UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Implementation Issues Under the Public Utility Regulatory Policies Act of 1978	**Docket Nos. RM19-15** **AD16-16**

Comments in Response to Notice of Proposed Rulemaking by the Solar Energy Industries Association

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I. INTRODUCTION

Pursuant to Rules 212, 213 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[1] the Solar Energy Industries Association ("SEIA")[2] moves to intervene and submits these Opening Comments for the record in response to the September 19, 2019 Notice of Proposed Rulemaking ("NOPR") whereby the Commission proposes to revise fundamentally its regulations implementing Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978[3] (the "PURPA").[4] While PURPA was passed into law decades ago, where a state has chosen not to join an Independent System Operator/Regional Transmission Operator ("ISO/RTO") or where a utility continues to operate as a vertically integrated monopoly and/or a does not offer open access on its distribution system, the landscape for independent power producers remains largely the same as it was forty years ago. In these states, millions of electric consumers have largely been denied the benefits of competition and open markets. In these regions, PURPA remains necessary.

While competition and competitive markets have expanded in some parts of the country since the 95th Congress voted PURPA into law, throughout much of the country electric service continues to be provided by vertically-integrated monopolies. The fact that competition and open

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[1] 18 C.F.R. §§ 385.212, 385.213, 385.214 (2019).

[2] The comments contained in this filing represent the position of SEIA as a trade organization on behalf of the solar industry, but do not necessarily reflect the views of any particular member with respect to any issue.

[3] Public Utility Regulatory Policies Act of 1978, Pub. L. No 95-617 (Section 210 is codified at 16 U.S.C. § 824a-3 (2012), Section 201 is codified at 16 U.S.C. § 796 (2012)).

[4] *Qualifying Facility Rates and Requirements, Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, 168 FERC ¶ 61,184 (September 19, 2019). ("NOPR"). *See also*, *Electronic Tariff Filings*, 130 FERC ¶ 61,047, P 16 (2010) (explaining that when the Commission establishes new root dockets, intervention is required to become a party to the new root docket).

market access exist in *other* parts of the country does not justify removing or limiting market access in regions where competition does not otherwise exist. Congress has not repealed PURPA, and this Commission has no authority to do so explicitly or by indirect effect; Congress alone has the authority to determine whether circumstances have changed to the point that PURPA's statutory directives are no longer needed.

The Commission's broad-sweeping "rebalancing" changes proposed in the NOPR fail to comport with the clear Congressional directive to implement rules and regulations that <u>encourage</u> the development of cogeneration and small power production facilities ("Qualifying Facilities" or "QFs"). While individual portions of these reforms may be defensible, when taken as a whole, the proposed reforms are an improper implementation of the statutory directive, and an arbitrary and capricious departure from Commission precedent and the requirements of the statute. Consistent with the continued Congressional directive to encourage the development of Qualifying Facilities and to not discriminate against such facilities, SEIA respectfully requests that the Commission reconsider many of the reforms proposed in the NOPR.

II. MOTION TO INTERVENE

A. Motion

SEIA is the national trade association of the solar energy industry and was an active participant in the Commission's underlying PURPA Technical Conference docket, designated as Docket No. AD16-16.[5] As the voice of the industry, SEIA works to make solar a mainstream and

[5] *See Comments on behalf of the Solar Energy Industries Association*, Docket No. AD16-16 (June 7, 2016) ("SEIA Technical Conference Testimony"); *see also Solar Energy Industries Association (SEIA) Post Technical Conference Comments*, Docket No. AD16-16 (Nov. 7, 2016) ("SEIA Post Technical Conference Comments"); *Supplemental Comments of the Solar Energy Industries Association*, Docket No. AD16-16 (Oct. 26, 2018) ("SEIA Supplemental Comments"); *Supplemental Comments and Counterproposal by the Solar Energy Industries Association*, Docket

significant energy source by expanding markets, reducing costs and increasing reliability, removing market barriers, and providing education on the benefits of solar energy. SEIA represents solar companies that own and operate a wide variety of projects throughout the country. SEIA's members include owners and operators of Qualifying Facilities, including numerous companies that sell, or plan to sell, to purchasing utilities pursuant to Section 210. Solar power is the fastest growing source of energy, worldwide, and SEIA's members include hundreds of stakeholders of the solar energy industry: installers, manufacturers, contractors, developers, financiers, and service providers that have an active stake in the ability to develop solar generation facilities within each state that is charged with implementing PURPA. These interests cannot be adequately represented by any other party. SEIA's intervention and participation serves the public interest.

B. Service and Communication

Service should be made upon and communications should be addressed to:

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No. AD16-16 (Aug. 28, 2019) ("SEIA Counterproposal"). *See also* Testimony of Todd G. Glass on behalf of the Solar Energy Industries Association before the United States House of Representatives Committee on Energy and Commerce Subcommittee on Energy, *Powering America: Reevaluating PURPA's Objectives and its Effects on Today's Consumers* (Sept. 6, 2017) ("SEIA House Testimony"), *available at* https://docs.house.gov/meetings/IF/IF03/20170906/106362/HHRG-115-IF03-Bio-GlassT20170906.pdf.

III. EXECUTIVE SUMMARY

Economic and technological circumstances of the electricity grid have changed since 1978, with unsubsidized renewable energy now often the cheapest source of new energy generation, but the Commission remains bound to act consistent with Congressional intent and the statutory directives of PURPA. Where QFs do not have nondiscriminatory access to buyers other than the host utility, the circumstances have not "changed considerably since the Commission implemented its PURPA regulations in 1980."[6] PURPA is a clear directive from Congress to diversify the number, ownership, size, and type of electric generators in the United States and provide such Qualifying Facilities a buyer in an otherwise monopoly-controlled industry. Congress enacted PURPA as part of a legislative initiative designed to combat the nationwide energy crisis, which Congress attributed in large part to monopoly utilities' failure to initiate and drive a plan to diversify generation resources and reduce reliance on foreign energy supplies.[7] As the Supreme Court explained when it reviewed the statute in 1982, "Section 210 of PURPA's Title II … seeks to encourage the development of cogeneration and small power production facilities. Congress believed that increased use of these sources of energy would reduce the demand for traditional fossil fuels."[8]

As part of the Energy Policy Act of 2005 ("EPAct 2005") Congress revised PURPA to reflect the emergence of competitive wholesale electricity and capacity markets and the deployment of open access transmission service. EPAct 2005 amended Section 210 of PURPA to add subsection

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[6] NOPR at P 3.

[7] *See* H.R. Rep. No. 95-1750 at 9 (1978) (Conf. Rep.); SEIA House Testimony at 3-4, 8-9 (providing historical perspective on PURPA).

[8] *See FERC v. Mississippi*, 456 U.S. 742, 750 (1982).

(m), which provided that where a QF has non-discriminatory access to a wholesale market that allows the QF a meaningful opportunity to sell energy and capacity over a short- and long-term, the Commission could reduce the level of encouragement.[9] Congress retained the mandatory purchase obligation in regions where competitive markets did not exist, reflecting its continued commitment to encouraging the development of this identified class of resources. Only Congress can repeal or change PURPA to eliminate such protections and it has not done so.

Since EPAct 2005, and the Commission's implementation of Section 210(m) through Order No. 688,[10] no new wholesale markets providing for the sale of energy and/or capacity have emerged. Where a QF is located within the territory of a vertically-integrated utility and does not have nondiscriminatory access to a competitive wholesale market, Congress has directed FERC to issue rules that "encourage the development of alternative generation resources that do not rely on fossil fuels."[11] PURPA was designed to allow competitive market entrants to drive change where monopolies refused to do so,[12] yet certain of the changes proposed in the NOPR will give monopoly utilities more market power, not less. As explained below, SEIA opposes (1) eliminating the QF's option to elect a term energy commitment and a forecast energy rate; adopting such revisions will have the effect of discouraging QFs; (2) imposing unreasonable barriers as prerequisites to formation

[9] *See* 16 U.S.C. § 824a-3(m)

[10] *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688 at PP 54, 139, FERC Stats. & Regs. ¶ 31,233 (2006) ("Order No. 688); *on reh'g*, Order No. 688-A, FERC Stats. & Regs. ¶ 31,250 (2007*), aff'd sub nom. American Forest and Paper Association v. FERC*, 550 F.3d 1179 (D.C. Cir. 2008).

[11] NOPR at P 2.

[12] *See, e.g., Indep. Energy Producers Ass'n, Inc. v. Cal. Pub. Utils. Comm'n*, 36 F.3d 848, 850 (9th Cir. 1994) (explaining that the purpose of PURPA was to eliminate "(1) the reluctance of traditional electric utilities to purchase power from and sell power to non-traditional facilities, and (2) the financial burdens imposed upon alternative energy sources by state and federal utility authorities.").

of a legally enforceable obligation; adopting such revisions will discourage QF development; (3) finding that QFs under 20 MW have non-discriminatory access to buyers other than the host utility within ISO/RTO markets; adopting such a revision is arbitrary and capricious and will have the effect of discouraging QFs; and (4) reforming Form 556 and the One Mile Rule; adopting such revisions is arbitrary and capricious and will impose substantial burdens that will have the effect of discouraging QFs.

IV. COMMENTS

A. Revisions to PURPA Regulations Must be Consistent with the Statute

Section 210(a) of PURPA requires FERC to "prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production." [13] The Commission has leeway to consider a number of factors in designing its regulations, but where Congressional intent is clear, an agency must "give effect to the unambiguously expressed intent of Congress."[14] Only Congress can determine if PURPA's goals have been achieved and eliminate its statutory mandates. The "rebalancing" proposed in the NOPR fails to comport with Congressional intent by mistakenly assuming all the goals of the statute have been achieved because natural gas is cheaper, renewables are more competitive, and some independent power is more prevalent in some regions in the United States than it was when PURPA was passed into law decades ago.[15] This assumption, however, fails to account for the fact that

[13] 16 U.S.C. § 824a-3(a).

[14] *Chevron v. Natural Resources Defense Council*, 467 U.S. 837, 843 (1984).

[15] *See, e.g.,* Consolidated Edison Development Comments on Proposed Rulemaking, Docket No. RM 19-15 (Nov. 18, 2019) (explaining that the NOPR operates under "factually fallacious assumptions").

where a state has not joined an ISO/RTO or where a utility continues to maintain vertical integration, the landscape for independent power producers remains largely the same as it was forty years ago.[16] In these places, the monopsony market is generally that of a single utility buyer with complete control of interconnection to its distribution system, incentivized to build and ratebase generation instead of purchasing from independent developers.

1. The Congressional Intent is Clear

The intent of Sections 201 and 210 of PURPA is manifest on its face: to give maximum encouragement to non-utility alternative energy generators by overcoming utility-imposed impediments to their development, and at the same time, ensure that rates for consumers caused by the introduction of QFs are no higher than they would be otherwise.[17] As the Commission has explained, when PURPA was implemented, "there was no market for electric energy produced by non-utility generators. Indeed this was a primary reason that PURPA was enacted."[18] When the Supreme Court reviewed the legality of the statute in 1982, the Court examined Congressional intent and determined that Congress designed Section 210 to address the fact that traditional electricity utilities were reluctant to purchase from nontraditional facilities, and that the regulation of alternative energy sources by state and federal utility authorities would discourage such facility

[16] *Id.* (explaining that the first QF in South Carolina was not developed until 2013).

[17] *See, e.g., Am. Paper Inst. v. Am. Elec. Power Serv. Corp.,* 461 U.S. 402, 405-07 (1983) (explaining that "Section 210 of PURPA was designed to encourage the development of cogeneration and small power production facilities") ("*American Paper*"); *Winding Creek Solar v. Peterman*, 932 F.3d 861,861 (2019) (explaining the statutory purpose and intent); *Indep. Energy Producers Ass'n, Inc.*, 36 F.3d at 850 (same).

[18] *Revised Regulations Governing Small Power Production and Cogeneration Facilities*, Order No. 671, FERC, ¶ 95 (2006). ("Order No. 671"), *order on clarification*, 114 FERC ¶ 61,128 (2006) ("Order No. 671-A").

development.[19] FERC has also similarly acknowledged that prior to the enactment of PURPA, a cogenerator or small power producer faced three major obstacles: (1) the refusal of utilities to purchase electricity produced by independent alternative energy generators; (2) the charging by utilities of discriminatorily high rates for back-up service required by alternative energy generators; and (3) the risk that independent alternative energy generators would be subject to burdensome public utility regulation.[20] As FERC has recognized, "Section 210 of PURPA was designed to remove these obstacles."[21] While Congress provides FERC the opportunity to revise its PURPA implementation program "from time to time,"[22] the rule changes must remain consistent with the Congressional directive "to encourage" QF development.

Many of the proposed changes in the NOPR are not consistent with, and in some cases, contrary to Congressional intent. The NOPR fails to examine whether the impediments identified by Congress have been resolved. Further, the NOPR fails to explain how the proposed reforms are consistent with the Congressional mandate to implement the statute in a manner that encourages the development of these resources without leading to rates higher than would otherwise be in place without PURPA.[23] Sections 201 and 210 of the statute were passed into law because Congress desired to *encourage* the development of cogeneration and small power production facilities. Congress believed that increased reliance on QFs would reduce the demand for traditional fossil

[19] *See FERC v. Miss*., 456 U.S. 742, 750 (1982); *see also American Paper,* 461 U.S. 402, 407 (1983).

[20] New PURPA 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities, Order No. 688, FERC, ¶ 22 (2006) ("Order No. 688").

[21] Order No. 688 at P 23.

[22] § 824a-3(a).

[23] *See American Paper*, 461 U.S. at 414-418.

fuels, enhance national security through increased fuel diversity, and reduce ratepayer costs by shifting risks of cost-overruns and plant failures to developers.[24] Congress has entertained numerous proposals to repeal Section 210 over the past two decades, but other than the reforms adopted EPAct 2005, Congress has consistently declined to revise the statute.

As SEIA explained in its testimony and comments submitted in the underlying docket, considerable resistance to purchasing from Qualifying Facilities continues to exist, including from state utility commissions that knowingly set rates that discourage QF development.[25] Some of the same state commissions that disfavor Qualifying Facilities also allow utilities to impose impediments to QF rights.[26] Vertically-integrated utilities continue to build and rate base generating assets when ratepayers would be better served by having Qualifying Facilities shoulder the responsibility for development costs.[27] The NOPR fails to examine or to determine whether the

[24] *See* Order No. 69 at ## (explaining that "ratepayers and the nation as a whole will benefit from the decreased reliance on scarce fossil fuels, such as oil and gas, and the more efficient use of energy").

[25] *See* Tom Lutey, *Hot mic records troubling conversation about solar regulation,* BILLINGS GAZETTE, June 27, 2019, https://billingsgazette.com/news/state-and-regional/govt-and-politics/hot-mic-records-troubling-conversation-about-solar-regulations/article_8499a49d-e281-5dd7-aae7-aecccfa0394e.html.

[26] Catherine Morehouse, *Montana Judge rules PSC intentionally set PURPA rates to kill solar projects*, Utility Dive (April 8, 2019), https://www.utilitydive.com/news/montana-judge-rules-psc-intentionally-set-purpa-rates-to-kill-solar-project/552236/; *see also* Complaint at ¶ 3-8, FERC v. Idaho Public Utilities Commission, No. 1:13-cv-141 (2013) ("Notwithstanding FERC's four declaratory orders issued over the course of more than one year, the Idaho Commission has not taken voluntary corrective measures). *See, e.g.,* SEIA Counterproposal at 25-32 (describing anticompetitive conduct that was not remedied by state commissions).

[27] *See* SEIA Counterproposal at 20-22 (explaining that many of PURPA's most vocal opponents, who claim that they do not need or want the power offered to them by independently-owned QF resources, are simultaneously proposing to develop renewable resources that they will own and include in their ratebases upon which they earn a return).

impediments identified by Congress have been resolved and, in doing so, fails to propose design reforms that are consistent with the statute.

2. FERC's Justifications for the NOPR's Proposal are Flawed

Despite clear Congressional intent to implement the statute in a manner that *encourages* the development of Qualifying Facilities, the NOPR fails to address this fundamental directive. Instead, the NOPR questions the value of the statute based on "important changes in circumstances that prompted Congress to pass PURPA in 1978."[28] If Congress determined that changes to the electricity market warranted another amendment of PURPA, Congress is enabled to make such changes as was done in EPAct 2005. The NOPR explains that the agency is changing its PURPA implementation program because (1) the availability of natural gas has changed completely; (2) PURPA is not the main driver supporting entry of renewable resources; and (3) 29 states and the District of Columbia have mandatory Renewable Portfolio Standard ("RPS") programs.[29] These factors do not bear on the Congressional intent underpinning PURPA. Even if Congress's intent in passing PURPA was ambiguous – which it is not – the Commission is required to undertake actions that further a reasonable interpretation of congressional intent.[30] An agency action is arbitrary and capricious if the agency has "relied on factors which Congress has not intended it to consider, entirely failed to consider an important aspect of the problem, offered an explanation for its decision that runs counter to the evidence before the agency, or is so implausible that it could not be ascribed to a difference in view or the product of agency expertise."[31]

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[28] NOPR at P 19.

[29] NOPR at PP 19-24.

[30] *Chevron,* 467 U.S. at 843.

[31] *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43 (1983) ("*State Farm*").

a. Congress did not intend that FERC consider natural gas generators a substitute for QFs.

The Commission is correct in its observation that there is an increased supply of natural gas resulting from advanced production techniques that have opened up large new natural gas reserves, but this does not justify the revisions proposed by the Commission. PURPA's express intent is *to reduce* the electric power system's reliance on fossil fuels.[32] PURPA was not designed to "provide incentives to address shortages of natural gas,"[33] but was designed to encourage use of alternative energy sources as an alternative to natural gas.[34] As the Commission itself has recognized, "With PURPA, Congress was seeking to diversify the Nation's generation fuel mix and promote more efficient use of fossil fuels when they were used for generation by encouraging renewable technologies and cogeneration, in order to cushion against further price shock and reduce dependence on fossil fuels."[35]

While natural gas can be a favorable resource in some scenarios, PURPA reflects Congress's goals to prevent utilities from relying on any single source of fuel. Low natural gas prices do not weaken Congress' express goal of promoting diversity in the electric system. Safe, reliable, and reasonably priced electric service requires a diverse portfolio of generation assets. Diversity helps mitigate price volatility and is an important way to avoid potential catastrophic issues with a single

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[32] *FERC v. Mississippi*, 456 U.S. at 750.

[33] NOPR at P 3.

[34] *See So. Cal. Edison*, 71 FERC ¶ 61,269, 62,079 (1995). The Fuel Use Act, passed in conjunction with PURPA, went so far as to prohibit the construction of new gas-fired generation units.

[35] *Id.*

class of generation.[36] QFs, by definition, provide a hedge to the utility against unforeseen natural gas constraints, curtailments, or infrastructure disruptions. The changes to the price and availability of natural gas have not caused Congress to repeal PURPA, and it is not the role of the Commission to act contrary to statutory direction to encourage the development of Qualifying Facilities that do not rely on fossil fuels.[37] The NOPR does not address the plausible scenario in which natural gas prices increase significantly in coming years based on changes in demand, supply, applicable regulations, or other factors, resulting in substantial cost to ratepayers above expected price forecasts. Utilities that overbuild natural gas generation[38] create the same type of overreliance scenario that caused Congress to pass PURPA during the energy crisis in 1978. A current, potentially temporary, increase in the supply of affordable natural gas does not justify the substantial revisions proposed by the Commission in the NOPR.[39]

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[36] For example, in ISO-NE about 50% of the region's generators rely on natural gas and "the price of this single fuel sets the energy market price most of the time." https://www.iso-ne.com/about/key-stats/markets/. As the Commission is aware, the overreliance on natural gas was a substantial contributor to the high prices in California during the Energy Crisis. *See, e.g.,* Final Report on Price Manipulation in Western Energy Markets: Fact Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000 (March 26, 2003).

[37] There is no guarantee that natural gas prices will remain low, and unexpected disruptions in the fuel supply can yield substantial volatility in the electricity markets. *See* Final Report on Price Manipulation in Western Energy Markets: Fact Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000 (March 26, 2003) (explaining the key relationships between natural gas and electricity markets).

[38] In 2008, the Arizona Corporation Commission moved to place a moratorium on new gas plants 150 MW or larger "in effort to protect ratepayers from potential unnecessary capital improvements in the near future and stranded asset costs in the long-term". *Arizona Regulators Move To Place Gas Plant Moratorium on Utilities*, UTILITYDIVE (Mar. 15, 2018), *available at*: https://www.utilitydive.com/news/arizona-regulators-move-to-place-gas-plant-moratorium-on-utilities/519176/.

[39] NOPR at P 29. Most importantly, even if it were the case that the expansion of natural gas reserves might obviate the need for QF development, that is a decision that must be made by Congress, not by the Commission.

b. Markets have not evolved in a manner that makes PURPA redundant.

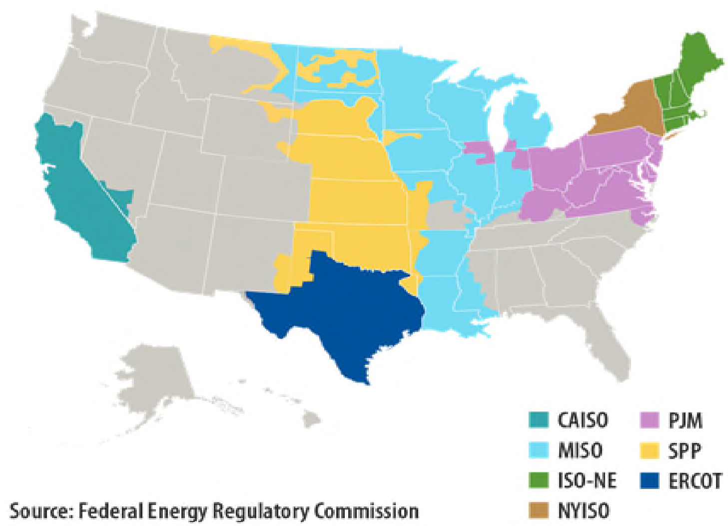
In issuing the regulations implementing Section 210(m) in 2006, the Commission explained that its action "continues to support QF development by ensuring that, where the requirements of section 210(m) are met, QF development will, as determined by Congress, be stimulated by market forces, and that where those requirements have not been met, QF development will continue to be stimulated as it is today through the mandatory purchase obligation."[40] The NOPR does not address what, if any, circumstances have changed since the issuance of Order No. 688.

First, the NOPR's claim that "vertically integrated utilities no longer dominate the wholesale electric markets throughout the United States as they did in the past"[41] is inaccurate and the NOPR's recitation of the gross amount of energy produced by independent power is misleading. The Commission is well-aware that the Southeast and much of the Pacific Northwest, Desert Southwest, and Mountain West regions have largely resisted changes in generation ownership or increased competition in wholesale generation. Utility consolidation over the past forty years has led to fewer, larger, and more powerful multi-state utility monopolies. In these regions, the market structure largely resembles that of 1978, with a single monopoly buyer that has the incentive to build, own, and ratebase new resources. As shown in Figure 1, approximately a third of the country still operates outside of organized wholesale electric markets, a fact that is overlooked in the NOPR. Notably, FERC has not approved any new ISO/RTO regions since the issuance of Order No. 688, and no other markets of comparable quality have emerged since that time.

[40] Order No. 688 at P 6.

[41] NOPR at P 29.

Figure 1: Wholesale Electric Power Markets



Incumbent utilities enjoy monopoly status, are insulated from direct competition, and, absent PURPA, have little or no motivation to purchase wholesale power from independent power producers. Not only does this preclude the likely cost-savings to ratepayers associated with competitive wholesale markets, it means that independent power producers have no other meaningful source of offtake, which substantially discourages QF development in those states. Nearly all new generation being built is owned by a utility or under a long-term offtake contract. Accordingly, where a state has failed to join an ISO/RTO or where a utility continues to maintain vertical integration, the landscape for independent power producers remains largely the same as it was forty years ago. As the noted industry economists Borenstein and Bushnell explain, "After a tumultuous period from 1996 to 2005, the regulatory/legal status of electricity restructuring – in generation, transmission, distribution and retailing – has changed little in the last decade."[42]

[42] Borenstein and Bushnell, The U.S. Electricity Industry after 20 Years of Restructuring, Energy Institute at Haas Working Paper, 20 (2015), https://ei.haas.berkeley.edu/research/papers/WP252.pdf.

Second, the NOPR glosses over vital distinctions in inaccurately claiming that "the participation of independently owned generation no longer is the exception but is the rule in much of the country."[43] As Figure 2 demonstrates, based on data assembled by the Energy Information Administration ("EIA"), in ten states the total IPP penetration is under 10%.[44]

Figure 2

State	Utilities	IPP	Total
Alaska	99.00%	1.00%	100.00%
Arkansas	91.53%	8.47%	100.00%
Florida	95.94%	4.06%	100.00%
Kentucky	99.09%	0.91%	100.00%
Louisiana	91.06%	8.94%	100.00%
Missouri	93.82%	6.18%	100.00%
South Carolina	96.92%	3.08%	100.00%
Tennessee	99.64%	0.36%	100.00%
Utah	90.17%	9.83%	100.00%
West Virginia	94.10%	5.90%	100.00%

In states where IPP generation is between 10 and 20 percent of the market, solar resources make up a small fraction of the generation mix even though the states listed in Figure 3 are suitable to solar development.

Figure 3

State	Total IPP	Solar IPP
Arizona	11.89%	3.98%
Georgia	11.75%	1.37%
Iowa	18.87%	0.01%
Indiana	16.77%	0.18%
Mississippi	13.40%	0.53%

[43] *Cf.* NOPR at P 29.

[44] A full chart is provided in Appendix 1, reflecting the breakdown of IPP generation by fuel source as derived from EIA Detailed State Data and the report titled *1990–2018 Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923)*, released on October 22, 2019, *available at*: https://www.eia.gov/electricity/data/state/

North Carolina	10.66%	4.27%
Nebraska	14.78%	0.07%
Oregon	19.36%	0.97%
Washington	11.20%	0.0%

In these states, and others, PURPA is the backstop protection for competition and may be the only pathway in which a QF can sell to a buyer in the state; a fact the NOPR wholly ignores.

In regions where wholesale electric markets exist, the markets provide varying levels of access to QFs. For example, while many utilities within SPP and MISO have relinquished their control as transmission operators, these utilities have retained monopoly control over generation planning and procurement. In other words, these utilities largely do not rely on competitive markets to procure the energy needed to serve their load and instead continue to self-generate. In these vertically-integrated territories within ISOs/RTOs, QFs continue to lack meaningful market access to a buyer other than the interconnected utility, and the NOPR fails to address the substantial barriers to entry for QFs within these monopoly-controlled regions which mirror many of the issues discussed above in the context of vertically-integrated monopoly utilities in non-RTO regions.

There are over 3,000 purchasing utilities in the United States,[45] but 80 percent of the nation's electricity is supplied by the regulated monopoly provider, as shown in Figure 4, with most competitive sales occurring in just a handful of states as shown in Figure 5.

[45] Francisco Flores-Espino et. Al, Competitive Electricity Market Regulation in the United States: A Primer, National Renewable Energy Laboratory. 5 (2016), https://www.nrel.gov/docs/fy17osti/67106.pdf.

Figure 4[46]

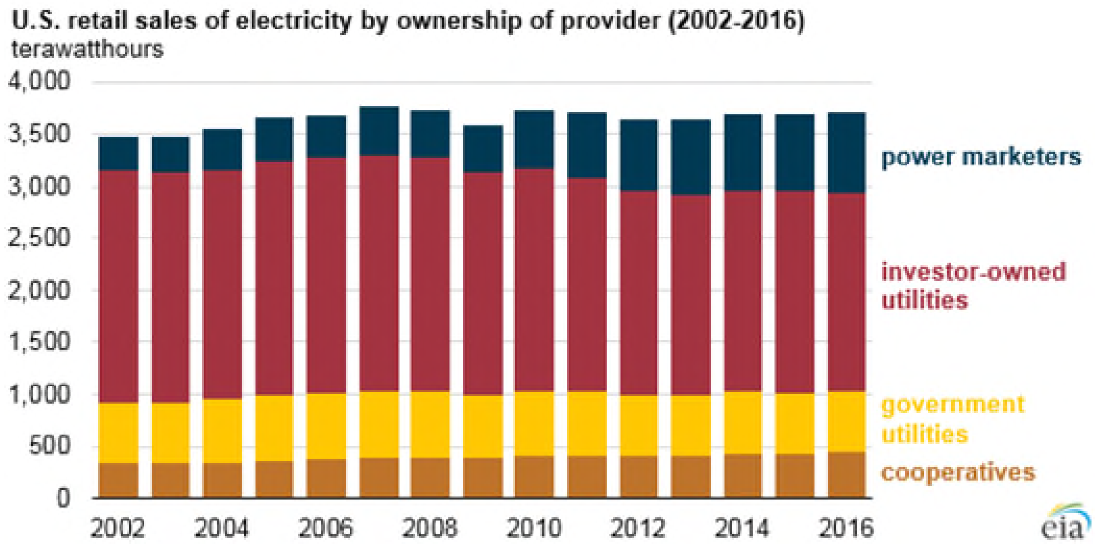


Figure 5

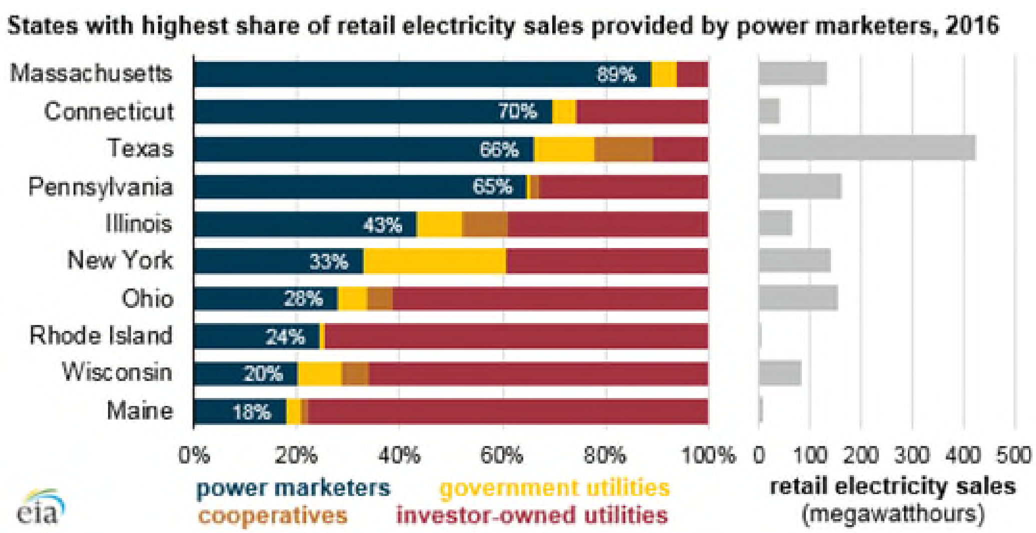


Figure 5 demonstrates that in 40 states, power marketers have less than an 18 percent share of the retail market. While the EIA data that serves as the basis for these figures reflects the state of

[46] *Power Marketers are Increasing their Share of U.S. Retail Electricity Sales*, U.S. Energy Information Administration: Today in Energy (June 12, 2018), https://www.eia.gov/todayinenergy/detail.php?id=36415.

competition in the industry at a high level, it is more relevant to the measure of competition and access to buyers than the total gross amount of electricity produced by independent power nationally cited in the NOPR.[47] As Appendix 1 reflects, in the majority of the states in the U.S., purchasing utilities still enjoy significant market power as buyer and sellers within their territories and there is little competition from the types of resources that Congress instructed this Commission to encourage.

As the data reveals, PURPA's fundamental purpose of ensuring that independent small power producers and cogenerators can obtain market access remains as necessary today as it was in 1978. Given the Commission's interest in the state of competition in US electric markets, SEIA would encourage a deeper Commission inquiry or study into the status of electric markets and competition. The U.S. solar industry is ready, willing, and able to compete, but in many places, the opportunities are significantly limited and controlled by monopsony buyers with market power

c. Policies in some states to encourage renewable development do not justify proposed reforms on a nationwide basis.

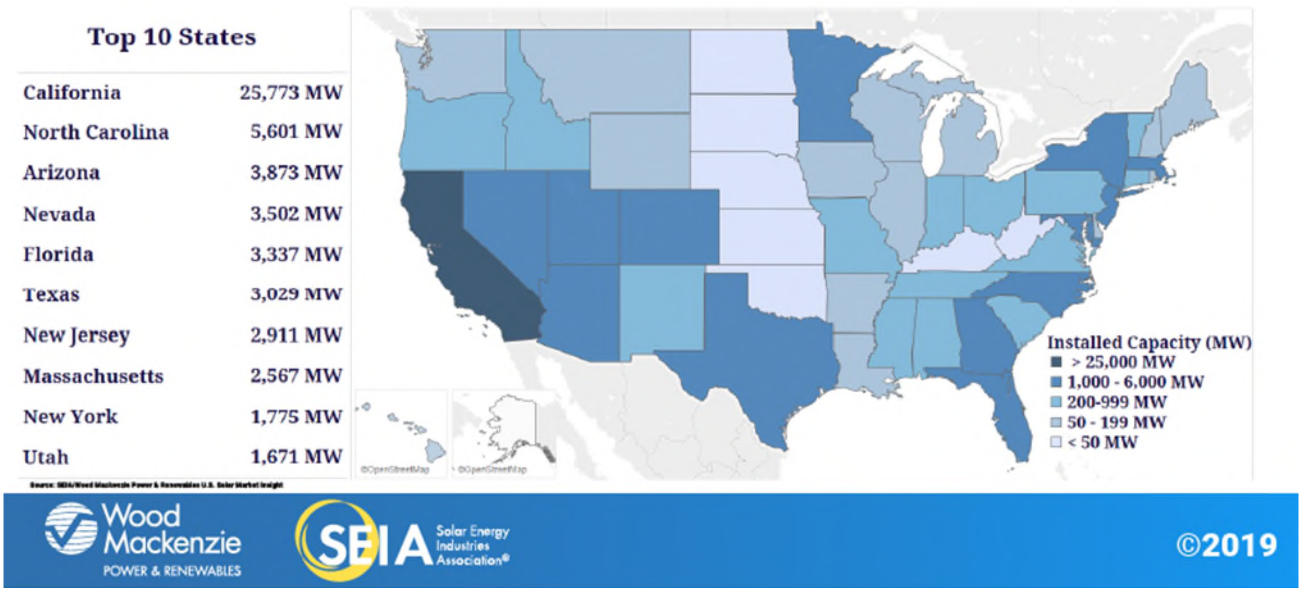
The NOPR correctly states that state-initiated efforts to promote carbon reduction and deploy RPS programs "[have] further influenced increasing investment in renewables in the United States."[48] The Commission incorrectly concludes, however, that these developments justify the proposed revisions. It is for Congress, not the Commission, to determine whether PURPA is now redundant or unnecessary. While the Commission explains that "29 states and the District of Columbia have mandatory RPS programs," the NOPR fails to acknowledge that this leaves 21 states

[47] NOPR at P 27.

[48] NOPR at P 23. The justifications in the NOPR do not support revising the PURPA program in states with vertically-integrated utilities that do not operate under an RPS compliance program.

without such programs and it does not speak to the size or effectiveness of such programs in those 29 states. Moreover, in states like Florida, the majority of the installed renewable capacity is utility self-builds even though QFs are willing to compete to provide the same service at a rate that is less than the cost to the utility.[49] As shown in Figure 6, while state programs have driven the development of solar in some states, in the 21 states that do not have an RPS program, deployment is substantially less.

Figure 6



Even if each of the remaining states passed an RPS program, the existence of state policies to incentivize the development of carbon-free generation does not affect the Commission's role in implementing PURPA. As the Commission explained in Order No. 69, "While the rules prescribed under Section 210 of PURPA are subject to the statutory parameters; the States are free, under their

[49] *See Developers Struggle to Find a Way In as Florida's Utility-Scale Solar Market Shines*, GREENTECH MEDIA (July 8, 2019), *available at*: https://www.greentechmedia.com/articles/read/a-look-at-floridas-rise-to-the-top-of-utility-scale-solar-rankings.

own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these technologies.[50]"

When the Supreme Court examined the impact of the federal PURPA mandate on state policies, the Court concluded that PURPA was structured in a manner that would allow states to maintain their own regulatory programs structured to meet both state and federal needs.[51] While 29 states and the District of Columbia have deployed RPS programs, such programs are generally "based on the State authority to establish such rates, and not on the Commission's rules."[52] The existence of such state programs, in some but not all of the states in the country, does not support reforms to the PURPA regulations.[53] The existence of state programs that provide additional market entry points for renewable resources does not lessen FERC's duty to carry out Congressional intent. A state's willingness to encourage the development QFs through additional measures, including a Renewable Portfolio Standard, does not lessen FERC's duty to ensure that QFs in every state in the country have the opportunity to access a buyer.[54]

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[50] *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, FERC, 45 Fed. Reg. 12,215, 12,221 (Feb. 25, 1980) ("Order No. 69").

[51] *FERC v. Mississippi*, 456 U.S. at 766-770.

[52] Order No. 69 at 12,221.

[53] Order No. 69 at 12,221 ("Relation to State Programs"); *see also* DSIRE: Renewable and Clean Energy Standards (June 2019), https://s3.amazonaws.com/ncsolarcen-prod/wp-content/uploads/2019/07/RPS-CES-June2019.pdf (overview map of state Renewable & Clean Energy Standards).

[54] Order No 69 at 12,221 ("the States are free, under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these technologies. However, State laws or regulations which would provide rates lower than the federal standards would fail to provide the requisite encouragement of these technologies, and must yield to federal law.")

3. FERC Cannot Abdicate its Role in Implementing a PURPA Framework for the States to Follow

In enacting PURPA in 1978, Congress charged the Commission with promulgating rules "necessary to encourage cogeneration and small power production" and "require electric utilities to . . . purchase electric energy from such facilities" and gave the Commission authority to enforce state commission compliance with such rules as promulgated under PURPA.[55] In so doing, Congress created a unique cooperative federalism system to implement PURPA in which FERC – as the federal body – must establish the QF rules and program to guide the states in their individual applications of the federal guidance.[56] EPAct 2005 did not change this basic system.

While SEIA appreciates the Commission's deference to state commissions and the offer of flexibility to accommodate unique situations, FERC must observe and fulfill its role in setting the PURPA framework. FERC cannot abdicate its PURPA responsibilities in the name of offering a state "flexibility" that has the ultimate effect of discouraging Qualifying Facilities. Congress intended that FERC would implement the statutory directives to develop regulations that would ensure QF development was encouraged across the country, and the Commission must continue to perform this function under existing or revised rules. Providing States with access to tools that may be used to discriminate against Qualifying Facilities and discourage QF development is inconsistent with the statute.[57]

The Commission must continue to ensure that there are federal regulations that encourage QF development in all regions across the country, while allowing states sufficient flexibility to ensure

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[55] 16 U.S.C. § 824a-3(h).

[56] *FERC v. Mississippi*, 456 U.S. at 751.

[57] 16 U.S.C. § 824a-3(a)(b)(2).

that rates are just and reasonable. When considering whether and how to delegate authority to the state commissions, the Commission must face the truth that some (not all) jurisdictions have demonstrated disregard for both QFs and the Commission's rules and orders implementing PURPA.[58] It is the role of this Commission to ensure that states are applying FERC's rules.

4. SEIA Renews its Request for Reforms to Encourage QF Development

As SEIA explained in the underlying docket, QFs are viable competitors to the utility and are facing a return of anticompetitive practices largely directed at preventing solar generators from obtaining a financeable contract, even when such contract is based on the costs the utility would otherwise pay.[59] Independent developers are motivated to utilize the market access opportunities that PURPA creates to drive further innovation and cost reduction in the industry, particularly in states that lack competition against the incumbent utility. PURPA's fundamental purpose of ensuring that Qualifying Facilities can compete with incumbent monopoly utilities remains as necessary today as it was in 1978. SEIA respectfully requests that the Commission reconsider the proposed reforms and focus on ensuring that competition by QFs can continue where it otherwise is prevented and that incumbent utilities do not impede the development of these resources through anticompetitive conduct.[60]

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[58] Complaint at ¶ 3-8, FERC v. Idaho Public Utilities Commission, No. 1:13-cv-141 (2013) ("Notwithstanding FERC's four declaratory orders issued over the course of more than one year, the Idaho Commission has not taken voluntary corrective measures); *see also* Tom Lutey, *Hot mic records troubling conversation about solar regulation,* BILLINGS GAZETTE, June 27, 2019, https://billingsgazette.com/news/state-and-regional/govt-and-politics/hot-mic-records-troubling-conversation-about-solar-regulations/article_8499a49d-e281-5dd7-aae7-aecccfa0394e.html.

[59] *See* SEIA Counterproposal at 10-37.

[60] *See* SEIA Counterproposal at 40-58.

B. Proposed Reforms to QF Rates Must Encourage QF Development and Provide QFs a Reasonable Opportunity to Attract Capital

As SEIA explains herein, the NOPR's reforms that "modify how states are permitted to calculate avoided costs" are inconsistent with the Commission's Full Avoided Cost determination, and neither the reasoning in the NOPR nor the record in the underlying proceeding support such a departure. While certain portions of these reforms may be defensible, others are an improper implementation of the statutory directive and an arbitrary and capricious departure from Commission precedent. SEIA does not object to incorporating market factors into the otherwise administratively-determined avoided cost of the purchasing utility. In the August 28, 2019 Counterproposal SEIA proposed one such pathway – a competitive bidding program that would relieve utilities of the obligation to pay QFs for avoided capacity costs when the utility satisfies all its needs through a fair and open competitive solicitation.

The NOPR proposes others, including (1) providing states the flexibility to adopt a Locational Marginal Price ("LMP") or liquid market trading hub ("Market Hub") market price, as applicable, as a proxy for the purchasing utility's "as-available" energy rate; (2) providing states "the flexibility to require" that rates paid to Qualifying Facilities in either a contract or through a legally enforceable obligation ("LEO") be determined at the time of delivery rather than being fixed for the term of the contract; and (3) providing states within an ISO/RTO market "the flexibility to instead implement an alternative approach of requiring that the fixed energy rate be calculated based on estimates of the present value of the stream of revenue flows of future LMPs or other acceptable as-available energy rates at the time of delivery."[61] The affidavits of Mr. McConnell and Mr. Shem,

[61] NOPR at P 32.

included as Attachment 2 and 3 respectively, explain how the revisions would discourage QF development by impeding access to capital market financing.

1. SEIA Does Not Oppose LMP and Hub Prices for As-Available Energy Paid at Delivery and Not Under Contract

When the Commission developed its PURPA implementation program it established regulations to give QFs and cogenerators the ability to elect the form of sale: either on an "as-available" basis or as part of a legally enforceable obligation for delivery of energy and capacity over a specified term. The regulations currently provide that the rates for purchases be based, ***at the option of the qualifying facility***, on either the avoided costs at the time of delivery or the avoided costs calculated at the time the obligation is incurred. As the Commission explained in Order No. 69, this regulatory framework was intended "to reconcile the requirement that rates for purchases equal the utility's avoided cost with the need for qualifying facilities to be able to enter into contractual commitments based, by necessity, on estimates of future avoided cost."[62] Where the purchasing utility has not demonstrated that it procures its marginal energy from an LMP or Hub, it should not be permitted to rely on the price discovery point as a reasonable approximation of avoided energy cost. Where such a demonstration has been made, SEIA does not oppose adopting the LMP or Hub price as a proxy for avoided energy costs calculated at the time the obligation is incurred (the "As-Available Energy") so long as there are published prices at the location.[63]

As-Available Energy is energy that is delivered without a legal obligation or contract. In practice, this means that the QF can sell its "excess" production to the utility, when and in what

[62] Order No. 69 12,224.

[63] For example, the EIA provides electricity market data based on the hubs reported by the Intercontinental Exchange ("ICE"), including Mid-C, Malin, Palo Verde, and Mass Hub, amongst others. Any Hub selected for use in the avoided cost determinations must, at a minimum, offer published prices.

quantities the QF determines, with no obligation to provide energy on a consistent basis. For energy that is not delivered pursuant to a contractual commitment (*i.e.,* the quantity and time of delivery are wholly within the control of the QF and the QF is not obligated to follow a predictable delivery schedule), it is appropriate to rely on the applicable LMP or published Hub price to approximate the purchasing utility's avoided cost at the time of delivery of the As-Available Energy. The LMP and Hub prices are generally thought to approximate the purchasing utility's marginal cost for each market interval, and where the purchasing utility procures its marginal generation needs from such markets, it is reasonable to provide states flexibility to set QF payment rates for As-Available Energy at the applicable LMP or published Hub price. "As-available" QF resources are not eligible to participate in an Energy Imbalance Market ("EIM") – either directly or through the purchasing utility – and thus it would be inappropriate to use the EIM price as a proxy where the market does not factor in the participation of the QF resource.

SEIA respectfully requests that the Commission make clear that the flexibility to set QF payment rates for As-Available Energy at the applicable LMP or published Hub requires an on-the-record determination that the purchasing utility procures incremental energy from the identified LMP or Hub market at those prices.[64] The Commission should also make clear that payments based on the LMP or a Hub 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 ("RECs"), frequency response capabilities, pro-rated capacity value, etc.). Finally, the Commission should make clear that the state's flexibility to allow utilities to set QF payment rates for As-Available Energy at the

[64] *See, e.g.,* Comment of Commissioner Slaughter of the Federal Trade Commission at 2, Docket No. RM19-15 (Nov. 26, 2019) (explaining why it is inconsistent with competitive outcomes to allow states to remove a qualifying facility's option for a fixed contract without any similar restriction on incumbent utilities that enjoy long-term revenue security).

applicable LMP or a published Hub does not in any way limit QFs' rights to establish a LEO or contract for a longer-term sale at fixed, full avoided costs.

2. Eliminating a QF's Option to Elect a Fixed Energy Price Discriminates Against QFs and Will Discourage Development

PURPA was implemented to provide small independent developers a meaningful opportunity to sell capacity and energy in vertically-integrated markets. Monopoly utilities can finance their own generation projects because, unlike QFs, they are guaranteed long-term fixed cost recovery from captive customers. Where a utility includes a resource in ratebase or procures energy over a term, whether from its merchant function or from a third-party selling under contract, it is discriminatory to deny QFs the option to elect the same term treatment.[65] Denying fixed energy pricing to QFs is thus both discriminatory and inconsistent with Congress's mandate that the Commission encourage QF development. As explained in the affidavits provided in Attachments 2 and 3, it is the rare case that a QF can secure capital market financing without a fixed price energy component and adopting variable energy payments in place of a known forecasted energy rate will discourage QF development.

a. Fixed Energy Rates are Necessary to Encourage QF Development.

As explained in Attachments 2 and 3, allowing states – particularly those operating outside of ISO/RTO markets – to remove the option for a QF to be paid a rate for energy equivalent to the purchasing utility's long term avoided energy costs will discourage QF development. The Commission has consistently acknowledged the needs of infrastructure investors, recognizing that"in

[65] SEIA appreciates the Commission's acknowledgement of the requirement to provide a firm capacity payment to a QF electing to sell pursuant to the legally enforceable obligation. *See* NOPR at P 72.

order to be able to evaluate the financial feasibility of a cogeneration or small power production facility, an investor needs to be able to estimate, with reasonable certainty, the expected return on a potential investment before construction of a facility."[66] SEIA's members are not asking the Commission to ensure access to favorable financing, but instead ensure the QFs are able to access the capital markets and obtaining regularly available financing that does not depend on special circumstances but instead meets the standard underwriting criteria within the mainstream capital markets.[67]

The NOPR concludes that a QF contract based on As-Available Energy rates that are not known at the time of contracting is sufficient to allow QFs to obtain financing. As Mr. Shem explains, in his substantial experiencing developing QF facilities, capital market providers do not provide backing to QFs based on energy rates that are unknown at the time contracting. 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. As Mr. McConnell details, he is unaware of any QFs that have been developed based on a variable, and unknown, energy rate without a financial hedge to back the revenue stream projections. As both Mr. Shem and Mr. McConnell explain, financial hedge products are not available outside of ISO/RTO markets. The NOPR fails to consider whether its proposed reform will impact regularly available QF financing options and whether there are sufficient financial products in the market to support the conclusion

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[66] Order No. 69 at 12,218.

[67] *See, e.g.,* Direct Testimony of Rebecca Chilton, S.C. Docket No. 2019-195-E (Sept. 11, 2019) (explaining the conditions of regularly-available capital market financing), *available at*: https://dms.psc.sc.gov/Attachments/Matter/1a21940c-f051-4151-9e6d-481e7e04cd7a; Surrebuttal Testimony of Rebecca Chilton, S.C. Docket No. 109-195-E (Oct. 11, 2019) (same), *available at*: https://dms.psc.sc.gov/Attachments/Matter/c2d0aa8a-1369-4071-b043-5aed7a700e87.

that QF projects will be able to obtain financing even without a known energy rate in the contract. Unduly restricting QFs to As-Available Energy rates, and eliminating a QF's option to elect a rate equivalent to the purchasing utility's forecasted avoided energy cost, will limit a QF's access to regularly available financing products and will result in the discouragement of QF development.

To obtain access to regularly available financing vehicles, a QF must secure a contractual commitment to sell the output of the plant at a rate that, when multiplied by the projected generation profile, provides sufficient revenue to pay for the QF's capital costs.[68] While certain merchant natural gas generators did construct new generating units based on a fixed capacity commitment and a market-based energy component, the market realities today are very different than they were just five years ago. Today, major generation owners – including Exelon and Calpine – have consistently made clear that the LMP energy prices in the ISO/RTO markets are not producing rates sufficient to support the continued operation of the existing fleet.[69] The Commission currently has proceedings underway to respond to the claims that energy market revenues will be insufficient to allow these plants to recover their costs, but the PJM proceeding highlights the fundamental flaws in the Commission's conclusion that energy market revenues are sufficient to attract new capital.

While fixed capacity payments and variable energy payments may have supported the entry of natural-gas fired generation, but as both Mr. McConnell and Mr. Shem explain in their affidavits, it would be the rare case that a renewable energy installation was developed and financed on this business model. QFs are distinct from fossil generators in that much of the cost of installation is incurred up-front, but once installed, the generation has little, if any, variable cost. As a

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[68] *Id.*

[69] *See, e.g.,* Millsap, Adam, *State Nuclear Subsidies Not Needed* (Apr. 19, 2019), *available at*: https://www.forbes.com/sites/adammillsap/2019/04/19/state-nuclear-subsidies-not-needed/#7a9613f5111d.

consequence of the high capital costs and virtually non-existent variable costs, capital market financing parties examine the QF's projected revenue stream to ensure that the revenue stream is sufficient to recover the installed costs plus a competitive return. This requires the QF to understand both the energy and capacity value of its installation upfront and to secure those commitments through a legally enforceable contract in a manner that will comport with common underwriting models.

The Commission improperly points to organized capacity market and hedging mechanisms such as contracts for differences to support its claim that fixed energy pricing is not needed in any market in the country. These "financial products" discussed by the Commission are not available outside of ISO/RTO markets, and where they are available, require substantial sophistication to access. Even in organized wholesale markets, SEIA is not aware of any significant number of QFs having been financed and built based on capacity payments alone and/or capacity payments with a variable energy component. The NOPR fails to consider what markets offer financial products, whether those financial products are available to QFs outside of an ISO/RTO, and whether such financial products will be sufficient to attract financing. Failing to examine these relevant factors is arbitrary and capricious.

As Mr. McConnell and Mr. Shem explain in their respective affidavits, to encourage QF development the Commission must ensure that QFs that commit to deliver energy over the term know the energy price at the time of contracting. Where energy will be procured over a known term, the purchasing utility is gaining hedging value from the QF contract and can optimize the resource as a revenue stream in connected markets. SEIA does not oppose the NOPR's proposal to allow "fixed energy rates to be based on forecasted estimates of the stream of revenue flows during the term of the contract,"[70] so long as such rates are known at the time of contracting and are non-discriminatory. SEIA strongly supports the Commission's holding that prior to revising the computation of forecasted energy costs, the utility **must** have published rates that separate state the energy, capacity, and environmental attribute components of the QF rate.

b. Restricting a QF to As-Available Energy rates is inconsistent with Full Avoided Cost.

PURPA requires that rates paid to QFs "shall not discriminate against qualifying cogenerators or qualifying small power producers."[71] As the Supreme Court explained, FERC's adoption of Full Avoided Cost requires utilities to pay QFs a rate equivalent to "the cost the utility would have incurred had it generated the electricity itself or purchased the electricity from another source"[72] These costs that a utility can avoid by purchasing from a QF are generally classified as either "energy costs" or "capacity costs"; with energy costs including the variable costs associated with producing electric energy such as fuel, operation, maintenance, and line losses.[73] When a QF elects to deliver energy and capacity over a term pursuant to a legally enforceable obligation (*i.e.,* a contract) there is insufficient record evidence to conclude that the LMP or Hub price rate reflects the purchasing utility's Full Avoided Costs. SEIA is unaware of any utility in the country that procures all its energy from an LMP or Hub market.[74] Where a QF contract will enable a purchasing utility to

[70] NOPR at P 61.

[71] 16 U.S.C. § 824a-3(b)(2).

[72] *American Paper*, 461 U.S. 402, 404 (1983).

[73] Order No. 69 at 12,216; 18 C.F.R. § 292.304(e)(4).

[74] *See, e.g., Causes and Lessons of the California Electricity Crisis*, CONGRESSIONAL BUDGET OFFICE (Sept. 2001) (explaining how limiting the utilities ability to enter into long-term contracts, combined with the mandated exclusive reliance on the short-term ISO and PX markets, were contributing factors to the Energy Crisis).

avoid the cost to construct a new generating plant or procure energy from another source, Full Avoided Cost mandates that the QF be compensated in full for the value.

Nothing in the record indicates that the LMP or Hub price approximates the purchasing utility's Full Avoided Cost. As SEIA explained previously, some of PURPA's most vocal utility opponents are simultaneously seeking to foreclose market opportunities for QFs while committing to build and own these exact same technologies.[75] For example, as SEIA documented in the record, PacifiCorp foreclosed QF and third-party market opportunities in Utah, Oregon, and Wyoming, and then later selected resources that it would build and own to fulfill its future resource needs.[76] In justifying the value of the company-owned resources, PacifiCorp relied on long term energy price forecasts, not the Mid-Columbia Hub spot price.[77] Where the purchasing utility does rely on an LMP or Hub to support resource acquisition, particularly for resources that it intends to own and include in rate base, the state should not be provided the flexibility proposed in the NOPR.

PURPA requires comparable and nondiscriminatory treatment. SEIA has consistently advocated for fair treatment and a level playing field and using an "apples-to-apples" comparison of avoided energy costs is the essence of the statutory directive to avoid discriminating against QFs. The Commission should make clear that a state commission cannot allow a purchasing utility to set its energy price for avoided cost at a price less than the actual cost the utility incurs in procuring energy. Allowing a state to require a QF to accept an LMP or Hub price when that QF has

[75] SEIA Counterproposal, at 20-21.

[76] *Id.* at 25-28.

[77] *See* Bates White Final Report on PacifiCorp's 2017R Request for Proposals to the Oregon Public Utility Commission at 15 ("Oregon IE Report"), available at https://www.utc.wa.gov/_layouts/15/CasesPublicWebsite/GetDocument.ashx?docID=848&year=2016&docketNumber=160353 (explaining that production cost modeling used to develop the "value of energy").

committed to deliver its energy over a term is discriminatory and inconsistent with the Commission's well-entrenched Full Avoided Cost standard.

Limiting QFs to as-available pricing would also be contrary to Congress's implicit requirement that all QFs must have the ability sell energy and capacity on a short- and long-term basis. Section 210(m) of PURPA, enacted as part of the 2005 EPAct, allowed utilities to obtain a waiver of the mandatory purchase obligation if they could demonstrate that QFs had nondiscriminatory access to markets in which to sell energy and capacity on a short-term and long-term basis.[78] This requirement reflects the Congressional intent that *all* QFs have the ability to sell energy and capacity on a short-term and long-term basis and clearly implies that QFs that do not have access to markets of the type described in Section 210(m)(1) must also be able to sell to their incumbent utility on a short-term or long-term basis through as-available pricing or pursuant to a LEO, respectively. By allowing states to limit QFs to short-term as-available pricing, FERC would be acting contrary to the clear intent of Congress. There is insufficient record evidence to conclude ratepayers are harmed by fixed energy payments to QFs that have committed to deliver over a term.

[78] Section 210(m)(1) states that a utility is not required to enter into new contracts with QFs if QFs have nondiscriminatory access to:

> (A)(i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or
> (B)(i) transmission and interconnection services that are provided by a Commission- -approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or
> (C) wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

In designing PURPA, the intent of the Congressional drafters was to "make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives."[79] A PURPA purchase will occur only when the "QF sells at a price no higher than the cost the utility would have incurred for the power if it had not purchased the QF's energy and/or capacity."[80] In calculating avoided cost rates for QF power, state authorities must determine the cost the utility avoids by considering the cost of alternative sources of power available to the utility.[81] In Order No. 69 the Commission explained that the statute does not require "a minute-by-minute evaluation of costs which would be checked against rates established in long term contracts between qualifying facilities and electric utilities."[82] The Commission must critically examine whether it is accurate that "allowing QFs to fix their avoided cost rates at the time a LEO is incurred has resulted in overpayments."[83] An expert witness for South Carolina's Office of Regulatory Staff, which represents the interests of the using and consuming public, testified before the state commission 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]."[84] The NOPR does not examine the "actual procurement requirements, and resulting costs" of a purchasing utility,[85] and fails to acknowledge the significant

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[79] *So. Cal. Edison*, 71 FERC at 62,079-80.

[80] *Id.*

[81] *Id.*

[82] Order No. 69 at 12,224.

[83] NOPR at P 39.

[84] Appendix 1: Public Service Commission of South Carolina Docket No. 2019-185 & 186-E, Hearing Transcript Vol. 2 at 596, lines 6 – 21.

[85] *See Cal. Pub. Util. Comm'n*, 133 FERC ¶ 61,059, P 26 (2010).

role that forward contracts play in a well-functioning market. The NOPR fails to address the central issue of any avoided cost determination: "what costs the electric utility is avoiding."[86]

Purchasing from QFs allows utilities to avoid constructing new power plants that would be included in the utility's rate base and recovered over a period of 20-50 years. The Commission is well-aware that, recently, there have been several high-profile cases where vertically-integrated utilities sought millions, and in some cases *billions*, of dollars from their ratepayers to fund substantial cost overruns for new utility-owned construction.[87] The NOPR fails to examine the cost-savings that could have accrued to ratepayers had these utilities foregone the construction opportunity and instead purchased from QFs. Had the utilities in South Carolina or Georgia purchased from QFs in lieu of constructing the V.C. Summer and Vogtle plants, respectively, ratepayers would have "avoided" billions of dollars in unnecessary cost expenditures. South Carolina Electric & Gas sought to recover $4.9 billion from ratepayers after abandoning V.C. Summer.[88] The Vogtle reactors were expected to cost a total of $14 billion, but recent estimates put the cost estimate around $27.5 billion – and construction is not yet complete.[89] There is no evidence

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[86] *Id.*

[87] *See, e.g., PGE – and ratepayers – off the hook for $130M cost overruns on Boardman plant*, PORTLAND BUSINESS JOURNAL (July 18, 2018) (explaining how ratepayers had been funding a $514M liability), *available at*: https://www.bizjournals.com/portland/news/2018/07/18/pge-and-ratepayers-off-the-hook-for-130m-cost.html; *Investigation: Xcel failures led to reactor cost overruns*, STAR TRIBUNE (Feb. 3, 2015) (explaining the results of an ALJ's investigation concluding that mismanagement led to $402 million in cost overruns).

[88] *See, Death of a Nuke Build: Summer Abandonment Leaves Ratepayers Holding the Bag*, UTILITY DIVE (Aug. 4, 2017) (explaining that South Carolina customers face 60 years of cost recovery), *available at*: https://www.utilitydive.com/news/death-of-a-nuke-build-summer-abandonment-leaves-ratepayers-holding-the-bag/448597/.

[89] *See, Georgia PSC Backs Additional Costs for Vogtle Nuclear Project*, POWERMAG (Feb. 19, 2019), *available at*: https://www.powermag.com/georgia-psc-backs-additional-costs-for-vogtle-nuclear-project/.

in the record to demonstrate that QF contracts harm ratepayers given the construction of uneconomic utility-owned generating assets.

Once a regulator approves the construction of a utility-owned generating plant, the costs are passed onto consumers through regulated electricity prices over the life of the investment, independent of the fluctuation of the market value of the investment over time due to changing energy prices, improving technology, or evolving supply and demand conditions. This structure allocates the risk of investment in generating capacity to ratepayers. PURPA was designed to shift this risk to independent market actors and lessen the burden on ratepayers, and that goals remains just as salient today as it was forty years ago. Long-term forward contracts are the foundation of the electric power industry. The claim that QF contracts are somehow more harmful to ratepayers than other long-term contracts or approved rate recovery of utility-owned assets is unsupported and inaccurate. In Order No. 69 the Commission recognized the "need for qualifying facilities to be able to enter into contractual commitments, based, by necessity on estimates of future avoided costs."[90] Nothing in the record has called that basic conclusion into question. Forward contracts yield recognized benefits in terms of risk management and long-term price and supply certainty, and it is arbitrary and capricious to allow states the option to deny a QF's request to contract at the purchasing utility's avoided cost.

SEIA acknowledges and celebrates that the cost of solar generation resources has declined, substantially, over the past twenty years. The fact that certain utilities' calculations of avoided costs have not been updated in a timely fashion to reflect current market conditions is not the fault of the QF. Utilities solely control whether and how often the they seek to adjust their avoided costs, and

[90] Order 69 at 12,224.

the NOPR fails to examine whether the "overpayments" were due to a stale avoided cost rate that a utility had failed to update.

3. Competitive Solicitations, with Adequate Safeguards, Can Deliver Substantial Value

In its Counterproposal, SEIA offered a significant concession to advocates of PURPA reform and put forth a detailed proposal for how competitive solicitations could be incorporated into the PURPA framework. Under the Commission's current PURPA regulations, whenever a utility has a capacity need, QF have the right to sell their output to the utility and be paid for the capacity they provide at an administratively determined avoided cost rate. Under the SEIA Counterproposal, where a utility seeks to meet identified capacity needs through an open, fairly designed, and independently administered competitive solicitation, (i) the utility would only have to pay QFs for capacity to the extent that the 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.[91] SEIA again urges the Commission to incorporate this concept into its revised PURPA regulations in lieu of the modifications to those regulations objected to by SEIA herein.

As discussed in SEIA's Counterproposal, where a state has created a well-structured, fairly administered, independently-monitored, and completely non-discriminatory process for procuring energy and capacity from new generation resources, SEIA does not oppose competitive solicitations. A competitive solicitation framework, when used in lieu of the existing administratively-determined avoided cost framework, must ensure that purchasing utilities are not allowed to manipulate

[91] *See* SEIA Counterproposal at 17-40.

competitive solicitation programs through the exercise of market power. As the Commission has long-recognized, "lack of market power is the key prerequisite for allowing market-oriented pricing."[92] High levels of concentration in generation ownership and sales are an indicator of the potential to exert market power in a region. Any competitive solicitation program adopted by the Commission must include measures to prevent self-dealing and affiliate abuse and ensure the QF contracts function in their intended way by furthering competitive outcomes.

The proposed reforms to Section 292.304(b)(5) set forth many important safeguards – SEIA supports the Commission's proposal to require that the solicitation process (i) be open and transparent; (ii) open to all sources; (iii) conducted at regular intervals; (iv) subject to oversight by an independent administer; and (v) certified by the state in fulfilling the requirements. The regulations, however, still provide leeway in which a purchasing utility could use the process to discriminate against QFs. For the reasons discussed in SEIA's Counterproposal, SEIA respectfully requests that the Commission supplement proposed Section 292.304(b)(5) to require that:

- Participants are provided with complete and transparent information regarding transmission constraints, levels of congestion, and interconnections; [93]
- Solicitation is linked with the purchasing utility's integrated resource plan and is conducted for the entirety of a utility's anticipated capacity needs;

In addition, SEIA respectfully requests that the Commission expressly implement safeguards to prevent utility self-dealing and affiliate abuse. The Commission has long recognized that self-dealing may arise in transactions where the utility's own assets compete in competitive solicitations

[92] *Ocean State Power*, 44 FERC ¶ 61,261, 61,979 (1988).

[93] *See* New PURPA 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities, Order No. 688-A, 119 FERC ¶ 61,305, ¶ 67 (2007) ("Order No. 688-A").

alongside independent power producers. Many states have not yet evolved to a point that lessens the import of the Commission's long-held observation that "[a]ffiliates may have the incentive to engage in preferential transactions because they share common corporate goals – profits for stockholders that own both entities."[94] For the Commission to find that the rates produced by a competitive solicitation are just and reasonable, the Commission must conclude that the concerns about self-dealing and/or reciprocal dealing have been adequately addressed and resolved.[95]

SEIA is concerned about the potential for affiliate abuse or self-dealing with regards to both the price and non-price terms and conditions. SEIA's Counterproposal presented specific details concerning the practices of PacifiCorp, NorthWestern, Duke, and Xcel; showing that while these utilities work to reduce QFs ability to sell they are simultaneously seeking to build and rate base substantial renewable resources. QFs are now in direct competition with incumbent utilities[96] and must be provided a level playing field on which to compete for any identified new capacity needs. SEIA requests that the Commission make explicit in Section 292.304(b)(5) that discrimination against QFs in favor of utility-owned resources in the course of a competitive will give rise to a cause of action before this Commission. Strengthened enforcement efforts must be part and parcel of an increased reliance on competitive options.

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[94] *See, e.g., Portland Gen. Elec.*, 51 FERC ¶ 61,108, 61,245 (1990); *Midwest Gas Users Ass'n v. FERC*, 833 F.2d 341, 354 (D.C. Cir. 1987) (coincidental economic interests may prevent arm's length bargaining).

[95] *TECO Power Services Corp.*, 53 FERC ¶ 61,202, 61,809-10 (1990).

[96] *See, e.g.,* Roberts, David, *A Major US Utility is Moving Toward 100% Clean Energy Faster Than Expected*, VOX MEDIA (May 29, 2019) (explaining the reasons and rationale for Xcel to ratebase new renewables), https://www.vox.com/energy-and-environment/2018/12/5/18126920/xcel-energy-100-percent-clean-carbon-free.

C. Imposing Unreasonable Prerequisites to LEO Formation Under PURPA Will Discourage QF Development

The NOPR discusses the Commission's concern with ensuring that, once a QF has obligated itself to deliver output to the utility, the purchasing utility will have assurances that the QF will complete development and achieve commercial operation on the promised timeframe.[97] The Commission is also interested in ensuring that, once online, the QF facility remains a safe and reliable generating asset throughout the term of the purchase obligation.[98] SEIA supports these aims, but the test proposed in the NOPR will not lead to achieving the ends the Commission claims to seek.

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. For states that do not publish the avoided costs, or for utilities that treat their avoided cost methodologies as confidential trade secrets, it would be unjust and unreasonable, and discriminatory, to require a QF to incur the substantial expense associated with establishing "commercial viability" without a reasonable understanding of the purchase rate.

Any discussion of the timing of LEO formation needs to be informed by a recognition that QFs (like other project developers) require certainty as to their revenue stream at a reasonable point

[97] NOPR at PP 137-142.

[98] *Id.*

in the development process so that they can justify substantial development expenses and secure project financing. Section 210 mandates that the Commission prescribe "such rules as it determines necessary to encourage cogeneration and small power production,[99]" and promoting a LEO baseline is necessary to encourage QF development and reduce administrative burden on all parties. If the Commission is concerned about "stale" rates, the best way to avoid overly outdated pricing while striking a balance with a QF need for price certainty at a reasonable point in the development process is through timing mechanisms.

The NOPR's proposal – to require QFs to demonstrate "commercial viability" and "financial commitment to construct" while deferring to individual states to determine if the QF's demonstration is sufficient – is unlikely to achieve an efficient or desired result.[100] While SEIA recognizes the cooperative federalism that informs PURPA, there is little benefit to any party in inviting 50 different tests for LEO formation. This approach will result in endless litigation before the Commission and in the courts and is not consistent with Congressional goals. SEIA recognizes the tension in creating a federal LEO standard, but all parties – QFs, utilities, ratepayers, state commissions, and FERC – will be better served if the Commission adopts a baseline for a LEO to guide the industry. SEIA therefore requests that the Commission craft a more concrete baseline that will guide all parties in determining when a QF is entitled to a purchase contract.

SEIA suggests that a timing mechanism is to link interconnection with the LEO. A developer needs to have a reasonable understanding of the cost and time necessary to interconnect its project prior to entering into a purchase agreement. SEIA also recognizes, unfortunately, that purchasing utilities can manipulate the interconnection process in a manner that discriminates

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[99] 16 U.S.C. § 824a-3(a).

[100] NOPR at PP 140-142.

against QFs. To strike a balance, and acknowledge the link between interconnection and development risk, SEIA suggests that FERC find that the first prerequisite to a LEO formation is 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.[101] 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 556, the Commission should find that the QF is eligible to establish a legally enforceable obligation 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. QFs that wish to secure a term commitment memorialized through a contract would, upon satisfaction of these criteria, be legally entitled to negotiate with the purchasing utility to develop a Power Purchase Agreement ("PPA") setting forth the terms and conditions of purchase, including liability if the QF fails to perform. Projects that reach agreement on price and non-price terms and conditions will proceed according to the terms of the PPA and the purchasing utility can establish milestones with sufficient financial protection to ensure that ratepayers will not be harmed if the QF fails to achieve

[101] While a LEO is most clearly and commonly formed through the execution of a PPA, the Commission, acting on Congressional concern about utility reluctance to enter to PPAs with QFs, has provided that a LEO may also be formed through a non-contractual commitment by the QF. FERC has held that a utility may not avoid the creation of a LEO by refusing to sign a contract, and the Commission should also make clear that a state cannot unreasonably create barriers as a means to prevent the QF from obtaining a contract. SEIA appreciates the NOPR's reaffirmance of unreasonable barriers to LEO formation. NOPR at P 135.

its commercial operation date. This approach allows a QF to obtain a firm purchase commitment sufficient to support financing and also provides a remedy to the utility in the event the project is delayed or cancelled.

D. Proposed Reforms to Relieve ISO/RTO Utilities of Obligation to Purchase from QFs Under 20 MW Lack Foundation

The NOPR also proposes to reduce the threshold for the rebuttable presumption of non-discriminatory access to competitive wholesale markets within RTOs and ISOs from 20 MW to 1 MW.[102] The Commission created the rebuttable presumption framework in response to Congress's enactment of section 210(m) in EPAct 2005, based on the conclusion that QFs with a net capacity no greater than 20 MW do not have nondiscriminatory access to wholesale markets.[103] Section 210(m) did not repeal the purchase obligation, but provided that the Commission could offer an exemption from the purchase obligation if it found that the ISO/RTO provided QFs with a meaningful opportunity to sell energy and capacity over a short and long term.[104] As the Commission then-explained, small QFs – those defined as under 20 MW – were rebuttably presumed *not* to have such access.[105]

The NOPR now asserts that "the markets are more mature, and the mechanics of participation in such markets are improved and better understood" and concludes, without foundation, that QFs "below 20 MW should be able to participate in such markets under most

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[102] NOPR at PP 126-130.

[103] Order No. 688 at ¶ 9.

[104] *See, e.g., American Paper*, 550 F.3d at 1181-83 (explaining that it is reasonable to conclude the markets described in Section 210(m) are inherently competitive).

[105] Order No. 688-A at P 95 (explaining that "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.").

circumstances."[106] SEIA vehemently disagrees with the Commission that any of the factors identified in Order No. 688 with respect to smaller QF access to wholesale markets have been resolved with the passage of time. Today, as was the case in 2006 when the Commission issued Order No. 688, (1) QFs connected to the distribution system face barriers to entry in wholesale markets, particularly in vertically-integrated territories within ISO/RTO markets; and (2) small QFs and less-sophisticated developers continue to face administrative and technical barriers to entry in accessing the long-term markets for energy and capacity operated by the ISOs/RTOs. In addition to these continuing systemic challenges, as the Commission is well-aware, the capacity markets in the ISO/RTO regions have not evolved to provide a meaningful opportunity to sell long-term capacity and to assert, in this proceeding, that these markets are providing any generators with a meaningful opportunity to sell long-term capacity, is disingenuous.[107]

Section 210(m) requires that, prior to relieving the purchase obligation, the Commission must find that the QF has nondiscriminatory access to the ISO/RTO markets. That fact that the markets exist, and that some entities participate in these markets, is not sufficient to meet the statutory standard for waiver. In the November 2016 Notice of Proposed Rulemaking "*Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators*" (the "DER NOPR") the Commission expressed concern that distributed energy resources "may face barriers that limit them from participating in organized wholesale electric

[106] NOPR at P 126.

[107] *See, e.g.,* Letter from Electric Power Supply Association to PJM Board of Managers (Nov. 14, 2019) (explaining the market pressure resulting from the continual delay in the capacity auctions), *available at*: https://epsa.org/wp-content/uploads/2019/11/EPSA-Letter-to-PJM-Board-re-Capacity-Mkt-Revisions-11.14.2019.pdf

markets."[108] The Commission and its staff conducted a two-day technical conference in April 2018 where the legal and technical barriers preventing distribution-connected resources from participating in the ISO/RTO markets were explored.[109] Data requests were issued to each of the ISO/RTO market operators in September 2019 seeking information on the interconnection process for distribution-connected resources as well as QFs, and the substantial (and varied) responses that were submitted in October 2019 confirm that "there is much work to be done to accommodate the unique characteristics of DER units."[110] After receiving the responses from each of the ISO/RTO regions, it is unclear how the Commission can genuinely take the position in this proceeding that distribution-connected resources or QFs have nondiscriminatory access to these markets. As the Commission explained in the DER NOPR, "Where rules designed for traditional generation resources are applied to new technologies, where new technologies are required to fit into existing participation models, and where participation models focus on the eligibility of resources to provide services more so than the technical ability of resources to provide services, barriers can emerge to the participation of new technologies in the organized wholesale electric markets."[111]

1. Distribution-Connected QFs Do Not Have Non-Discriminatory Access to ISO/RTO Markets

SEIA acknowledges that each ISO/RTO has distinguishing features, but no ISO/RTO offers non-discriminatory access for distribution-connected resources. While there is no strict size

[108] Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,121 at P 7 (Nov. 17, 2016) ("DER NOPR").

[109] *See Notice Inviting Post-Technical Conference Comments*, Docket No. RM18-9 (Apr. 27, 2018) (describing the technical conference and seeking further input).

[110] FERC Docket RM18-9, Response to Data Request of Midcontinent Independent System Operator, Inc. under RM18-9-000, 2 (Oct. 7, 2019). ("MISO Response").

[111] DER NOPR at P 2.

threshold for a QF to be distribution-connected, most distribution-connected QFs are between 1-20 MW. As the Commission explained in Order No. 688, QFs connected to the distribution grid may be faced with "technical enhancements required to move power injected into such facilities upstream to the transmission grid to access the broader wholesale market" and are "more likely to have to overcome other obstacles, such as jurisdictional differences, pancaked delivery rates, and perhaps additional administrative procedures, to obtain access to distant buyers."[112] None of this has changed.

The recent responses to the DER Data Requests highlight the challenges faced by distribution-connected resources. SPP explains that "There is no DER directly participating in the SPP Integrated Marketplace."[113] The outlook in MISO is similar, with MISO explaining that "the application of current rules to DERs remains untested in practice and MISO's responses consequently are to some degree hypothetical."[114] Each ISO/RTO explained the substantial hurdles to interconnecting distribution-level resources, with MISO succinctly explaining that processing requests for interconnection from distribution-connected resources "likely will require carefully-considered adjustments to MISO's interconnection rules in order to address the unique challenges presented by DERs, such as defining a permissible geographic scope, refining study processes to account for changes to aggregations, and enhancing coordination procedures with the diverse distribution providers in the MISO region."[115]

[112] Order No. 688-A at P 96.

[113] FERC Docket RM18-9, Response of Southwest Power Pool, Inc. to September 5, 2019 Data Request under RM-18-9, 7 (Oct. 4, 2019). ("SPP Response").

[114] MISO Response at 2.

[115] MISO Response at 3.

While ISO-NE has a substantial penetration of DERs, the data responses confirmed that when an existing facility that has interconnected under a state-jurisdictional process transitions to participate in the wholesale markets, the existing facility will be required to initiate a new interconnection request and be restudied.[116] In practice, most developers of small projects are discouraged by the high costs and lack of accountability in the ISO-NE interconnection process, which has encouraged developers to connected under better-organized state programs. When taken together, the ISO/RTO responses to the September 2019 data requests confirm that distribution-connected resources, including QFs, do not have non-discriminatory access to the wholesale markets.

Further, the conditions identified by the Commission in Order No. 688 continue to exist. Distribution-connected resources face rate pancaking in a number of territories where the host utility imposes a "Wholesale Distribution Charge" or a "Wholesale Distribution Access Charge," if they can obtain access to the distribution system at all. The cost to add telemetry and advanced communication equipment to smaller distribution-connected resources remains a barrier to entry, with many resources finding that such technical costs exceed the project's projected wholesale revenues. And states have now taken the position before the D.C. Circuit on appeal that allowing distribution-connected resources access to the wholesale markets is a matter entirely within the *state's* discretion.[117] In the face of this evidence, and the substantial ongoing work at the Commission to explore the barriers to entry facing distribution-connected resources, the NOPR's

[116] FERC Docket RM18-9, Response of ISO New England Inc. to September 5, 2019 Data Request under Rm18-19, 15-16 (October 7, 2019). ("ISO-New England Response").

[117] *See Brief of the National Association of Regulatory Utility Commissioners*, D.C. Cir. No. 19-1142 (Oct. 31, 2019); *Brief of the American Public Power Association*, D.C. Cir. No. 19-1142 (Oct. 31, 2019).

proposal to find that resources 1 to 20 MW in size now have non-discriminatory access to wholesale markets is arbitrary, capricious, and inconsistent with reasoned decision-making.

2. Certain ISO/RTO Regions Do Not Provide Opportunity to Sell Long-Term Capacity

Section 210(m) allows for a waiver of the mandatory purchase obligation only where the Commission has found that QFs have non-discriminatory access to a market for long-term sales of capacity. The NOPR fails to address this crucial statutory element and does not acknowledge that, despite the passage of time, certain ISO/RTO regions do not provide QFs with any opportunity to sell long-term capacity. For example, MISO administers a "Planning Resource Auction" that only provides a one-year purchase arrangement. PJM is not procuring capacity given the Commission's July 2019 Order. SPP does not have a centralized capacity market at all. These facts matter, and the NOPR has failed to consider the current market realities and the inability of QFs to avail themselves of an opportunity to sell capacity long-term to a buyer other than the purchasing utility within ISO/RTO regions. Without a finding that the ISO/RTO markets provide QFs with an opportunity to sell long-term capacity, the Commission cannot relieve purchasing utilities of the obligation to buy from QFs under 20 MW. PURPA exists to *encourage* a certain class of resources, and while Section 210(m) provides a relief valve when the QF has access to other short and long-term sales opportunities, where such opportunities do not exist the statute requires that the mandatory purchase obligation is preserved.

3. The Commission Should Investigate the Status of Market Access, Not Just Assume It

PURPA modernization cannot and should not be a one-way street. As mentioned above, the solar industry is ready, willing, and able to compete. SEIA applauds the Commission's encouragement of retail access as a means of relieving utilities of the burden to PURPA's must purchase obligations. In all other markets, the Commission should take a hard look at the status of competition and market access before eliminating PURPA's requirements to encourage QFs. As SEIA explained in its Counterproposal, a significant reason that PURPA accounts for only a modest portion of total renewables deployment is that PURPA has not been appropriately implemented in many states.[118] From SEIA's perspective, the uneven growth in Qualifying Facilities among states is not evidence of PURPA's modern-day irrelevance, but rather is evidence of the inconsistency and inadequacy of PURPA's implementation in many states. Qualifying Facilities that are able to sell at the utility's avoided cost are supporting PURPA's important statutory goals of fuel diversity and national security and contributing to the overall resilience of the system, while simultaneously placing downward pressure on the utility's incremental cost to serve.

SEIA's members have experienced discrimination in non-price terms and conditions in numerous states where vertically-integrated utilities remain the dominant generation owners and wholesale markets are less developed and liquid. When presented with commercially unreasonable contract terms by utilities, as frequently occurs, developers often are faced with the untenable choice of either abandoning a project to preserve their equity or funding costly litigation or formal arbitration efforts (which may or may not be successful) against the incumbent utilities with the authority to recover all such legal and expert expenses through rates, which allows a purchasing utility to drain developers' limited equity resources by forcing them to expend substantial legal and operational fees on gatekeeping issues.[119]

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[118] SEIA Counterproposal at 40-46.

[119] *See, e.g.,* SEIA Technical Conference Testimony at 4-5; SEIA Post-Technical Conference Comments at 7-15; SEIA 2018 Supplemental Comments at 24-30; SEIA Counterproposal at 43-46.

SEIA encourage the Commission to refocus its PURPA modernization efforts on ensuring transparency in the computation and publication of avoided costs. The failure of utilities to update their avoided costs, or the failure of state regulators to implement a reliable avoided cost methodology, are not problems that can be attributed to QFs or PURPA itself. While SEIA acknowledges the reality that administratively-determined avoided cost rates may never perfectly reflect the utility's actual avoided costs, utilities and state commissions have tools and resources at their disposal to improve avoided costs. Accurate and granular rate designs send the most accurate price signals possible and deploying such rates should be the first step taken to modernize PURPA and increase transparency.

E. Proposed Reforms to Self-Certification and the One Mile Rule Will Substantially Increase Regulatory Burdens on QFs Contrary to Congressional Intent

The reforms proposed in the NOPR to the One Mile Rule and Form 556 are severe, and as SEIA has pointed out numerous times, there is a lack of any evidence in the record that any "gaming" has occurred under the current construct. Purchasing utilities have a pathway by which they can currently raise any gaming challenges on a project-specific basis, and the Commission has an established process to waive the declaratory order filing fee if necessary.[120] As the 1978 Conference Report makes clear, burdensome public utility regulation was one of the main barriers impeding the development of independent generators that the statute's drafters sought to relieve through the passage of PURPA. The proposed changes to the Self-Certification procedures and the One Mile Rule run contrary to Congressional intent and will impact thousands of entities.[121] These

[120] 18 C.F.R. § 381.106(a).

[121] SEIA notes that there were approximately 4,000 QF certifications received by the Commission in the past two and a half years.

proposed changes will increase the regulatory burden and discourage QF development are not consistent with FERC's statutory mandate and could cause unintended harm to thousands of entities.

In Order No. 732, FERC explained that the purpose of Form 556 was to "increase the effectiveness of the Commission's policies encouraging cogeneration and small power production, as required by section 210 of [PURPA]"[122] and "was intended, in part, to make the certification process quick and not unduly burdensome."[123] The proposed reforms to the Self-Certification process and Form 556 itself – both in encouraging challenges to self-certifications and redefining what constitutes the "same site" – will unwind the reforms which the Commission achieved through Order No. 732. If the proposed reforms in the NOPR are adopted, the Self-Certification process will no longer be quick and it will become unduly burdensome for all parties, including the Commission and its staff.

1. NOPR Fails to Account for Harm to QFs that Do Not Sell to Purchasing Utility

In the NOPR, the Commission estimates that each QF self-certification or re-certification will only face an additional burden of 8 hours with a cost of $632 per docket. SEIA believes this is a substantial underestimation of both time and cost and is not aware of the record from which such estimates were derived. Commercial, industrial, and residential QF installations all submit a Form 556 to the Commission to memorialize the facility designation for the non-utility buyers and associated financing parties. As Sunrun explained in its Petition for Declaratory Order, "the need to monitor the geographic concentration of hundreds of thousands of systems nationwide and to update

[122] FERC Docket RM18-9, Response to Data Request of Midcontinent Independent System Operator, Inc. under RM18-9-000, 2 (Oct. 7, 2019). ("MISO Response")

[123] Order No. 732 at P 8.

QF certifications continuously will become unduly burdensome for residential PV developers, and will generate certification filings too voluminous and duplicative to be of any use to the Commission."[124] Sunrun provided details of the burden of continuously filing and updating Form 556s for distributed generation assets, explaining that "without the waivers, it will be compelled to monitor the geographic concentration of its PV systems (currently numbering 202,000 in 22 states) and to generate a highly burdensome number of initial filings and continuously update them, resulting in voluminous and duplicative filings that provide little information of use to the Commission."[125] As Sunrun explained, and as the Commission is aware, numerous facilities offer residual energy and capacity into wholesale markets and rely on QF status to obtain exemptions from the FPA and PUHCA for the jurisdictional transactions with buyers other than the host utility. These QFs that do not sell to the purchasing utility rely on QF status to maintain important and necessary exemptions from regulation that Congress specifically granted in order to attract investment into the industry. The NOPR fails to explain the reason for increasing the regulatory burden these small facilities that do not sell to host utilities will face under the Revised Form 556.

Further, the burden Sunrun described will only be increased exponentially if the One Mile Rule is expanded into the "Ten Mile Rule." As the Commission noted in Order No. 732, while QF certification filings from facilities 1 MW or less represent only approximately one half of one percent of QF capacity certified, these submissions represent "48 percent of all QF filings."[126] The flood of self-certification filings and updates that would flow in from these QFs would be a

[124] Petition for Declaratory Order of Sunrun, Inc. at 2, Docket No. EL18-205 (Sept. 24, 2018) ("Sunrun Petition").

[125] *See Sunrun Inc.*, 167 FERC ¶ 61,059 (2019).

[126] Order 732 at P 35.

substantial burden on the Commission staff and would provide little value to the Commission or the public. The increased regulatory burden that will arise for these facilities if the Ten Mile Rule is adopted is not addressed in the NOPR, but if adopted, the administrative burden that these entities face in order to remain in compliance with the Commission's regulations will be significant greater in comparison to the status quo. When the Commission considered, and ultimately rejected, collecting Connected Entity information it gave substantial weight to the comments of Berkshire and EEI, among others, recognizing that "Berkshire states that its subsidiaries with market-based rate authority do not have ready access to information about their more than 5,000 commonly owned affiliates and lack the ability to require their affiliates to provide information regarding their activities" as well as EEI's belief that "the actual time required to make baseline and subsequent update filings would greatly exceed the [cost and time] estimates provided in the NOPR."[127] After consideration of the burden of Connected Entity collection, the Commission has deferred consideration of such information collection to Docket No. AD19-17 for possible consideration in the future.[128] Unless and until the Commission makes a determination on the burden associated with collecting, reporting, and updating the Connected Entity information, it would be unjust and unreasonable for the Commission to impose similar burdens on QF entities through the Form 556. 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 for QFs that do not sell to purchasing utilities.

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[127] *See Data Collection for Analytics and Surveillance and Market-Based Rate Purposes*, Order No. 860, 168 FERC ¶ 61,039, P 183 (2019).

[128] *Id.* at P 184.

The negative impact is not limited to QFs under 1 MW. Other small facilities, particularly those under 20 MW that have been installed more than one (1) mile apart, could now lose their FPA and PUHCA exemptions if there are multiple such facilities within a ten-mile radius. For QFs that are not selling to the host utility, this is a substantial harm and will have a negative impact on numerous investors that relied on the existence of such regulatory exemptions in making their investment decisions. 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."[129] When the Commission undertook a revision to the regulatory exemptions in Order No. 671 it acknowledged the hardship smaller QFs would face in losing regulatory exemptions and, based on a weighing of the evidence and comments submitted therein, preserved the regulatory exemptions for small QFs. There has been no record evidence in this proceeding to justify, or call into question, the Commission's determination in Order No. 671 that exemption from regulation is part and parcel of the Commission's obligation to encourage QF development. Attempting to consolidate unrelated commercial, industrial, and residential site installations within a ten-mile radius, where such sites are developed and sold to different customers and are financed under separate and distinct arrangements, is not just and reasonable and is inconsistent with the statutory directive.

The exemptions that the Commission established in Order No. 671 are necessary and appropriate, particularly for QFs that are not selling to the host utility, and the NOPR wholly fails to explain how these burdensome proposals are consistent with the statute or Commission precedent. The underlying proceedings did not provide any notice of this dramatic departure from precedent.

[129] 16 U.S.C. § 824a-3(e)(1).

2. The Proposed Reforms to Form 556 are Inconsistent with Precedent

When the Commission removed the contents of the Form 556 from Part 131 of the Commission's regulations through Order No. 732, it was intended that substantive changes to this form *would not* require a rulemaking and instead that "Future changes to [Form 556] would be reviewed by the Office of Management and Budget following a solicitation of comments from the public on proposed changes."[130] Order No. 732 was issued in 2010 and the Commission does not devote any effort in the NOPR to explain why it has now initiated a formal rulemaking to revise Form 556 when it expressly stated that its intent was otherwise. As the Commission then-explained, the process of Self-Certification is intended to be both informative and simple.[131]

The proposed item 8b to the Form 556 would require a listing of all affiliated facilities whose nearest electrical generating equipment is greater than one mile and less than ten miles from the electrical generating equipment of the certifying-QF. This 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. As the Commission explains, the intent of this new requirement is to determine if entities that would not otherwise meet the definition of affiliate in 18 C.F.R. §35.36(a)(9) "should be treated as an affiliate."[132] 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 findings on the burden of collecting Connected Entity information.[133] The Commission's suggestion that it could broaden the definition of

[130] Order No. 732 at P 21.

[131] *Id*.

[132] NOPR at P 106.

[133] *See* Order No. 860 at P 184.

"affiliate" in only the QF context is concerning, and is directly contrary to the statutory instruction to relieve QFs from burdensome public-utility style regulation. Collecting such information, and particularly collecting with the intent of imposing more stringent affiliate requirements on QFs than are imposed on other participants in the electric industry, constitutes unwarranted discriminatory treatment and is arbitrary and capricious. Requiring QFs to complete the new item 8b, and imposing an ongoing update obligation, ignores this history and the intent of the Form 556, is an abuse of discretion, inconsistent with Order Nos. 732 and 860, and contrary to the Congressional directive to relieve QFs of the burdens of public utility regulation. Proposed item 8b should not be accepted into the Form 556.

3. The Proposed Challenge Procedures Unfairly Burden QFs

As the Commission is aware, unlike the purchasing utilities, QFs do not recover their legal and regulatory operation costs from ratepayers. The potential burden of defending numerous Self-Certifications over a facility's life is unduly burdensome and discriminatory for this class of resources. Under the NOPR's proposed reforms, and the Commission's policy on updating the information in a Form 556, a QF could be forced to recertify any time the information represented changes, including ownership changes to affiliated facilities located within ten miles. As Avangrid explained in the context of the Connected Entity collection proposal, these types of upstream ownership information collection requirements increase the burden on market participants "without any demonstration that doing so is necessary for FERC to achieve its statutory objectives."[134] Avangrid estimated that the regulatory burden on reporting Connected Entity information would impose, upon each of its companies, "approximately 180 to 220 hours to comply with FERC's

[134] Comment of Avangrid, Inc. in response to the July 21, 2016 Notice of Proposed Rulemaking at 7, Docket No. RM16-17 (Sept. 19, 2016).

requirements during the initial year of implementation" and an additional "approximately 90 to 120 hours per year to comply with FERC's proposals, including monitoring for any material changes triggering a reporting obligation, submission of change in status and quarterly update filings, and ongoing training for employees."[135] If FERC accepted the revisions to Form 556 and imposed a Ten Mile Rule, SEIA believes that these estimates are a reasonable approximation of the burden QFs would face in complying with these new requirements. Further, under FERC's proposal, it is easily foreseeable that a QF will have to engage in multiple defenses of its status. At each such turn, the QF will need to engage legal counsel and devote scarce internal company resources to preserve the status of its already-installed plant. As the Commission recognized in the NOPR, most QFs are small businesses, and the potential burden here is substantial.[136]

Most troubling is that the NOPR lacks important details that could impact a QF's legal rights: including whether the Commission's determination is subject to rehearing and whether such a final decision can be appealed under the Federal Power Act to an appellate court. Under the prior procedure, the Commission has clearly-established method for issuing declaratory orders and seeking review of the same, and the courts have precedent for the deference owed to declaratory orders. In providing for a different challenge process, one arising out of a QF self-certification docket, the NOPR has left vital procedural questions unanswered and it is unclear if the QF would ever have a path to relief if the Commission erred in its determination. Given that an adverse determination by FERC could impose substantial harm to any QF, potentially upwards of $100 million in harm, this is a crucial procedural issue that must be resolved before the challenge

[135] *Id.* at 13-14.

[136] *See also* Attachment 2 (providing a copy of an affidavit on behalf of Patrick McConnell, explaining that QFs would be required to rely on development capital to fund such efforts).

procedures are accepted. The original balance, where the QF self-certified based on the Form 556 issued with Order No. 732 and the challenger bore the responsibility of seeking declaratory relief, struck the appropriate balance. The NOPR's proposed reforms to allow for challenge to a QF's self-certification impose an unfair burden on QFs in contravention of Congressional intent and should be rescinded in favor of retaining the existing procedure.

4. Adopting the Ten Mile Rule Will Discourage QF Development

The statute provides that a QF is a facility that "has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 MW."[137] FERC has the exclusive jurisdiction in defining what it means for a facility to be at the "same site," and in Order No. 70 FERC set forth a standard to implement the 80 MW limitation.[138] This has become known as the One Mile Rule.

In Order No. 732, the Commission denied a request to consider changes to the One Mile Rule. In the Order No. 732 proceeding, EEI had requested that the Commission reconsider the One Mile Rule and instead "adopt a rebuttable presumption that facilities on sites located more than a ten-mile apart are independent for purposes of QF certification, with a utility or other interested party able to rebut that presumption by showing that two or more facilities are part of a common enterprise."[139] FERC declined to consider the issue, explaining that "the one-mile rule has been part of the Commission's regulations since the initial implementation of PURPA."[140] The NOPR does

[137] 16 U.S.C. § 796(17)(a)(ii)

[138] FERC Order No. 70, Small Power Production and Cogeneration Facilities—Qualifying Status, 45 Fed. Reg. 17,959 (March 20, 1980) ("Order No. 70")

[139] Comments of the Edison Electric Institute at 3, Docket No. RM 09-23 (Dec. 22, 2009).

[140] Order No. 732 at n.38.

not address this precedent or explain what justifies the departure from the conclusion reached by the Commission in Order No. 732.

a. Establishing an irrebuttable presumption that facilities located within one mile are at the "same site" is unjust and unreasonable.

SEIA opposes the proposed regulatory changes to irrebuttably presume that facilities located within one mile or less are at the same site. This is an unexplained, and unjustified, departure from precedent. In establishing the One Mile Rule, FERC held that it would aggregate "the capacity of all facilities which use the same energy resource, are owned by the same person, and are located within one mile of each other."[141] Recognizing the somewhat arbitrary nature of the One Mile Rule, FERC explained that "Where it appears that rigid application of the rule would classify a number of facilities as being on the same site, when a common sense conclusion would reach the opposite result, the Commission believes it is appropriate to waive the rule."[142]

The NOPR departs from this well-reasoned precedent and proposes establishing an "irrebuttable presumption" that will eliminate the common-sense application of the rule. FERC has granted waiver of the One Mile Rule where facilities were closely located but specific conditions warranted a conclusion that the facilities were installed at separate sites.[143] The Commission has likewise denied waiver where the sites were not distinct.[144] There is no record to justify a rigid application of the One Mile Rule and to abandon the common sense approach that the Commission has utilized to-date. Solar generating facilities are installed in retail locations, hospitals, schools,

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[141] Order No. 70, at 17,965.

[142] *Windfarms, Ltd*., 13 FERC ¶ 61,017, 61,032 (1980) ("Windfarms, Ltd.")

[143] *Id.*

[144] *Vulcan/BN Geothermal Power Co*., 52 FERC ¶ 61,095 (1990)

residential, and other commercial and industrial sites, some of these facilities being located within One Mile of each other. Establishing an irrebuttable presumption that all installations within a geographic radius constitute a single site, without taking into account relevant details that demonstrate the separate nature of the sites (*e.g.*, a behind-the-meter industrial site development and a separate installation on the grounds of a hospital) is arbitrary, capricious, and not consistent with reasoned decisionmaking. The Commission must preserve a facility's ability to request waiver of the One Mile Rule when a rigid application would produce an arbitrary result.

b. Applying the "Ten Mile Rule" will discourage QF development and will discourage investment in the electric industry.

The NOPR proposes to establish a Ten Mile Rule that finds that affiliated projects located more than one mile, but less than ten miles, "are actually part of a single facility, and not separate facilities."[145] The Ten Mile Rule runs contrary to the Commission's precedent in *El Dorado County Water*, where the Commission explained that this "critical test under PURPA relates to whether the facilities are located at one site rather than whether they are integrated as a project."[146] The Ten Mile Rule, in the proposed form, appears to turn this analysis on its head and 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.

By transforming the analysis from a site-specific analysis into an integrated-project analysis the NOPR fails to examine the impact and disruption to existing facilities that installed their assets based on the Commission's long-established precedent on the One Mile Rule. The level of potential

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[145] NOPR at P 94.

[146] *El Dorado Co. Water Agency and El Dorado Irrigation Dist.*, 24 FERC ¶ 61,280, 61,578 (1983).

harm to many different parties cannot be overlooked and must be weighed against any "value" in expanding the rule tenfold. Expanding the radius for the same site determination will not encourage QF development, as less facilities will be eligible for qualification and administrative burdens will be crippling. Each of these facilities could be on distinct parcels of land with separate points of interconnection, but if they happened to be financed by the same investors and lender and built by the same contractors, SEIA understands that there is a chance these will be aggregated into the "same site," leaving all projects within the ten mile radius ineligible for QF status. Such a result is patently unreasonable and inconsistent with the long-established precedent. Adopting the Ten Mile Rule will discourage the development of future QFs, jeopardize the investment community's confidence in FERC's regulatory regime, and will have wide-reaching consequences throughout the electric power sector.

Nothing in the record supports the Ten Mile Rule. The One Mile Rule has been in place for forty years and has provided certainty, predictability, and stability to the industry. It is not uncommon for a single developer to mitigate its development risk by concentrating its development activities in areas where it has had previous success with permitting, with staged projects that are initially developed in the same area, but soon transferred to separate owners and operators. Revising the "same site" standard into an "integrated project" standard, without an adequate justification to do so, is arbitrary and capricious and not consistent with reasoned decisionmaking. Retroactively applying the Ten Mile Rule to physical facilities that were developed based on the 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. Adopting the Ten Mile Rule will discourage these QFs from developing future distributed energy resource aggregations, will discourage developers from installing separate commercial and industrial sites in a small geographic region, and will impose substantial friction in the rooftop solar industry as the owners and operators of hundreds of separate facilities attempt to parse whether any could be considered located at the "same site". This increased burden is an unnecessary and substantial disincentive to development and is inconsistent with the Congressional directive. Retroactive application of the Ten Mile Rule for existing facilities would constitute a manifest injustice.[147]

It is important to note that application of the Ten Mile Rule, procedurally, will occur through the Self-Certification challenge procedures. With the potential risks of application of the Ten Mile Rule, it is imperative that the Commission make clear the parties rights to review, challenge, and appeal such determinations. As noted above, the current proposal does not provide a clear pathway for appellate review of an adverse determination. Under the Administrative Procedures Act, declaratory orders are non-coercive, meaning they cannot impose a penalty, sanction or other liability. Neither Section 210(g) nor 210(h) appear to provide a pathway by which a QF could seek appeal of an adverse determination. Self-certifications are not filed under the Federal Power Act and the Federal Power Act does not provide the Commission with the grant of authority to make the same site determinations. It cannot be the case that a QF is prevented from seeking review and challenge to FERC's determinations, particularly where the consequences of an adverse determination are so severe.

[147] The D.C. Circuit has articulated a non-exhaustive list of factors used to evaluate a claim of manifest injustice: (1) whether the particular case is one of first impression, (2) whether the new rule represents an abrupt departure from well-established practice or merely attempts to fill a void in an unsettled area of law, (3) the extent to which the party against whom the new rule is applied relied on the former rule, (4) the degree of the burden which a retroactive order imposes on a party, and (5) the statutory interest in applying a new rule despite the reliance of a party on the old standard.

VI. CONCLUSION

As discussed herein, many elements of the NOPR are inconsistent with the Congressional intent and the statutory directive and other elements are unsupported by evidence in the record and based on the false premise that development in organized wholesale markets justify rescinding market opportunities in monopoly service territories. SEIA encourages the Commission to consider Congressional intent and statutory purpose in developing its final rule and respectfully requests that the Commission decline to adopt the reforms that would: (1) eliminate the QF's option to elect a term energy commitment and a forecast energy rate; adopting such revisions will discourage QF development; (2) impose unreasonable barriers as prerequisite to formation of a legally enforceable obligation; adopting such revisions will discourage QF development; (3) find that QFs under 20 MW have non-discriminatory access to buyers other than the host utility within ISO/RTO markets; adopting such a revision is arbitrary and capricious and will discourage QF development; and (4) reform Form 556 and the One Mile Rule; adopting such revisions will impose substantial burdens and will discourage QF development.

Respectfully submitted,

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December 3, 2019

ATTACHMENT 1

ATTACHMENT NO. 1
TO
OPENING COMMENTS OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION[1]

State	Energy	Utilities	IPP	Total
AK	Coal	6.17%	0.00%	6.17%
	Hydroelectric Conventional	26.43%	0.00%	26.43%
	Natural Gas	51.19%	0.00%	51.19%
	Other	-0.06%	0.00%	-0.06%
	Petroleum	13.51%	0.00%	13.51%
	Wind	1.75%	1.00%	2.75%
State Total		99.00%	1.00%	100.00%
AL	Coal	23.41%	0.00%	23.41%
	Hydroelectric Conventional	8.22%	0.00%	8.22%
	Natural Gas	14.95%	23.98%	38.93%
	Nuclear	29.11%	0.00%	29.11%
	Other	0.00%	0.00%	0.00%
	Other Biomass	0.00%	0.03%	0.03%
	Petroleum	0.02%	0.02%	0.04%
	Solar Thermal and Photovoltaic	0.02%	0.24%	0.26%
State Total		75.73%	24.27%	100.00%
AR	Coal	38.09%	8.00%	46.09%
	Hydroelectric Conventional	4.55%	0.08%	4.63%
	Natural Gas	29.21%	0.00%	29.21%
	Nuclear	19.57%	0.00%	19.57%
	Other Biomass	0.00%	0.08%	0.08%
	Petroleum	0.04%	0.01%	0.05%
	Pumped Storage	0.06%	0.00%	0.06%
	Solar Thermal and Photovoltaic	0.00%	0.31%	0.31%
State Total		91.53%	8.47%	100.00%
AZ	Coal	27.52%	0.00%	27.52%
	Hydroelectric Conventional	6.25%	0.00%	6.25%
	Natural Gas	25.86%	7.24%	33.10%
	Nuclear	27.83%	0.00%	27.83%
	Other	0.00%	0.00%	0.00%
	Other Biomass	0.00%	0.03%	0.03%
	Petroleum	0.04%	0.00%	0.04%
	Pumped Storage	0.00%	0.00%	0.00%
	Solar Thermal and Photovoltaic	0.61%	3.98%	4.59%
	Wind	0.00%	0.47%	0.47%
	Wood and Wood Derived Fuels	0.00%	0.16%	0.16%
State Total		88.11%	11.89%	100.00%
CA	Geothermal	0.48%	6.64%	7.12%
	Hydroelectric Conventional	15.19%	0.86%	16.05%
	Natural Gas	18.29%	20.42%	38.71%
	Nuclear	11.11%	0.00%	11.11%

[1] *See* EIA Detailed State Data, *1990–2018 Net Generation by State by Type of Producer by Energy Source* (EIA-906, EIA-920, and EIA-923), released on October 22, 2019, *available at*: https://www.eia.gov/electricity/data/state/.

	Other	-0.01%	0.05%	0.04%
	Other Biomass	0.06%	1.06%	1.12%
	Other Gases	0.00%	0.00%	0.00%
	Petroleum	0.02%	0.00%	0.02%
	Pumped Storage	-0.09%	0.00%	-0.09%
	Solar Thermal and Photovoltaic	0.32%	16.03%	16.35%
	Wind	0.52%	8.03%	8.54%
	Wood and Wood Derived Fuels	0.00%	1.04%	1.04%
State Total		45.87%	54.13%	100.00%
CO	Coal	47.88%	0.00%	47.88%
	Hydroelectric Conventional	2.91%	0.38%	3.29%
	Natural Gas	25.06%	4.36%	29.42%
	Other	0.00%	0.03%	0.03%
	Other Biomass	0.00%	0.08%	0.08%
	Petroleum	0.02%	0.00%	0.02%
	Pumped Storage	-0.48%	0.00%	-0.48%
	Solar Thermal and Photovoltaic	0.01%	1.90%	1.91%
	Wind	0.92%	16.76%	17.69%
	Wood and Wood Derived Fuels	0.00%	0.16%	0.16%
State Total		76.32%	23.68%	100.00%
CT	Coal	0.00%	0.87%	0.87%
	Hydroelectric Conventional	0.11%	1.35%	1.46%
	Natural Gas	0.16%	48.84%	49.00%
	Nuclear	0.00%	44.29%	44.29%
	Other	0.00%	1.22%	1.22%
	Other Biomass	0.00%	1.30%	1.30%
	Petroleum	0.01%	0.86%	0.87%
	Pumped Storage	0.00%	0.01%	0.01%
	Solar Thermal and Photovoltaic	0.01%	0.27%	0.27%
	Wind	0.00%	0.03%	0.03%
	Wood and Wood Derived Fuels	0.00%	0.68%	0.68%
State Total		0.29%	99.71%	100.00%
DE	Coal	0.00%	5.39%	5.39%
	Natural Gas	0.48%	88.32%	88.80%
	Other Biomass	0.00%	0.92%	0.92%
	Petroleum	0.12%	3.79%	3.91%
	Solar Thermal and Photovoltaic	0.12%	0.85%	0.97%
State Total		0.73%	99.27%	100.00%
FL	Coal	12.74%	0.00%	12.74%
	Hydroelectric Conventional	0.10%	0.00%	0.10%
	Natural Gas	68.74%	2.25%	70.98%
	Nuclear	12.37%	0.00%	12.37%
	Other	0.00%	0.64%	0.64%
	Other Biomass	0.04%	0.89%	0.93%
	Petroleum	0.86%	0.01%	0.87%
	Solar Thermal and Photovoltaic	0.86%	0.16%	1.01%
	Wood and Wood Derived Fuels	0.24%	0.11%	0.35%
State Total		95.94%	4.06%	100.00%
GA	Coal	25.85%	0.00%	25.85%
	Hydroelectric Conventional	2.97%	0.01%	2.98%

	Natural Gas	31.72%	9.65%	41.37%
	Nuclear	27.78%	0.00%	27.78%
	Other	0.00%	0.00%	0.00%
	Other Biomass	0.00%	0.24%	0.24%
	Petroleum	0.08%	0.06%	0.15%
	Pumped Storage	-0.40%	0.00%	-0.40%
	Solar Thermal and Photovoltaic	0.24%	1.37%	1.61%
	Wood and Wood Derived Fuels	0.00%	0.41%	0.41%
State Total		88.25%	11.75%	100.00%
HI	Geothermal	0.00%	1.69%	1.69%
	Hydroelectric Conventional	0.30%	0.65%	0.95%
	Other	2.92%	-0.01%	2.90%
	Other Biomass	0.82%	0.78%	1.60%
	Petroleum	76.72%	4.05%	80.77%
	Solar Thermal and Photovoltaic	0.58%	2.25%	2.83%
	Wind	0.00%	9.24%	9.24%
	Wood and Wood Derived Fuels	0.00%	0.00%	0.00%
State Total		81.34%	18.66%	100.00%
IA	Coal	44.19%	0.00%	44.19%
	Hydroelectric Conventional	1.50%	0.01%	1.52%
	Natural Gas	10.99%	0.00%	10.99%
	Nuclear	0.00%	8.02%	8.02%
	Other	0.00%	0.00%	0.00%
	Other Biomass	0.03%	0.18%	0.21%
	Petroleum	0.10%	0.01%	0.11%
	Solar Thermal and Photovoltaic	0.01%	0.01%	0.02%
	Wind	24.31%	10.65%	34.95%
	Wood and Wood Derived Fuels	0.00%	0.00%	0.00%
State Total		81.13%	18.87%	100.00%
ID	Geothermal	0.00%	0.47%	0.47%
	Hydroelectric Conventional	58.15%	4.84%	62.99%
	Natural Gas	8.87%	9.11%	17.98%
	Other Biomass	0.08%	0.12%	0.20%
	Petroleum	0.00%	0.00%	0.00%
	Solar Thermal and Photovoltaic	0.00%	3.18%	3.18%
	Wind	0.91%	14.26%	15.17%
State Total		68.02%	31.98%	100.00%
IL	Coal	2.20%	29.23%	31.43%
	Hydroelectric Conventional	0.03%	0.05%	0.08%
	Natural Gas	0.66%	7.81%	8.47%
	Nuclear	0.00%	53.28%	53.28%
	Other	0.00%	-0.01%	-0.01%
	Other Biomass	0.05%	0.18%	0.23%
	Petroleum	0.00%	0.02%	0.03%
	Solar Thermal and Photovoltaic	0.00%	0.03%	0.03%
	Wind	0.01%	6.45%	6.46%
State Total		2.96%	97.04%	100.00%
IN	Coal	71.72%	0.00%	71.72%
	Hydroelectric Conventional	0.22%	0.00%	0.22%
	Natural Gas	10.76%	11.21%	21.97%

	Other	0.00%	0.00%	0.00%
	Other Biomass	0.31%	0.05%	0.36%
	Other Gases	0.00%	0.00%	0.00%
	Petroleum	0.11%	0.00%	0.11%
	Solar Thermal and Photovoltaic	0.11%	0.18%	0.29%
	Wind	0.00%	5.33%	5.33%
	Wood and Wood Derived Fuels	0.00%	0.00%	0.00%
State Total		83.23%	16.77%	100.00%
KS	Coal	39.67%	0.00%	39.67%
	Hydroelectric Conventional	0.00%	0.05%	0.05%
	Natural Gas	5.66%	0.00%	5.66%
	Nuclear	17.76%	0.00%	17.76%
	Other Biomass	0.00%	0.13%	0.13%
	Petroleum	0.10%	0.00%	0.10%
	Solar Thermal and Photovoltaic	0.00%	0.01%	0.01%
	Wind	3.68%	32.92%	36.61%
State Total		66.88%	33.12%	100.00%
KY	Coal	75.59%	0.00%	75.59%
	Hydroelectric Conventional	5.63%	0.01%	5.64%
	Natural Gas	17.52%	0.89%	18.41%
	Other	0.08%	0.00%	0.08%
	Other Biomass	0.12%	0.01%	0.13%
	Petroleum	0.09%	0.00%	0.09%
	Solar Thermal and Photovoltaic	0.05%	0.00%	0.05%
	Wood and Wood Derived Fuels	0.00%	0.00%	0.00%
State Total		99.09%	0.91%	100.00%
LA	Coal	11.40%	5.87%	17.27%
	Hydroelectric Conventional	0.00%	1.73%	1.73%
	Natural Gas	48.30%	1.23%	49.53%
	Nuclear	25.13%	0.00%	25.13%
	Other	0.00%	0.00%	0.00%
	Other Biomass	0.00%	0.12%	0.12%
	Petroleum	6.22%	0.00%	6.22%
	Solar Thermal and Photovoltaic	0.00%	0.00%	0.00%
State Total		91.06%	8.94%	100.00%
MA	Coal	0.00%	0.00%	0.00%
	Hydroelectric Conventional	1.09%	3.52%	4.61%
	Natural Gas	0.68%	63.85%	64.53%
	Nuclear	0.00%	18.14%	18.14%
	Other	0.00%	3.46%	3.46%
	Other Biomass	0.00%	4.21%	4.21%
	Petroleum	0.30%	1.43%	1.73%
	Pumped Storage	0.00%	-1.89%	-1.89%
	Solar Thermal and Photovoltaic	0.08%	3.90%	3.97%
	Wind	0.24%	0.57%	0.80%
	Wood and Wood Derived Fuels	0.00%	0.44%	0.44%
State Total		2.39%	97.61%	100.00%
MD	Coal	0.00%	22.14%	22.14%
	Hydroelectric Conventional	0.00%	7.07%	7.07%
	Natural Gas	9.45%	19.95%	29.41%

	Nuclear	0.00%	37.43%	37.43%
	Other	0.00%	0.40%	0.40%
	Other Biomass	0.00%	0.60%	0.60%
	Petroleum	0.01%	0.55%	0.56%
	Solar Thermal and Photovoltaic	0.02%	0.94%	0.96%
	Wind	0.00%	1.42%	1.42%
State Total		9.48%	90.52%	100.00%
ME	Coal	0.00%	0.00%	0.00%
	Hydroelectric Conventional	0.00%	36.13%	36.13%
	Natural Gas	0.00%	21.52%	21.52%
	Other	0.00%	0.44%	0.44%
	Other Biomass	0.00%	0.83%	0.83%
	Petroleum	0.00%	1.83%	1.83%
	Solar Thermal and Photovoltaic	0.00%	0.14%	0.14%
	Wind	0.00%	27.37%	27.37%
	Wood and Wood Derived Fuels	0.00%	11.74%	11.74%
State Total		0.00%	100.00%	100.00%
MI	Coal	42.23%	0.00%	42.23%
	Hydroelectric Conventional	1.45%	0.12%	1.57%
	Natural Gas	10.59%	6.87%	17.46%
	Nuclear	25.26%	5.51%	30.77%
	Other	0.00%	0.08%	0.08%
	Other Biomass	0.00%	0.83%	0.83%
	Other Gases	0.15%	0.00%	0.15%
	Petroleum	1.11%	0.00%	1.11%
	Pumped Storage	-0.71%	0.00%	-0.71%
	Solar Thermal and Photovoltaic	0.09%	0.03%	0.12%
	Wind	2.05%	3.46%	5.51%
	Wood and Wood Derived Fuels	0.00%	0.88%	0.88%
State Total		82.22%	17.78%	100.00%
MN	Coal	38.95%	0.00%	38.95%
	Hydroelectric Conventional	1.22%	0.40%	1.62%
	Natural Gas	12.19%	1.00%	13.20%
	Nuclear	24.66%	0.00%	24.66%
	Other	0.31%	0.24%	0.55%
	Other Biomass	0.38%	0.34%	0.72%
	Petroleum	0.05%	0.03%	0.07%
	Solar Thermal and Photovoltaic	0.00%	1.75%	1.76%
	Wind	4.06%	13.99%	18.05%
	Wood and Wood Derived Fuels	0.20%	0.22%	0.42%
State Total		82.03%	17.97%	100.00%
MO	Coal	73.73%	0.00%	73.73%
	Hydroelectric Conventional	1.02%	0.00%	1.02%
	Natural Gas	5.71%	2.52%	8.23%
	Nuclear	13.13%	0.00%	13.13%
	Other	0.00%	0.00%	0.00%
	Other Biomass	0.04%	0.06%	0.10%
	Petroleum	0.12%	0.00%	0.12%
	Pumped Storage	0.06%	0.00%	0.06%
	Solar Thermal and Photovoltaic	0.01%	0.10%	0.11%

	Wind	0.00%	3.49%	3.49%
	Wood and Wood Derived Fuels	0.00%	0.00%	0.00%
State Total		93.82%	6.18%	100.00%
MS	Coal	3.98%	4.60%	8.58%
	Natural Gas	71.35%	8.25%	79.59%
	Nuclear	11.24%	0.00%	11.24%
	Other Biomass	0.00%	0.02%	0.02%
	Petroleum	0.04%	0.00%	0.04%
	Solar Thermal and Photovoltaic	0.00%	0.53%	0.53%
State Total		86.60%	13.40%	100.00%
MT	Coal	0.85%	47.32%	48.17%
	Hydroelectric Conventional	40.66%	0.49%	41.15%
	Natural Gas	1.23%	0.47%	1.70%
	Other	0.00%	1.10%	1.10%
	Petroleum	0.00%	0.05%	0.06%
	Solar Thermal and Photovoltaic	0.00%	0.12%	0.12%
	Wind	0.81%	6.90%	7.71%
State Total		43.55%	56.45%	100.00%
NC	Coal	23.88%	0.03%	23.92%
	Hydroelectric Conventional	4.97%	0.04%	5.01%
	Natural Gas	27.76%	5.10%	32.86%
	Nuclear	31.99%	0.00%	31.99%
	Other	0.00%	0.10%	0.10%
	Other Biomass	0.00%	0.39%	0.39%
	Petroleum	0.43%	0.03%	0.46%
	Pumped Storage	0.00%	0.00%	0.00%
	Solar Thermal and Photovoltaic	0.29%	4.27%	4.56%
	Wind	0.00%	0.41%	0.41%
	Wood and Wood Derived Fuels	0.00%	0.29%	0.29%
State Total		89.34%	10.66%	100.00%
ND	Coal	64.73%	0.00%	64.73%
	Hydroelectric Conventional	7.47%	0.00%	7.47%
	Natural Gas	2.37%	0.00%	2.37%
	Other	0.12%	0.00%	0.12%
	Petroleum	0.09%	0.00%	0.09%
	Wind	9.70%	15.52%	25.22%
State Total		84.48%	15.52%	100.00%
NE	Coal	62.70%	0.00%	62.70%
	Hydroelectric Conventional	3.78%	0.00%	3.78%
	Natural Gas	2.63%	0.00%	2.63%
	Nuclear	15.40%	0.00%	15.40%
	Other Biomass	0.21%	0.00%	0.21%
	Petroleum	0.03%	0.00%	0.03%
	Solar Thermal and Photovoltaic	0.00%	0.07%	0.07%
	Wind	0.46%	14.71%	15.17%
State Total		85.22%	14.78%	100.00%
NH	Coal	3.89%	0.00%	3.89%
	Hydroelectric Conventional	2.18%	5.79%	7.98%
	Natural Gas	0.18%	17.20%	17.38%
	Nuclear	0.00%	59.23%	59.23%

	Other	0.00%	0.28%	0.28%
	Other Biomass	0.00%	0.55%	0.55%
	Petroleum	0.59%	0.36%	0.95%
	Wind	0.00%	2.39%	2.39%
	Wood and Wood Derived Fuels	1.49%	5.86%	7.35%
State Total		8.34%	91.66%	100.00%
NJ	Coal	0.00%	0.02%	0.02%
	Hydroelectric Conventional	0.00%	0.05%	0.05%
	Natural Gas	0.24%	48.65%	48.89%
	Nuclear	0.00%	47.91%	47.91%
	Other	0.00%	0.59%	0.59%
	Other Biomass	0.00%	1.03%	1.03%
	Petroleum	0.00%	0.35%	0.35%
	Pumped Storage	-0.17%	0.00%	-0.17%
	Solar Thermal and Photovoltaic	0.11%	1.18%	1.29%
	Wind	0.00%	0.03%	0.03%
State Total		0.19%	99.81%	100.00%
NM	Coal	41.22%	0.00%	41.22%
	Geothermal	0.00%	0.04%	0.04%
	Hydroelectric Conventional	0.46%	0.00%	0.46%
	Natural Gas	22.39%	12.93%	35.32%
	Other	0.00%	0.00%	0.00%
	Other Biomass	0.00%	0.02%	0.02%
	Petroleum	0.06%	0.00%	0.06%
	Solar Thermal and Photovoltaic	0.81%	3.34%	4.15%
	Wind	0.00%	18.73%	18.73%
State Total		64.94%	35.06%	100.00%
NV	Coal	3.90%	2.82%	6.72%
	Geothermal	0.00%	9.27%	9.27%
	Hydroelectric Conventional	4.90%	0.18%	5.08%
	Natural Gas	65.26%	0.01%	65.27%
	Other	0.08%	0.00%	0.08%
	Other Biomass	0.00%	0.14%	0.14%
	Petroleum	0.02%	0.01%	0.03%
	Solar Thermal and Photovoltaic	0.11%	12.46%	12.57%
	Wind	0.00%	0.84%	0.84%
State Total		74.27%	25.73%	100.00%
NY	Coal	0.00%	0.58%	0.58%
	Hydroelectric Conventional	21.37%	3.80%	25.17%
	Natural Gas	8.83%	22.43%	31.26%
	Nuclear	0.00%	36.53%	36.53%
	Other	0.00%	0.51%	0.51%
	Other Biomass	0.00%	1.13%	1.13%
	Petroleum	0.52%	0.72%	1.24%
	Pumped Storage	-0.37%	0.00%	-0.37%
	Solar Thermal and Photovoltaic	0.00%	0.25%	0.25%
	Wind	0.00%	3.40%	3.40%
	Wood and Wood Derived Fuels	0.00%	0.30%	0.30%
State Total		30.35%	69.65%	100.00%
OH	Coal	7.55%	39.66%	47.21%

	Hydroelectric Conventional	0.18%	0.01%	0.20%
	Natural Gas	6.40%	28.63%	35.02%
	Nuclear	0.00%	14.72%	14.72%
	Other	0.00%	0.00%	0.00%
	Other Biomass	0.00%	0.37%	0.37%
	Petroleum	0.03%	1.02%	1.05%
	Solar Thermal and Photovoltaic	0.01%	0.09%	0.09%
	Wind	0.01%	1.34%	1.35%
State Total		14.17%	85.83%	100.00%
OK	Coal	15.44%	0.00%	15.44%
	Hydroelectric Conventional	2.44%	0.00%	2.44%
	Natural Gas	30.82%	18.54%	49.35%
	Other Biomass	0.00%	0.02%	0.02%
	Petroleum	0.02%	0.00%	0.02%
	Pumped Storage	-0.16%	0.00%	-0.16%
	Solar Thermal and Photovoltaic	0.07%	0.00%	0.07%
	Wind	1.61%	31.20%	32.80%
State Total		50.24%	49.76%	100.00%
OR	Coal	2.53%	0.00%	2.53%
	Geothermal	0.00%	0.30%	0.30%
	Hydroelectric Conventional	60.37%	0.42%	60.79%
	Natural Gas	15.49%	6.32%	21.81%
	Other	0.00%	0.06%	0.06%
	Other Biomass	0.10%	0.36%	0.46%
	Petroleum	0.01%	0.00%	0.01%
	Solar Thermal and Photovoltaic	0.01%	0.97%	0.98%
	Wind	2.13%	10.64%	12.77%
	Wood and Wood Derived Fuels	0.00%	0.28%	0.28%
State Total		80.64%	19.36%	100.00%
PA	Coal	0.00%	20.07%	20.07%
	Hydroelectric Conventional	0.07%	2.02%	2.09%
	Natural Gas	0.00%	34.14%	34.14%
	Nuclear	0.00%	40.94%	40.94%
	Other	0.00%	0.30%	0.30%
	Other Biomass	0.00%	0.77%	0.77%
	Other Gases	0.00%	0.00%	0.00%
	Petroleum	0.00%	0.24%	0.24%
	Pumped Storage	0.00%	-0.32%	-0.32%
	Solar Thermal and Photovoltaic	0.00%	0.02%	0.02%
	Wind	0.00%	1.75%	1.75%
State Total		0.07%	99.93%	100.00%
RI	Coal	0.00%	0.00%	0.00%
	Hydroelectric Conventional	0.00%	0.05%	0.05%
	Natural Gas	0.00%	94.26%	94.26%
	Other Biomass	0.00%	2.58%	2.58%
	Petroleum	0.00%	0.90%	0.90%
	Solar Thermal and Photovoltaic	0.00%	0.35%	0.35%
	Wind	0.00%	1.85%	1.85%
State Total		0.00%	100.00%	100.00%
SC	Coal	20.08%	0.00%	20.08%

	Hydroelectric Conventional	3.02%	0.08%	3.10%
	Natural Gas	19.50%	2.14%	21.64%
	Nuclear	54.32%	0.00%	54.32%
	Other	0.00%	0.00%	0.00%
	Other Biomass	0.09%	0.01%	0.10%
	Petroleum	0.34%	0.00%	0.34%
	Pumped Storage	-0.73%	0.00%	-0.73%
	Solar Thermal and Photovoltaic	0.00%	0.52%	0.53%
	Wood and Wood Derived Fuels	0.30%	0.31%	0.61%
State Total		96.92%	3.08%	100.00%
SD	Coal	18.54%	0.00%	18.54%
	Hydroelectric Conventional	49.67%	0.00%	49.67%
	Natural Gas	9.26%	0.00%	9.26%
	Other	0.00%	0.00%	0.00%
	Other Biomass	0.00%	0.00%	0.00%
	Petroleum	0.05%	0.00%	0.05%
	Solar Thermal and Photovoltaic	0.00%	0.01%	0.01%
	Wind	6.73%	15.74%	22.47%
State Total		84.24%	15.76%	100.00%
TN	Coal	25.67%	0.00%	25.67%
	Hydroelectric Conventional	13.01%	0.00%	13.01%
	Natural Gas	15.87%	0.02%	15.88%
	Nuclear	45.71%	0.00%	45.71%
	Other Biomass	0.00%	0.10%	0.10%
	Petroleum	0.16%	0.00%	0.16%
	Pumped Storage	-0.78%	0.00%	-0.78%
	Solar Thermal and Photovoltaic	0.00%	0.20%	0.20%
	Wind	0.00%	0.05%	0.05%
State Total		99.64%	0.36%	100.00%
TX	Coal	12.09%	16.46%	28.55%
	Hydroelectric Conventional	0.28%	0.01%	0.29%
	Natural Gas	11.30%	29.03%	40.34%
	Nuclear	0.00%	10.52%	10.52%
	Other	0.00%	0.00%	0.00%
	Other Biomass	0.00%	0.11%	0.11%
	Petroleum	0.01%	0.00%	0.01%
	Solar Thermal and Photovoltaic	0.00%	0.82%	0.82%
	Wind	0.07%	19.25%	19.33%
	Wood and Wood Derived Fuels	0.00%	0.04%	0.04%
State Total		23.75%	76.25%	100.00%
UT	Coal	65.89%	1.06%	66.95%
	Geothermal	0.58%	0.58%	1.15%
	Hydroelectric Conventional	2.37%	0.02%	2.40%
	Natural Gas	21.11%	0.19%	21.30%
	Other	0.14%	0.00%	0.14%
	Other Biomass	0.00%	0.17%	0.17%
	Petroleum	0.09%	0.00%	0.09%
	Solar Thermal and Photovoltaic	0.00%	5.75%	5.75%
	Wind	0.00%	2.05%	2.05%
State Total		90.17%	9.83%	100.00%

VA	Coal	9.28%	0.59%	9.87%
	Hydroelectric Conventional	1.86%	0.08%	1.94%
	Natural Gas	35.37%	17.32%	52.68%
	Nuclear	32.10%	0.00%	32.10%
	Other	0.00%	0.35%	0.35%
	Other Biomass	0.00%	1.08%	1.09%
	Petroleum	0.76%	0.18%	0.94%
	Pumped Storage	-1.42%	0.00%	-1.42%
	Solar Thermal and Photovoltaic	0.16%	0.68%	0.84%
	Wood and Wood Derived Fuels	1.32%	0.29%	1.61%
State Total		79.43%	20.57%	100.00%
VT	Hydroelectric Conventional	18.29%	40.00%	58.29%
	Natural Gas	0.03%	0.00%	0.03%
	Other	-0.01%	0.00%	-0.01%
	Other Biomass	0.00%	0.55%	0.55%
	Petroleum	0.14%	0.00%	0.14%
	Solar Thermal and Photovoltaic	1.68%	3.23%	4.91%
	Wind	7.94%	9.22%	17.16%
	Wood and Wood Derived Fuels	11.25%	7.67%	18.92%
State Total		39.33%	60.67%	100.00%
WA	Coal	0.00%	4.68%	4.68%
	Hydroelectric Conventional	70.31%	0.35%	70.66%
	Natural Gas	5.92%	2.79%	8.70%
	Nuclear	8.48%	0.00%	8.48%
	Other	0.00%	0.05%	0.05%
	Other Biomass	0.07%	0.11%	0.18%
	Petroleum	0.00%	0.01%	0.01%
	Pumped Storage	0.02%	0.00%	0.02%
	Solar Thermal and Photovoltaic	0.00%	0.00%	0.00%
	Wind	3.69%	3.22%	6.90%
	Wood and Wood Derived Fuels	0.29%	0.00%	0.29%
State Total		88.80%	11.20%	100.00%
WI	Coal	52.17%	0.00%	52.17%
	Hydroelectric Conventional	3.35%	0.21%	3.57%
	Natural Gas	23.54%	0.72%	24.26%
	Nuclear	0.00%	16.05%	16.05%
	Other	0.03%	0.00%	0.03%
	Other Biomass	0.02%	0.55%	0.57%
	Petroleum	0.22%	0.00%	0.22%
	Solar Thermal and Photovoltaic	0.00%	0.05%	0.05%
	Wind	1.39%	1.16%	2.55%
	Wood and Wood Derived Fuels	0.54%	0.00%	0.54%
State Total		81.25%	18.75%	100.00%
WV	Coal	74.21%	19.49%	93.70%
	Hydroelectric Conventional	0.99%	0.77%	1.76%
	Natural Gas	0.26%	1.36%	1.62%
	Other	0.00%	-0.02%	-0.02%
	Petroleum	0.22%	0.02%	0.24%
	Wind	0.00%	2.69%	2.69%
	State Total	75.68%	24.32%	100.00%

	Coal	86.66%	1.43%	88.10%
	Hydroelectric Conventional	2.17%	0.02%	2.19%
	Natural Gas	0.52%	0.00%	0.53%
	Petroleum	0.09%	0.00%	0.09%
	Solar Thermal and Photovoltaic	0.00%	0.00%	0.00%
	Wind	4.65%	4.45%	9.10%
State Total		94.10%	5.90%	100.00%
US	Coal	22.21%	6.84%	29.05%
	Geothermal	0.03%	0.39%	0.41%
	Hydroelectric Conventional	6.91%	0.62%	7.52%
	Natural Gas	18.60%	13.61%	32.20%
	Nuclear	10.96%	9.89%	20.85%
	Other	0.01%	0.15%	0.16%
	Other Biomass	0.03%	0.39%	0.43%
	Other Gases	0.00%	0.00%	0.00%
	Petroleum	0.44%	0.13%	0.56%
	Pumped Storage	-0.12%	-0.03%	-0.15%
	Solar Thermal and Photovoltaic	0.13%	1.51%	1.63%
	Wind	0.99%	6.04%	7.04%
	Wood and Wood Derived Fuels	0.09%	0.20%	0.29%
US Total		60.27%	39.73%	100.00%

ATTACHMENT 2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Implementation Issues Under the Public Utility Regulatory Policies Act of 1978	**Docket Nos. RM19-15 AD16-16**

Affidavit of Patrick McConnell on behalf of the Solar Energy Industries Association

1. My name is Patrick McConnell and I am providing this affidavit in support of the Comments submitted by the Solar Energy Industries Association ("SEIA") in this important docket regarding the Commission's proposed changes to its rules implementing the Public Utility Regulatory Policies Act of 1978 ("PURPA").

2. I am presently a co-founder and partner at Lacuna Sustainable Investments, a principal investment and advisory firm engaged in deploying funds across the capital spectrum into solar projects in the United States.

3. From 2014 until earlier this year, I served as the Chief Structured Finance Officer and Board member of Cypress Creek Renewables, Inc. ("CCR"), leading CCR's project finance and project acquisition and disposition activities for all projects that cycled through the CCR ecosystem, the majority of which were solar qualifying facilities ("QFs"). During this time, I led a team of 25 investment professionals that closed over $5.0 billion of debt, tax equity, and a project sales involving 3 GW of generating assets in 15 states, including many QF projects.

4. Prior to CCR, I worked for 10 years in different structured finance capacities, most recently at Heelstone Energy, a solar development and investment company I co-founded and led. Prior to Heelstone, I spent time with a number of investment banking firms including Legg Mason Capital Markets, RBS Greenwich Capital, and Stonehenge Capital, at each stop predominantly focused on the sizing, structuring and monetization/securitization of contracted and uncontracted cash flows across a variety of asset classes.

5. I am providing this Affidavit to provide an overview of project financing options available to QFs in order to assist the Commission in understanding the minimum standards a QF must meet in order to secure a typical suite of capital market financing options. While I do not intend for my testimony to be restrictive or definitive, as each financing arrangement will have unique characteristics, in my experience there are certain consistent markers that are common across the capital markets when financing independent power projects, specifically "independent alternative energy generators," as that term has been defined by statute. I want to explain why certain aspects of QF rights provided by PURPA and the Commission's current implementing regulations are necessary to encourage development and financing of solar QF projects. Specifically, a long-term, fixed price for energy in a power purchase agreement (PPA), and the predictable revenue stream that it provides, is the key that unlocks the capital necessary to develop renewable energy projects

6. As a preliminary matter, I'd like the Commission to understand that solar QF developers compete vigorously for capital necessary to develop and finance solar projects. Put simply, the capital intensiveness of the industry is extreme relative to the average size of the entities developing QF projects. Therefore, the reliance on the capital markets is extremely high, and considerations related to financeability are significant determinants of industry health and growth. Utility-scale solar projects have developed longer and longer track records of efficient, low-cost operation while technology risks in solar and inverter technologies have decreased, and investor interest in the solar industry has grown significantly in response. Yet, when seeking the capital to site, permit, purchase equipment for, construct, operate and maintain these facilities, solar QF developers must always compete against other revenue-generating asset classes. Financiers are economically rational in placing investments: they seek to invest capital where it will earn the greatest return for the least amount of risk. Vigorous diligence and scrutiny "weed out" many

non-viable projects at an early stage of the development cycle, such that projects that have secured financing generally come to market within the projected commercial operation schedule. If financiers see greater risk-adjusted returns for other asset classes, they will invest or lend into those asset classes before (or instead of) putting money into solar QF projects.

7. QF developers generally require four types of capital, which can be roughly categorized as development capital, tax equity, long-term debt, and long-term sponsor equity. Solar QF developers compete for all four types, both within the solar industry and amongst the entire energy/infrastructure capital markets. Development capital is the earliest, highest risk, highest return capital. This capital is relied upon before a purchase commitment is secured and is used to pay for interconnection studies, transmission upgrades, real estate development, permitting, and other early stage capital needs. Development capital is generally relied upon before securing a revenue stream, but it is costly and limited. Once a revenue stream for a project is secured, tax equity investments, long-term debt, and sponsor equity arrangements are generally established. In order to secure tax equity, long-term debt, and sponsor equity arrangements, the market conditions generally require that a QF demonstrate that both its revenue stream and term of contract are known. It would be extremely rare to secure financing for a QF without a fixed revenue stream over a known term. To date, those financings have been virtually non-existent within the renewable industry.

8. Development capital generally has the highest-required rate of return and the shortest tenor (less than 10 years), whereas long-term debt has the lowest rates of return and the longest tenor (sometimes in excess of 20 years). Tax equity falls in between in terms of both return requirements and tenor, with sponsor equity generally having a long tenor and moderate return requirements. Development success begets further development success: the proceeds of long-term financings on existing projects are often used as the seed capital for new project

development efforts. Individual projects can be combined into portfolios of projects that help to further mitigate risk (e.g., by increasing geographic and offtaker diversity) and improve investor interest. Developing these capital stacks requires balancing competing risk tolerances, collateral packages and investment strategies. All of these complex, interlocking financial transactions are premised on one fundamental building block: a PPA that provides an ascertainable stream of revenue over a term sufficient to repay the financed obligations.

Price

9. The Commission has proposed to give state commissions and utilities the latitude to use short term locational marginal pricing (LMP) or market hub energy pricing as a substitute for fixed avoided cost rates. PURPA NOPR, at ¶ 66. I do not agree with the Commission's assessment: "The Commission understands that fixed energy rates are not required in the electric industry in order for electric generation facilities to be financed." PURPA NOPR, at ¶ 70. I am not aware of any capital market financing arrangements for independent power producers that finance renewable projects based on variable short-run market energy prices. If put into effect, I would expect that this change would even further discourage solar QF development and severely limit future viable QF development opportunities. In effect, adopting this proposal would starve solar QF developers of the capital necessary to develop and finance projects.

10. The Commission's energy pricing proposal puts an inordinate amount of risk on the solar QF developer – risk that it will not be able to bear itself or convince financiers to tolerate. To obtain development, tax equity, or long-term capital to finance a solar QF, the developer will have to develop price forecasts, and the use of predictable modeling will subject solar QF project financings to some combination of premiums for uncertainty, increased collateral requirements and lower investment yields, all of which will limit financing opportunities and curtail development. While some pricing volatility is acceptable when it can be hedged or at the tail of a

long-term PPA, it's reasonable to presume the levels of uncertainty this change would subject projects to would make them simply unfinanceable. Infrastructure investors will always be attracted to longer term, more clearly-determinable revenue streams and will avoid unbounded price risk. The Commission's proposal seems more likely to produce the latter (in addition to being a clear break from the historical reassurance of the former).

11. Financial products, such as contracts-for-difference, are available within some ISO/RTO markets, including ERCOT. Access to such financial products is more limited in MISO and SPP, whereas PJM and ERCOT markets allow access to more sophisticated financial products. Where available, financial products can "hedge" a variable LMP, but I am not aware of financial products available to QFs outside of an ISO/RTO market. It would be a rare circumstance for a QF to obtain a financial product to "hedge" a variable Hub price unless the Hub was within one of the more-sophisticated ISO/RTO markets. In those states dominated by vertically-integrated utilities, however, spot markets are insufficiently liquid to attract market-makers to create products to allocate risk. Accordingly, I do not see the ability to finance solar QF projects on variable energy pricing in states dominated by vertically-integrated utilities, which have no market forces dictating pricing, and only held in check by state utilities commissions that may or may not desire to encourage solar QFs..

12. Proposing to limit solar QF developers to short-run and/or variable pricing mechanisms while allowing incumbent utilities the certitude of long-term financing arrangements for their owned assets will create an anti-competitive regime of energy project development, in at least two respects: (1) it will further entrench the dominant energy industry players while (2) weakening the ability of solar QF developers to compete for capital in comparison to other asset classes that are not subject to similar regulatory deterrence

Term

13. The Commission correctly notes that state public utility commissions and utilities have engaged in a practice to limit the term of a QF contract. Regardless of intent, without exception, the effect of shortening the term in each market has been to chill development where implemented. PURPA NOPR, at ¶ 65. Long term contracts are necessary to encourage development and financing of solar QF projects.

14. In my experience, long-term investors and debt-providers analyze a QF's projected revenue stream over project's useful life (approximately 35-40 years) in order to determine whether the potential investment meets their internal criteria. Equity investors look to meet internal rates of return on their investments, whereas debt providers seek to ensure that capital loaned will be repaid. In either case, long-term capital providers balance the price in the purchase contract with the term.

15. Any rational business that depends upon a commodity will come up with a strategy that combines long-term, medium, and short-term resources. A portfolio approach limits exposure to volatility – especially important with a commodity like energy, which is purchased and sold at wholesale before being sold on to retail consumers. Public utilities use integrated resource planning (IRP) tools to plan resource portfolios and, in my experience, utilities plan to meet load through procurement of long-term generation through self-build, build-transfer, or long-term PPAs. The market for such longer-term assets procured through IRP RFPs are generally 20 years which is more akin to the economic lives of the utilities' assets. Short-term purchases are reserved for load, weather, and other less predictable sources of volatility.

16. It is with these long-term generation assets that utility scale solar QFs most naturally compete. Solar projects have decades-long useful lives, just like the historical fossil-fueled generators they are now replacing, and just like the renewable resources that certain utilities are now seeking, via their IRP processes, to add to their owned generation portfolios. The flexibility of renewable

resources – especially with the addition of continually cheaper energy storage technologies – may make them an increasingly more attractive resource for replacing “peaker” resources that must respond quickly but for much shorter durations. In short, if competing on a level playing field, wind and solar, when combined with storage, have the potential to provide the “best of both worlds” with long-term price certainty, extremely limited variable costs (zero fuel/feed stock costs), and the demand response capabilities the utilities and rate-payers require.

17. My understanding is that a purchasing utility is obligated to buy from a QF when it “avoids” an investment or purchase elsewhere. In general, the integrated resource plans of purchasing utilities include long-term procurement options, including self-build, build-transfer, and long-term contracts. I am unaware of any integrated resource plan that has been based exclusively on short-term procurement, as this would produce volatility and potential rate shock.

18. I also understand, under current rules, when a QF wants to sell to a utility pursuant to its PURPA rights, the QF is allowed to choose to sell its output either as part of the utility’s long-term generation assets or as a short-run generation resource. Those QFs choosing to be part of the long-term resource mix have historically (in markets where the utilities actually comply with PURPA) had access to 20 year PPAs (more in line with the useful life of the renewable project’s equipment and the utility-owned generation assets they were intended to replace and/or supplement). Unless the Commission sets a minimum PPA length standard, the NOPR’s proposal could lead to a reduction in the term of many QF PPAs to 10 or 5 or 2 years, as some states have required, and such a result would discourage development. My expectation is that this will at a minimum significantly curtail and will likely (in some markets, in particular) effectively eliminate the ability for QF developers to build and finance solar projects because the certainty on the return of capital is so long that the capital necessary to finance a project will be far less willing to lend or invest. In the absence of some form of credit enhancement (i.e., looking to a

separate credit-worthy counterparty versus the project itself), long-term debt would be presumptively inaccessible. You simply cannot finance 18-20 year debt facilities with 2 years of known and predictable revenue. Such reductions in term will eliminate not only that financing mechanism for renewable QFs but will curtail or preclude investment from certain sectors.. Pension plans, insurance and other long-term investors prefer longer-lived asset classes; limiting QF project returns will make them significantly less attractive to these types of investors.

19. An artificially short term would be expected to negatively affect other parts of the capital stack as well. For example, most tax equity investors requires a PPA term of at least 10 years before investing in the asset, and development capital is generally not accessible unless a project can demonstrate that it has reasonable assurances it will obtain longer term capital (especially tax and sponsor equity) to repay or refinance the development obligations. If the term of a PPA is insufficient to attract a significant portion of the long-term investors in the market, development is starved.

20. In my view, term could become even more important in the future. A volatile interest rate environment, compressed yields requirements, accelerated technological advancements for all generation types, and an uncertain political climate regarding carbon emissions, all serve to make longer term PPAs even more critical in encouraging solar QFs, as each increase investor risk

21. One specific, rather extreme example is worth mentioning. Idaho has limited the term of a QF PPA to two years and other state commissions and utilities have attempted to follow suit. PURPA NOPR, at ¶ 65. Two years is absolutely insufficient to project finance a solar QF. The hope of extending the PPA every two years on an evergreen basis is simply insufficient certainty to attract the capital necessary to finance a project.

Discriminatory Conduct

22. In my experience, there are some state commissions that take PURPA and its intention to foster competitive energy markets seriously. For instance, the Oregon PUC has found that a 20 year PPA for QFs, the first 15 years at a fixed price, the last five years tracking the market, was a fair compromise between the needs to foster QF competition to incumbent utilities and the concern for (effectively) obligating utility ratepayers to pricing determined on a forward-looking basis. Similarly, until legislation passed in 2017, the North Carolina Utilities Commission mandated a fixed price standard offer contract be offered for facilities under 5 MW for 15 years. These state PURPA programs had the effect of encouraging solar QF development in those states.

23. In other states, solar QFs face significant obstacles erected by utilities that amounts to discriminatory behavior and commissions are not as receptive to the needs of independent developers when such developers are competing against the incumbent utility. For instance, I have seen QFs in endless interconnection processes with the purchasing utility, with the purchasing utility using the process to defeat the “legally enforceable obligation.” Interconnection delays are also a tactic used to eliminate PPAs and their QF projects even where developers are successful in coming to such terms with utilities. Time is the most effective weapon utilities implement in frustrating the contract process with IPPs. Due to their cost of capital advantages and guaranteed return, utilities can simply drag out the process much longer than developers can afford to wait. It’s an uneven playing field with little or no recourse.

Summary

24. A national policy that guides the industry will further the efficient allocation of capital in the electric power industry. I encourage the Commission to use it important authority under PURPA to level the playing field by establishing some minimum guidelines for a financeable contract that can assist state public utility commissions in applying PURPA.

25. This concludes my Affidavit.

ATTACHMENT 3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Implementation Issues Under the Public Utility Regulatory Policies Act of 1978	**Docket Nos. RM19-15 AD16-16**

AFFIDAVIT OF RAY SHEM
OF PINE GATE RENEWABLES
ON BEHALF OF THE SOLAR ENERGY INDUSTRIES ASSOCIATION

1. My name is Ray Shem. I am Chief Financial Officer at Pine Gate Renewables. My business address is 130 Roberts St., Asheville, NC 28804. This Affidavit is provided in support of the Comments filed by the Solar Energy Industries Association ("SEIA") in this docket. The information provided herein is based on my own experience and from information relayed by personnel that work at my direction.

2. I received my undergraduate degree from Yale University and have a master's degree in business administration from the University of North Carolina at Chapel Hill. Prior to beginning work in the energy industry, I worked in commercial real estate raising capital for multifamily project development and investment. In 2013, I joined FLS Energy, Inc., a North Carolina-based developer of utility scale solar projects, as Vice President of Project Finance. FLS Energy specialized in the development and construction of solar facilities in North Carolina, all of which were qualifying facilities ("QFs") under the federal Public Utility Regulatory Policies Act ("PURPA"). In 2015, I became the CFO of FLS Energy and remained in that role until the sale of the company in 2016. In January 2017, I joined Pine Gate Renewables as partner and CFO. Pine Gate Renewables develops, finances, and constructs utility scale solar facilities throughout the US, the majority of which are QFs under PURPA. During my career in the solar industry, I have secured financing for over 800 MW of solar QFs.

3. I am offering this affidavit to provide the Commission with information about the impact on QF development if FERC adopts its proposed revisions that would eliminate the fixed energy pricing in QF contracts with purchasing utilities.

4. Based on my personal experience in the development of QF facilities across the country, eliminating QF's access to fixed energy pricing will "materially affect[t] the ability of QFs to obtain financing." The Commission's suggestion at ¶ 70 "that fixed energy rates are not generally required in the electric industry in order for electric generation facilities to be financed" has no foundation in the reality of financing QF projects in most of the country, and particularly in vertically integrated markets.

5. Throughout my career, the availability of long-term, fixed-price contracts has been crucial to securing the long-term debt and equity financing required for PURPA QFs; and eliminating this option will discourage future QF development. As a QF developer, Pine Gate relies on the availability of third-party project financing in order to secure sufficient capital to construct each facility, and these counterparties overwhelmingly look to invest in projects with long-term revenue streams backed by fixed-rate energy and capacity contracts to provide the necessary visibility and stability of future cash flows.

6. The availability of long-term, fixed-rate energy contracts contributes materially to a QF's ability to secure capital market financing, and denying such contracts would severely limit future QF development. In markets that have not consistently provided fixed-rate contracts of sufficient duration, solar QF development has been extremely limited because these markets do not attract capital market financing. For example, until recently, the North Carolina Utilities Commission required North Carolina utilities to offer a 15-year standard offer contract with fixed capacity and energy pricing. This construct allowed for QF developers to have a high degree of certainty around anticipated future revenue streams, and as a result, developers were able to secure capital readily for new project development. In other states, such as Florida, the public service

commission has historically interpreted PURPA to allow for short-term contracts with variable energy pricing. In those markets, solar QF development has been almost non-existent because short-term contracted cash flows are not sufficient to attract capital market financing. There is a direct correlation between the availability of long-term, fixed-price PPAs for energy and capacity and the development of QFs.

7. Solar QFs are typically financed through a suite of capital market financing, including tax equity investment, permanent sponsor equity investment, and long-term debt financing. Each of these investor groups requires a measure of visibility around future revenue streams in order to be able to underwrite their investment, consistent with standard infrastructure investment guidelines. As a result, rarely will financing parties provide capital to short-term and variable rate energy contracts.

8. Long-term debt providers look to contracted, predicable revenue almost exclusively in determining the ability for a QF to repay project debt financing, as the collateral value of the materials and equipment used to construct the facility declines over time and hence is not a material source of repayment. While there are some niche or specialty lenders that may be willing to underwrite variable contracts to a limited extent, the availability of capital from these sources is extremely limited and the associated cost of capital is often prohibitively high. In order to secure market-rate, competitive debt financing, a QF developer is required to be able to demonstrate that future cash flows are predictable and of sufficient value to substantiate the repayment of the associated financing. In my experience, I have never seen a lender close debt financing for a fixed-price PPA less than 10 years in length, much less a variable price PPA. In addition, I have financed several PPAs with both an initial fixed-price term, followed by a variable-price term, and in those situations, lenders have effectively treated the variable-price term as if no contract were in place at all. This directly contradicts the Commission's statement that "allowing states to require contractual energy rates to vary could result in longer QF

contracts, and perhaps other more favorable treatment, that would improve the financeability of QF projects." (¶ 77)

9. Similarly, equity providers evaluate their investment on, among other things, their return on their invested capital during the contracted term of the investment. While these investors are often more attuned to energy markets and are willing to take long-term views on power pricing, they still require some degree of visibility into their future returns in order to substantiate their investment and provide a floor to their potential returns. Similar to debt providers, I have seen little evidence of any interest from equity investors in deploying capital into projects with fixed-rate contracts less than 10 years, much less fully variable rate contracts.

10. These issues are of particular importance in vertically integrated power markets, where there is effectively no alternative buyer for QF energy generation and limited access to financial products such as hedges. Organized wholesale markets provide some ability for QF developers to effectively fix a merchant or variable rate profile (through third-party PPAs, financial hedges, etc.), which again, is required from financing counterparties in order to secure the repayment of their capital. However, in vertically integrated markets, the PURPA-created obligation to provide fixed-price, long-term contracts is critical to continued QF development, as there is effectively no alternative way for QF developers to secure off-take necessary to capitalize the facility and financial products that could mitigate a variable energy rate are not available. As discussed above, providing long-term contracts with variable energy rates that are unknown at the time of contracting does not provide financing counterparties the visibility on repayment that they require, and as such is akin to simply not providing a contract at all.

11. The Commission's suggestion that QFs can be financed based on fixed capacity payments alone has no basis in my on-the-ground experience. In the Carolinas where I have primarily been involved in QF financing, but I believe in other vertically integrated markets as well, capacity payments account for a relatively small portion of a QF's PPA revenues, and utilities have been

seeking to reduce this revenue component. And as the Commission notes, in some cases the appropriate price for QF capacity may be zero. To suggest that a PPA in a vertically-integrated market can be financed with only a small fraction of its contract revenues known at the time of contracting simply ignores the reality of capital market QF financing.

12. To my knowledge, the hedging and financial products, including contracts for differences, that the Commission suggests (at ¶ 72) can ameliorate the uncertainty of variable energy pricing do not exist outside of organized wholesale markets. It would be the rare case for a QF to be able to secure such a product outside of ISO/RTO markets.

13. The fact that some renewable energy facilities have been financed without reliance on PURPA, as discussed by the Commission at ¶¶ 74-75, says nothing about the need for fixed energy pricing. As the Commission itself notes at ¶ 76, some form of fixed pricing is required for the financing of virtually all renewable energy facilities (as well as other infrastructure projects). The Commission fails to examine the extent and nature of the fixed pricing that capital markets require and fails to recognize that no alternative form of meaningful fixed pricing for QFs is available in many states in the country. These are states that have seen virtually no independent renewables project development.

14. The Commission's suggestion at ¶ 77 that the elimination of fixed-energy pricing will facilitate QF development because state commissions will be more inclined to approve longer-term QF PPAs misses the critical point: in the absence of fixed-energy pricing known at the time of contracting, equity and debt investors will not be willing to finance PURPA PPAs regardless of how long their term may be.

15. This concludes my Affidavit.