1 MW.	Self-certification ...	no change (63)	no change (1.25)	no change (78.75)	no change (1.5 hrs.); $0.	no change (118.125 hrs.); $0.	0
Cogeneration Facility > 1 MW.	Application for FERC certification.	no change (1)	no change (1.25)	no change (1.25)	no change (50 hrs.); $0.	no change (62.5 hrs.); $0.	0
Small Power Production Facility > 1 MW, ≤ 1 Mile from Affiliated Small Power Production QF.	Self-certification ...	no change (899) [1052].	no change (1.25)	no change (1,123.75).	2 hrs.; $166	2,247.5 hrs.; 186,542.5.	207.5
Small Power Production Facility > 1 MW, ≤ 1 Mile from Affiliated Small Power Production QF.	Application for FERC certification.	no change (0)	no change (1.25)	no change (0)	6 hrs.; $498	no change (0 hrs.); $0.	0
Small Power Production Facility > 1 MW, > 1 Mile, < 10 Miles from Affiliated Small Power Production QF.	Self-certification ...	no change (900) ..	no change (1.25)	no change (1,125)	8 hrs.; $664	9,000 hrs.; $747,000.	830
Small Power Production Facility > 1 MW, > 1 Mile, < 10 Miles from Affiliated Small Power Production QF.	Application for FERC certification.	no change (0)	no change (1.25)	no change (0)	12 hrs.; $996	no change (0 hrs.); $0.	0
Small Power Production Facility > 1 MW, ≥ 10 Miles from Affiliated Small Power Production QF.	Self-certification ...	no change (899) ..	no change (1.25)	no change (1,123.75).	2 hrs.; $166	2,247.5 hrs.; $186,542.5.	207.5
Small Power Production Facility > 1 MW, ≥ 10 Miles from Affiliated Small Power Production QF.	Application for FERC certification.	no change (0)	no change (1.25)	no change (0)	6 hrs.; $498	no change (0 hrs.); $0.	0
FERC–556, Total Additional Burden and Cost Due to Final Rule.	....	no change (3,454)	....	no change (4,317.5).	....	13,495 hrs.; $1,120,085.	....

700. The table below reflects the additional estimated public reporting burdens associated with reducing the PURPA section 210(m) rebuttable presumption regarding small power production QFs' nondiscriminatory access to certain markets from 20 MW to 5 MW, which affects the FERC–912.[1053] The FERC–912 is optional, but if electric utilities located in relevant markets choose to submit to the

[1050] The figures in this table reflect estimated changes to the current OMB-approved inventory for the FERC Form No. 556 (approved by the Office of Management and Budget (OMB) on November 18, 2019).

Where ''no change'' is indicated, the current figure is included parenthetically for information only. Those parenthetical figures are not included in the final total for column 5.

Commission staff believes that the industry is similarly situated in terms of wages and benefits. Therefore, cost estimates are based on FERC's 2020 average hourly wage (and benefits) of $83.00/hour. (The submittal to and approval of OMB in 2019 for FERC Form No. 556 was based on FERC's 2018 average annual wage hourly rate of $79.00/hour. Because the change from the $79.00 hourly rate to the current $83.00 hourly rate was not due to the final rule, this chart does not depict this increase.)

[1051] Not required to file.

[1052] In the FERC Form No. 556 approved by OMB in 2019, for the category ''Small Power Production Facility > 1 MW, Self-certification,'' we estimated the number of respondents at 2,698. We have now divided that category into three categories: ''Small Power Production Facility > 1 MW, ≤ 1 Mile from Affiliated Small Power Production QF,'' ''Small Power Production Facility > 1 MW, > 1 Mile, < 10 Miles from Affiliated Small Power Production QF,'' ''Small Power Production Facility > 1 MW, ≥ 10 Miles from Affiliated Small Power Production QF.'' In this column, the numbers 899, 900, and 899 are a distribution of those same estimated 2,698 respondents across the three categories.

[1053] This information was not included in the burden estimates in the NOPR.

Commission a PURPA section 210(m) petition for termination of the PURPA mandatory purchase obligation for small power production QFs between 20 MW and 5 MW, then we would expect the following burdens and cost estimates to apply.

FERC–912, CHANGES DUE TO FINAL RULE IN DOCKET NOS. RM19–15–000 AND AD16–16–000

(Termination of obligation to purchase)	Number of respondents (1)	Annual number of responses per respondent (2)	Total number of responses (1) × (2) = (3)	Increased average hours and cost per response ($) (4)	Increased total annual burden hours and total annual cost ($) (3) * (4) = (5)	Increased annual cost per respondent (at $83/hr.) (5)/(1) = (6)
Electric utility burden of reducing 210(m) rebuttable presumption from 20 MW to 5 MW [1054].	30	1	30	12 hrs.; $996	360 hrs.; $29,880	$996
Total	30	1	30	12 hrs.; $996	360 hrs.; $29,880	996

Title: FERC–556 (Certification of Qualifying Facility (QF) Status for a Small Power Production or Cogeneration Facility), and FERC–912 (PURPA Section 210(m) Notification Requirements Applicable to Cogeneration and Small Power Production Facilities).

Action: Revisions to existing information collections FERC–556 and FERC–912.

OMB Control No.: 1902–0075 (FERC–556) and 1902–0237 (FERC–912).

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; electric utilities filing to terminate their obligation to purchase, at avoided cost rates, the output of small power production QFs between 5 MW and 20 MW.

Frequency of Information: Ongoing.

Necessity of Information: The Commission directs the changes in this final rule revising its implementation of PURPA in order to continue to meet PURPA's statutory requirements.

Internal Review: The Commission has reviewed the 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.

701. 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* or by phone (202) 502–8663].

Please send comments concerning the collection of information and the associated burden estimates to: Office of Information and Regulatory Affairs, Office of Management and Budget [Attention: Federal Energy Regulatory Commission Desk Officer]. Due to security concerns, comments should be sent directly to *www.reginfo.gov/public/do/PRAMain.* Comments submitted to OMB should be sent within 30 days of publication of this notice in the **Federal Register** and should refer to FERC–556 (OMB Control No. 1902–0075) and FERC–912 (OMB Control No. 1902–0237).

VI. Environmental Analysis

702. The Commission in the NOPR explained that it was not possible to determine the environmental effects of the changes proposed, given the numerous uncertainties regarding the potential effects of the changes proposed. The Commission in the NOPR stated that, given these uncertainties, the National Environmental Policy Act of 1969 (NEPA) [1055] does not require that the Commission conduct an environmental review of the proposed revised PURPA Regulations.[1056]

A. Comments

703. Several commenters argue that the Commission erred in failing to conduct such a review.[1057]

704. Biological Diversity asserts an urgent need to take measures to reduce greenhouse gas emissions to address climate change.[1058] Biological Diversity states that the Commission's rationale for revising the PURPA Regulations, namely the increased availability of ''fossil gas,'' requires the Commission to consider the reasonably foreseeable impacts on climate and the environment, including on threatened and endangered species, in order to fulfill its responsibilities under NEPA and the Endangered Species Act (ESA).[1059] Biological Diversity includes a list of what it alleges are reasonably foreseeable impacts from increased use of ''fossil gas.'' [1060] Biological Diversity maintains that the proposed revised PURPA Regulations would prevent renewable energy development and lock in ''fossil gas'' development and supply, thereby requiring the Commission to prepare an environmental impact statement and to obtain a biological opinion before proceeding to a final rule.[1061]

705. NIPPC, CREA, REC, and OSEIA state that ''the Commission must, at a minimum, complete the requisite scoping and other process associated with an EA and then revise and reissue, or abandon, the NOPR after considering the issues developed in the EA.'' [1062] NIPPC, CREA, REC, and OSEIA argue that it would not be too speculative for the Commission to undertake a NEPA analysis.[1063] NIPPC, CREA, REC, and OSEIA state that it is possible to study the environmental effects of the NOPR proposals because the Commission undertook a NEPA analysis when it first implemented PURPA, imposing a moratorium on certifying cogeneration facilities as QFs until it completed an

[1054] The staff estimates a total of 90 discretionary responses may be submitted in Years 1–3, with an annual average of 30.

[1055] 42 U.S.C. 4321 *et seq.*

[1056] NOPR, 169 FERC ¶ 61,184 at PP 154–55.

[1057] Allco Comments at 21–22; Biological Diversity Comments at 14; NIPPC, CREA, REC, and OSEIA Comments at 83; Public Interest Organizations Comments at 21.

[1058] Biological Diversity Comments at 2–7.

[1059] *Id.* at 14.

[1060] *Id.* at 15–17.

[1061] *Id.* at 17.

[1062] NIPPC, CREA, REC, and OSEIA Comments at 83–85 (citing, *e.g.,* 42 U.S.C. 4332(A); 18 CFR 380.5, 380.4, 380.11; 40 CFR 1500.1, 1502.5; *LaFlamme* v. *FERC,* 852 F.2d 389, 397 (9th Cir. 1988); *Am. Bird Conservancy, Inc.* v. *FCC,* 516 F.3d 1027, 1033–34 (D.C. Cir. 2008); *N. Plains Res. Council, Inc.* v. *Surface Transp. Bd.,* 668 F.3d 1067, 1075 (9th Cir. 2011) (*N. Plains Res. Council*)).

[1063] NIPPC, CREA, REC, and OSEIA Comments at 92–94 (citing, *e.g., Am. Bird Conservancy, Inc.* v. *FCC,* 516 F.3d 1033); *N. Plains Res. Council,* 668 F.3d at 1076, 1078–79.

Environmental Impact Statement (EIS) and recognizing the environmental benefits from encouraging the development of QFs, and also studied the environmental impacts for Order No. 888.[1064]

706. Public Interest Organizations state that the Commission must prepare an Environmental Assessment (EA) in order to support its position that this rulemaking may not have any significant foreseeable environmental impacts.[1065] Public Interest Organizations describe the NOPR's ''cursory treatment of the Commission's environmental review obligations'' as undermining NEPA's purposes ''that agencies give due consideration to environmental impacts when making major environmental decisions, and guaranteeing that the public is informed of such impacts.''[1066] Public Interest Organizations argue that states' exercise of new flexibility granted by the proposed revised PURPA Regulations are reasonably foreseeable indirect and cumulative impacts that the Commission must study. Public Interest Organizations assert that the Commission likely will ''need to prepare a full EIS to evaluate the serious environmental impacts that will result from dismantling regulations that continue to play an important role in development of renewable generation resources across the country.''[1067]

707. NIPPC, CREA, REC, and OSEIA argue that the Commission has failed to explain how eliminating the market for at least 10% to 20% of renewable energy facilities would have no impact on the human environment.[1068] NIPPC, CREA, REC, and OSEIA contend that the Commission has failed to analyze how the proposals would impact regions like the Northwest that lack robust implementation of PURPA, the 21 states without renewable power standards (such as the Idaho, whose Legislature affirmatively refused to adopt a renewable power standard), or the one third of the country that is not located in an RTO or ISO.[1069]

708. Allco argues that it is reasonably foreseeable that the proposed revisions to the PURPA Regulations and resulting increased fossil fuels use could add significant levels of greenhouse gas emissions to the atmosphere and endanger the climate.[1070] The effects of such endangerment to the climate from fossil fuel use and reduced renewable energy QF generation, according to Allco, include mass extinction of species, in violation of the ESA.[1071] Allco contends that the Commission's failure to consult with the U.S. Fish and Wildlife Service and the National Marine Fisheries Service (collectively, the Services) prior to issuing the NOPR constituted a violation of its obligations under the ESA, ''to insure that its actions are not likely to jeopardize the continued existence of endangered or threatened species, or result in the destruction or adverse modification of critical habitat.''[1072]

709. According to Allco, the PURPA NOPR triggered the ESA's consultation requirement because the proposed changes will increase fossil fuel generation that will, in turn, displace ''over 2 [terawatts (TWs)] of solar generation over the next 20 years as compared to the baseline scenario of application and faithful adherence to existing PURPA rules.''[1073] Allco alleges that increased fossil-fuel generation will ''increase land and ocean temperatures above what they would have been, . . . resulting in increased pollution to the waters of the United States, and harming federally endangered and threatened species, including, without limitation, the Piping plover and the Right whale.''[1074]

B. Commission Determination

710. We find that no EA or EIS of the final rule is required. NEPA requires federal agencies to prepare a detailed statement on the environmental impact of ''major Federal actions significantly affecting the quality of the human environment.''[1075] The Council on Environmental Quality's (CEQ) regulations implementing NEPA provide that federal agencies can comply with NEPA by preparing: (a) An Environmental Impact Statement (EIS); or (b) an Environmental Assessment (EA) to determine whether the proposed action significantly affects the quality of the human environment and requires the preparation of an EIS.[1076] CEQ regulations also state that federal agencies are not obligated to prepare either an EIS or an EA if they find that a categorical exclusion applies.[1077] Additionally, courts have held that an EIS or EA is not required under NEPA ''unless there is a particular project that 'define[s] fairly precisely the scope and limits of the proposed development.' ''[1078]

711. No EA or EIS of the final rule is required because, as discussed below, the final rule does not propose or authorize, much less define, the scope and limits of any potential energy infrastructure and, as a result, there is no way to determine whether issuance of the rule will significantly affect the quality of the human environment. In the alternative, a categorical exclusion applies so that an EA or EIS need not be prepared. For similar reasons, there is no requirement that the Commission engage in consultation pursuant to the ESA with respect to this action.

1. No EIS or EA Is Required

a. There Is No Project That Defines the Scope and Limits of QF Development

712. In *Center for Biological Diversity,* the court held that no NEPA review was required with respect to actions taken by the United States Forest Service that were similar in all relevant respects to the action taken here by the Commission in promulgating the final rule. That case involved the designation by the Forest Service, pursuant to the Healthy Forests Restoration Act (HFRA), of certain forests as ''landscape-scale areas.'' Such designation meant that specific treatments could be proposed to address insect infestation in those designated ''landscape-scale areas.''[1079] The court held that no NEPA review was required for the designations, noting that no specific projects were proposed for any of the landscape-scale areas and stating that ''[i]n such circumstances, 'any attempt to produce an [EIS] would be little more than a study . . . containing estimates of potential development and attendant environmental consequences.' ''[1080] The court concluded that ''unless there is a particular project that 'define[s] fairly

[1064] *Id.* at 94–96.

[1065] Public Interest Organizations Comments at 21.

[1066] *Id.*

[1067] *Id.* at 26.

[1068] NIPPC, CREA, REC, and OSEIA Comments at 86–87.

[1069] *Id.* at 87–88.

[1070] Allco Comments at 31.

[1071] *Id.*

[1072] *Id.* at 34 (quoting 16 U.S.C. 1536(a)(2)) (internal quotations omitted).

[1073] *Id.*

[1074] *Id.* at 34–35.

[1075] 42 U.S.C. 4332(C) (2018); *see also Regulations Implementing the National Environmental Policy Act,* Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[1076] 40 CFR 1501.4 (2019).

[1077] CEQ regulations state that a categorical exclusion ''means a category of actions which do not individually or cumulatively have a significant effect on the human environment and which have been found to have no such effect in procedures adopted by a federal agency in implementation of these regulations and for which, therefore, neither an environmental assessment nor an environmental impact statement is required.'' 40 CFR 1508.4 (2019).

[1078] *Center for Biological Diversity* v. *Ilano,* 928 F.3d 774, 780 (9th Cir. 2019) (*Center for Biological Diversity*) (quoting *Kleppe* v. *Sierra Club,* 427 U.S. 390, 402 (1976)).

[1079] *Center for Biological Diversity,* 928 F.3d at 778.

[1080] *Id.* at 780 (quoting *Kleppe* v. *Sierra Club,* 427 U.S. 390, 402 (1976)).

precisely the scope and limits of the proposed development of the region,' there can be 'no factual predicate for the production of an [EIS] of the type envisioned by NEPA.' '' [1081]

713. Similarly, here, the final rule does not authorize the development or construction of any facilities, but simply addresses the rates that QFs can charge and certain requirements under which proposed facilities may qualify as a QF.[1082] The final rule does not fund any particular QFs, or issue permits for their construction or operation (neither of which the Commission has jurisdiction to do). The Commission does not, in its regulations or in this final rule, authorize or prohibit the use of any particular technology or fuel, nor does it mandate or prohibit where QFs should be or are built. This final rule does not exempt QFs from any Federal, state, or local environmental, siting, or similar laws or regulatory requirements, (again something the Commission has no authority to do).

714. Even with respect to rates, while the Commission has established and here revises the factors and approaches that states can take into account when they set QF rates, it is ultimately the states and not the Commission that set those rates. The final rule continues to give states wide discretion and it is impossible to know what the states may choose to do in response to this final rule, whether they will make changes in their current practices or not, and how those state choices would impact QF development and the environment in any particular state, let along any particular locale.

715. Moreover, the scope of this final rule is even less defined than the landscape-scale area designations at issue in the *Center for Biological Diversity* case. PURPA applies throughout the entire United States, and the revisions implemented by the final rule theoretically could affect future QF development anywhere in the country.

716. While courts have held that NEPA requires ''reasonable forecasting,'' ''NEPA does not require a 'crystal ball' inquiry.'' [1083] Further, 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'' [1084] or to ''foresee the unforeseeable.'' [1085] In that vein, ''[i]n determining what effects are 'reasonably foreseeable,' an agency must engage in 'reasonable forecasting and speculation,' . . . with *reasonable* being the operative word.'' [1086] Environmental impacts are not reasonably foreseeable if the impacts would result only through a lengthy causal chain of highly uncertain or unknowable events.[1087]

717. Commenters' allegations regarding potentially reduced QF development hinge on the claim that the NOPR proposed to ''repeal'' or ''eliminate'' critical PURPA Regulations, which is not true. The Commission proposed in the NOPR, which this final rule generally affirms, to clarify some existing PURPA regulations and modify other PURPA Regulations to make them consistent with the statute, based on changed circumstances since the time those regulations originally were promulgated. Any consideration of whether the revised rules could potentially result in significant new environmental impacts due to less QF development and increased development of coal, nuclear, and combined cycle natural gas plants, would be highly speculative, based on the difficulty in determining which additional flexibilities the final rule provides to the states that each state will adopt, if any; how such state rules would impact QF development going forward; and whether any reduction in QF renewables would be replaced by the much greater amount of non-QF renewable resources with similar environmental characteristics.[1088]

718. As was the case in *Center for Biological Diversity,* any attempt to evaluate the environmental effects of the final rule by necessity would involve nothing less than hypothesizing the potential development of QFs and the resultant environmental consequences. Indeed, any attempt by the Commission to estimate the potential environmental effects of the final rule would be considerably more speculative than the estimates of potential development and attendant environmental consequences that the court in *Center for Biological Diversity* held are not required under NEPA. That case involved limited zones in which some projects to treat insect infestation almost certainly would be proposed. Here, it simply is not possible to provide any reasonable forecast of the effects of the final rule on future QF development, whether any affected potential QF would be a renewable resource (such as solar or wind) or employ carbon-emitting technology (*e.g.,* a fossil-fuel-burning cogenerator or a waste-coal-burning small power production facility). Moreover, environmental effects on land use, vegetation, water quality, etc. are all dependent on location, which are unknown and could be anywhere in the United States.

719. Because, even more so than in *Center for Biological Diversity,* the final rule does not authorize, or define any limit on the scope of, any potential QF or other infrastructure development, any attempt to prepare an analysis of the potential effects of the final rule on future QF development would be so speculative as to render meaningless any environmental analysis of these impacts. Therefore, no such analysis is required by NEPA.

b. A Categorical Exclusion Applies

720. There is a separate and independent alternative reason why no environmental analysis is warranted: the final rule falls within a categorical exclusion promulgated by the Commission pursuant to the CEQ's NEPA regulations.[1089] Specifically, the final rule falls within the categorical exclusion for rules that: (1) Are clarifying in nature, (2) are corrective in nature, (3) are procedural in nature, or (4) do not substantially change the effect of the regulation being amended.[1090] Here, each of the revisions to the PURPA Regulations implemented by the

[1081] *Id.* (quoting *Kleppe,* 427 U.S. at 402); *see also Northcoast Environmental Center* v. *Glickman,* 136 F.3d 660, 668 (9th Cir. 1998) (citing *Kleppe* in support of its holding that NEPA does not require agency to complete environmental analysis where environmental effects are speculative or hypothetical).

[1082] *See Sugarloaf Citizens Ass'n* v. *FERC,* 959 F.2d 508, 514 n.29 (4th Cir. 1992) (finding that in the QF certification context ''FERC does little more than regulate the rates paid by utilities to the qualifying facility and does not control the financing, construction or operation of the project. Although the Facility receives an economic benefit, no direct federal funding or other substantial federal assistance is provided, and no licensing action is involved.'').

[1083] *Vt. Yankee Nuclear Power Corp.* v. *Nat. Res. Def. Council, Inc.,* 435 U.S. 519, 534 (1978) (quoting *Nat. Res. Def. Council, Inc.* v. *Morton,* 458 F.2d 827, 837 (D.C. Cir. 1972)).

[1084] *N. Plains Res. Council* v. *Surface Transp. Board,* 668 F.3d 1067, 1078–79 (9th Cir. 2011) (citation omitted).

[1085] *Concerned About Trident* v. *Rumsfeld,* 555 F.2d 817, 830 (D.C. Cir. 1976) (citation omitted).

[1086] *Sierra Club* v. *U.S. Dep't of Energy,* 867 F.3d 189, 198 (D.C. Cir. 2017) (emphasis in original) (citation omitted).

[1087] *See Dep't of Transp.* v. *Pub. Citizen,* 541 U.S. 752, 767 (2004) (''NEPA requires a 'reasonably close causal relationship' between the environmental effect and the alleged cause.''); *Metro. Edison Co.* v. *People Against Nuclear Energy,* 460 U.S. 766, 774 (1983) (noting effects may not fall within section 102 of NEPA because ''the causal chain is too attenuated'').

[1088] *See infra* VI.B.2.

[1089] CEQ regulations provide that agencies shall issue procedures that provide specific criteria for classes of action which ''normally do not require either an environmental impact statement or an environmental assessment (categorical exclusion)''. 40 CFR 1507.3 (2019).

[1090] *See* 18 CFR 380.4(a)(2)(ii) (categorical exclusion applies to ''promulgation of rules that are clarifying, corrective, or procedural, or that do not substantially change the effect of . . . regulations being amended.'').

final rule fits into one of these categories:

i. Changes That Are Clarifying in Nature

721. Several of the changes to the PURPA Regulations are clarifying in nature. These include the changes clarifying how market prices can be used to set as-available energy rates,[1091] the changes clarifying how fixed energy rates in contracts or LEOs may be determined,[1092] and the changes clarifying how competitive solicitations can be used to set avoided cost rates.[1093] Other non-rate related clarifying revisions in the final rule include a clarification regarding the relationship between avoided costs and decreases in a purchasing utility's load as a consequence of retail competition,[1094] a clarification as to how electric generating equipment should be defined for purposes of determining whether small power production facilities are located at the same site,[1095] and a clarification as to when a LEO is established.[1096]

ii. Changes That Are Corrective in Nature

722. The Commission interprets the categorical exclusion for changes to its regulations that are corrective in nature as including changes needed in order to ensure that a regulation conforms to the requirements of the statutory provisions being implemented by the regulation.[1097] To be clear, the Commission does not find that its existing PURPA Regulations were inconsistent with the statutory requirements of PURPA when promulgated. Rather, the Commission finds that the changes adopted in this final rule are required to ensure continued future compliance of the PURPA Regulations with PURPA, based on the changed circumstances found by the Commission in this final rule.

723. Three aspects of the final rule are corrective in nature. The first is the change allowing states to require variable energy rates in QF contracts.[1098] As the Commission explains above, this change is required based on the Commission's finding that, contrary to the Commission's expectation in 1980, there have been numerous instances where overestimates and underestimates of energy avoided costs used in fixed energy rate contracts have not balanced out, causing the contract rate to not violate the statutory avoided cost rate cap. Giving states the ability to require energy rates in QF contracts to vary based on the purchasing utility's avoided cost of energy at the time of delivery ensures that QF rates do not exceed the avoided cost rate cap imposed by PURPA.[1099]

724. The second corrective aspect is the change in the PURPA Regulations regarding the determination of what facilities are located at the same site for purposes of complying with the statutory 80 MW limit on small power production facilities located at the same site.[1100] As explained above, the Commission found, based on changed circumstances, that the current one-mile rule is inadequate to determine which facilities are located at the same site. Based on this finding, the Commission was obligated by PURPA to revise its definition of when facilities are located at the same site.[1101]

725. The third corrective aspect of the final rule relates to the implementation of PURPA section 210(m). That statutory provision allows purchasing utilities to terminate their obligation to purchase from QFs that have nondiscriminatory access to certain statutorily-defined markets, which the Commission has determined to be the RTO/ISO markets. The final rule revises the presumption in the PURPA Regulations that QFs with a capacity of 20 MW or less do not have non-discriminatory access to such markets, reducing the threshold for such presumption to 5 MW.[1102]

726. The Commission has determined in the final rule that, since the 20 MW threshold was established in 2005, the RTO/ISO markets have matured and the industry has developed a better understanding of the mechanics of market participation. This determination has rendered inaccurate the presumption currently reflected in the PURPA Regulations that QFs 20 MW and below do not have non-discriminatory access to the relevant markets. Once the Commission made this determination, it was appropriate for the Commission to update the 20 MW threshold to comply with the requirements of PURPA section 210(m).[1103]

i. Changes That Are Procedural in Nature

727. The remaining two revisions implemented by the final rule are procedural in nature. The first is a revision to the procedures that apply to QF certification.[1104] The second is a revision to the Commission's Form 556, used by QFs seeking certification.[1105]

2. The NEPA Analysis for Promulgation of the Original PURPA Regulations in 1980 Cannot Be Replicated Here

728. As commenters note, in 1980 the Commission conducted an EA and later an EIS for its initial rules implementing PURPA. Initially, the Commission found (and the Final EIS also found) that new diesel cogeneration, and dual-fuel cogeneration particularly, in New York City, could cause significant environmental effects on air quality.[1106] In Order No. 70–E, however, the Commission ultimately opted to treat such cogeneration the same as all other cogeneration given, among other things, that the PURPA Regulations were not the driving force behind the development of such cogeneration in New York City.[1107] In doing so, the Commission emphasized that QF status was not a license nor a permit to operate but instead only entitled the QF to a rate for purchases and to certain exemptions from regulation. Moreover, QFs were not exempted from any Federal, state, or local environmental, siting or other similar requirements.[1108]

[1091] *See* Sections IV.B.2–5.

[1092] *See* Section IV.B.6.

[1093] *See* Section IV.B.8.

[1094] *See* Section IV.C.

[1095] *See* Section IV.D.2.

[1096] *See* Section IV.H.

[1097] For example, the Commission relied on this categorical exclusion when it revised the PURPA Regulations in 2006 to comply with the amendments to PURPA enacted as part of EPAct 2005. *See Revised Regulations Governing Small Power Production and Cogeneration Facilities,* Order No. 671, 114 FERC ¶ 61,102 at P 118. Further, this interpretation is also consistent with the Supreme Court's holding that NEPA review is not required when an agency's action is required by statute. *See Dep't of Transp.* v. *Pub. Citizen,* 541 U.S. 752, 770 (2004) (''where an agency has no ability to prevent a certain effect due to its limited statutory authority over the relevant actions, the agency cannot be considered a legally relevant ''cause'' of the effect [and] . . . under NEPA and the implementing CEQ regulations, the agency need not consider these effects in its EA.''); *see also Safari Club Intern.* v. *Jewell,* 960 F.Supp.2d 17, 79–80 (D.D.C. 2013) (relying on *Dep't of Transp.* v. *Pub. Citizen* to hold that NEPA review is not required for an agency rule issued to comply with a statutory requirement).

[1098] *See* Section IV.B.7.

[1099] *Id.*

[1100] *See* Section IV.D.

[1101] *See* Section IV.D.1.c.

[1102] *See* Section IV.G.1.

[1103] *Id.*

[1104] *See* Section IV.E.

[1105] *See* Section IV.F

[1106] Final EIS at I–7a.

[1107] *See* Order No. 70–E, 46 FR 33025, 33026 (June 18, 1981).

[1108] *Id.* The Commission stated in its EA that:

The rules provide encouragement to the development of certain types of facilities. They do not prevent any facility which does not qualify from using cogeneration or small power production, or from using any type of fuel. The rules merely grant or deny certain benefits to certain facilities.

In this environmental assessment, the environmental effects of these rules are limited to the effects resulting from the construction and/or operation of facilities which occur as a result of the granting of these benefits, or from changes in the operating characteristics of existing facilities which

729. The original PURPA EA for the pre-existing PURPA Regulations was based on a market penetration study of PURPA-induced facilities. In order to carry out that market penetration study, the original PURPA EA had to make the simplifying assumption that the mere implementation of PURPA would necessarily result in the development and operation of certain types of generation facilities that would not otherwise be developed.[1109] Based on these types of facilities, that EA identified specific resource conflicts related to each type of facility, which were nothing more than a generalized listing of potential impacts.[1110] That EA found that, because the various types of facilities operate differently, there would be no cumulative impacts and this finding, coupled with the geographic distribution of facility development from the market penetration study, resulted in a finding of no significant impact for all types of facilities except diesel and dual-fueled cogeneration facilities in the Mid-Atlantic, which that EA found could cause significant environmental impacts on air quality.[1111]

730. Subsequently, an EIS was prepared that addressed only air quality in New York City and the broader Mid-Atlantic region. The bulk of the EIS focused on how national, state, and local air pollution regimes would address air quality surrounding the construction and operation of such facilities.[1112]

731. Several commenters cite to this previous NEPA analysis conducted in connection with the original PURPA Regulations to support their assertion that a NEPA analysis similarly should be possible for this rulemaking. However, those assertions are undermined by the fact that circumstances have changed significantly since the promulgation of the original PURPA Regulations in 1980. Prior to 1980, essentially no QF generation technologies or other independent generation facilities (other than those used to supply the loads of the owners rather than to sell at wholesale) had been constructed. By contrast, today QF generation technologies and other independent generation facilities are common, and they are predominantly built and operated outside of PURPA.[1113]

732. Because there was virtually no QF or independent power development in 1980, the original PURPA EA could reasonably project that the incentives created by PURPA and the original PURPA Regulations would lead to increased development of power generated by QF technologies. The market penetration study conducted by the Commission, and the Commission's conclusion that the PURPA Regulations could lead to an increase in diesel-fired cogeneration in New York City, were based on these projections.

733. By contrast, it is not possible here to make simplifying assumptions that the mere implementation of the revised regulations necessarily would result in specific changes in the development of particular generation technologies compared to the status quo. First, the revisions to the PURPA regulations are premised on a finding that, even after the revisions, the PURPA regulations will continue to encourage QFs. Consequently, there is no way to estimate whether any reduction in QF development, as opposed to the status quo, will be focused on one or more of the many different types of QF technologies, some of which are renewable resources and some of which are fueled by fossil fuels[1114] and have emissions comparable to non-QF fossil fueled generators. Moreover, because the rule primarily increases state flexibility in setting QF rates, including giving states the option of not changing their current rate-setting approaches, there is no way to develop any estimate of the location or size of any hypothetical reduction in QF development.

734. In addition, as mentioned above, renewable generation technologies today are commonly, and even predominantly, built and operated outside of PURPA. Current projections show that most new generation construction will be of renewable resources.[1115] Indeed, the cost of renewables has declined so much that in some regions renewables are the most cost effective new generation technology available.[1116] Thus, even if the final rule was to result in reduced renewable QF development, there is little likelihood today that hypothetical, unbuilt QFs necessarily would be replaced by new conventional fossil fuel generation.

735. Alternatively, in the absence of these hypothetical, unbuilt QFs, existing generation units—whose current emissions, if any, would already be part of the baseline for any environmental analysis of the impacts of the final rule—might continue to operate without any change in their emissions; in sum, in the absence of these hypothetical, unbuilt QFs, emissions would remain at the baseline and might not increase at all. Indeed, in the current environment where stagnant load growth has prevailed in recent years, this would seem to be a more likely scenario than an alternative where these hypothetical, unbuilt QFs are replaced by brand new fossil fuel generation that would increase emissions over the baseline.

736. Given these facts, it would not be possible to perform a market penetration study of the effects of the final rule that would not be wholly speculative. Without such a study, there could be no analysis defining the types and geographic location of facilities that could serve as the basis for any NEPA analysis similar to that performed in 1980.

3. This Proceeding Does Not Trigger Any ESA Consultation Requirement

737. Similar to our finding that it would be nearly impossible to conduct a meaningful NEPA review, we disagree with Biological Diversity and Allco that either the PURPA NOPR or this final rule trigger any consultation requirement under the ESA.

The ESA requires that agencies consult with the Secretary of the Interior or the Secretary of Commerce to "insure that any action authorized, funded, or carried out by such agency . . . is not likely to jeopardize the continued existence of any endangered species or threatened species or result in the destruction or adverse modification of [critical] habitat of such species."[1117]

738. The ESA regulations require consultation only if the Commission determines that a proposed action may affect listed species or critical habitat.[1118] We find that there are no

results from the granting of these benefits. If a cogeneration or small power production facility would be constructed or operated without the incentives of these rules, the environmental effects resulting therefrom cannot properly be described as environmental effects of these rules. However, a technical and environmental discussion of each technology is provided whether or not its use is expected to be encouraged by these rules.

Small Power Production and Cogeneration Facilities—Environmental Findings; No Significant Impact and Notice of Intent To Prepare Environmental Impact Statement, 45 FR 23661, 23664 (Apr. 8, 1980) (Original PURPA EA).

[1109] *Id.* at 23,665.

[1110] *Id.* at 23,675–82.

[1111] *Id.* at 23,679, 23,682–83.

[1112] Order No. 70–E, 46 FR at 33026.

[1113] *See supra* P 240.

[1114] This would include both cogeneration, which typically is fossil fueled, and those small power production facilities that are fueled by waste, which would include a range of fossil fuel-based waste. *See* 18 CFR 292.202(b), 292.204(b)(1).

[1115] EIA, Annual Energy Outlook 2020, at tbl. 9 (Jan. 29, 2020) (in table see rows labeled Cumulative Planned Additions and Cumulative Unplanned Additions in the reference case) (Annual Energy Outlook 2020), *https://www.eia.gov/outlooks/aeo/.*

[1116] *See supra* P 240.

[1117] 16 U.S.C. 1536(a)(2).

[1118] 50 CFR 402.14(a).

effects from the final rule for which the Commission could consult with the Services. Under the ESA regulations, as recently revised, the effects of an agency's action are

> all consequences to listed species and critical habitat that are caused by the proposed action. A consequence is caused by the proposed action if it would not occur but for the proposed action and *it is reasonably certain to occur.*[1119]

The ESA regulations also state that a consequence is not considered to be caused by a proposed action if ''[t]he consequence is only reached *through a lengthy causal chain that involves so many steps* as to make the consequence not reasonably certain to occur.'' [1120] This determination must be made ''based on clear and substantial information,'' [1121] and ''should not be based on speculation or conjecture.'' [1122] In addition to the above, the same ESA regulation states that factors for the agency to consider when determining whether a consequence is not caused by the proposed agency action include: ''(1) The consequence is so remote in time from the action under consultation that it is not reasonably certain to occur; or (2) [t]he consequence is so geographically remote from the immediate area involved in the action that it is not reasonably certain to occur[.]'' [1123]

739. Because the NOPR was a *proposed* rule that in and of itself had no legal effect, the NOPR is not an agency ''action'' under the regulations implementing the ESA, which define agency action as the ''the *promulgation* of regulations.'' [1124] Because the NOPR did not constitute agency action, the Commission was not required to engage in consultation under the ESA prior to the NOPR's issuance.

740. In this final rule, we are promulgating regulations, which does constitute agency action. Nevertheless, for the same reasons that an environmental review of the impacts of this final rule under NEPA would be impossible to conduct, there is similarly no basis to conclude that harm to endangered species is reasonably certain to occur as a result of this final rule.

741. We find that the effects on endangered and threatened species alleged by Allco are not reasonably certain to occur, not only because any such harm is completely speculative, but also because it could result only through a lengthy causal chain of highly uncertain or unknowable events, none of which are within the Commission's authority to authorize or preclude: (1) That the final rule causes a reduction in the aggregate amount of QF capacity constructed in the future; (2) that any reduction in renewable resource QFs would not be offset by increased construction of renewable resources outside of PURPA, resulting from either other incentive programs or simply the increased cost-competitiveness of such resources; (3) that construction of such non-QF renewable resources would yield an increase in carbon emissions resulting from the reduction in renewable resource QFs that is not offset by other renewable resources; and (4) that such increase in carbon emissions would have an adverse effect on endangered and threatened species. Furthermore, the consequences of this rule would be remote in time and geographically remote because it would require action by individual generators, QF or non-QF, to propose, site, permit, construct, and operate a facility, in underdetermined locations potentially anywhere in the United States. In addition, many of these generators, QF and non-QF, would be subject to state approval and permitting requirements over which the Commission has no control.

742. Further, there is no support in the record for Allco's claim that the changes proposed in the PURPA NOPR would displace over 2 TWs of solar generation over the next 20 years.[1125] Allco provides no citation or other support whatsoever for this assertion but simply makes the claim with no elaboration. We find that such speculation or conjecture provides no basis upon which to either initiate or conduct any meaningful consultation with the Services on the impacts to endangered species from this final rule.

VII. Regulatory Flexibility Act Certification

743. The Regulatory Flexibility Act of 1980 (RFA) [1126] generally requires a description and analysis of 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 rule will not have a significant economic impact on a substantial number of small entities.[1127] The Commission in the NOPR stated that the proposed rule would not significantly impact a substantial number of small entities. Some commenters argue otherwise.[1128]

744. The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[1129] The SBA size standard for electric utilities is based on the number of employees, including affiliates.[1130] 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 [1131] 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.

745. This rule directly affects qualifying small power production facilities and cogeneration facilities, the majority of which the Commission estimates are small businesses. With respect to the changes related to the Form No. 556 and new protests allowed pursuant to this rule, 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. Those revisions may result in additional information being submitted by some small power production QF applicants (especially those with affiliated small power production qualifying facilities using the same energy resource located over one and less than 10 miles away). The Commission estimates that less than 10 percent of QF applications and self-certifications meet these criteria.

[1119] 50 CFR 402.2 (emphasis added).

[1120] 50 CFR 402.17(b)(3) (emphasis added).

[1121] *Id.*

[1122] *Endangered and Threatened Wildlife and Plants; Regulations for Interagency Cooperation,* 84 FR 44976, 44993 (Aug. 27, 2019).

[1123] 50 CFR 402.17(b).

[1124] 50 CFR 402.2 (emphasis added).

[1125] Allco Comments at 34.

[1126] 5 U.S.C. 601–12.

[1127] 5 U.S.C. 605(b).

[1128] *See* Allco Comments at 33.

[1129] 13 CFR 121.101.

[1130] SBA final rule on ''Small Business Size Standards: Utilities,'' 78 FR 77343 (Dec. 23, 2013).

[1131] 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).

746. In the final analysis, the other changes in this final rule [1132] largely impact payments to QFs by electric utilities. More accurate avoided cost rates may result in lower payments from certain electric utilities to certain QFs. In this regard, the final rule provides states greater flexibility than they have today to set the rate that electric utilities will pay QFs, but there is no way to know in advance which new flexibility state regulatory authorities and nonregulated electric utilities will exercise, or what impact that new flexibility might have given the different circumstances likely to apply to each determination of avoided cost. Under the final rule, additionally, states also have the discretion to continue setting the rate as they do today and not to adopt the Commission' proposed greater rate flexibilities. Therefore, it is not possible to estimate what the dollar impact might be. However, because of the way PURPA is structured, whatever the potential dollar impacts of these changes on small QFs may be, to the extent that they reduce the amounts paid to certain QFs, such reductions could be matched dollar-for-dollar by savings experienced by purchasing electric utilities, which should be flowed through to their retail ratepayers, some of whom would also tend to qualify as small entities.[1133]

747. While Allco argues that the Commission should have attempted to minimize the impacts on small renewable energy producers and consider alternative structures, the fact is that these offsetting impacts result from changes that are necessary to ensure the Commission's regulations continue to meet PURPA's statutory requirements. For example, allowing states to use competitive prices may benefit small QFs inasmuch as the rate-setting process for purchases of energy from these entities would be more straightforward and efficient than the administrative processes currently in use. Furthermore, providing flexibility in setting energy rates may result in state entities approving longer duration contracts for capacity (at fixed rates) and energy. The impacts of these changes, therefore, are reasonable alternatives to the status quo while adhering to the requirements of PURPA.

748. This final rule establishes a rebuttable presumption that a qualifying small power production facility whose electrical generating equipment is more than one but less than 10 miles from affiliated electrical generating equipment using the same energy resource is at a separate site. The Commission finds that this rebuttable presumption imposes a lower burden than imposing a rule that any affiliated electrical generating equipment less than 10 miles apart is presumed to be at the same site. Similarly, the Commission, while removing the rebuttable presumption that qualifying small power production facilities more than 5 MW but under 20 MW lack nondiscriminatory access, has provided factors that such facilities could use to demonstrate lack of such access—allowing them to retain the mandatory purchase obligation. The Commission estimates that annual additional compliance costs on industry (detailed above) will be approximately $1,149,965 (or an average additional burden and cost per response, of 3.187 hrs. and the corresponding $264.51) to comply with these requirements.[1134]

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

VIII. Document Availability

750. 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*). At this time, the Commission has suspended access to the Commission's Public Reference Room due to the President's March 13, 2020 proclamation declaring a National Emergency concerning the Novel Coronavirus Disease (COVID–19).

751. 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.

752. 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.*

IX. Effective Dates and Congressional Notification

753. These regulations are effective December 31, 2020. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a ''major rule'' as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996. This final rule is being submitted to the Senate, House, Government Accountability Office, and Small Business Administration.

List of Subjects in 18 CFR Part 292

Electric power plants; Electric utilities, Reporting and recordkeeping requirements.

List of Subjects in 18 CFR Part 375

Authority delegations (Government agencies); Seals and insignia; Sunshine Act.

By the Commission. Commissioner Glick is dissenting in part with a separate statement attached.

Issued: July 16, 2020.

Nathaniel J. Davis, Sr.,

Deputy Secretary.

In consideration of the foregoing, the Commission amends parts 292 and 375, chapter I, title 18, Code of Federal Regulations, as follows.

SUBCHAPTER K—REGULATIONS UNDER THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978

* * * * *

[1132] I.e., use of locational marginal prices, competitive market price, and use of forecasted stream of market revenues for energy rate component of QF contracts or legally enforceable obligations; use of variable energy rates in QF contracts or legally enforceable obligations; use of competitive solicitations to set avoided energy and capacity rates; reducing the PURPA section 210(m) rebuttable presumption regarding access to markets from 20 MW to 5 MW; and the commercial viability and financial commitment to construct demonstration necessary to obtaining a legally enforceable obligation.

[1133] While this potential beneficial impact on retail ratepayers would be an indirect impact of this final rule, the Small Business Administration Office of Advocacy encourages such indirect costs to be analyzed as well: ''Although it is not required by the RFA, the Office of Advocacy believes that it is good public policy for the agency to perform a regulatory flexibility analysis even when the impacts of its regulation are indirect.'' SBA, Office of Advocacy, *A Guide for Government Agencies: How to Comply with the Regulatory Flexibility Act* at 23 (Aug. 2017), *https://www.sba.gov/sites/default/files/advocacy/How-to-Comply-with-the-RFA-WEB.pdf. But see Mid-Tex Elec. Co-op., Inc.* v. *FERC,* 773 F.2d 327, 343 (D.C. Cir. 1985) (''Congress did not intend to require that every agency consider every indirect effect that any regulation might have on small businesses in any stratum of the national economy.'').

[1134] Annual additional cost of $1,149,965 [($1,120,085 for FERC–556) + (29,880 for FERC–912)] and average additional burden of 13,855 hours [(13,495 hrs. for FERC–556) + (360 hrs. for FERC–912)] divided by the number of affected responses of 4,347.5 [(4,317.5 for FERC–556) + (30 responses for FERC–912)].

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.

* * * * *

(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, 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 qualifying 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), there is an irrebuttable presumption that affiliated small power production qualifying facilities that use the same energy resource and are located one mile or less from the facility for which qualification or recertification is sought are located at the same site as the facility for which qualification or recertification is sought.

(B) For purposes of this paragraph (a)(2), for facilities for which qualification or recertification is filed on or after December 31, 2020 there is an irrebuttable presumption that affiliated small power production qualifying facilities that use the same energy resource and are located 10 miles or more from the facility for which qualification or recertification is sought are located at separate sites from the facility for which qualification or recertification is sought.

(C) For purposes of this paragraph (a)(2), for facilities for which qualification or recertification is filed on or after December 31, 2020, there is a rebuttable presumption that affiliated small power production qualifying facilities that use the same energy resource and are located more than one mile and less than 10 miles from the facility for which qualification or recertification is sought are located at separate sites from the facility for which qualification or recertification is sought.

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

(ii) For purposes of making the determinations in paragraph (a)(2)(i), the distance between two facilities shall be measured from the edge of the closest electrical generating equipment for which qualification or recertification is sought to the edge of the nearest electrical generating equipment of the other affiliated small power production qualifying facility using the same energy resource.

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

(4) *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 size of other small power production facilities less than 10 miles from such facilities.

* * * * *

■ 5. Amend § 292.207 by:

■ a. Revising paragraphs (a), (b) intructory text, (b)(2), (c), and (d);

■ b. Adding paragraphs (e) and (f).

The revisions and additions read as follows:

§ 292.207 Procedures for obtaining qualifying status.

(a) *Self-certification.* (1) *FERC 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 FERC Form No. 556 and filing that form with the Commission, pursuant to § 131.80 of this chapter, and complying with paragraph (e) 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 FERC Form No. 556, provide information asserting factors showing that the facility for which qualification or recertification 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) *Commission action.* Self-certification and self-recertification are effective upon filing. If no protests to a self-certification or self-recertification are timely filed pursuant to paragraph (c) of this section, no further action by the Commission is required for a self-certification or self-recertification to be effective. If protests to a self-certification or self-recertification are timely filed pursuant to paragraph (c) of this section, a self-certification or self-recertification 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 qualification or recertification, 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. Absent Commission action before the expiration of the tolling period, a protest will be deemed denied, and the self-certification or self-recertification will remain effective.

(b) *Optional procedure—Commission certification.* * * *

(2) *General contents of application.* The application must include a properly completed FERC 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 FERC 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.

* * * * *

(c) *Protests and Interventions.* (1) *Filing a Protest.* Any person, as defined in § 385.102(d) of this chapter, who opposes either a self-certification or self-recertification making substantive changes to the existing certification filed pursuant to paragraph (a) of this section or an application for Commission certification or Commission recertification making substantive changes to the existing certification filed pursuant to paragraph (b) of this section for which qualification or recertification is filed on or after December 31, 2020, may file a protest with the Commission. Any protest to and any intervention in a self-certification or self-recertification 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 or self-recertification is filed. Any protestor must concurrently serve a copy of such filing pursuant to § 385.211 of this chapter. Any protest must be adequately supported, and provide any supporting documents, contracts, or affidavits to substantiate the claims in the protest.

(2) *Limitations on protest.* Protests may be filed to any initial self-certification or application for Commission certification filed on or after the effective date of this final rule, and to any self-recertification or application for Commission recertification that are filed on or after December 31, 2020 that makes substantive changes to the existing certification. Once the Commission has certified an applicant's qualifying facility status either in response to a protest opposing a self-certification or self-recertification, or in response to an application for Commission certification or Commission recertification, any later protest to a self-recertification or application for Commission recertification making substantive changes to a qualifying facility's certification must demonstrate changed circumstances that call into question the continued validity of the certification.

(d) *Response to protests.* Any response to a protest must be filed on or before 30 days from the date of filing of that protest and will be allowed under § 385.213(a)(2) of this chapter.

(e) *Notice requirements.* (1) *General.* An applicant filing a self-certification, self-recertification, application for Commission certification or application for Commission recertification of the qualifying status of its facility must concurrently serve a copy of such filing on each electric utility with which it expects to interconnect, transmit or sell electric energy to, or purchase supplementary, standby, back-up or maintenance power from, and the State regulatory authority of each state where the facility and each affected electric utility is located. The Commission will publish a notice in the **Federal Register** for each application for Commission certification and for each self-certification of a cogeneration facility that is subject to the requirements of § 292.205(d).

(2) Facilities of 500 kW or more. An electric utility is not required to purchase electric energy from a facility with a net power production capacity of 500 kW or more until 90 days after the facility notifies the facility that it is a qualifying facility or 90 days after the utility meets the notice requirements in paragraph (c)(1) of this section.

(f) *Revocation of qualifying status.* (1)(i) If a qualifying facility fails to conform with any material facts or representations presented by the cogenerator or small power producer in its submittals to the Commission, the notice of self-certification or Commission order certifying the qualifying status of the facility may no longer be relied upon. At that point, if the facility continues to conform to the Commission's qualifying criteria under this part, the cogenerator or small power producer may file either a notice of self-recertification of qualifying status pursuant to the requirements of paragraph (a) of this section, or an application for Commission recertification pursuant to the requirements of paragraph (b) of this section, as appropriate.

(ii) The Commission may, on its own motion or on the motion of any person, revoke the qualifying status of a facility that has been certified under paragraph (b) of this section, if the facility fails to conform to any of the Commission's qualifying facility criteria under this part.

(iii) The Commission may, on its own motion or on the motion of any person, revoke the qualifying status of a self-certified or self-recertified qualifying facility if it finds that the self-certified or self-recertified qualifying facility does not meet the applicable requirements for qualifying facilities.

(2) Prior to undertaking any substantial alteration or modification of a qualifying facility which has been certified under paragraph (b) of this section, a small power producer or cogenerator may apply to the Commission for a determination that the proposed alteration or modification will not result in a revocation of qualifying status. This application for Commission recertification of qualifying status should be submitted in accordance with paragraph (b) of this section.

■ 6. Amend § 292.304 by:

■ a. Adding paragraph (b)(6) through (8); and

■ b. Revising paragraphs (d) and (e).

The additions and revisions read as follows:

§ 292.304 Rates for purchases.

* * * * *

(b) *Relationship to avoided costs.* * * *

(6) *Locational Marginal Price.* There is a rebuttable presumption that 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 electric utilities located in a market 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 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 which a state regulatory authority or nonregulated electric utility determines represents an appropriate measure of the electric utility's avoided cost for as-available energy, and is a hub to which the electric utility has reasonable access, based on an evaluation by the state regulatory authority or nonregulated electric utility 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 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 electric utility's purchases from the relevant qualifying facility 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, a proxy heat rate, and variable operations and maintenance costs 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 measure of the purchasing electric utility's avoided cost for energy, 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 measure 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.* (i) 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 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:

(A) The solicitation process is an open and transparent process that includes, but is not limited to, providing equally to all potential bidders substantial and meaningful information regarding transmission constraints, levels of congestion, and interconnections, subject to appropriate confidentiality safeguards;

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

(C) Solicitations are conducted at regular intervals;

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

(E) Solicitations are certified as fulfilling the above criteria by the relevant state regulatory authority or nonregulated electric utility through a post-solicitation report.

(ii) To the extent that the electric utility procures all of its capacity, including capacity resources constructed or otherwise acquired by the electric utility, through a competitive solicitation process conducted pursuant to paragraph (b)(8)(i) of this section, the electric utility shall be presumed to have no avoided capacity costs unless and until it determines to acquire capacity outside of such competitive solicitation process. However, the electric utility shall nevertheless be required to purchase energy from qualifying small power producers and qualifying cogeneration facilities.

(iii) To the extent that the electric utility does not procure all of its capacity through a competitive solicitation process conducted pursuant to paragraph (b)(8)(i) of this section, then there shall be no presumption that the electric utility has no avoided capacity costs.

* * * * *

(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 electric utility's avoided cost for energy 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 paragraph (d)(2) of this section, 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 vary through the life of the obligation, and be set at the electric utility's avoided cost for energy calculated 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 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.

* * * * *

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

§ 292.309 Termination of obligation to purchase from qualifying facilities.

* * * * *

(c) For purposes of paragraphs (a)(1), (2) and (3) of this section, with the exception of paragraph (d) of this section, there is a rebuttable presumption that a qualifying facility has nondiscriminatory access to the market if it is eligible for service under a Commission-approved open access transmission tariff or Commission-filed reciprocity tariff, and Commission-approved interconnection rules.

(1) If the Commission determines that a market meets the criteria of paragraphs (a)(1), (2) or (3) of this section, and if a qualifying facility in the relevant market is eligible for service under a Commission-approved open access transmission tariff or Commission-filed reciprocity tariff, a qualifying facility may seek to rebut the presumption of access to the market by demonstrating, *inter alia,* that it does not have access to the market because of operational characteristics or transmission constraints.

(2) For purposes of paragraphs (a)(1), (2), and (3) of this section, a qualifying small power production facility with a capacity between 5 megawatts and 20 megawatts may additionally seek to rebut the presumption of access to the market by demonstrating that it does not have access to the market in light of consideration of other factors, including, but not limited to:

(i) Specific barriers to connecting to the interstate transmission grid, such as excessively high costs and pancaked delivery rates;

(ii) Unique circumstances impacting the time or length of interconnection studies or queues to process the small power production facility's interconnection request;

(iii) A lack of affiliation with entities that participate in the markets in paragraphs (a)(1), (2), and (3) of this section;

(iv) The qualifying small power production facility has a predominant purpose other than selling electricity and should be treated similarly to qualifying cogeneration facilities;

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

(vi) The qualifying small power production facility lacks access to markets due to transmission constraints. The qualifying small power production 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.

(d)(1) For purposes of paragraphs (a)(1), (2), and (3) of this section, 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 paragraphs (a)(1), (2), and (3) of this section, there is a rebuttable presumption that a qualifying small power production facility with a capacity at or below 5 megawatts does not have nondiscriminatory access to the market.

(3) Nothing in paragraphs (d)(1) through (3) of this section affects the rights the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or non-regulated electric utility on or before December 31, 2020, to purchase electric energy or capacity from or to sell electric energy or capacity to a small power production facility between 5 megawatts and 20 megawatts under this Act (including the right to recover costs of purchasing electric energy or capacity).

(4) For purposes of implementing paragraphs (d)(1) and (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 paragraphs (a)(1)(i) and (ii) of this section, and there is a rebuttable presumption that small power production facilities with a capacity greater than 5 megawatts 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 paragraph (a)(3) of this section, and there is a rebuttable presumption that small power production facilities with a capacity greater than five megawatts 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

■ 8. 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.

■ 9. Amend § 375.302 by revising paragraph (v) to read as follows:

§ 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.

UNITED STATES OF AMERICA 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 July 16, 2020)

GLICK, Commissioner, *dissenting in part:*

1. I dissent in part from today's final rule (Final Rule [1]) because it effectively guts the Commission's implementation of the Public Utility Regulatory Policies Act (PURPA).[2] The Commission's basic 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, in the public interest, and do not exceed the incremental costs to the utility of alternative energy.[3] I do not believe that today's Final Rule satisfies those responsibilities. Instead, the Final Rule raises as many questions as it answers, not least of which is the long-term legal viability of an approach that does so little to encourage QF development.

2. Although I have concerns about many of the individual changes imposed by the Final Rule,[4] I remain, on a broader level, dismayed that the Commission is attempting to accomplish via administrative fiat what Congress has repeatedly declined to do via legislation. I am especially disappointed because Congress expressly provided the Commission with a different avenue for ''modernizing'' our administration of PURPA. The Energy Policy Act of 2005 gave the Commission the authority to excuse utilities from their obligations under PURPA where QFs have non-discriminatory access to competitive wholesale markets.[5] Had we pursued reforms based on those provisions, rather than gutting our longstanding regulations, I believe we could have reached a durable, consensus solution that would ultimately have done more for all interested parties, even those that may celebrate the immediate effects of this Final Rule.

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

3. This proceeding began with a bang. My colleagues championed the proposed rule as a ''truly significant'' action that would fundamentally overhaul the Commission's implementation of PURPA.[6] And so it was. The NOPR proposed to alter almost every significant aspect of the Commission's PURPA regulations, thereby transforming the foundation on which the Commission had carried out its statutory responsibility to ''encourage'' the development of QFs.

4. I dissented from the NOPR in large part because I believe that it is not the Commission's role to sit in judgment of a duly enacted statute and determine whether it has outlived its usefulness. As I explained, ''almost from the moment PURPA was passed, Congress began to hear many of the arguments being used today to justify scaling the law back.'' [7] Congress, however, has seen fit to significantly amend PURPA only once in its more-than-forty-year lifespan. As part of the Energy Policy Act of 2005, Congress amended PURPA, leaving in place the law's basic framework, while adding a series of provisions that allowed the Commission to excuse utilities from its requirements in regions of the country with sufficiently competitive wholesale energy markets.[8] And while Congress considered numerous proposals to further reform the law, it never saw fit to act on them.[9] Against that background, I could not support my colleagues' willingness to ''remove[ ] an important debate from the halls of Congress and isolate[] it within the Commission.'' [10] Whatever your position on PURPA—and I recognize views vary widely—''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.'' [11]

5. Today's Final Rule retreats from much of the original rationale used to support the NOPR, but the effect is the same: The Commission is administratively gutting PURPA. Make no mistake, although the Commission has dropped much of the NOPR preamble's opening screed against PURPA's continuing relevance, this Final Rule is a full-throated endorsement of the conclusion that PURPA has outlived its usefulness. And while walking back the argument that PURPA is antiquated may reduce the risk that this Final Rule is overturned on appeal, that does not change the fact that today's Final Rule usurps what should be Congress's proper role.

6. Throughout this proceeding, the Commission has been quick to point to Congress's directive to from time to time

[1] *Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* Order No. 872, 172 FERC ¶ 61,041 (2020) (Final Rule).

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

[3] *See* 16 U.S.C. 824a–3(a)–(b) (2018).

[4] Notwithstanding those concerns, I support certain aspects of this Final Rule. First and foremost, I agree with the update to the ''one-mile'' rule, which prior to today provided an irrebuttable presumption that resources located more than one mile apart are separate QFs. In addition, I support requiring that QFs demonstrate commercial viability before securing a legally enforceable obligation with the relevant utility. Finally, I also support the revision to allow stakeholders to protest a QF's self-certification.

[5] Public Law 109–58, 1253, 119 Stat. 594 (2005).

[6] Sept. 2019 Commission Meeting Tr. at 8.

[7] *Qualifying Facility Rates and Requirements Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* Notice of Proposed Rulemaking, 168 FERC ¶ 61,184 (2019) (NOPR) (Glick, Comm'r, dissenting in part at P 3).

[8] Public Law 109–58, 1253, 119 Stat. 594 (2005).

[9] *See* Solar Energy Industries Association (SEIA) Comments at 11.

[10] NOPR, 168 FERC ¶ 61,184 (Glick, Comm'r, dissenting in part at P 4).

[11] *Id.*

amend our regulations implementing PURPA.[12] This Final Rule, however, is a wholesale overhaul of the Commission's PURPA regulations that reflects a deep skepticism of the need for the law we are charged with implementing. I doubt that is what Congress had in mind when it gave us responsibility for periodically updating our implementing regulations.

II. The Commission's Proposed Reforms Are Inconsistent With Our Statutory Mandate

7. PURPA directs the Commission to adopt such regulations as are ''necessary to encourage'' QFs,[13] including by establishing rates for sales by QFs that are just and reasonable and by ensuring that such rates ''shall not discriminate'' against QFs.[14] As explained below, many of the changes adopted by the Commission in the Final Rule fail to meet that standard. In addition, many of the reforms are unsupported—or, in many cases, contradicted—by the evidence in the record.[15] Accordingly, I believe today's Final Rule is not just poor public policy, but also arbitrary and capricious agency action.

A. Avoided Cost

8. The Final Rule adopts two fundamental changes to how QF rates are determined. First, and most importantly, it eliminates the requirement that a utility must afford a QF the option to enter a contract at a rate for energy that is either fixed for the duration of the contract or determined at the outset—*e.g.,* based on a forward curve reflecting estimated prices over the term of the contract.[16] Second, it presumptively allows states to set the rate for as-available energy at the relevant locational marginal price (LMP) or a similarly ''competitive market price.'' [17] The record in this proceeding does not support either of those changes.

i. Elimination of Fixed Energy Rate

9. Prior to today's Final Rule, a QF generally had two options for selling its output to a utility. Under the first option, the QF could 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 could enter into a fixed-duration contract at an avoided cost rate that was fixed either at the time the QF established a legally enforceable obligation (LEO) or at the time of delivery. This is generally known as the contract option. The ability to choose between both types of sale options played an important role in fostering the development of a variety of QFs. For example, the as-available option provided a way for QFs whose principal business was not generating electricity, such as industrial cogeneration facilities, to monetize their excess electricity generation. The contract option, by contrast, provided QFs who were principally in the business of generating electricity, such as small renewable electricity generators, a stable option that would allow them to secure financing. Together, the presence of these two options allowed the Commission to satisfy its statutory mandate to encourage the development of QFs and ensured that the rates they received were non-discriminatory.

10. The Final Rule eliminates the requirement that states provide a contract option that includes a fixed energy rate.[18] Prior to this proceeding, the Commission recognized time and again that fixed-price contracts play an essential role in the financing of QF facilities, making them a necessary element of any effort to encourage QF development, at least in certain regions of the country.[19] In addition, fixed-price contracts have helped prevent discrimination against QFs by ensuring that they are not structurally disadvantaged relative to vertically integrated utilities that are guaranteed to recover the costs of their prudently incurred investments through retail rates.[20]

11. If anything, the record before us confirms the continuing importance of fixed-price contracts. Numerous entities with experience financing and developing QFs explain that a fixed revenue stream of some sort is necessary to obtain the financing needed to develop a new QF.[21] The fixed revenue stream is particularly important because QFs are overwhelmingly developed outside of the organized markets, meaning that developers cannot necessarily obtain hedging contracts to create the revenue predictability needed to obtain financing.[22] And that is why the Final Rule's parade of statistics about the growth of renewables misses the point.[23] It is true that, primarily in

[12] Final Rule, 172 FERC ¶ 61,041 at PP 24, 48, 54, 67, 296, 628; NOPR, 168 FERC ¶ 61,184 at PP 4, 16, 29, 155.

[13] A QF is a cogeneration facility or a small power production facility. *See* 18 CFR 292.101(b)(1) (2019).

[14] 16 U.S.C. 824a–3(a)–(b).

[15] *Genuine Parts Co.* v. *EPA,* 890 F.3d 304, 312 (D.C. Cir. 2018) (''[A]n agency cannot ignore evidence that undercuts its judgment; and it may not minimize such evidence without adequate explanation.'') (citations omitted); *id.* (''Conclusory explanations for matters involving a central factual dispute where there is considerable evidence in conflict do not suffice to meet the deferential standards of our review.'' (quoting *Int'l Union, United Mine Workers* v. *Mine Safety & Health Admin.,* 626 F.3d 84, 94 (D.C. Cir. 2010)).

[16] Final Rule, 172 FERC ¶ 61,041 at P 253.

[17] *Id.* PP 151, 189, 211.

[18] *Id.* P 253.

[19] *See, e.g., 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 30,880, *order on reh'g sub nom.* Order No. 69–A, FERC Stats. & Regs. ¶ 30,160 (1980), *aff'd in part vacated in part, 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). (justifying the rule on the basis of ''the need for certainty with regard to return on investment in new technologies''); NOPR, 168 FERC ¶ 61,184 at P 63 (''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.''); *Windham Solar LLC,* 157 FERC ¶ 61,134, at P 8 (2016).

[20] *See, e.g.,* ELCON Comments at 21–22 (''More varible avoided cost rates will result in unintended consequences that result in less competitive conditions and may leave consumers worse off, as utility self-builds do not face the same market risk exposure. Pushing more market risk to QFs while utility assets remain insulated from markets creates an investment risk asymmetry. This puts QFs at a competitive disadvantage''); South Carolina Solar Business Association Comments at 8 (''[A]s-available rates for QFs in vertically-integrated states therefore discriminate against QFs by requiring QFs to enter into contracts at substantially and unjustifiably different terms than incumbent utilities.''); Southern Environmental Law Center Supplement Comments, Docket No. AD16–16–000, at 6–8 (Oct. 17, 2018) (explaining that vertically integrated utilities in Indiana, Alabama, Virginia and Tennessee only offer short-term rates to QFs); sPower Comments at 13; *see also* Statement of Travis Kavulla, Docket No. AD16–16–000, at 2 (June 29, 2016).

[21] *See, e.g.,* SEIA Comments at 29; North Carolina Attorney General's Office Comments at 5; Con Ed Development Comments at 3; South Carolina Solar Business Association Comments at 6; sPower Comments at 11; Resources for the Future Comments at 6–7.

[22] *See, e.g.,* SEIA Comments at 29–30 (''As both Mr. Shem and Mr. McConnell explain, financial hedge products are not available outside of ISO/RTO markets.''); Resources for the Future Comments at 6–7 (''[W]hile hedge products do support wind and solar project financing, they would not be suited for most QF projects. To hedge energy prices, wind projects have used three products: bank hedges, synthetic power purchase agreements (synthetic PPAs), and proxy revenue swaps . . . . From U.S. project data for 2017 and 2018, the smallest wind project securing such a hedge was 78 MW, and most projects were well over 100 MW. *Additionally, as hedges rely on wholesale market access and liquid electricity trading, all of the projects were in ISO regions.*'') (emphasis added).

[23] Harvard Electricity Law Comments at 22 (referring to a similar statistical parade in the NOPR and observing that ''[a]ll [the Commission] can actually conclude from this loosely connected array of facts, data, and speculation is that some non-QF generators are developed with variable-rate energy contracts. That unremarkable conclusion has no bearing on whether repeal will discourage QF development by 'materially affect[ing] the ability of QFs to obtain financing.' '' (citing NOPR, 168 FERC ¶ 61,184 at P 69)); SEIA Comments at 30.

organized markets, independently developed renewables are able to develop without the entitlement to a fixed-price contract for energy from the relevant utility.[24] But the growth of renewables and their financeability in organized markets tells us almost nothing about what is required to sufficiently encourage QFs outside those markets.[25]

12. It would be one thing to eliminate the requirement to provide a fixed-price option for energy rates for QFs that are entitled to a fixed price for capacity. Although reasonable minds might disagree about whether a fixed price for capacity alone is sufficient encouragement, combining one with a variable price for energy would provide at least some guaranteed revenue stream with which to finance new development.[26] Indeed, much of the Commission's justification for eliminating the fixed-price contract option for energy rests on the availability of a fixed-price contract option for capacity.[27] Commission precedent, however, permits utilities to offer a capacity rate of zero to QFs when the utility does not need incremental capacity.[28] That means that, as a result of this Final Rule, QF developers will face the very real prospect of not receiving any fixed revenue stream, whether for energy or capacity, in areas where they also cannot secure hedging products or other mechanisms needed to finance a new QF.[29] It is hard for me to understand how the Commission can, with a straight face, claim to be encouraging QF development while at the same time eliminating the conditions necessary to develop QFs in the regions where they are being built.[30]

13. The Commission sidesteps this point in responding that PURPA does not require that QFs be financeable. That is true in a literal sense; nothing in PURPA directs the Commission to ensure that at least some QFs be financeable. But it does require the Commission to encourage their development, which we have previously equated with financeability.[31] If the Commission is going to abandon that standard, it must then explain why what is left of its regulations provides the requisite encouragement—an explanation that is lacking from this Final Rule, notwithstanding the Commission's repeated assertions to the contrary.

14. The Commission also does not sufficiently explain how eliminating the fixed-price contract requirement is consistent with PURPA's requirement that rates ''shall not discriminate against'' QFs.[32] Vertically integrated utilities effectively receive guaranteed fixed-price contracts through their rights to recover prudently incurred investments. The equivalent right to receive fixed-price contracts has to date proved an integral element of the Commission's ability to satisfy PURPA's prohibition on discriminatory rates.[33]

15. And yet this Final Rule fails to explain how eliminating the fixed-price option is consistent with that prohibition or, moreover, how permitting QFs to receive variable contract rates while vertically integrated utilities receive fixed ones is consistent with the Commission's obligation to promote QFs.[34] Instead, the Commission notes that, through so-called fuel adjustment clauses, vertically integrated utilities' rates change as the price of fuel changes.[35] The idea that those clauses, which ensure that utilities recover a specific variable cost (*i.e.,* their cost of fuel), is the same thing as having your entire revenue exposed to variations in prevailing market conditions is hogwash. The presence of fuel adjustment clauses in no way suggests that vertically integrated utilities are subject to anything remotely close to the level of revenue variation contemplated in this Final Rule.

16. Finally, the Commission fails to explain why allegations of QF rates exceeding a utility's actual avoided cost requires us to abandon the Commission's long-held principles regarding certainty and financing.[36] As an initial matter, the Commission has recognized that QF rates may exceed actual avoided costs, but, at the same time, recognized that avoided cost rates might also turn out to be lower than the electric utility's avoided costs over the course of the contract. The Commission has reasoned that, ''in the long run, 'overestimations' and 'underestimations' of avoided costs will balance out.'' [37] However, when presented with a couple allegations that avoided costs were overestimated,[38] the Commission now concludes that that possibility suggests it must abandon the fixed-energy rate

[24] *See* Final Rule, 172 FERC ¶ 61,041 at P 340 (''EIA data demonstrates that net generation of energy by non-utility owned renewable resources in the United States grew by almost 700% between 2005 and 2018.''). Although independent power producers, renewable or otherwise, within the RTO/ISO markets are not entitled to fixed price contracts for energy as a matter of law, they generally do rely on alternative tools, such as commodity hedges, to lock-in energy revenue streams. *See, e.g.,* EEI Comments at 36; sPower Comments at 12.

[25] In the logical leap of the year, the Commission notes that in some areas of the country, unspecified resources are developed with a fixed-price contract for capacity and a variable price for energy and, separately, that renewables have grown nationwide more than seven-fold between 2005 and 2018. Final Rule, 172 FERC ¶ 61,041 at P 340. From those disparate observations, the Commission concludes that ''renewable resources are able to acquire financing even without the right to require long-term fixed energy rates.'' *Id.* But nothing in the record suggests that that phenomenal growth in renewables was at all the result of that bifurcated contract structure. That, it should be clear, is not reasoned decisionmaking. *Cf. Nat'l Ass'n of Recycling Indus., Inc.* v. *Fed. Mar. Comm'n,* 658 F.2d 816, 820 n.10 (D.C. Cir. 1980) (''We do not want, after all, blithely to compare apples and oranges. Likewise, an agency should also avoid unavailing comparisons of nonsubstitutes.''); *see also* Commissioner Slaughter Comments at 4 (noting the ''widespread geographic differentiation'' in renewable energy progress and ''barriers to independent renewable energy-based power producers'').

[26] *See, e.g.,* SEIA Comments at 29 (''While securing financing based on an As-Available Energy rate and a fixed capacity rate may be a rare possibility in a few sub-markets across the country, as Mr. Shem explains, it certainly is not the case in any state that does not participate in an ISO/RTO market.'').

[27] *See* Final Rule, 172 FERC ¶ 61,041 at P 36 (''This assertion that the Commission has eliminated fixed rates for QFs is not correct . . . . The NOPR thus made clear: 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.'') (internal quotation marks omitted); *id.* P 237 (''The Commission stated that these fixed capacity and variable energy payments have been sufficient to permit the financing of significant amounts of new capacity in the RTOs and ISOs.'').

[28] *See, e.g., id.* P 422 (citing to *City of Ketchikan, Alaska,* 94 FERC ¶ 61,293, at 62,061 (2001)).

[29] *See, e.g.,* Resources for the Future Comments at 6; SEIA Comments at 30; Southeast Public Interest Organizations Comments at 12.

[30] *See* Public Interest Organizations Comments at 10–11 (''Obviously, rules that have an effect of *discouraging* QFs cannot be 'necessary to' encouraging them.''); *see also* Massachusetts Attorney General Maura Healey Comments at 6 (''This action may reduce investor confidence and discourage future development. That outcome is a negative one for the Commonwealth and its ratepayers.'').

[31] *See, e.g.,* 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''); NOPR, 168 FERC ¶ 61,184 at P 63 (''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.'').

[32] 16 U.S. Code § 824a–3(b)(2). Unlike provisions of the Federal Power Act, PURPA prohibits any discrimination against QFs, not just undue discrimination. *See* ELCON Comments at 21–22; South Carolina Solar Business Alliance Comments at 7–8; sPower Comments at 13.

[33] *See supra* n.20; Commissioner Slaughter Comments at 4.

[34] Public Interest Organizations Comments at 51 (''[L]imiting QFs to contracts providing no price certainty for energy values, while non-QF generation regularly obtains fixed price contracts and utility-owned generation receives guaranteed cost recovery from captive ratepayers, constitutes discrimination.'').

[35] Final Rule, 172 FERC ¶ 61,041 at P 122.

[36] *See supra* n.19.

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

[38] Final Rule, 172 FERC ¶ 61,041 at PP 265, 268.

contract altogether. The Commission, however, makes no effort to validate these allegations,[39] or assess whether the overestimations of avoided cost were, in fact, balanced out.[40] It is arbitrary and capricious to point to only half the picture in abandoning a forty-year-old principle.

ii. Rebuttable Presumption for Setting Avoided Cost at LMP and Similar Measures

17. I also do not support the Commission's decision to treat LMP or other ''competitive market prices'' as a presumptively reasonable measure of an as-available avoided cost for energy.[41] Liquid price signals can be useful and transparent inputs and ought to be *considered* in calculating an appropriate avoided-cost figure. But considering those price signals in setting avoided cost is not the same thing as presuming that LMP or similar measures are alone sufficient to establish avoided cost. Many regions of the country—often the same regions where the debates about PURPA are most heated—have not established sufficiently competitive markets. In these regions it is not clear from the record that the prices in, for example, a neighboring RTO, are a representative measure of a utility's avoided cost. In those less competitive markets, it simply does not make sense to presume that LMP or other ''competitive market prices'' are a representative measure of avoided cost, rather than one of many criteria that should go into that determination.[42]

18. For similar reasons, I share the concern of many commenters that short-term or spot prices, such as LMP, may not reflect the long-term marginal energy costs avoided by purchasing utilities, especially outside of organized markets.[43] Although the Commission revises the NOPR's *per se* rule to be a rebuttable presumption, it nevertheless plows ahead with the conclusion that LMP, and similar measures, reflect a utility's avoided cost of energy. Where there is good reason to believe that those measures do not actually reflect the long-term value of energy that they are supposed to represent, it makes no sense to put the burden on QFs to prove the point,[44] rather than leaving the burden with the proponents of using such measures.

19. The Commission's presumptive approval of LMP and similar measures is even more problematic when combined with the decision to allow utilities to eliminate the fixed-price contract option. Following this Final Rule, QFs may be reduced to relying solely on some synthetic and highly variable measure of what spot prices *should* be in a competitive market based on gas prices and heat rates, all while the utilities whose costs the QF is avoiding recovers an effectively guaranteed rate potentially in excess of this representative ''competitive market price.'' I am not persuaded that this approach will satisfy our obligation to encourage QFs and to do so using rates that are non-discriminatory across all regions of the country.

B. Rebuttable Presumption 20 MW to 5 MW

20. Following the Energy Policy Act of 2005, the Commission established a rebuttable presumption that QFs with a capacity greater than 20 MW operating in RTOs and ISOs have non-discriminatory access to competitive markets, eliminating utilities' must-purchase obligation from those resources.[45] The Final Rule reduces the threshold for that presumption from 20 MW to 5 MW. [46] That is an improvement over the NOPR, which—without any support whatsoever—proposed to lower that threshold to 1 MW.[47] But, even so, the reduced 5 MW threshold is unsupported by the record and inadequately justified in today's Final Rule.

21. When it originally established the 20 MW threshold, the Commission pointed to an array of barriers that prevented resources below that level from having truly non-discriminatory access to RTO/ISO markets. Those barriers included complications associated with accessing the transmission system through the distribution system (a common occurrence for such small resources), challenges with reaching distant off-takers, as well as ''jurisdictional differences, pancaked delivery rates, and additional administrative procedures'' that complicate those resources' ability to participate in those markets on a level playing field.[48] In just the last few years, the Commission has recognized the persistence of those barriers ''that gave rise to the rebuttable presumption that smaller QFs lack nondiscriminatory access to markets.'' [49]

22. Nevertheless, the Final Rule abandons the 20 MW threshold based on the conclusory assertion that ''it is reasonable to presume that access to RTO/ISO markets has improved'' and it is, therefore, ''appropriate to update the presumption.'' [50] No doubt markets have improved. But a borderline-truism about maturing markets does not explain how the barriers arrayed against small resources have dissipated, why it is reasonable to ''presume'' that the remaining barriers do not inhibit non-discriminatory access, or why 5 MW is

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[39] *Id.* PP 291, 293.

[40] The Commission is quick to point to ''the precipitous decline in natural gas prices'' starting in 2008 that may have caused QF contracts fixed prior to that period to underestimate the actual cost of energy. *See, e.g.,* Final Rule, 172 FERC ¶ 61,041 at P 287). However, PURPA has been in place for forty years, and the Commission does not wrestle with the magnitude of potential savings conveyed to consumers from the fixed-price energy contracts that locked-in low rates for consumers during the decades prior when natural gas prices were several times higher. *See* Energy Information Administration Total Energy, tbl. 9.10 (last viewed July 15, 2020), *https://www.eia.gov/totalenergy/data/browser/.*

[41] Final Rule, 172 FERC ¶ 61,041 at PP 151, 189, 211.

[42] Congress itself seems to have contemplated that states would not rely solely on spot market prices when establishing avoided cost. H.R. Rep. No. 95–1750, at 7833 (1978) (''In interpreting the term 'incremental cost of alternative energy,' the conferees expect that the Commission and the states may look beyond the cost of alternative sources which are instantaneously available to the utility.'').

[43] Final Rule, 172 FERC ¶ 61,041 at n.163; Hydro Comments at 11; Southeast Public Interest Organizations Comments at 19; NIPPC, CREA, REC, and OSEIA Comments at 52, 55; Union of Concerned Scientists Comments at 6. Take, for example, the Commission's approval of the Mid-Columbia market hub price as presumptively reflecting a utility's avoided cost for energy. *See* Final Rule, 172 FERC ¶ 61,041 at PP 180, 189. Notwithstanding explicit support for this approach from the regulated utility industry, the Washington Utilities and Transportation Commission which, when addressing Puget Sound Energy's plan to increase wholesale purchases from the Mid-Columbia market ''liquid hub'' to 1,600 MW, expressed a concern about the regulated utility's overreliance on such wholesale market pricing and directed them to pursue an alternative plan to eliminate this ''excessive risk.'' That is the exact type of tension conveyed in the record—i.e, that such competitive market prices may not accurately reflect a utility's avoided cost, as approved by regulators. *See* Washington UTC, *Acknowledgment Letter Attachment, Puget Sound Energy's 2017 Electric and Natural Gas Integrated Resource Plan,* Wash. UTC Docket Nos. UE–160918, UG–160919 (Revised June 19, 2018); *see* NIPPC, CREA, REC, and OSEIA Comments at 56.

[44] Final Rule, 172 FERC ¶ 61,041 at P 152.

[45] *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities,* Order No. 688, 117 FERC ¶ 61,078, at P 72 (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); *see* 16 U.S.C. § 824a–3(m).

[46] Final Rule, 172 FERC ¶ 61,041 at P 625.

[47] NOPR, 168 FERC ¶ 61,184 at P 126.

[48] Order No. 688–A, 119 FERC ¶ 61,305 at PP 96, 103.

[49] *E.g., N. States Power Co.,* 151 FERC ¶ 61,110, at P 34 (2015).

[50] Final Rule, 172 FERC ¶ 61,041 at P 629 (''Over the last 15 years, the RTO/ISO markets have matured, market participants have gained a better understanding of the mechanics of such markets and, as a result, we find that it is reasonable to presume that access to the RTO/ISO markets has improved and that it is appropriate to update the presumption for smaller production facilities.'').

an appropriate new threshold for that presumption.

23. Instead of any such evidence, the Final Rule notes that the Commission uses the 5 MW as a demarcating line for other rules applying to small resources. Specifically, it points to the fact that resources below 5 MW can use a ''fast-track'' interconnection process, whereas larger ones must use the large generator interconnection procedures.[51] But the fact that the Commission used 5 MW as the cut off in another context hardly shows that it is the right cut off to use in this context.

24. Lacking substantial evidence to support the 5 MW threshold, the Commission falls back on a deferential standard of review.[52] But while judicial review of agency policymaking is deferential, it is not toothless. The same cases on which the Commission relies require that, when an agency's policy reversal ''rests upon factual findings that contradict those which underlay its prior policy,'' the agency must ''provide a more detailed justification than what would suffice for a new policy created on a blank slate.'' [53] That is because reasoned decisionmaking requires that, when an agency changes course, it must provide ''a reasoned explanation . . . for disregarding facts and circumstances that underlay or were engendered by the prior policy.'' [54] For the foregoing reasons, the Commission has failed to produce any such explanation, making its change of course arbitrary and capricious.

III. Environmental Review Under the National Environmental Policy Act

25. In contrast to the Commission's crowing over the significance of its PURPA overhaul, the Final Rule describes the changes adopted as merely corrective and clarifying in nature when it comes to conducting an environmental review.[55] In particular, the Commission contends that ''the changes adopted in this final rule are required to ensure continued future compliance of the PURPA Regulations with PURPA, based on the changed circumstances found by the Commission in this final rule.'' [56] In other words, because the Commission believes that the changes adopted are necessary to conform with the statute, they are mere corrective changes, which, in turn, qualifies them for the categorical exemption from any environmental review under NEPA, or so the argument goes.

26. But by that logic, any Commission action needed to comply with our various statutory mandates—whether ''just and reasonable'' or the ''public interest''—would be deemed corrective in nature and, therefore, excluded from environmental review. The Commission, however, fails to point to any evidence suggesting that is what the Council on Environmental Quality contemplated when it allowed for categorical exemptions.

IV. The Way To Revise PURPA Is To Create More Competition, Not Less

27. It didn't have to be this way. When Congress reformed PURPA in the 2005 Energy Policy Act amendments, it indicated an unmistakable preference for using market competition as the off-ramp for utilities seeking relief from their PURPA obligations.[57] Those reforms directed the Commission to excuse utilities from those obligations where QFs had non-discriminatory access to RTO/ISO markets or other sufficiently competitive constructs.[58]

28. This record contains numerous comments explaining how the Commission could use those amendments as a way to ''modernize'' PURPA in a manner that both promotes *actual* competition and reflects Congress's unambiguous intent.[59] For example, in a white paper released prior to the NOPR, the National Association of Regulatory Utility Commissioners (NARUC) urged the Commission to give meaning to the 2005 amendments 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 solicitations for energy and capacity.[60] Other groups, including representatives of QF interests, submitted additional comments on how an approach along those lines might work.[61] Several parties commented on those proposals.[62]

It is a shame that the Commission has elected to administratively gut its long-standing PURPA implementation regime, rather than pursuing reform rooted in PURPA section 210(m), such as the NARUC proposal. Pursuing an option along those lines could have produced a durable, consensus solution to the issues before us. I continue to believe that the way to modernize PURPA is to promote real competition, not to gut the provisions that the Commission has relied on for decades out of frustration that Congress has repeatedly failed to repeal the statute itself.

For these reasons, I respectfully dissent in part.

Richard Glick,

Commissioner.

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[51] *Id.* P 630.

[52] *Id.* P 637 (citing *FCC* v. *Fox Television,* 556 U.S. 502, 515 (2009), for the proposition that an agency ''need not demonstrate to a court's satisfaction that the reasons for the new policy are better than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency *believes* it to be better, which the conscious change of course adequately indicates.'').

[53] *Fox Television,* 556 U.S. at 515; Advanced Energy Economy Comments at 6.

[54] *Fox Television,* 556 U.S. at 516; Advanced Energy Economy Comments at 6–7.

[55] Under the National Environmental Policy Act (NEPA), the Commission must consider whether its action associated with rulemakings will have a significant impact on the environment. *See* 42 U.S.C. 4321 *et seq.*

[56] Final Rule, 172 FERC ¶ 61,041 at P 722.

[57] 16 U.S.C. § 824a–3(m).

[58] *See* Order No. 688, 117 FERC ¶ 61,078 at P 8.

[59] *See* Advanced Energy Economy Comments at 13; Industrial Energy Consumers Comments at 13–14; EPSA Comments at 16.

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

[61] *See, e.g.,* SEIA Supplemental Comments, Docket No. AD16–16–000 (Aug. 28, 2019).

[62] *See, e.g.,* Advanced Energy Economy Comments at 12; APPA Comments at 29; Colorado Independent Energy Comments at 7; ELCON Comments at 19; Public Interest Organizations Comments at 90; SEIA Comments at 24; Xcel Comments at 11.