UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

COMMENTS OF ENVIRONMENTAL LAW AND POLICY CENTER, NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, SOUTHERN ENVIRONMENTAL LAW CENTER, SUSTAINABLE FERC PROJECT, VOTE SOLAR, NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, AND MONTANA ENVIRONMENTAL INFORMATION CENTER IN OPPOSITION TO THE COMMISSION'S NOTICE OF PROPOSED RULEMAKING UNDER PURPA

Environmental Law and Policy Center, Natural Resources Defense Council, Sierra Club, Southern Environmental Law Center, Sustainable FERC Project, Vote Solar, North Carolina Sustainable Energy Association, and Montana Environmental Information Center ("Public Interest Organizations") respectfully submit these comments in response to the Federal Energy Regulatory Commission's ("FERC" or "the Commission") Notice of Proposed Rulemaking ("NOPR" or "the proposal"), proposing to revise its regulations implementing sections 201 and 210 of the Public Utility Regulatory Policies Act ("PURPA").[1] Public Interest Organizations are non-profit organizations who advocate for a level playing for clean energy before the Commission and state utility commissions across the country, including advocacy for robust implementation of PURPA. Public Interest Organizations submit that the Commission must reject the NOPR as a whole because it is fatally flawed procedurally and violates the Commission's statutory authority under PURPA.

1 *Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978,* Notice of Proposed Rulemaking, 84 Fed. Reg. 53,246 (Oct. 4, 2019) ("NOPR").

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SUMMARY

I. Introduction

Congress charged the Commission with one core task when developing the rules to implement section 210 of PURPA: to reduce fossil fuel consumption by encouraging qualifying facility ("QF") development and ensuring equitable rates for consumers. Toward that end, the Commission must ensure that any rules issued under PURPA section 210(a) provide rates that (1) are "necessary to encourage" QF development; (2) are just and reasonable and in the public interest; and (3) shall not discriminate against QFs. Thus, it is a prerequisite that the Commission first understand the ongoing barriers to QF development so that it can ensure rules that encourage QF development. In the same vein, when Congress provided for narrow exemptions to PURPA in 2005, it directed the Commission to eliminate the must-purchase obligation only after making a finding that a QF has nondiscriminatory access to certain types of market with demonstrated competitive quality. That is, the Commission's central mandate to encourage QF development persists wherever QF development is not sufficiently supported by access to competitive markets meeting specific statutory standards.

The NOPR is unlawful because it fails to fulfill these core statutory mandates. The NOPR does not, as it purports to do, "modernize" PURPA implementation. Instead, it is a rollback of essential provisions necessary to enable QF development and a capitulation to the anti-competitive desires of incumbent electricity providers. Indeed, the Commission is correct that PURPA reform is needed—but it is needed in the opposite direction of the Commission's proposal. More robust safeguards are needed, not less, to enable QF development in the many regions of the country that have still, decades later, failed to realize PURPA's core objective.

II. NOPR Pricing Provisions

The NOPR fundamentally undercuts certainty around the price a QF will be able to receive, creating significant new barriers to financeability and development of QF projects. First, the NOPR eliminates the investment certainty provided by fixed energy rates for QFs—even though such certainty is the norm for the vast majority of non-QF generators through fixed price power purchase agreements or cost-recovery from captive wholesale customers and ratepayers.

Second, the NOPR virtually guarantees that QFs will be paid less than generation owned by rate regulated utilities and unregulated wholesale generators with all-requirements customers. The NOPR would allow states and self-regulating utilities to limit QFs to energy pricing based on locational marginal price ("LMP"),a non-RTO proxy "market" price, or to a price determined by an undefined competitive solicitation, *while the utility's own generation faces no such price limit.* Cost-of-service rate-regulated utilities and unregulated wholesale providers with captive customers often recover more than the LMP, or the relevant "competitive price" proxy, for their own generation costs. Moreover, LMPs do not reflect actual production costs across RTO/ISOs, as prices are deflated by the ability of generators to incur uneconomic costs—such as through self-scheduling—that are passed along to ultimate customers through non-market mechanisms.

The NOPR price provisions run afoul of all three requirements of PURPA section 210(a). The Commission lacks a factual basis to conclude that the new rate "flexibilities" that the NOPR provides will incentivize QF development. It nonsensically extrapolates from evidence of non-QF development to speculate that QFs will figure out other ways, aside from PURPA, to attain the price certainty necessary for financeability. The Commission ignores record evidence of QF's particular financing needs that contradicts its wild supposition. It also ignores the track record in states that have adopted similar (if less extreme) rate structures—which have uniformly killed QF development.

The Commission does not even acknowledge its statutory obligation to consider the impacts of its proposal on consumers and the public interest. To the extent the Commission considers consumers at all, it focuses on blanket, and unsubstantiated claims that forecasted QFs rates overestimate avoidable cost, while ignoring the well-established benefits of QF competition. Consumers will suffer under the NOPR because diminished competition from QFs weakens the pressure on utilities to become more efficient. Consumers also lose the benefit that long-term QF contracting represents in terms of shifting risk away from rate-payers (which bear the risks of monopoly utility cost overruns) to the project developer.

Finally, the NOPR opens the door to rate discrimination against QFs, by restricting QFs to various forms of pricing where the utility is not constrained to the same. These comments show exhaustively that utilities across the country, within organized markets and without, are receiving prices that are more favorable than those to which the Commission would hold QFs.

III. Rebuttable Presumption and Other NOPR Provisions

The NOPR is flawed beyond its pricing provisions. The NOPR would impose new limits on the must-purchase obligations and the length of contracts for QFs in restructured states, without statutory basis.

The Commission also proposes to take the first step toward extinguishing the must-purchase obligation of small QFs located in competitive wholesale markets, proposing to extend the rebuttable assumption that QFs have nondiscriminatory market access to QFs as small as 1MW. While in theory reversible, small QFs face significant resource and information asymmetries compared to utilities, and the rebuttable presumption will in practice eliminate incentives for small QFs through PURPA, without ensuring a countervailing opportunity for development through market forces.

The Commission's extension of the rebuttable presumption is legally flawed. The record before the Commission is barren of any evidence that the multitude of barriers to small QFs, which the Commission itself identified in 2006 and acknowledged the persistence of as recently as 2016, have been alleviated. The Commission makes no inquiry into the actual conditions surrounding access for small QFs across different RTO/ISOs. The Commission does not even acknowledge its own ongoing investigation into the barriers to wholesale market participation faced by distributed energy resources—which many small QFs are, or share relevant similarities with. Submissions from RTO/ISOs in that docket show tremendous variability in the interconnection process faced by distribution-connected resources; that huge uncertainties around the process persist; and that many RTO/ISOs have not seen a single such resource navigate the interconnection process.

Small QFs categorically continue to lack nondiscriminatory access to organized markets. These comments document disproportionate technical and logistical difficulties QFs often face in interconnecting to the transmission or distribution system in order to make wholesale transactions, as well as financial costs to access markets that do not scale with the size of the interconnecting resource, and thus have disproportionate impacts on small QFs. The facts demonstrate that markets have not "evolved" past the significant, often prohibitive barriers small QFs face to access organized markets. The Commission's speculative conclusions to the contrary are unreasoned and lack substantial support in the record.

On top of the pricing provisions and change to the rebuttable presumption, the NOPR also creates a suite of new administrative and regulatory burdens and legal risks for QFs. From shifting the burden on QFs to demonstrate their lack of access to wholesale markets or that they are a single facility, to needlessly making it easier for utilities to baselessly oppose QF self-certification, the NOPR adds to the barriers to QF development. Most egregiously, the Commission's proposal to require "commercial viability" requirements before obtaining a legally enforceable obligation places QFs in a "catch-22": QFs can't obtain financing without the certainty of a buyer and a fixed price, but can't obtain either without first securing the financing necessary to show commercial viability. In enacting PURPA, Congress recognized that administrative red tape alone is enough to kill QF development. The unjustified burden these provisions impose on QF development flies in the face of PURPA's statutory purpose and scheme.

IV. Threshold Procedural Defects of the NOPR

Finally, in addition to its deep substantive flaws, the NOPR is also procedurally defective. Each of the following three threshold legal failings provide independent grounds for the Commission to abandon the current proposal and complete the necessary deliberative steps before proceeding.

First, the Commission failed to issue a finding that that the revisions to its PURPA rules are "necessary to encourage" QF development, as the statute requires. Moreover, the Commission could not rationally issue such a finding—the "flexibilities" the NOPR affords uniformly cut in the direction of discouraging QF development. The Commission's seeming view that PURPA's incentives are no longer needed to spur QF development conflicts with the evidence of the continued, widespread, and egregious tendency of utilities to afford preferential treatment to their own generation. The Commission cannot ignore the stark record of monopolistic behavior, a factor that is central to the statutory scheme and purpose, in determining the rules that are "necessary to encourage" QF development.

Second, the Commission failed to comply with PURPA consultation requirements. The NOPR was issued without consulting with relevant federal and state officials; a flaw that is not only procedurally fatal, but also a misstep that deprives the Commission of relevant expertise and information that could have provided the basis for a much stronger and more readily implementable rules.

Lastly, the Commission failed to comply with National Environmental Policy Act ("NEPA"). The proposed changes to the PURPA regulations are a major federal action subject to NEPA, causing foreseeable environmental impacts in every state where the new rules impact QF development. The environmental impacts of removing major incentives for emissions-free renewable resources will be significant and far-reaching—from impacts on local air and water quality to increased emissions of greenhouse gases. While the Commission claims that the effects of the NOPR are too uncertain to require such analysis, the Commission has managed to conduct such analysis of the environmental impacts of prior PURPA rulemakings, and must do so again here.

COMMENTS

I. The issuance of the NOPR is substantively and procedurally flawed, and therefore unlawful.

A. The Commission did not, and could not, issue the necessary threshold finding that the revised rules are "necessary to encourage" qualifying facilities.

Congress's clear central goal when enacting § 210 of PURPA "was to increase the utilization of cogeneration and small power production facilities and to reduce reliance on fossil fuels."[2] To achieve that objective, Congress required the Commission to issue implementing rules within one year and to revise "such rules as it *determines necessary to encourage* cogeneration and small power production" from time to time thereafter.[3] Thus, the statute conditions the Commission's authority to revise its implementation rules on a threshold finding that such revised

[2] *Am. Paper Inst. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 417 (1983).

[3] *Id.* at 418 (emphasis added).

rules are "necessary to encourage" QFs.[4] Obviously, rules that have an effect of *discouraging* QFs cannot be "necessary to" encouraging them.

1. The Commission failed to issue the necessary threshold finding.

The NOPR does not purport to find that the revised rules would promote increased utilization of qualifying facilities. Rather, the Commission focuses on the need to "modernize" and "rebalance" its PURPA regulations, reflecting a belief that the current rules support too much QF development and a desire to reduce the incentives in current rules for QF development.[5] The NOPR also focuses on providing states additional "flexibility" in implementing PURPA.[6]

To the extent that the NOPR is premised on any findings, the Commission purports to justify its decision to revise the PURPA rules on: (1) the increased supply of natural gas; (2) the decreased prevalence of vertically integrated utilities and increase in independently-owned generation in some regions of the country; and (3) the existence of economic and policy factors other than PURPA that separately drive production of renewable energy.[7] Even if assumed true, these are not the findings that Congress set as the predicate to rules under section 210(a).

The Commission obliquely acknowledges its statutory obligation by claiming that it "believes [the NOPR] will continue to encourage QFs."[8] But a bare assertion of belief is insufficient; it is not the statutorily required finding that its rules are

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[4] *Cf., Ethyl Corp v. EPA*, 541 F.2d 1, 14 (D.C. Cir. 1976) (by conditioning EPA's authority on the Administrator's "judgment" in two Clean Air Act provisions, "Congress demanded a threshold determination."); *Natural Resources Defense Council v. EPA,* 824 F.2d 1146, 1165 (D.C. Cir. 1987) (*en banc*) (statutory language requiring the EPA Administrator to "establish any such standard at the level which in his judgment provides an ample margin of safety to protect the public health" requires a determination on the record of "what is 'safe.'").

[5] NOPR at P 29 ("the Commission preliminarily finds . . . that the Commission's PURPA Regulations should be modernized"); *id.* at P 31. ("Consequently, the Commission is proposing revisions to its PURPA Regulations to rebalance the approach adopted in the 1980s").

[6] *Id.* at PP 5-7.

[7] *Id.* at P 29.

[8] *Id.* at P 4

"necessary to" encourage QFs. The Commission notably evades addressing the net effect of the rule changes on QF development.[9]

The Commission's motive for the NOPR—that "there no longer is the same need to provide incentives" and that most renewable resources "do not rely on PURPA"—is strongly suggestive that the Commission believes its rules will reduce the incentives for development through PURPA.[10] In stating that the NOPR will "continue to encourage QFs" the Commission may mean that other laws and factors outside PURPA will encourage renewable energy development, or that its proposed revisions to PURPA rules will not wholly extinguish future development and operation of qualifying facilities. But neither such finding would meet the statutory standard. To amend the rules, the Commission must first determine that the actual changes it proposes increase development and utilization of QFs. Because the Commission fails to issue that finding, the NOPR is inconsistent with PURPA.

2. The Commission could not support such a threshold finding on this factual record.

i. The NOPR decreases certainty around price and availability of a buyer, while increasing administrative and regulatory burdens for QFs.

Even if the Commission had made the predicate finding that the proposed reforms are necessary to encourage QF development, the Commission must base that finding on the record. Here, the Commission cannot present facts sufficient to support such a conclusion. In fact, the record demonstrates that the new rules will *discourage* the development and operation of qualifying facilities. As described at length in these comments, the sum effect of the NOPR will be to *decrease* the certainty around whether, how, and how much qualifying facilities will be paid for their energy and to *increase* the administrative burden and regulatory hurdles to obtaining a legally enforceable obligation. Both price certainty and the legal certainty of having a buyer are well-recognized, crucial components to financeability of a project. Because the NOPR will negatively impact both, while simultaneously creating additional barriers to development of qualifying facilities, it will discourage QF development. In short, because Congress required the Commission to find that its rules under 210(a) *encourage* qualifying facilities[11], the Commission cannot

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[9] *See also id.* at P 13 (asserting that the rule changes, "in conjunction with" existing rules, act to encourage QFs).

[10] *Id.* at P 3

[11] In the Energy Policy Act of 2005, Congress directed the Commission to provide exemptions to PURPA in very specific circumstances, where Congress concluded established competitive markets would otherwise enable qualifying

permissibly adopt revised rules without the factual basis to support a finding that the revisions encourage QFs.[12]

ii. The Commission fails to grapple with an egregious record of utilities continuing to afford preferential rates to their own generation.

The Commission's belief that PURPA's safeguards for QFs are no longer critical to development of QF-like facilities is wrong. Not only is PURPA still needed to drive investment in non-fossil fuel generating, independently-owned facilities, the Commission's existing rules are not going far enough to ensure that development occurs. In its belief that QF development will persist notwithstanding substantial roll backs of PURPA regulatory requirements, the Commission turns a blind eye to monopoly utilities' persistent opposition to PURPA implementation. The Commission's failure to take into account utilities' predictable pattern of affording their own generation preferential terms is a flaw that infects every aspect of the NOPR. And by failing to open its eyes to ongoing utility efforts to circumvent PURPA, the Commission fails to see that achieving its statutory mandate to encourage QFs requires *strengthening* PURPA rules, not weakening them.

The record before the Commission is unequivocal: the current PURPA rules are not encouraging qualifying facilities in large parts of the country that would benefit most from their competition. The current PURPA rules have failed to prevent utilities from offering discriminatory rates that create an insurmountable barrier to QF development, even though the utility owned-generation's high production costs should generate opportunities for QFs to compete.

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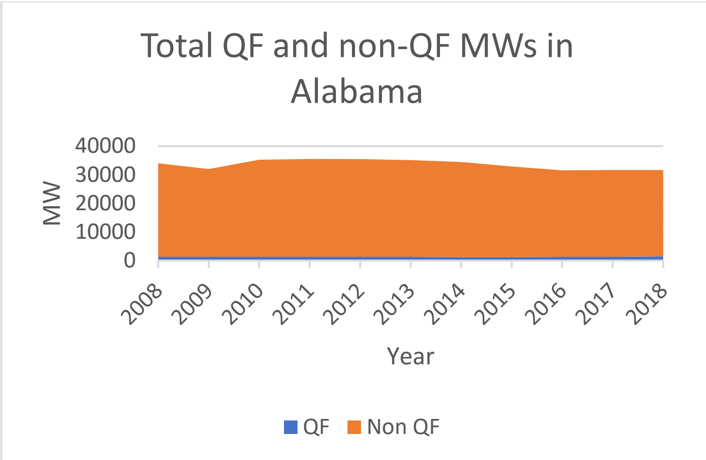
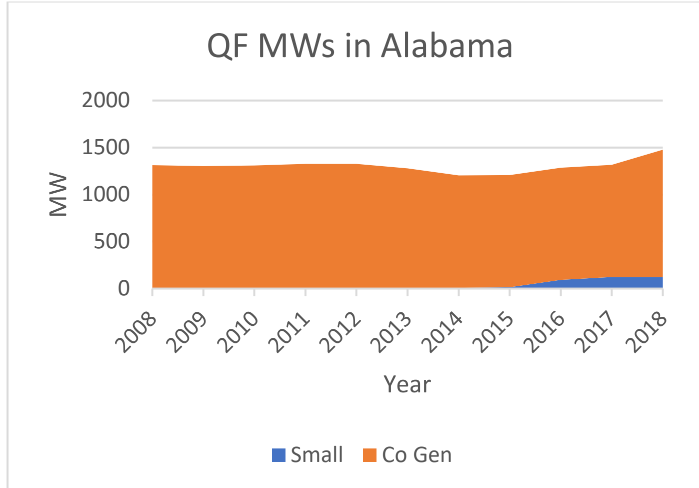
facility development. *See* 16 U.S.C. 824a-3(m). Notably, Congress did not alter the Commission's core task in implementing PURPA in the rest of the country, which remains to encourage qualifying facilities.

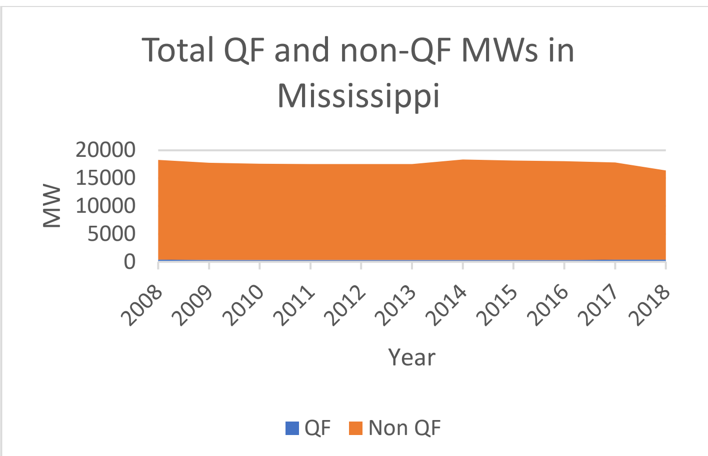
12 *Cf. Am. Paper Inst.*, 461 U.S. at 416 (explaining that the Commission would have "encountered considerable difficulty" setting a rate less than the one that provides a maximum incentive for QFs in rejecting challenges to the original PURPA rules).

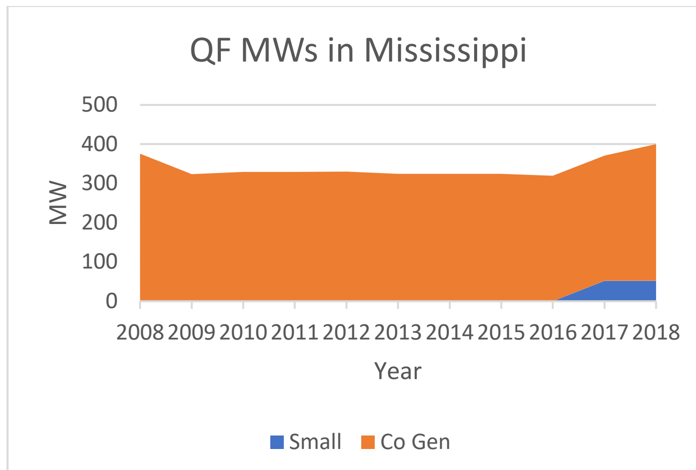
Source: EIA, Annual Electric Generator Data Form EIA-860

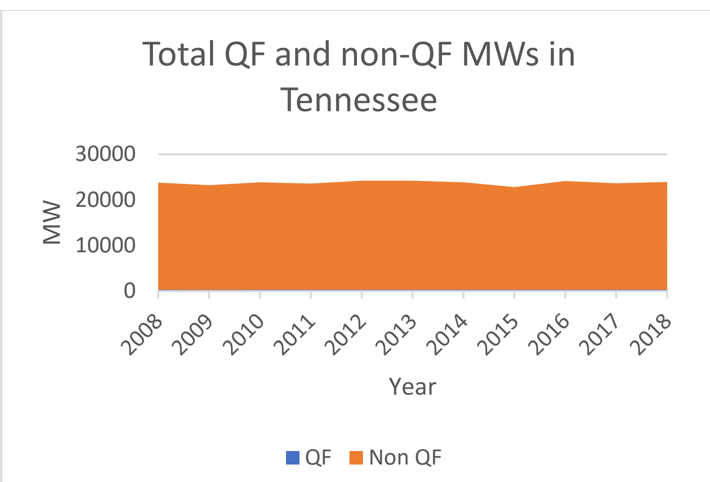
QF development is notably uneven across states in non-RTO regions. Even states located in close proximity, which share a common competitive landscape and latent potential for QF development, diverge greatly in the actual penetration of QFs. The large number of states that continue to lack any meaningful development of QFs is even more noteworthy given that costs of QF-eligible technologies, such as solar PV, are lower than alternatives. Michigan has seen some recent interest in QF development while neighboring Wisconsin and Indiana see virtually none. Similarly, while North Carolina and South Carolina see QF development that one would expect given the lower cost of QF technologies, nearby neighbors Tennessee, Alabama, and Mississippi persistently fail to see any significant investment in non-congeneration QFs.

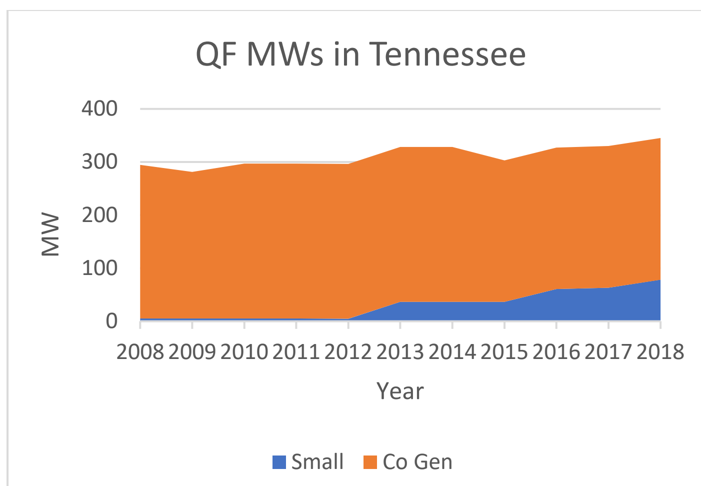






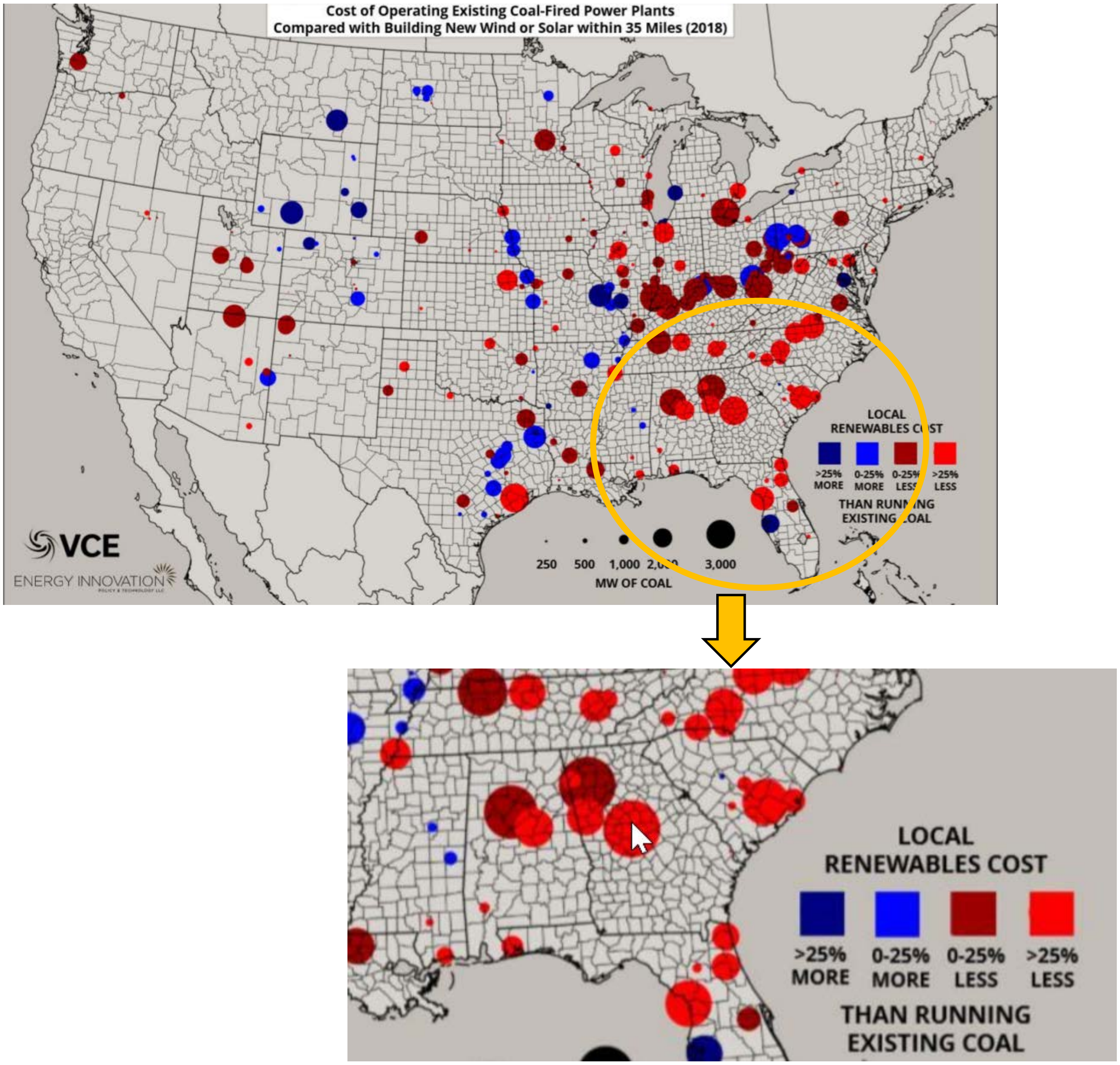






Source: EIA, Annual Electric Generator Data Form EIA-860

This is precisely the scenario in which Congress intended PURPA to enable qualifying facilities to compete, producing energy more cheaply to the benefit of utility customers. Yet for millions of customers across the country, the persistent failure of PURPA and, more precisely, the Commission's PURPA regulations, to enable this development of qualifying facilities leaves them paying higher energy bills.



Source: The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Sources, Energy Innovation (2018)[13]

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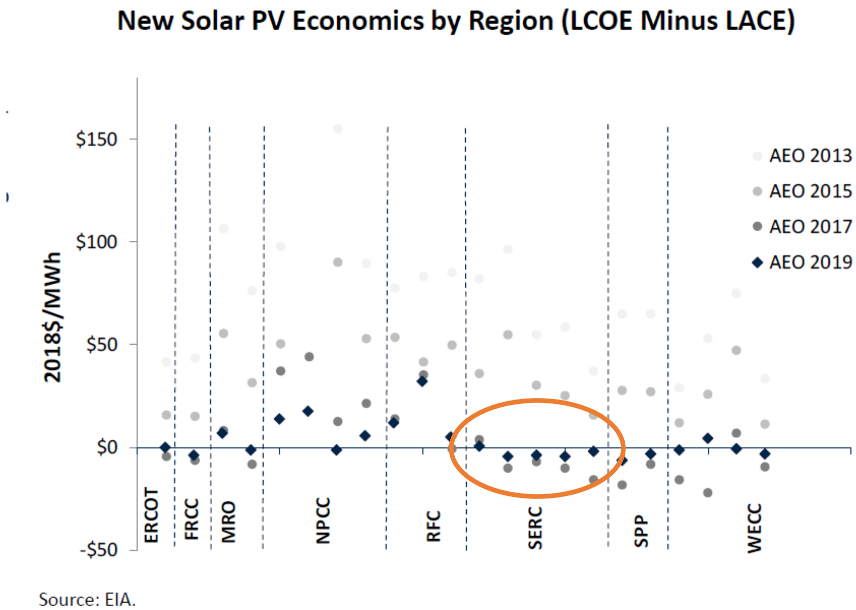
13 Eric Gimon, Michael O'Boyle, Christopher T.M. Clack, and Sarah McKee, *The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Sources* at 3 (2018) https://energyinnovation.org/wp-content/uploads/2019/03/Coal-Cost-Crossover_Energy-Innovation_VCE_FINAL.pdf



Source: PURPA Resurgence and Avoided Costs (2019) [14]

In addition to the macro evidence that the aims of PURPA are not being adequately achieved, there are innumerable particular examples of utility efforts to offer discriminatory rates that have the impact of discouraging or eliminating QF development.[15] Utilities seek to limit QF contract lengths, while maintaining long-term revenue certainty for their own generation.[16] They use Requests for Proposals

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14 Metin Calebi, PURPA Resurgence and Avoided Costs, presented at EUCI Symposium at 16 (Sept. 9, 2019), https://brattlefiles.blob.core.windows.net/files/17081_purpa_resurgence_and_avoided_costs.pdf.

15 *See, e.g., Comments of AllCo Renewable Ltd*, Docket No. AD16-16 at 1 (June 16, 2016) ("AllCo June 2016 comments") ("utilities fight QFs at every opportunity").

16 Idaho Public Utilities Commission, *Petition of Rocky Mountain Power*, Case No. PAC-E-15-03, In the Matter of Rocket Mountain Power Company's Petition to Modify Terms and Conditions of PURPA Purchase Agreements at 3-4 (Feb. 27, 2015) (application of PacifiCorp to reduce the maximum PURPA contract length from 20 years to 3 years); Public Service Commission of Wyoming, *Application of Rocky Mountain Power*, Docket No. 20000-481-EA-15, In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase Agreements with Qualifying Facilities at 7 (Nov. 2, 2018) (application of PacifiCorp to reduce the maximum contract term of PPAs with QFs from 20 years to 7 years); Public Service Commission of Utah, *Application of Rocky Mountain Power*, Docket No. 15-035-53, In the Matter of the Application of Rocky Mountain Power for Modification of Contract Term of PURPA Power Purchase

(RFPs) abusively to minimize QFs ability to compete.[17] Utilities exploit their exclusive control over the interconnection process to make access more difficult and costly for QFs.[18] They deploy restrictive terms for security and curtailment as

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Agreements with Qualifying Facilities at 1 (May 11, 2015) (application of PacifiCorp to reduce the maximum contract term of PPAs with QFs from 20 years to 3 years); Florida Public Service Commission, *Duke Energy Florida, LLC's Petition for Declaratory Statement regarding PURPA solar qualifying facility power purchase agreements* Docket No. 20180169-EQ, In re: Petition for Declaratory Statement by Duke Energy Florida, LLC, Regarding PURPA Solar Qualifying Facility Power Purchase Agreements at 1 (Sept. 7, 2018) (petition to limit PURPA contract length with solar QFs to 2 years); Alabama Public Service Commission, *Order Approving Petition*, Docket No. U5213, For approval of Rate CPE – Contract for Purchased Energy Alabama Power, Petitioner at 8 (March 7, 2017) (approving one year term for fixed rates); Georgia Power, "Georgia Power's 2017 Avoided Cost and Solar Avoided Cost Projections" Georgia Public Service Commission Docket No. 16573 (Dec. 28, 2017) at https://psc.ga.gov/search/facts-document/?documentId=170653 (limiting price certainty to two years) ;Indiana Utility Regulatory Commission , *Response to Objection to Duke Energy Indiana's Standard Contract Rider No. 50, IURC 30-Day Filing No. 50119* at 3 (April 2, 2018) (explaining term is restricted to one year); *Supplemental Comments of Covanta Ltd*, Docket No. AD16-16 at 2-3 (Oct. 19, 2018) (Consumers Energy seeks to move to single year contracts).

[17] *Comments of Northwest and Intermountain Independent Power Producers Coalition*, Docket No. AD16-16 at 5 (June 7, 2016) (new competitive bidding guidelines have not prevented PacificCorp and Portland General Electric from winning virtually all solicitations, and 95% of new capacity remains utility-owned); *Speaker Materials of Todd Glass on Behalf of SEIA*, AD16-16 at 7 (June 29, 2016) ("Glass Comments") (utilities use RFPs that are available once in a multi-year period or that set limited procurement targets to restrict QF competition); *Supplemental Comments of Covanta Ltd*, AD16-16 at 2-3 (Oct. 19, 2018) (competitive bids based on characteristics of utility's own generation used to set price).

[18] Glass Comments at 7, n.14 (PacificCorp imposed discriminatory third party transmission charges in Oregon, claiming QFs were located in a "load pocket" and established a separate, more onerous interconnection process for QFs in Utah, Wyoming, and Idaho); *Comments of North Carolina Clean Energy Business Alliance and the North Carolina Sustainable Energy Association*, AD16-16 at 5-6 (Nov. 7, 2016) (Duke arbitrarily added a new screen to its interconnection process, forcing only QFs to halt development, redo interconnection studies, and install expensive equipment; Duke later cut-off all distribution system interconnection for QFs).

barriers to development.[19] Across state after state, utilities have one thing to say about the need for and value of their own generation, while saying something totally different (and using different numbers) when it comes to the need for and value of QFs[20] And in some of the most egregious cases, utilities simply refuse to comply with the law, knowing that by virtue of their superior power and size, they can outlast QFs in the long regulatory and legal battles to vindicate the law.[21]

While blatantly inconsistent with PURPA, too often gaps in the Commission's existing regulations enable this behavior to persist. Stronger rules are needed to put an end to utility circumvention of the law. In sum, the Commission is wrong that PURPA, or robust implementing regulations, are no longer necessary to ensure QFs have an opportunity to compete with utilities.

In order to ensure that revised rules encourage qualifying facilities, the Commission must first address the evidence that the current rules are insufficient to promote QFs because of the continued, widespread and egregious behavior of utilities in affording preferential rates to utility-owned generation. Having failed to even acknowledge that record of ongoing utility discrimination against qualifying facilities, the Commission cannot move to the next step to finalize rules.

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19 Glass Comments at 4 (PacifiCorp requires QFs to agree to a term allowing it, rather than the lender, to seize the project in event of default); *Comments of LS Power Associates, LP*, AD16-16 at 4, 8 (identifying unreasonable curtailment provisions as barrier to financing).

20 *See Supplemental Comments of Southern Environmental Law Center, et al.*, AD16-16 at 21 (Oct 17, 2018) ("Supplemental Comments of PIOs") (Duke Energy Indiana charged customers on average $143.19/MWh for power from its Edwardsport coal gasification plant, while offering less than one fifth that as its avoided cost to QFs); *id.* at 21-22 (planned utility-owned generation in Georgia and South Carolina would cost customers 5 times the avoided cost rate provided to QFs, while in Mississippi a failed construction of utility owned project cost customers nearly 10 times the avoided cost rate provide to QFs); AllCo June 2016 Comments at 3-4 (Green Mountain Power Corporation in Vermont presented forecasts of avoided costs for its own solar projects over 25 years, but declined to use these forecasts to set QF rates); *Supplemental Comments of the American Forests and Paper Association and Electricity Consumers Resource Council*, AD16-16 at 7 (Nov. 30,2018) (noting inconsistencies in utility's stated need for capacity in IRPs and in QF dockets).

21 AllCo June 2016 Comments, AD16-16 at 3, n.9 (June 16, 2016) (documenting years of delay tactics of the Public Service Company of New Mexico to avoid issuing a PURPA contract); *Comments from NewSun Energy LLC*, AD16-16 at 3 ("NewSun Energy Comments") (describing utility delay tactics, resulting in substantial cost and delay for the QF).

B. The NOPR fails to comply with mandatory PURPA consultation requirements.

1. The Commission must follow PURPA section 210's procedural requirements before revising its regulations.

The Commission cannot yet revise its PURPA regulations because it has not followed clear procedural requirements in the statute. The NOPR repeatedly cites PURPA section 210's requirement that the Commission revise its PURPA regulations "from time to time," but it ignores procedural requirements for such a rulemaking contained in that very section:

> "Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments."[22]

Legislative history makes clear that Congress intended these provisions to be "procedural requirements."[23]

2. The Commission failed to consult with federal and state regulatory agencies with ratemaking authority.

The consultation requirement exists for good reason, as states have primary responsibility for implementing PURPA under the statute's "cooperative federalism scheme."[24] There are at least 50 state regulatory agencies with ratemaking authority for electricity utilities, and the Commission cannot craft informed policy to encourage QF generation without their input. PURPA's plain language makes clear that such consultation is an integral and non-optional part of the Commission's Congressionally-delegated authority to issue regulations under the statute. Failure to follow this express statutory procedural requirement renders the NOPR ultra vires.[25]

In its initial issuance of the PURPA regulations, the Commission specifically solicited the input of public utility commissioners on the draft rule, affording them

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22 16 U.S.C. § 824a-3(a).

23 H.R. Rep No. 95-1750 at 97 (1978), as reprinted in 1978 U.S.C.C.A.N. 7797, 7831.

24 *FERC v. Mississippi*, 456 U.S. 742, 767 (1982).

25 *See Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947, 955 (D.C. Cir. 2016) ("When the Commission acts contrary to the statute its action is ultra vires.").

an opportunity to share their views on a final draft at a meeting dedicated to that purpose.[26] The meeting with commissioners took place after a period of broader comment, a series of public hearings, and only after considering that input and incorporating it into a final draft.[27]

Nothing in the NOPR administrative record indicates that the Commission has consulted with relevant state agencies. While the Commission held a single technical conference focused on "Implementation Issues Under the Public Utility Regulatory Policies Act of 1978," such a request for public comment on a broad set of PURPA implementation issues does not meet the requirement to consult with the relevant federal and state regulatory authorities regarding a specific set of rule changes. Moreover, in other statutes that incorporate both requirements to "consult" and for "comment," it is well established that those terms connote different meanings.[28] General solicitation of public comment does not satisfy specific statutory requirements to consult with particular entities, which Congress determined have a particular stake or expertise of unique value to the rulemaking process.[29]

The Commission's denial of a motion for extension of time to comment by officials from six states and the District of Columbia, including public utility commissions and attorneys general representing ratepayers, only underscores the inadequacy of the Commission's consultation with relevant regulatory agencies.[30]

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26 *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, Order No. 69, 45 Fed. Reg. 12,214, 12,215/3 (Feb. 25, 1980) ("Order No. 69").

27 *Id.* at 12215/2 - /3.

28 *See, e.g.,* 50 C.F.R. § 402.14 (establishing separate procedural requirements to satisfy Endangered Species Act's direction to federal agencies to issue determinations "in consultation with" other expert agencies under section 7(a)(2), 16 U.S.C. §1536); *see also Cooling Water Intake Structure Coal. v. U. S. Envtl. Prot. Agency*, 905 F.3d 49, 78 (2d Cir. 2018) (distinguishing between consultation requirements under the Endangered Species Act and public comment requirements).

29 *See, e.g.*, *Ctr. for Biological Diversity v. Envtl. Prot. Agency*, 847 F.3d 1075, 1084 (9th Cir. 2017) (Under the Endangered Species Act, "[c]onsultation allows agencies to draw on the expertise of wildlife agencies") (internal quotation omitted).

30 *See* "Joint Motion for Extension of Time to Submit Comment and for an Order Scheduling the Submission of Reply Comments of the California Public Utilities Commission, Attorney General for the State of Connecticut, Attorney General for the District of Columbia, Attorney General of Maryland, Attorney General of Massachusetts, Attorney General of Oregon, the Public Utility Commission of Oregon, and the Rhode Island Division of Public Utilities and

As the state officials described, they have had an inadequate time and opportunity to "consider, analyze, and comment on significant proposed changes to those regulations," including on "fundamental aspects of PURPA implemented by the states."[31] The states officials conclude that "[t]he time frame currently provided for comments on the NOPR does not allow for this critical coordination and consultation."[32] In sum, the Commission's failure to consult with relevant regulatory authorities which will implement the revised regulations as required by the statute is not harmless procedural error, but rather fundamentally impairs the Commission's ability to issue rules that will advance statutory objectives.

C. The NOPR violates NEPA.

1. The Commission must prepare an Environmental Impact Statement or Environmental Assessment as required by NEPA.

The Commission states that it "will not prepare an environmental document" required by the National Environmental Policy Act ("NEPA") for the changes proposed in the NOPR, claiming that there are "no reasonably foreseeable environmental impacts for the Commission to consider."[33] The Commission misapprehends its obligations under NEPA, which mandates the preparation of an Environmental Impact Statement ("EIS") for any "major federal action significantly affecting the quality of the human environment."[34] If the Commission maintains that this rulemaking may not have any significant foreseeable environmental impacts, it must support such a determination with an Environmental Assessment ("EA").[35] The proposed changes to the PURPA regulations will have profound effects on QF development in many parts of the country, with significant foreseeable impacts on the environment. The NOPR's cursory treatment of the Commission's environmental review obligations undermines NEPA's twin purposes—ensuring that agencies give due consideration to environmental impacts when making major decisions, and guaranteeing that the public is informed of such impacts.

Carriers," RM19-15 (Nov. 5, 2019). A separate motion was also filed by the Industrial Energy Consumers of America.

[31] *Id.* at 2.

[32] *Id.* at 3.

[33] NOPR at P 155.

[34] 42 U.S.C. § 4332; 40 C.F.R. § 1502.9.

[35] 40 C.F.R. §§ 1501.4(b), 1508.9.

2. **NEPA imposes clear requirements for assessing the environmental impacts of agency actions.**

NEPA is the "basic national charter for protection of the environment."[36] As noted above, it requires federal agencies to prepare an EIS, for any "major Federal actions significantly affecting the quality of the human environment."[37] To determine whether an action "significantly affects" the environment, the agency must consider several factors, such as the degree to which the proposed action affects public health or safety, the degree to which the effects on the quality of the human environment are likely to be highly controversial or highly uncertain, the degree to which the action may establish a precedent for future actions, and the degree to which the action may adversely affect an endangered or threatened species.[38]

"There is a major Federal action subject to NEPA review 'whenever an agency makes a decision which permits action by other parties which will affect the quality of the environment.'"[39] Further, "[t]he duty to prepare an EIS normally is triggered when there is a proposal to change the status quo." [40]

An EIS must discuss:

> "(i) the environmental impact of the proposed action, (ii) any adverse environmental effects which cannot be avoided should the proposal be implemented, (iii) alternatives to the proposed action, (iv) the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and (v) any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented."[41]

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36 *Id.* § 1500.1.

37 42 U.S.C. § 4332; 40 C.F.R. § 1502.9.

38 40 C.F.R. § 1508.27(b).

39 *Humane Soc. of U.S. v. Johanns*, 520 F. Supp. 2d 8, 22 (D.D.C. 2007) (quoting *Scientists' Inst. for Pub. Info. v. Atomic Energy Comm'n*, 481 F.2d 1079, 1088–89 (D.C. Cir. 1973); see also *NAACP v. Med. Ctr., Inc.*, 584 F.2d 619, 629 n.15 (3d Cir. 1978) ("In each instance cited by Judge Wright in Scientists' Institute, the agency action was one which was an absolute legal condition precedent to the action which would affect the environment.").

40 *Humane Soc. of U.S.*, 520 F. Supp. 2d at 29 (quoting *Comm. for Auto Responsibility v. Solomon*, 603 F.2d 992, 1002–03 (D.C. Cir. 1979)).

41 42 U.S.C. § 4332(c).

An EIS serves the statute's two key goals: (a) to ensure the agency, in reaching its decision, will have available, and will carefully consider, detailed information concerning significant environmental impacts, and (b) to guarantee that the relevant information will be made available to the public.[42]

NEPA thus requires an agency to consider all foreseeable impacts on the environment of a major Federal action including, among others, "effects on air and water and other natural systems."[43] "Foreseeable" is "properly interpreted as meaning that the impact is sufficiently likely to occur that a person of ordinary prudence would take it into account in reaching a decision."[44] An EIS must also consider "cumulative" effects—i.e., "the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or Non-Federal) or person undertakes such other actions."[45] Agencies must also consider "[i]ndirect effects, which are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable."[46]

If it is not clear whether an EIS is required, the agency must prepare an Environmental Assessment ("EA"), which is defined as a "concise public document" that sets forth the evidence and analysis for deciding whether to proceedwith an EIS.[47] If, based on the EA, the agency determines that an EIS is warranted, it must proceed with the EIS.[48] However, if the agency determines that an EIS is not warranted, the agency must issue a finding of no significant impact ("FONSI") explaining why the proposed action will not significantly affect the environment.[49]

3. The Commission cannot avoid NEPA-mandated environmental review with unsupported claims that environmental impacts are unforeseeable.

The proposed changes to the PURPA regulations are a major federal action subject to NEPA, with environmental impacts everywhere the new rules affect QF

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42 *See, e.g.*, *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 349 (1989).

43 40 C.F.R. § 1508.8(b).

44 *Sierra Club v. Marsh*, 976 F.2d 763, 767 (1st Cir. 1992).

45 40 C.F.R § 1508.7.

46 *Id.* § 1508.8.

47 *Id.* §§ 1501.4(b), 1508.9.

48 *Id.* § 1501.4(d).

49 *Id.* §§ 1501.4(e), 1508.13.

development. Nonetheless, the Commission attempts to sidestep its statutory obligations. The NOPR claims it is "impossible to know what actions the states may take in response to the revisions proposed here, and how any such actions would, on balance, impact QF development and the environment going forward."[50] The Commission also suggests that the PURPA regulations do not have foreseeable environmental impacts because they do not on their own enable QFs to operate, mandate their construction, or exempt them from federal, state, and local environmental laws.[51] The NOPR concludes that "any environmental impacts analysis" of its proposal would be "speculative and not meaningfully inform the Commission or the public of the revisions' impact on QF development or, correspondingly, of any associated potential impacts on the environment."[52]

The Commission is mistaken. None of the reasons given in the NOPR's single paragraph on environmental impacts negate its obligations under NEPA. As noted above, NEPA requires agencies to examine all foreseeable impacts, including cumulative and indirect impacts—in a rulemaking that grants states new regulatory authority, this plainly includes states' exercise of that authority. Further, "speculation is implicit in NEPA," and agencies may not "shirk their responsibilities under NEPA by labeling any and all discussion of future environmental effects as crystal ball inquiry."[53] Accordingly, "reasonably foreseeable future actions need to be considered even if they are not specific proposals."[54] For example, in a case challenging permitting of a railroad extension that would increase the availability of coal, the Eighth Circuit found it foreseeable that new coal power plants would be constructed in the area served even though the railroad had not yet executed coal-hauling contracts with area utilities.[55] The court concluded, "when the *nature* of the effect is reasonably foreseeable but its *extent* is not, we think that the agency may not simply ignore the effect."[56]

Fortunately, the Commission has experience conducting NEPA review that accounts for the complexity and uncertainty inherent in PURPA's regulatory regime. Issued in 1980, Order No. 70 instituted many of the original regulations under PURPA section 201 governing how facilities attain QF status, and the

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50 NOPR at P 155.

51 *Id.*

52 *Id.*

53 *N. Plains Res. Council, Inc. v. Surface Transp. Bd.*, 668 F.3d 1067, 1079 (9th Cir. 2011) (internal quotation marks and citation omitted).

54 *Id.* (internal citation omitted).

55 *Mid States Coal. for Progress v. Surface Transp. Bd.*, 345 F.3d 520, 549–50 (8th Cir. 2003).

56 *Id.* at 549 (emphasis in original).

Commission prepared an accompanying EA following a period of public consultation.[57] The EA examined how PURPA would affect the deployment of each qualifying technology through market penetration analyses, estimating "the amount of capacity expected to be induced on a regional and national basis through January 1, 1995, assuming the broadest implementation of this program."[58] The EA also quantified projected changes in fossil fuel consumption due to QF deployment and resulting deferrals or cancellations of non-QF power plants.[59] Order No. 70 noted that although EA concluded that the program overall would not have a significant impact on the environment, the Commission would delay approval of diesel cogeneration QFs until a full EIS could be prepared for that class of resources—responding to comments raising concerns that such facilities could have significant environmental impacts.[60]

Similarly, before proposing PURPA regulation changes that would authorize bidding procedures as a means of calculating rates for QFs under PURPA section 210, the Commission prepared "extensive environmental analysis . . . undertaken from the early stages of this proceeding."[61] The EA found that although the proposal would not have significant nationwide impacts, significant local impacts were possible. The Commission concluded: "While the Commission has doubts about aspects of this analysis, *it cannot foreclose the possibility that the proposal may have a significant impact* in certain areas of the country. Therefore, in the interest of assuring a thorough environmental review, the Commission will prepare an environmental impact statement (EIS) for this proposal.".[62]

The current rulemaking will have significant foreseeable impacts on the environment. As detailed in sections II-V, the changes proposed in the NOPR will gut PURPA-mandated measures to encourage QF development. States that follow the Commission's lead and exercise their new "flexibility" to weaken these measures will see QFs development suffer, regardless of the fact that the proposed changes do not mandate or prohibit the construction of any specific QFs. The environmental impacts of removing major incentives for emissions-free renewable resources will be significant and far-reaching—from impacts on local air and water quality to

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57 *See* Small Power Production and Cogeneration Facilities – Qualifying Status, Order No. 70, 45 Fed. Reg. 17959, 17964 (Mar. 20, 1980).

58 *Id.* at 17,964/2.

59 *Id.* at 17,964/2.

60 *Id.* at 17,965/1.

61 Regulations Governing Bidding Programs, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,455 at 32,047 (1988), 2015 WL 8610975 (Mar. 16, 1988) ("Bidding NOPR").

62 *Id.* (emphasis added)

increased emissions of greenhouse gases. The Commission cannot ignore these impacts simply because their precise extent has yet to be determined.

Order No. 70 contains an observation on NEPA as relevant today as it was in 1980:

> "The Commission acknowledges the difficulty in identifying the levels of the environmental effects associated with the programmatic encouragement and deregulation of various types of technologies as are present under this program. There are, of course, a great number of uncertainties in any such analysis. However, *the Commission is required under NEPA to assess these effects to the fullest extent possible*."[63]

As with Order No. 70, the changes proposed in the NOPR are programmatic and nationwide, and quantifying their effects on the environment presents genuine difficulties. Unlike Order No. 70, in this proceeding the Commission has abdicated its responsibility under NEPA to assess those effects to the fullest extent possible. The Commission must at minimum prepare an EA before it can lawfully find that there are "no reasonably foreseeable environmental impacts" to consider. More likely, the Commission will need to prepare a full EIS to evaluate the serious environmental impacts that will result from dismantling regulations that continue to play an important role in development of renewable generation resources across the country.

II. The NOPR's Pricing Proposals Do Not Comply With PURPA

The NOPR proposes several structural changes to the Commission's existing regulations specifying the price that utilities must pay to QFs for their electricity, which implements 16 U.S.C. § 824a-3(a) and (b). Those changes would:

- Eliminate the right of QFs to obtain predetermined and fixed energy prices at contract (or LEO) formation necessary to develop QF generation and regardless of the fact that utility-owned and non-QF contracted generation is guaranteed long term energy price certainty.
- Allow states to set QF pricing based on short-term Locational Marginal Prices (LMP) or regional trading hub prices for short term energy, regardless of whether such costs reflect the incremental cost of energy that the utility would have acquired without the QF generation and regardless of the fact that utility owned generation and non-QF generation is not limited to such prices.
- Allow states to set QF pricing based on "competitive solicitation" without safeguards necessary to ensure that such pricing reflects the incremental cost of generation, including the utility's own generation and non-QF generation.

63 Order No. 70, 45 Fed. Reg. at 17,965/1 (emphasis added).

For the reasons set forth below, the proposed changes violate the Commission's statutory authority under 16 U.S.C. § 823a-3(a) because the changes fail to encourage QF development and result in rates that are not just and reasonable and that discriminate against QFs.

A. 16 U.S.C. § 824a-3 Requires Rates That Encourage QF Development, Are Just and Reasonable, and Do Not Discriminate against QFs.

Congress directed the Commission to "prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production."[64] Congress provided that those rules "shall insure that… the rates for such purchase (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and (2) shall not discriminate against qualifying cogenerators or qualifying small power producers."[65] Thus, the Commission's rule must ensure that the prices paid to QFs meet the statutory floor of a price that encourages QF generation, is just and reasonable to the utility's customers, and does not discriminate against QFs.

The Commission's first rules implementing PURPA complied with those requirements by setting the QF price at the statutory maximum, full avoided cost price. That price maximized incentives for QFs, thus meeting the statutory requirement to encourage QFs.[66] Additionally, because the price paid to QFs is the same as what the utility would pay for alternative sources of supply, but for the QF generation, it insured just and reasonable rates to customers and non-discriminatory pricing to QFs. Since the price was set at the statutory maximum, neither the Commission nor any subsequent reviewing courts considered whether any rate lower than the full avoided cost rate would meet the statutory requirements of encouraging QFs, producing just and reasonable rates to customers, and ensuring that QFs receive non-discriminatory prices.

B. The Changes Proposed in the NOPR Violate 16 U.S.C. § 824a-3(a) Because The Rates Do Not Encourage QF Development.

1. The NOPR's Proposal To End Predetermined Energy Pricing Known At Contract or LEO Formation Will Discourage, Rather Than Encourage, QF Development.

The Commission's original PURPA implementation rules correctly recognized that fixing QF prices at the inception of a contract or LEO was necessary to provide QFs the "need for certainty with regard to return on investment" that requires a

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64 16 U.S.C. § 824a-3(a).

65 16 U.S.C. § 824a-3(b).

66 *See Am. Paper Inst., v. Elec. Power Serv. Corp.,* 461 U.S. 402 at 406-07.

period of price certainty "long enough to allow QFs reasonable opportunities to attract capital from potential investors."[67] As recently as 2016, the Commission reiterated its view that QFs' "need for certainty with regard to return on investment" persists, and that PURPA therefore requires the price certainty of a legally enforceable obligation to endure "long enough to allow QFs reasonable opportunities to attract capital from potential investors."[68] The Commission reasoned that providing the necessary long term price certainty for maximizing QF development does not violate the prohibition on rates that exceed "the incremental cost to the electric utility of alternative electric energy" because that provision does not require a "minute-by-minute" accounting, but allows long term projections that—when correctly done—"balance out" periods of overestimation and underestimation.[69]

Since PURPA's initial adoption, the Commission has persistently and on the basis of substantial cumulated evidence concluded that the revenue certainty afforded by the fixed energy rate option is an essential driver of QF development.[70] Billions of dollars in investment in QFs has relied upon this price certainty to be constructed, and substantial proposed investments across the country continue to rely upon that certainty to be developed. The record evidence here confirms that QF financing needs are distinct, the barriers to obtaining financing are distinct and typically more onerous than non-QFs, and that obtaining financing remains a substantial barrier to QF development.[71] For example, the Solar Energy Industries

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67 Order 69, 45 Fed. Reg. at 12,224/2 (Feb. 25, 1980); *Windham Solar LLC & Allco Fin. Ltd.*, 157 FERC ¶ 61,134 at P 8 (Nov. 22, 2016).

68 *Windham Solar LLC & Allco Fin. Ltd.*, 157 FERC ¶ 61,134 at P 8 (Nov. 22, 2016).

69 Order 69, 45 Fed. Reg. at 12224/2 (Feb. 25, 1980).

70 *See, e.g.*, *New York State Elec. & Gas Corp.*, 71 FERC ¶ 61,027 *14-15 (Apr. 12, 1995) (agreeing with arguments made by commenters that there is a greater need for certainty with regard to return on investments in new technologies that outweighs concerns that projected prices may turn out to have been too high); *Windham Solar*, 157 FERC ¶ 61,134 at P 8; *see also JD Wind 1, LLC*, 130 FERC 61,127, 61,631 (Feb. 19, 2010) (long term fixed price contracts are consistent with PURPA even when the projected price turns out to be too high); *W. Penn Power Co.*, 71 FERC ¶ 62253, 61,495-96 (May 8, 1995).

71 SEIA Post-Technical Conference Comments, AD16-16 at 8-12 (Nov. 7, 2016) ("Independent renewable generators do not have access to the breadth of financing options that are available to incumbent utilities with guaranteed rate base return, or their generation affiliates that have large balance sheets and the ability to use utility-parent guarantees to obtain favorable financing arrangements…. Small independent developers do not have access to the substantial equity balances that a

Association (SEIA) representative Mr. Glass testified during the technical conference that, based upon his more than twenty years of experience working in support of independent power producers, securing a fixed price for a financeable term is indispensable to secure financing.[72] He explained that "[t]here is no generation that's being financed on a merchant basis. You know, QFs don't get financed that way."[73]

Additional evidence underscores that the Commission's proposal will substantially impact QF ability to obtain financing. In sworn testimony before the North Carolina Utilities Commission, the Director of National Economic Research Associates Kurt Strunk explained how restricting the term of fixed energy prices to two years would impact QF financeability, notwithstanding the ten-year term of the PPA.[74] Strunk explains that "the proposed reduction of the time period over which

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large portfolio owner may have."); Post-Technical Conference Comments of the Independent Power Producers Coalition of Michigan, AD16-16 at 1-2 (Nov. 7, 2016) (describing how capital expenditures require longer amortization periods, which impacts certainty needed for finance ability); NewSun Energy Comments, AD16-16 at 2-3 (developer does not build in jurisdictions lacking long-term price certainty inspite of experience in neighboring jurisdiction); *see also* Andrea S. Kramer and Peter C. Fusaro*, Energy and Environmental Project Finance Law and Taxation: New Investment Techniques* at 140 (Oxford 2010), ("The small group of lenders willing to finance a merchant power project have required significant levels of equity or contingent equity support and/or funded reserves, as well as cash sweep requirements. . . Since the tightening of the credit markets in September 2008 and the lack of correlation or power and gas hedges in certain markets, it is unlikely that lenders will be willing to provide financing for renewable projects without a long-term PPA with a creditworthy offtaker"); Deborah A. DeMasi and Kenneth B. Weiner, *International Project Financing* §10.05[1] (4th ed. 2012) ("Although some "merchant" electricity generation projects (projects that sell electricity in open markets) were financed in the 1990s, typically lenders prefer the project company to enter into long-term power sales or tolling agreements with creditworthy offtakers.").

72 Technical Conference on Implementation Issues Under The Public Utility Regulatory Policies Act of 1978, Dt. No. AD16-16, Technical Conference Transcript at 70 (June 29, 2019)("Technical Conference Tr.").

73 *Id.*

74 Direct Testimony of Kurt G. Strunk on behalf of North Carolina Sustainable Energy Association, Docket No. E-100, SUB 148, Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2016 at 11 (N.C. PUC, Mar. 28, 2017),

fixed rates apply will lead [] lenders to view the effective PPA coverage period as only two years" and that "lenders will significantly discount the revenues available beyond that two-year period."[75] Consequently, "it is unlikely that project debt could be obtained in reasonable quantities for terms longer than two (2) years."[76] Strunk's testimony shows that the bare existence of a must-purchase obligation, without firm revenue, is not enough to enable QF development.

The testimony of Rebecca Chilton, an expert with nearly a decade of experience at national financial institutions lending to utility scale utility projects, before the South Carolina Public Service Commission also describes that the number of QFs which obtain financing without revenue certainty through the PPA is quite limited.[77] Such financing depends on special lenders with limited-access funds or credit supports that are not widely available to all QFs.[78] Indeed, over the course of her work for two mainstream national lenders, Chilton never provided a single loan to a QF that lacked revenue certainty for a period of at least 10 years.[79] Finally, Chilton describes that in South Carolina regulated monopoly market a "QF is limited to only a single buyer: the utility."[80] QFs lack multiple offtake options that may exist in more competitive, non-monopoly wholesale markets. In short, obtaining revenue certainty is especially necessary to secure financing when there is a sole potential buyer, itself a monopoly utility who competes to produce the same generation and therefore has inherent incentive to deny fair terms to competitors.

Yet, despite this evidence that price certainty is critical to QF development, and a lack of any direct evidence to the contrary, the NOPR proposes to remove price certainty and allow states to offer only a floating energy price, which provides no certainty to QF developers of the return on their investment at contract formation.[81] The Commission does not revise, or even address, its prior

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https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=b6449036-9361-4793-b87f-22bb131876f7 (attached as Ex. 1).

75 *Id.*

76 *Id.*

77 Direct Testimony of Rebecca Chilton on behalf of Johnson Development Associates, Docket Nos. 2019-185-E & 2019-186-E, In re: South Carolina Energy Freedom Act (H.3659) at 4-5 (Sept. 11, 2019), https://dms.psc.sc.gov/Attachments/Matter/1a21940c-f051-4151-9e6d-481e7e04cd7a (attached as Ex. 2).

78 *Id.*

79 *Id.* at 5.

80 *Id.* at 6.

81 NOPR at P 66.

determinations that long-term price certainty has been necessary for QF development. The Commission's rationale for concluding that rates without a fixed energy price "should be adequate to support financing for QFs" boils down to the fact that some non-QFs, including renewables and traditional generators, are able to secure financing and get built without PURPA.[82] Yet, the Commission acknowledges that it has no basis to believe that substantial non-QF capacity is being financed and constructed without any form of fixed revenue to support financing.[83] The Commission thus concedes that it has no basis to dispute that price certainty is crucial to project financeability. Instead, the Commission's theory that QFs will be able to secure the long-term contracts requisite to project development without PURPA is pure speculation.

The Commission contends that "there is evidence that" the need for long term price certainty at contract formation "is no longer true."[84] That "evidence", however, is not evidence that QFs are being developed without long term price certainty, which the Commission acknowledges it lacks any direct evidence of. Instead, the Commission cites renewable energy projects–including merchant generators–being constructed without the benefits of QF status[85] and the Commission's theorizing that QFs can avail themselves of other federal and state incentives sufficient to ensure they obtain necessary financing for development.[86] That "evidence" is not only insufficient, but actually contradicts the conclusions that the Commission draws from it. First, the fact that non-QF renewable energy projects are being developed says nothing about what is necessary to encourage "cogeneration and small power production," which is what Congress mandated in 16 U.S.C. § 824a-3(a). Second, even if development of non-QF generation were relevant to what is required to encourage QF development, the terms under which the non-QF generation is developed belies a conclusion that long-term price certainty is unnecessary. Non-QF renewable energy developed by non-utility merchant generation owners obtain long-term, fixed price contracts.[87] Thus,

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82 NOPR at P 78.

83 *Id.* at P 76.

84 *Id.* at P 73.

85 *Id.* at PP 74, 75

86 *Id.* at P 76.

87 *See, e.g.*, Techren V Power Purchase Agreement at §§ 2.2, 4.1.2.1, and Exhibit 2A (25 year predetermined price) (relevant portions attached as Ex. 3); Battle Mountain Power Purchase Agreement at §§ 2.2, 4.1.2, and Exhibit 2A (same) (relevant portions attached as Ex. 4); Copper Mountain Solar Power 5 Purchase Agreement §§ 2.2, 4.1.2, and Exhibit 2A (same) (relevant portions attached as Ex. 5); Dodge Flat Solar Power Purchase Agreement at §§ 2.2, 4.1.2, and Exhibit 2A (same) (relevant portions attached as Ex. 6); Eagle Shadow Mountain Solar Farm

contrary to the Commission's reliance on non-QF projects as evidence that long-term price certainty is not necessary, the non-QF generation contract terms reinforce that long-term price certainty is critical for non-QF merchants as well as QF projects. Third, there is no evidence that whatever tax credits and other government incentives may be available to QF developers are sufficient to overcome the lack of long-term price certainty in obtaining the required financing at reasonable terms to develop QF generation, nor that eliminating fixed energy prices may result in more favorable contract terms for QFs.[88]

The Commission points to a series of reports, data, and testimony in support of its claim that QFs no longer need the fixed energy rate option in order to be constructed. None of that purported evidence directly addresses the question at hand: how price certainty over a fixed period affects the ability of QFs to obtain financing to construct their projects. As noted above, and described at length below, evidence about merchant gas generators, large scale utility-owned renewables, or the one-off experiences of particular utility cannot provide a reasonable basis for the Commission to assess the impacts of its proposal *on QFs*. A foundational premise of PURPA is that the combination of size, independent ownership, operational characteristics, and monopolization of energy generation by incumbent utilities creates unique barriers to the development of QFs. The Commission fails to address that purpose to determine how its proposed revisions would impact QFs due to their unique circumstances.

i. The Commission's incorrectly relies on a PJM Market Report by Monitoring Analytics, LLC.

The Commission attempts to show that removing the right to forecasted avoided energy cost rates will not materially harm QF development and financing opportunities by citing to a PJM Market Report by Monitoring Analytics, LLC.[89] The PJM Market Report shows that, since 2007, over 23,000 MW of new capacity was constructed in PJM Interconnection, L.L.C. ("PJM"). However, this PJM-specific report says nothing about the unique circumstances of small QF generation. Moreover, the experience within the PJM Interconnection—where, unlike many other regions of the country, vertically integrated utilities with cost of service rate regulated generation are atypical—does not and cannot demonstrate general

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Power Purchase Agreement at §§ 2.2, 4.1.2, and Exhibit 2A (same) (relevant portions attached as Ex. 7); Jackpot Holdings Power Purchase Agreement at §§ 4.1, 6.1.2, and Exhibit 5 (20 year predetermined price) (relevant portions attached as Ex. 8).

88 NOPR at P 77.

89 NOPR at P 70, n.113 (citing Monitoring Analytics, LLC., Third Quarter, 2018 State of the Market Report for PJM, January through September, at 249, Table 5-6 (Nov. 8, 2018). ("PJM Market Report")

patterns of project development outside of that market. Moreover, according to the market report, of the 23,000 MW of new capacity added to the PJM footprint since 2007-2008, only 7,029 MW were generation projects with "nonmarket funding". That is, a significant portion of the generation included in the report was financed "from guaranteed revenues, including cost of service rates for a regulated utility and subsidies." That is, even in PJM, a significant portion of new generation clearly does not rely on the short term variable energy payments that the Commission seeks to impose on QFs. That is not to say that the remaining ~16,000 MW that does rely on short term market energy rates to obtain financing. In fact, the PJM Market Report provides no insight into whether the remaining 16,000 MW of projects relied solely on variable energy payments, rather than obtaining long term fixed price payments. Importantly, the report distinguishes projects based on "market funding", which it defines as investors bearing risk instead of guaranteed payment from ratepayers, which is not the same as relying on short term energy market revenues instead of long-term contract pricing.[90] Indeed, the distinction between market and nonmarket funding does not reflect whether a given projected relied upon PPAs—including those with fixed pricing.[91] Thus the Commission cannot infer—as it apparently intends to do—that all or some of the ~16,000 MW labeled as "market funded" projects in the report actually financed solely through variable and unknown future energy market pricing.

Moreover, as noted above, QFs face hurdles that are unique compared to much larger projects and compared to fossil fuel projects. The PJM Market Report does not provide a breakdown of the proportion of projects that would qualify as QFs in PJM, or even the share of new capacity that are projects of 20 MW or less. Thus, even if the report infers that some projects can be successfully financed and enter into operation without fixed energy prices, which provides no evidence that QF sized renewable energy projects can.

ii. The Commission relies on testimony which does not support its conclusions.

The Commission cites to the 2016 Technical Conference's transcript to support its conclusion that "non-QF independent power projects located outside of RTOs enter into contracts with fixed capacity and variable energy prices."[92] As a threshold matter, the Commission cannot uncritically extrapolate from the experience of non-QFs, which may be of types or sizes that result in wholly different financing needs and structures, to reach conclusions about QF development. A gas plant with a fixed capacity contract covering its capital costs and variable energy costs and revenues is categorically different from a renewable project with different

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90 PJM Market Report at 247.

91 *Id.*

92 NOPR at P 70, n.114 (citing to Technical Conference Tr. at 167-69 (Southern Company)).

capacity payments and nominal variable costs. Unlike the gas plant, renewable generation must typically recover capital costs through variable revenues.

Moreover, the testimony does not establish the proposition the Commission cites it for. A full reading of the cited statements made by Southern Company reveals that while it said this:

> So if we enter into a bilateral contract with an independent power producer for combustion turbine or combined cycle capacity, we don't fix the energy price. The capacity payment is a fixed payment. That's their fixed [stream]. The energy price is typically indexed to the price of natural gas.[93]

It also reveals this statement:

> We now have almost ten times the number of long-term contracts with renewable generators than what [they] have [with] QF contracts…. Because we're willing to give longer terms, longer contract terms generally speaking, *with locked in fixed energy price…*[94]

Thus, contrary to the Commission's conclusion that QFs do not require long term fixed prices, the testimony the Commission cites actually confirms that fixed energy rates are a crucial factor to enabling project development. Rather than picking irrelevant anecdotes from the testimony discussing non-QF natural gas plant PPAs while ignoring the testimony specifically noting the need for fixed energy rates for renewable QF generators at issue in the Commission's rulemaking.

The Commission also erroneously cites portions of testimony from the American Forest & Paper Association.[95] However, the Commission's interpretation of that testimony fails to acknowledge that the speaker was not providing empirical evidence based on an actual program or contract, but rather, was providing a hypothetical example for illustrative purposes:

> So I hear that we've got a "one-mile rule" and the problem is that somebody's siting a project that's bigger than what somebody else thinks it should be, based on that, which I think is a reasonable rule. You know, one-mile, you've got to put it in the statute somehow.
>
> And the big problem is, is that a next project is lower than the utility's avoided cost. I'm a consumer. I'm thinking, how is that gaming me? What is it that I'm being deprived of by having that other project within a mile? I mean as a consumer, maybe I'll propose a half-mile rule. Because essentially, what

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93 *Id.*

94 Technical Conference Tr. at 200 (Southern Company) (emphasis added).

95 NOPR at P 70, n.114, (citing Technical Conference Tr. at 153 ("Now, you sign a long-term IPP contract. That contract [has] got a variable energy cost in it.")).

> we want to see is, we want to see the projects built that are the lowest cost, that have the best chance of working out in the market.
>
> Now, you sign a long-term IPP contract. That contract is got a variable energy cost in it. There's nothing you can point to when you say, "Oh, gee, that energy price went up from where we thought it was going to be when we signed it originally."[96]

This testimony does not purport to describe a general practice, and the Commission cannot rely on it to reach general conclusions about the ease of financing and building projects based on variable energy rates.

Yet another example of the Commission citing evidence that contradicts the Commission's interpretation upon closer examination is comments filed by SEIA.[97] SEIA's comments contradict the Commission's conclusion in the NOPR that long term price certainty is not necessary. As SEIA actually noted, predictable revenue streams are critical to project development:

> Fixed Price: A predictable stream of revenue from the project asset is the fundamental basis of any project financing. Most solar QF developers elect the option under 18 CFR 292.304(d)(2) to provide energy and/or capacity pursuant to a PPA over a specified term. Developers need rates for such sales of energy and/or capacity to be fixed, based on avoided costs calculated at the time the obligation (of the QF to sell and the utility to buy) is incurred, rather than varying over time.[98]

The second sentence's reference to "energy and/or capacity" does not mean one or the other, such that fixed energy rates are not necessary. Instead, the comment parallels that language of 18 CFR 292.304(d)(2), which entitles a QF to sell its "energy or capacity" (depending on the capacity needs of the utility) to a utility over a specified LEO. The "and/or" is an acknowledgement that a PPA may provide fixed capacity in addition to fixed energy revenue, not a suggestion that a QF can be developed without a predictable energy revenue stream.

iii. Reliance on Idaho's unlawful state interpretation of existing rules and speculation that changing the rules would help QFs is arbitrary and capricious.

96 Technical Conference Tr. at 153 (American Forest & Paper Association).

97 NOPR at P 70, n.115 (citing Solar Energy Industries Association Comments, Docket No. AD16-16-000, at 3 (June 29, 2016) ("Developers need rates for such sales of energy and/or capacity to be fixed").

98 Solar Energy Industries Association Comments, Docket No. AD16-16-000, at 3 (June 29, 2016).

The Commission asserts without factual support that state regulators elect to impose short term contracts because of the requirement to forecast avoided energy cost rates.[99] The Commission further speculates that, if such a requirement were removed, state regulators would opt for longer contracts.[100] That rationale is flawed. The Commission fails to acknowledge that the Idaho Commission's practice of limiting contract terms to two years is, itself, unlawful for at least three reasons. First, existing regulations allow the QF developer to create its own enforceable obligation—including the term of that obligation—and then require the Idaho Commission to calculate the avoided cost rate for the obligation the QF created.[101] Neither PURPA nor this Commission's existing rules provide states with the right to dictate the terms of a utility's obligation to the QF—such as contract length—before establishing the applicable price.[102] Second, the two year contract length in Idaho applies only to solar and wind QFs between 100 kW and 10 aMW (annual average megawatts)[103] and has decimated the market for such QFs. As of January 20, 2015, there were at least 36 proposed solar QFs in Idaho proposing agreements to Idaho Power.[104] Each proposed at term of at least 20 MW.[105] However, following the August 20, 2015, effective date of Idaho's change to two year contract terms for wind and solar QFs, no wind or solar QFs have progressed to a contract and been developed.[106] Thus, in addition to exercising authority that the Idaho Commission does not have to set terms of an enforceable obligation, Idaho's two-year limit violates the requirement that states set rates that allow reasonable financing.[107] Third, Idaho allows contract terms for other QFs between 100 kW and 10 MWa (such as hydro and cogeneration) longer than two years, and non-QF contracts longer than two years[108], so Idaho's two year limit is also unlawfully discriminatory against wind and solar QFs.[109] Rather than, perversely relying on this unlawful practice as a rationale to further undermine QF price certainty, the Commission should have corrected Idaho's unlawful implementation of current rules.

Further, even if Idaho's two-year contract length cap were not unlawful, the Commission's supposition that allowing states to provide only short run energy

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[99] NOPR at P 77.

[100] *Id.*

[101] 18 C.F.R. § 292.304(d)(2) (QF has the right to provide energy or capacity pursuant to a legally enforceable obligation and that an avoided cost calculated at the time the QF incurs that obligation).

[102] In fact, the sequential approvals required for short term contract lengths—what the Idaho PUC calls "successive short-term contracts", Idaho PUC Order 33419 2015 WL 6958997 at *17 (Nov. 5, 2019), emulates exactly the type of state ratemaking oversight of QFs that Congress specifically sought to avoid. 45 Fed. Reg. at 12,222 (quoting Conf. Report on H.R. 4018, H.Rep. No. 1750, 9th Cong., 2d

Sess. (1976)); see also FLS Energy Inc., 157 FERC ¶ 61,211 at PP 24-26 (finding state policy that, while not explicitly prohibited by FERC rules, violates PURPA by indirectly achieving what the state is prohibited from directly doing).

[103] Idaho PUC Order No. 33357 applies to resources subject to the so-called "IRP-based contracts" but not the QFs using the published avoided cost methodology in Idaho. Order No. 33357, 2015 WL 5002133, at 23-25, 28-29 (Aug. 20, 2015); Order 32176 at 11-12, 287 PUR4th 316, 2011 WL 490884 (Feb. 7, 2011) (temporarily limiting solar and wind QFs between 100 kw an 10 aMW to IRP based contracts but allowing all other QFs to use published avoided cost rates up to 10 aMW); Order 32262 (June 8, 2011) (permanently subjecting solar and wind QFs between 100 kW and 10 MWa to IRP pricing while allowing all other QFs to use published avoided costs), http://www.puc.idaho.gov/fileroom/cases/elec/GNR/GNRE1101/ordnotc/20110608FINAL_ORDER_NO_32262.PDF.

[104] Idaho Power Allphin Direct Exhibit 3 (attached as Ex. 9).

[105] *Id.*

[106] Idaho Power Response to Discovery (Data Requests of Idaho Conservation League and Sierra Club in Docket No IPC-E-17-01) (attached as Ex. 10). Notably, QFs other than wind and solar, which are not subject to the 2 year contract length, continue to be developed in Idaho and prior PPAs that are also not subject to the 2 year limit have been renewed. Id. (biomass project continued to contract); see also Idaho PUC Order 34441 (approving contract renewal with a 1.75 MW hydro generator with fixed prices for entire 20 year contract term beginning November 1, 2019), https://puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1924/ordnotc/20190917FINAL_ORDER_NO_34441.PDF; Idaho PUC Order No. 33992 (approving PPA for hydro generator with 20 year fixed prices), http://www.puc.idaho.gov/fileroom/cases/elec/AVU/AVUE1801/ordnotc/20180221FINAL_ORDER_NO_33992.PDF; Idaho PUC Order No. 34252 (approving contract pricing for a 132.2 MW QF thermal generator with 5 year fixed pricing for both sale and purchase of electrical energy), https://puc.idaho.gov/fileroom/cases/elec/AVU/AVUE1813/ordnotc/20190227FINAL_ORDER_NO_34252.PDF; Idaho PUC Order No. 33677 (20 year fixed price PPA with hydro project), https://puc.idaho.gov/orders/33699/33677.pdf; and Idaho PUC Docket No. IPC-E-19-29 (application of existing hydro generator for 20 year contract renewal with fixed prices beginning December, 2019), http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1929/20190827APPLICATION.PDF; Idaho PUC Docket No. IPC-E-19-30 (extension of hydro PPA for 20 years with fixed prices beginning January 2020),

costs in QF pricing will encourage more QF development is false. With only two-year prices in Idaho—which is two years longer than the Commission's proposal to provide no price certainty and force QFs to take then-prevailing market rates at time of deliver—no QFs have been developed in Idaho. Providing even less price certainty—which includes offering a longer contract term that provides no long term price certainty—will not encourage more QF development. There is no basis for the Commission's theory that eliminating all energy price certainty "could result in longer QF contracts, and perhaps other more favorable treatment, that would improve the financeability of QF projects."[110] In short, a longer contract with no price certainty will not improve financeability from a contract that provide two-year price certainty, which has proven insufficient to finance a single QF in Idaho subject to the two year limit.

iv. The Commission errs in relying on growth of non-utility-owned renewable resources to support its proposal.

The Commission relies on EIA data to show that the number of terawatt-hours (TWh) generated by non-utility-owned renewable resources increased from 51.7 TWh in 2005 to 340 TWh in 2018. The Commission then jumps to the conclusion that this increase in TWh supports its contention that some projects may be able to develop without forecasted or fixed energy rates.[111] The Commission's reliance on this datapoint is misplaced for two reasons.

First, the change in TWh since 2005 does not indicate any ability of a single generator to obtain financing without price certainty. In fact, if all or most of the additional ~288 TWh generated since 2005 were from projects with fixed energy rate contracts, the data support the opposite conclusion than the Commission attempts to draw from them.

Second, the change in TWh since 2005 provides no insight into the size of the projects that have been developed, which is relevant when considering that QFs in RTOs are only 20 MW or smaller and 80 MW or smaller in non-RTO States. Thus, even if the data could allow an inference that the generation was from projects financed without any energy price certainty (which they cannot), there would still be no basis to extrapolate that to small QFs. That is, even if the new TWh

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http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1930/20191004APPLICATION.PDF.

107 45 Fed. Reg. at 12,218/1; *Windham Solar LLC & Allco Fin. Ltd.*, 157 FERC ¶ 61,134 at P 8 (Nov. 22, 2016).

108 *See, e.g.*, Jackpot Holdings Power Purchase Agreement, *supra* note 87.

109 16 U.S.C. § 824a-3(b)(2); 18 C.F.R. § 292.304(a)(1)(ii).

110 NOPR at P 77.

111 NOPR at P 75-76.

generated in RTO regions from 2005 to 2018 came from QF-like projects larger than 20 MW, it would not support the Commission's decision to remove price certainty for projects 20 MW and smaller. Likewise, if the generation came from QF-like projects larger than 80 MW, it would not support the Commission's decision to remove price certainty for QF projects.

The Commission's belief that 20 MW and smaller (in RTOs) or 80 MW or smaller (outside RTOs) can obtain financing without fixed energy rates is not supported by irrational and unsupported inferences from merely the number of new TWh generated by non-utility-owned renewable resources.

v. The Commission errs by relying on a policy argument that, in sum and effect, is nothing more than a disagreement with Congress's decision to retain PURPA.

At the time of PURPA's amendment in 2005, Congress was well aware of the existence of federal and state renewable energy incentives, such as state renewable portfolio standards and the investment tax credit, and their effect of encouraging investment in renewable energy. And yet, Congress did not eliminate or curb PURPA obligations in states adopting, or manifesting significant investment due to, such renewable energy incentives. Instead, it kept PURPA largely intact, clearly evidencing Congress's intent to retain the inducements the law provides for renewable energy—and other qualifying generation—notwithstanding, and in fact, in addition to other renewable energy incentives.

The Commission must follow the policy choice of Congress. It cannot choose to undermine PURPA because it disagrees with Congress's policy choice. Yet, that is exactly what the Commission attempts by pointing to the fact that other policies are also independently supporting renewable energy investment within some states. Congress granted the Commission no discretion to determine that there is "enough" QF development and conclude that it need no longer fully implement the statute. The Commission cannot permissibly consider policy factors that are outside the scope of the statute, such as whether it is advisable to afford PURPA support in addition to other federal or state policy support, in deciding what rules are necessary to encourage QFs.[112]

2. There is no evidence that long term price forecasts used to set QF prices result in higher costs than would have been otherwise incurred.

The Commission's additional justification for eliminating long-term price certainty for QFs–that the difference between forecasted avoided costs and actual costs "may" not have balanced out in the past and, second, that this trend "may

112 *Cf. Mass v. EPA,* 549 U.S. 497 (2007) (rejecting agency argument that policy considerations divorced from the statutory text are a basis for failing to exercise statutory authority).

persist"–is similarly baseless.[113] There is no evidence of systematic overestimation of utilities' incremental costs occurs over the long term when avoided costs are corrected projected. Instead, the Commission relies on examples offered by the investor owned utility industry based on selective years that compare QF contract prices to short term market prices. Those comparisons reflect the general decline in wholesale power prices across the entire industry from falling natural gas prices. Thus, at most, it indicates that contracts entered just before the fall in natural gas prices failed to predict that decline. However, that failure is not limited to QF price projections: the entire electric utility industry failed to project the decline in natural gas prices that occurred in the late 2000s. The but-for test required by 16 U.S.C. § 824a-3(b) requires a comparison of the QF contracts with the generation that the utility would have otherwise procured. There is no evidence that utilities would have relied on the short term energy market but-for QF contracts entered into before the decline in gas prices. Instead, those utilities would have entered contracts for non-QF generation or constructed and rate-based their own long-term supplies. Those decisions would have been based on the same failure to project the drop in natural gas prices and a hind-sight look at those investments would show a similar margin above short term prices. Monopoly utilities regularly operate at production costs that far exceed short term market rates.[114] Therefore, a few complaints of overestimated QF prices compared to sort term market prices provides no evidence that QF prices are above what the utilities would have paid for alternative supply. There is no evidence that QF contracts entered into before the decline in natural gas prices exceed the price the utility would have paid for non-QF generation committed to at the same time.

The Commission's sole support for its proposed factual finding of overestimated QF prices is three comments filed in Docket AD16-16, none of which compare QF forecasts with the forecasts that utilities were simultaneously using for non-QF generation construction and procurement decisions.[115] The comments of monopoly utility owner Alliant Energy Corporate Services merely compares historic forecasts of avoided energy rates with after the fact "market-based wind prices" taken from a different period of time.[116] The temporal mismatch incorrectly infers that without QF generation, Alliant Energy would not have acquired additional supply until wind prices declined to the post hoc "market-based" prices it later cites. Of course, absent QF generation the utility may have added non-QF energy based on the same energy price projects that were used for QF pricing. That is the correct measure of the incremental cost to the utility in the absence of QF generation. By

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113 NOPR at PP 30, 68.

114 See infra section II.D.

115 NOPR at P 64, fn. 101

116 *Id.* (citing Alliant Energy Comments, Docket No. AD16-16-000, at 5 (Nov. 7, 2016))

that measure, non-QF acquisitions made based on the same projected energy prices used for the QF pricing would not show the same difference as Alliant's post hoc wind price comparison. Moreover, Alliant's comments contain no discussion of how it derived the QF pricing, the "market-based wind prices," or whether Alliant Energy was concurrently using similar energy price projections for its own investment decisions as those used for QF pricing. Relying on Alliant's unsubstantiated and irrelevant comments is arbitrary and capricious.

Likewise, the comments of Edison Electric Institute ("EEI") do not contain an analysis of the long-term balancing of its forecasted avoided energy rates with actual avoided energy costs.[117] Like the Alliant Energy comments, EEI does a post hoc comparison of forecasted prices to short term prices at the Mid-Columbia wholesale power market trading hub. That implies—incorrectly—that PacifiCorp would have relied on the Mid-Columbia hub for all energy needs but-for QF contracts based on forecasts. There is no basis for that assumption. PacifiCorp did not have unlimited transmission access from the Mid-C hub to load. Moreover, PacifiCorp would not have relied on the short term market for all energy requirements but-for QF generation. PacifiCorp owns and operates a fleet of ratebased generation, builds new generation, and enters long term supply contracts with non-QF generators. Absent QF generation, PacifiCorp would have acquired other generation at costs higher than the Mid-C short term market price. PacifiCorp's 2007 and 2009 PacifiCorp's Integrated Resource Plans anticipated acquiring non-QF generation and demand side management at levelized prices significantly higher than the post-hoc short term Mid-C prices used in the EEI comparison.[118] Thus, contrary to the EEI comparison, the correct comparison for any cost difference is the QF contract price and the non-QF generation that PacifiCorp intended to acquire instead. That correct comparison would show similar costs between QF and non-QF generation.

Finally, the comments of a Commissioner Raper from the Idaho Public Utilities Commission also studiously avoids the utility's actual alternative

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117 *Id.* (citing EEI Supplemental Comments, Docket No. AD16-16-000, attach. A at 3-4 (June 25, 2018)).

118 Based on those projected prices, PacifiCorp proposed to add 700 MW of large scale wind generation at levelized prices of $72.49/MWh ($55.13 after tax credits) and $72.35/MWh ($54.99 after tax credits). *See* PacifiCorp 2007 IRP at 8 (Table 1.3 Preferred Plan adding 700 MW of utility scale wind generation over three years), 95-96 (Tables 5.3, 5.4 showing wind generation at levelized prices of $72.49/MWh ($55.13 after tax credits) and $72.35/MWh ($54.99 after tax credits)) (relevant portions attached as Ex. 11); 2009 PacifiCorp IRP at 6, 104, 128 (proposing to add non-QF wind at $74.38/MWh, combined heat and power at $82.71/MWh, class 1 DSM at $70/MWh, and Class 2 DSM at $90/MWh) (relevant portions attached as Ex. 12).

incremental costs.[119] Interestingly, the Commissioner uses the same flawed comparison as Alliant Energy and PacifiCorp. Commission Raper compares post-hoc Mid-Columbia hub prices to Idaho Power's "average cost for PURPA power since 2001."[120] That avoids comparing the PURPA contract prices with the long-term price of alternative sources of supply that the utility would have entered into at the same time. There is no evidence that Idaho Power's source of supply, absent QF generation, would have been short term supply from the Mid-Columbia hub. More likely, the utility would have acquired other generation or rate based generation investments that would have been based on the same market projections as the QF prices. It is revisionist history to infer—as the Commissioner does—that the Idaho Commission's inability to correctly forecast market prices when approving QF contracts would not have applied equally to approving whatever supply obligation Idaho Power would have entered but-for the QF supply. Moreover, even if the utility would have relied solely on short term Mid-C energy purchases, the hub price is not the same as the cost to Idaho Power because of losses and transmission costs to bring it to the utility's load.

Moreover, even the misleading comparison of long term QF prices to post hoc short term market prices offered by the utility industry and Commissioner Raper fail to present an accurate comparison across the country. As shown in the Department of Energy graph below, the decline in wholesale energy prices corresponding to a decline in natural gas prices are not uniform geographically or temporally.[121] As the Department of Energy explained in a 2017 staff report on electricity markets, "[gas] prices show periodic regional, seasonal, or local price spikes, and even sustained price increases" that make it reasonable to continue to expect "regional differentials." Further, if gas prices do rise, "wholesale electricity costs are likely to rise in regions where natural gas remains the marginal fuel."[122]

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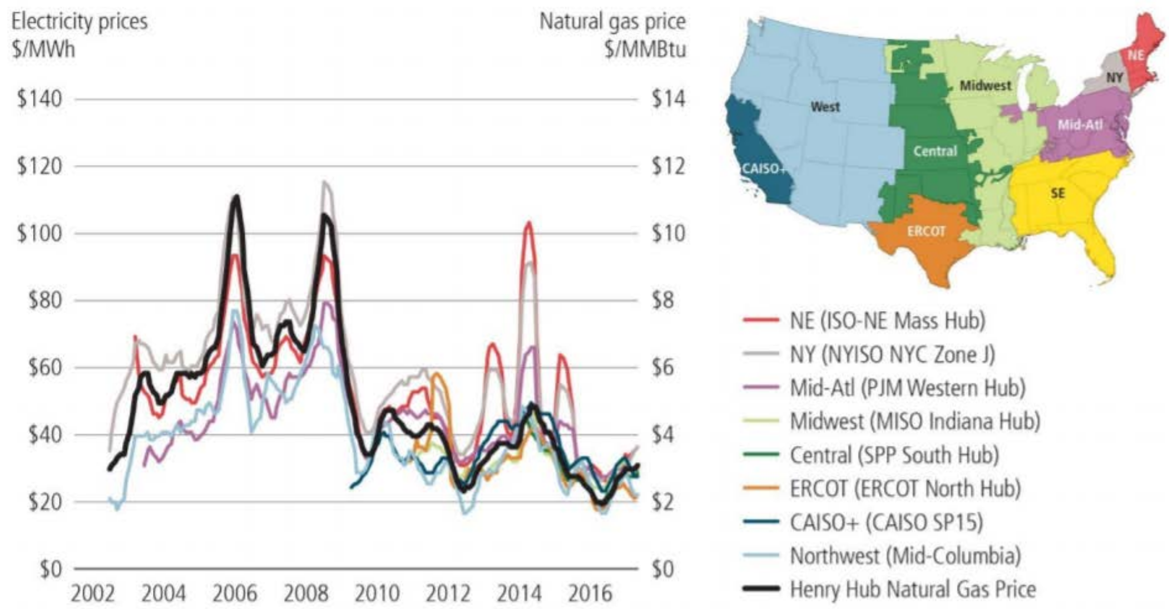
119 *See* NOPR at P 64, fn. 101 (citing Comments of Comm'r Kristine Raper, Docket No. AD16-16-000, at 3-4 (June 29, 2016)).

120 Comments of Comm'r Kristine Raper Comments, Docket No. AD16-16-000, at 3-4 (June 29, 2016) Note that looking at the average of QF avoided costs since 2001 can smooth out significantly variability from year to year.

121 Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability at 122 (Aug. 2017) at https://www.energy.gov/downloads/download-staff-report-secretary-electricity-markets-and-reliability; *see also id.* at Appendix A (showing variability of energy prices changes by region from 2002-201)

122 *Id.* at 124.

Figure 6.2. Average Wholesale Electric Costs/MWh Have Fallen between 2002 and 2016[446]



Moreover, the utility industry comments primarily indicate that, in some parts of the country (where cost of service ratemaking for production still controls), wholesale prices that are the product of competitive forces are cheaper than utility-owned generation's projected production costs. Such a conclusion is unremarkable, and irrelevant. PURPA is intended to encourage QFs to compete against utilities where competition otherwise remains constrained by utilities' monopolistic tendencies. Because monopoly utilities continue to operate their own generation at above-market costs, and almost certainly would have added their own generation at above-market prices without QF competition, it is not surprising that QF energy rates, which are paid based upon the utility's production costs, are higher than market rates. That may suggest that the utilities do not get the windfall they would have otherwise seen, but does not mean QF's fixed energy costs are higher than the costs consumers would otherwise have paid.

The Commission's record cannot support a conclusion that forecasted energy prices used to set long term QF prices diverge substantially and consistently, across geography and over extended periods of time, from the actual costs that would have been incurred for non-QF generation and utility-owned generation in the absence of QF generation.

3. There is no evidence that LMP, market hub, or efficient combined cycle plant prices are sufficient to incentivize qualifying facility development, as PURPA requires.

Like the Commission's proposal to end long term price certainty to the detriment of QF development, the Commission also proposes to allow states to effectively cap QF energy prices at a short term or market proxy.[123] The Commission's NOPR does not explain how those prices are sufficient to ensure QF development, nor contain any record evidence that short term LMP, market hub, or combined cycle proxy fuel costs are sufficient to promote QF development. There are few, if any, new generation sources—QF or otherwise—that rely solely on short term spot market pricing for energy. In those states currently offering QFs pricing based on the short term market price for energy, there is virtually no QF development. For example, Wisconsin utilities offer QFs a price consisting only of an LMP value.[124] There has been no QF development in response to those rates, whereas in neighboring states offering long term pricing at full avoided cost rates, QFs are viable and new projects are developed.

C. The Proposed Changes to QF Pricing Violate 16 U.S.C. § 824a-3(b)(1) Because The Resulting Rates Will Not Ensure Just and Reasonable Rates To Utility Customers.

Section 210(b)(1), 16 U.S.C. § 824a-3(b)(1), requires that the Commission adopt rules ensuring that rates "shall be just and reasonable to the electric consumers of the electric utility and in the public interest."[125] The House Conference Report makes clear that that phrase "just and reasonable" is to "be interpreted in a manner which looks to protecting the interests of the electrics consumer in receiving electric energy at equitable rates."[126]

The Commission has long recognized that the full avoided cost of the purchasing utility protects consumer interests and advances the public interest by encouraging QF development. Commission staff's analysis forming the foundation for the Commission's original rules explained that the statutory requirement to ensure just and reasonable rates is met "so long as the [QF] price is less than the alternative cost to the utility" because "the buying utility's ratepayers benefit from such transactions."[127] That is, by encouraging increased competition in the generation of electricity by encouraging QFs that are able to compete with utility-

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123 NOPR at PP 51-60.

124 *See* Wisconsin Electric Power Company Rate Schedule CGS DS-VP (attached as Ex. 13); Wisconsin Public Service Corporation Tariff Schedule PG-2A (attached as Ex. 14); Madison Gas and Electric Company Tariff Sheet E-55 (attached as Ex. 15).

125 16 U.S.C. § 824a-3(b)(1).

126 H.R.Conf.Rep. No. 95–1750, 95th Cong., 2d Sess. 98 (1978), U.S.Code Cong. & Admin.News 1978, at 7659, 7832.

127 Staff Discussion Paper, 44 Fed. Reg. at 38,863, 38,870/2 (July 3, 1979).

owned and third party generation, customers benefit by driving down prices. Indeed, as the Commission staff concluded, "we have difficulty in describing some particular price other than the avoided cost as being just and reasonable to the utility's customers."[128] Thus, in its original rules implementing PURPA, the Commission rejected alternative proposals to pay QFs only a percentage of avoided costs, ordering payment of full avoided costs because QF rates at less than full avoided cost would merely result in utilities operating generation that is less efficient (i.e., more costly to consumers).[129] Moreover, the Commission determined that a rate less than full avoided cost would fail to maximize QF development, which in turn would result in higher consumption of fossil fuel than could be achieved with maximum QF development, which is contrary to the public interest the statute sought to advance.[130] Thus, rates are "just and reasonable and in the public interest"–as required by 16 U.S.C. § 824a-3(b)(1)–when they maximize QF development by offering maximum incentives, because QFs are able to provide electric services at the same or lower cost than the utility would otherwise incur for the same supply and with less consumption of fossil fuels. Conversely, rates that fail to enable such QF development and utilization inevitably result in higher cost generation from fossil fuels, leaving customers paying for inefficient and more costly generation, while failing to achieve the reduction in fossil fuel consumption that is a core statutory objective.

1. Eliminating fixed energy rates and effectively killing off QF development fails to ensure just and reasonable rates that result from competition by QF development.

The Commission has a statutory obligation to ensure that QF rates are just and reasonable and in the public interest, but the NOPR utterly fails to consider it.[131] While the Commission focuses on the unsubstantiated claim that forecasted energy rates may cause consumers to pay too much, it ignores the known and well-documented impacts to consumers of undercutting QF development. The Commission has long recognized that PURPA is a critical source of competition with monopoly utilities, and it is a touchstone principle of the Commission's decision making that competition benefits consumers. Indeed, Congress itself recognized

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128 *Id.*

129 Order No. 69, 45 Fed. Reg. at 12,223/1 (Feb. 25, 1980).

130 *Id.*; *see also Am. Paper Inst..*, 461 U.S. at 415-18 (determining "the Commission's judgment that the entire country will ultimately benefit from the increased development of these technologies and the resulting decrease in the nation's dependence on fossil fuel" are appropriate factors to consider in setting QF rates in light of the statutory purpose).

131 16 U.S.C. § 824a-3(b)(1).

that robust implementation of PURPA would not only ensure more efficient QFs are built and replace inefficient utility-owned generation, but would also stimulate the monopoly utility to operate its own units more efficiently.[132] In addition, while the Commission focuses on the risk of PURPA contracts setting the rate too high, it ignores the benefits to consumers of risk hedging from long-term contracts. QFs, unlike regulated utilities, bear their own operational and construction risks – which, in turn, means that the consumers are shielded from those risks. Protection from the cost-overruns that monopoly utilities regularly incur may well provide billions of dollars in benefits to consumers.[133] The proposal to eliminate the right to fixed energy rates places all of these consumer benefits at risk. The Commission astonishingly and unlawfully simply ignores the other side of the ledger.

2. Capping QF prices at LMP, market hub or competitive solicitation pricing, where utility generation is not held to the same standard, fails to ensure just and reasonable rates for customers.

As described more fully below, the NOPR would allow states to limit QF pricing to a short term market price or competitive solicitation that the utility's own generation and non-QF purchase power agreements are not subject to. Utilities regularly recover costs of energy higher than the so-called market price or competitive solicitation price. Thus, imposing such limits on QFs but not on the utilities' other sources of supply removes the competitive downward pressure by QFs on non-QF energy. The resulting rates will be higher than if QFs were allowed to compete directly with utility owned generation and non-QF purchases, instead of being hampered by asymmetrical price caps. Those higher rates due to reduced competition from QFs are not just and reasonable.

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132 *See* S. REP. 95-442 95TH Cong., 1ST Sess. 1977, 1978 U.S.C.C.A.N. 7903 at 7906, 7919-7921, 7930 (1977) (discussing concerns about electric utilities inefficiencies and growing cost, and potential for incentives to spur new efficiencies).

133 *See* Supplemental Comments of PIOs, Docket No. AD16-16 at 5, 19-21 (Oct 17, 2018) (documenting multi-billion-dollar utility construction projects with hundreds of millions to multi-billion-dollar cost overruns across 5 states).

D. The Proposed Changes Discriminate Against QFs In Violation of 16 U.S.C. § 824a-3(b)(2).

PURPA requires the Commission to promulgate rules insuring that utilities pay QFs a rate that does "not discriminate against" QFs.[134] Notably, unlike other provisions in the Federal Power Act referring to discrimination, the prohibition on discriminatory rates for QFs is not qualified.[135] In other statutes, prohibiting price discrimination without the modifiers "unreasonable" or "undue," means any difference in price for the same commodity.[136]

1. Limiting QFs to variable energy contracts when non-QF generation rely on long-term contracts with predetermined prices discriminates against QFs.

As noted above, the NOPR proposes to revise 18 C.F.R. § 292.304(d) "to permit a state to limit a QF's option to elect to fix at the outset of a LEO the energy rate for the entire length of its contract, and instead allow the state to require QF energy rates to vary during the term of the contract."[137] The purported basis for this change is that in the past, a few utilities entered contracts with QFs, or QF formed LEOs, based on projected future prices that, in hindsight, were too high.[138] That rationale fails to acknowledge that the projections it relies on were primarily made before decreases in natural gas prices due to shale gas technology changes, not something inherent to QF and not limited to QFs. As demonstrated in PacifiCorp's IRP, which was developed contemporaneous to the QF contracts complained of, PacifiCorp was projecting natural gas and wholesale market prices for its own, non-PURPA, resource procurement decisions that, in hindsight, were also much higher than actual market prices.

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134 16 U.S.C. § 824a-3(b)(2).

135 Compare 16 U.S.C. § 824a-3(b)(2) ("shall not discriminate…") to 16 U.S.C. § 824e(a) (authorizing actions to address rate that are "*unduly* discriminatory or preferential") (emphasis added).

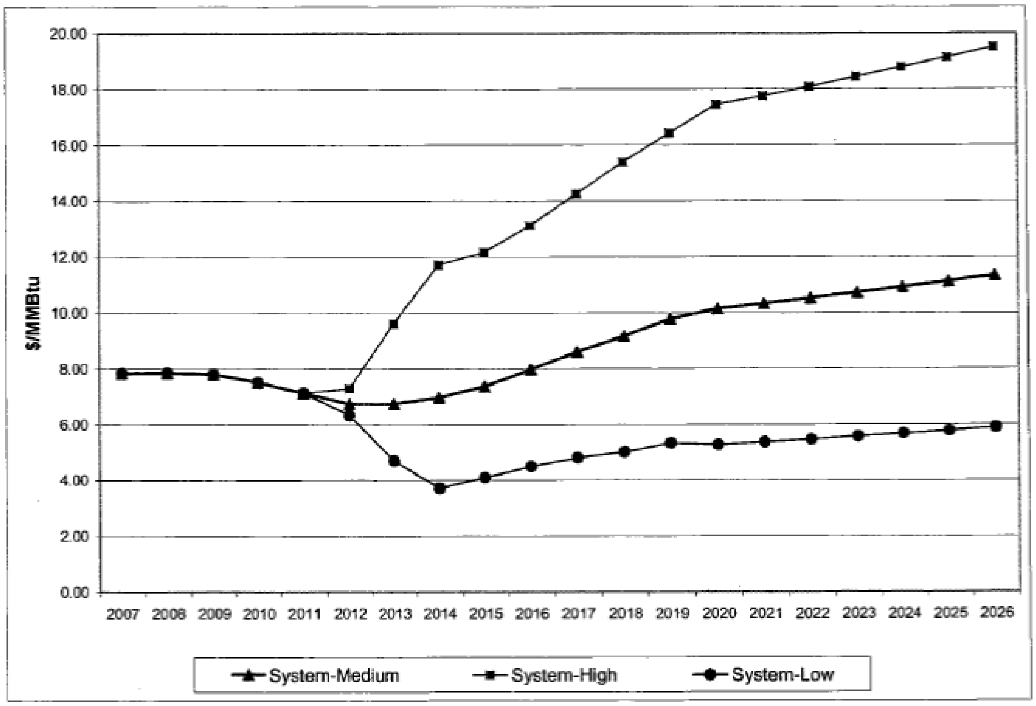
136 *See F.T.C. v. Anheser-Busch, Inc.*, 363 U.S. 536, 549 (1960).

137 NOPR at P 66.

138 NOPR at PP 64, 68 and note 101.

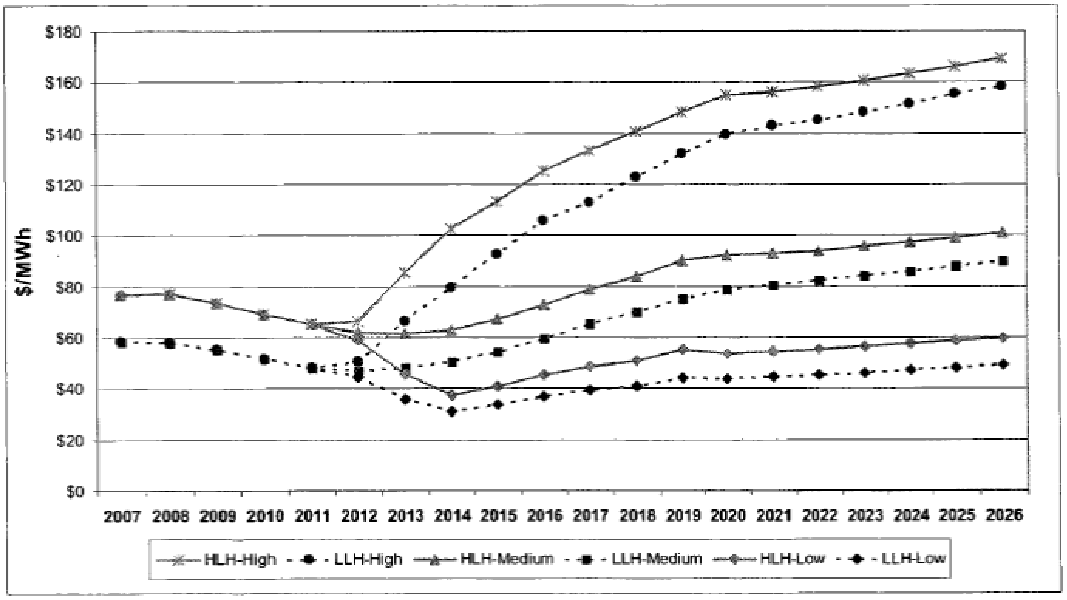
From PacifiCorp's 2007 IRP[139]

Figure 6.2 – System Average Annual Natural Gas Prices: Low, Medium, and High Scenario Values



139 Oregon Public Utilities Commission, PacifiCorp 2007 Integrated Resource Plan, Docket No. LC 42, *In the Matter of PACIFICORP, dba PACIFIC POWER & LIGHT COMPANY Application for Acknowledgement of its 2007 Integrated Resource Plan* at 122-23 (May 30, 2007) ("PacifiCorp 2007 IRP").

Figure 6.3 – System Average Annual Electricity Prices for Heavy and Light Load Hour Natural Gas Prices: Low, Medium, and High Scenario Values



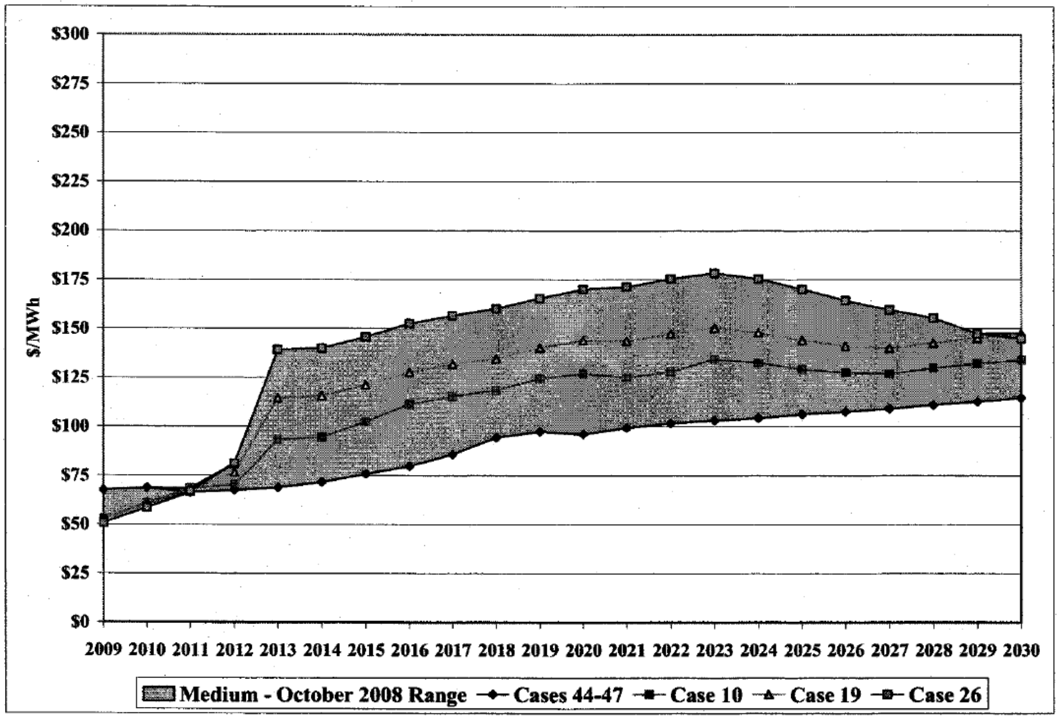
From PacifiCorp's 2009 IRP[140]

Table 7.6 – Underlying Henry Hub Price Forecast Summary (nominal $/MMBtu)

Forecast Name	2010	2015	2020	2025	2030
High - June 2008	$18.06	$18.71	$21.21	$23.28	$25.55
High - October 2008	$11.57	$14.68	$19.98	$21.93	$24.07
Medium - June 2008	$11.23	$9.90	$12.31	$13.51	$14.83
Medium - October 2008	$7.83	$8.58	$11.07	$12.85	$14.11
Low - June 2008[39]	$5.83	$6.29	$7.09	$7.78	$8.54

140 Idaho Public Utilities Commission, PacifiCorp 2009 Integrated Resource Plan, Case No PAC-E-09-06, *In the Matter of the Filing by PacifiCorp dba Rocky Mountain Power of Its 2009 Electric Integrated Resource Plan (IRP)* at 150, 156 (May 29, 2009) ("PacifiCorp 2009 IRP").

Figure 7.13 – Western Electricity Prices from the Medium ~~June~~ 2008 Underlying Gas Price Forecast



Note: Western electricity prices are presented as the average of flat prices at Mid-Columbia and Palo Verde.

Thus, all utility generation acquisitions—not just QF contracts—entered before fracking technology and an economic recession were likely premised on forecasts that, in hindsight, turned out to have been too high. There is no evidence that absent QF generation, utilities would have made the choice to add no alternative generation and, instead, accept risk of short term market purchases. Indeed, many utility contracts and investments made before the shale gas build-out were based on projected energy prices that turned out to be too high.

Even though all utility acquisition decisions made before the decline in gas and wholesale market prices missed the drop in prices, the Commission proposes to limit QF prices, but no other generation acquisition, to short term energy prices. That violates 16 U.S.C. § 824a-3(b)(2). The NOPR would deny long term price certainty to QFs, even though non-QF generators and vertically integrated utilities continue to receive that certainty. For example, Arizona limits QF price certainty to five years while utilities rate-base investments and sign long term PPAs with non-QFs for longer periods.[141] Similarly, Idaho limits QF price certainty to two years,

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141 Compare Arizona Corporation Commission, Decision No. 75859, Docket No. E-00000J-14-0023, In the matter of the Commission's Investigation of Value and Cost of Distributed Generation at 148 (Jan. 3, 2017) (adopting a 5-year avoided cost methodology) with APS Solar Partner Program, https://www.aps.com/en/About/Sustainability-and-Innovation/Technology-and-

but its utilities sign long-term, 20 year, PPAs with non-QFs.[142] Wisconsin Electric has long-term, fixed price, contracts for nuclear generation while providing no long term price certainty to QFs. And non-regulated wholesale providers regularly obtain long-term fixed price contracts with captive customers.[143]

The prosed amendment to 18 C.F.R. § 292.304(d) to allow states to provide QFs with energy rates to vary during the term of the contract while non-QFs are able to obtain long-term price certainty violates16 U.S.C. § 824a-3(b)(2).[144] Therefore, limiting QFs to contracts providing no price certainty for energy values, while non-QF generation regularly obtains fixed price contracts and utility-owned generation receives guaranteed cost recovery from captive ratepayers, constitutes discrimination.

Innovation/Solar-Partner-Program (utility-owned rooftop solar program includes 20-year term); Keefer, DW, *APS Moves Ahead on Its Plan to Add Storage and Solar*, EnergyCentral (Feb. 22, 2019) *available at* https://www.energycentral.com/c/gn/aps-moves-ahead-its-plan-add-storage-and-solar (15 and 20 year contract for non-QF PPAs) and, Bade, Gavin, *APS to install 850 MW of solar in major clean energy buy*, Utility Dive (Feb. 21, 2019) *available at* https://www.utilitydive.com/news/aps-to-install-850-mw-of-storage-100-mw-of-solar-in-major-clean-energy-buy/548886/ (APS signed a "short term" seven year contract with Calpine for output from a 463 MW gas fired generator).

142 Compare Idaho Public Utility Commission, Order No. 33357, Case No. IPC-E-15-01, *In re Idaho Power Co's Pet. To Modify Terms and Conditions of PURPA Purchase Agreements* , (Aug. 20, 2015) (2 year maximum contract term for QFs) with Idaho Public Utilities Commission, Order No. 34479, Case No. IPC-E-19-14, *In re Application of Idaho Power for Approval of Power Purchase Agreement with Jackpot Holdings* (Nov. 7, 2019) (seeking comment on application of Idaho Power to enter 20 year fixed-price contract with non QF generator), *available at* https://puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1914/ordnotc/20191107NOTICE_OF_COMMENT_DEADLINES_ORDER_NO_34479.PDF.

143 Cordes, Henry J., *NPPD gets more customers to sign long-term contracts*, Omaha World Herald (Oct. 22, 2015) *available at* https://www.omaha.com/money/nppd-gets-more-customers-to-sign-long-term-contracts/article_dccdc7d6-25a3-5ce2-96ac-6a7f9581fa88.html (Nebraska Public Power District requires 20 year power purchase agreements from all requirements customers).

144 The prohibition on rates for purchase that discriminate against QFs in 16 U.S.C. § 824a-3(b)(2) is not limited to the per-MWh price, but extends to all attributes of sale that relate to price. *See, e.g.*, *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215, 62,162, 62,189 (Dec. 16, 2013) (applying 16 U.S.C. § 824a-3(b)(2) and 18 C.F.R. § 292.304(a)(1)(ii) to curtailment).

2. Limiting QF Energy Prices to LMP, Market Hub, Natural Gas Proxy or Competitive Procurement While Non-QF Generation Owned or Contracted By A Utility Is Not Similarly Capped Discriminates Against QFs.

As noted above, FERC has always required payment at full avoided cost, so neither this Commission nor any court has determined whether a lower price violates 16 U.S.C. § 824a-3(b)(2). However, the decisions applying 16 U.S.C. § 824a-3(b)(2) and the parallel requirement in 18 C.F.R. § 292.304(a)(1)(ii) confirm that QFs must be treated equally to non-QFs delivering the same fungible megawatt hours of energy.[145] Thus, 16 U.S.C. § 824a-3(b)(2) requires that the Commission's rules establishing prices for QF generation ensure that QFs receive at least the equivalent price for their generation as utility-owned and other non-QF generation. The proposed rules, however, would discriminate against QFs compared to how non-QF generation owned or contracted by the utility is treated.

i. Use of LMP as the QF price discriminates where utility-owned generation and non-QF generators are not limited to LMP.

The NOPR proposes to change 18 C.F.R. § 292.304(b)(6) to provide that:

> A state regulatory authority or nonregulated electric utility may use a locational marginal price as a rate for as-available qualifying facility energy

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[145] *See Morgantown Energy Assoc. v. Pub.Serv. Comm'n of W.Va*, 2013 WL 5462386 *21, *25 (S.D.W.Vva. Sept. 30, 2013) (holding that 16 U.S.C. § 824a-3(b)(2) requires QFs be treated equally to non-QFs in assignment of renewable energy credits between buyer and seller under contracts predating creation of the credits); *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215, 62,162, 62,189 (Dec 16, 2013) (16 U.S.C. § 824a-3(b)(2) and 18 C.F.R. § 292.304(a)(1)(ii) as require a utility to treat QFs equal to the utility's own Network Resources in curtailment); *Entergy Servs. Inc. Gen. Coal. v. Entergy Servs., Inc.*, 103 FERC ¶ 61,125, 61,398 (May 5, 2003) (finding violation of 16 U.S.C. § 824a-3(b)(2) where utility bills QFs for generation deficiencies under retail rates while charging non-QF generators for deficiencies through more beneficial "imbalance energy" rates); Fed. Energy Reg. Comm'n Rep. P 32,455, 32,031 ("to the extent that QFs are not even given an opportunity to sell power of comparable quality to the purchasing utility at a price comparable to the source from which the utility is actually purchasing, such a capacity reservation would appear to run afoul of the section 210(b) proscription against rates that discriminate against QFs"); Staff Discussion Paper, 44 Fed. Reg. at 38,869 (July 3, 1979) ("one can well argue that to pay the QF a price based only on displaced energy costs where another utility would receive a capacity payment as well for the same service is discriminatory in violation of the statute.").

sales to purchasing utility located in a market operated as defined in § 292.309(e), (f) or (g).

The NOPR reasons that LMPs reflect an optimal dispatch of resources to balance supply and demand, taking into account actual system conditions including congestion, to "reflect the true marginal cost of production…"[146] Putting aside problems with how bids are developed and the LMP is calculated, a fundamental problem with the Commission's proposal is that it does not ensure that the LMP-price for QFs does not discriminate since non-QF generators are not limited to receive only the LMP value of the energy they generate. To the extent that non-QF generation is allowed to receive effective prices greater than the LMP, limiting QF generators to the LMP violates 16 U.S.C. § 824a-3(b)(2).

Contrary to the assumption underlying the NOPR's proposal to use LMP as "an accurate measure of the varying actual avoided costs for each receipt point where the utility receives power from QFs," utilities incur energy costs that exceed the LMP because their own self-generation costs and power purchase agreements are not capped at the LMP.[147] Utilities self-schedule and self-commit their own generation that incurs costs higher than the LMP value for that generation. Moreover, utilities enter bilateral contracts that incur costs higher than the LMP value for the energy. Under cost-of-service ratemaking, all production costs pass through unless disallowed by the regulator. To the knowledge of the undersigned commenters, no utility commission has disallowed costs of self-schedule and self-commit generation or power purchases that exceed the time of delivery LMP value of the energy. Limiting QFs to the LMP, while allowing utilities to collect higher costs of their own generation from captive ratepayers discriminates against the QFs in violation of 16 U.S.C. § 824a-3(b)(2).

a. Sierra Club's Analysis of RTO/ISO Markets Confirms That Regulated Utilities With Coal Generation Often Have Production Costs Higher Than LMP Values

A recent analysis by Sierra Club demonstrates that cost-of-service regulated, vertically integrated utilities in the MISO, SPP, ERCOT and PJM markets "are systematically operating coal plants out of merit, to an extent not seen in merchant-owned coal plants."[148] The report estimates "that captive ratepayers of regulated utility coal plants paid $3.5 billion more for energy from 2015-2017 due to non-

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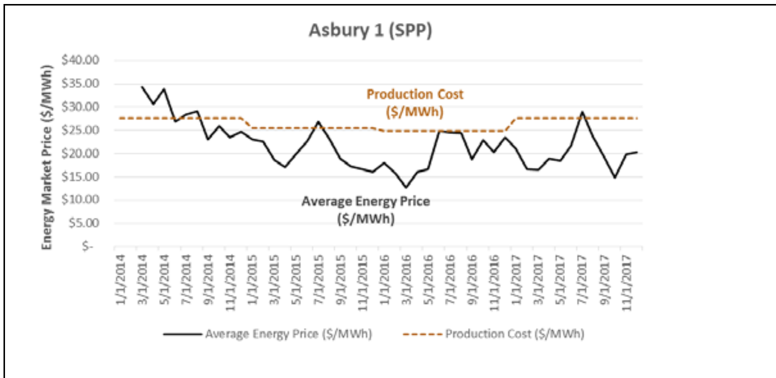
146 NOPR at P 44.

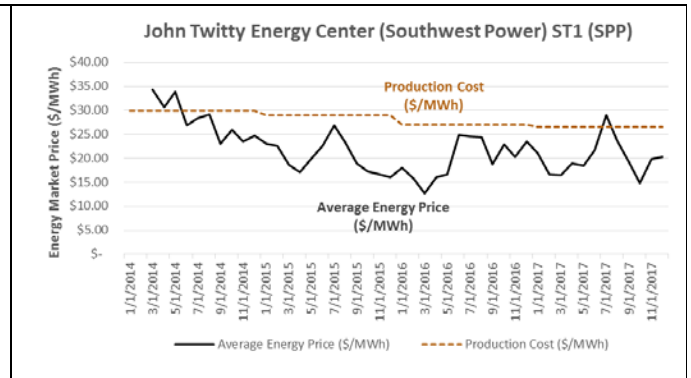
147 NOPR at P 45.

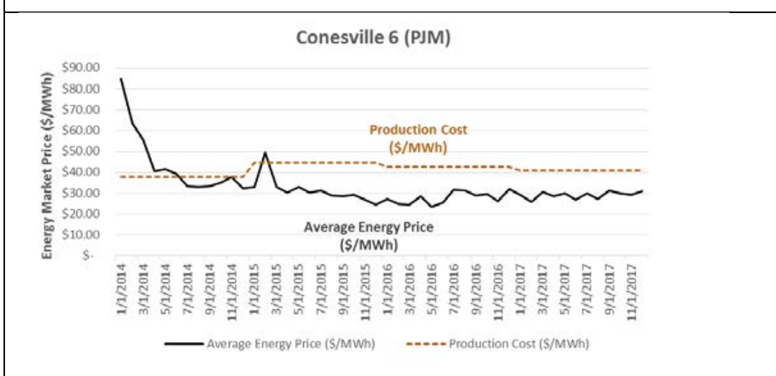
148 Fisher, Jeremy, et al., *Playing with Other People's Money, how Non-Economic Coal Operations Distort Energy Markets* at 4 (Oct. 2019) ("Other People's Money" or "OPM") (attached as Ex. 16).

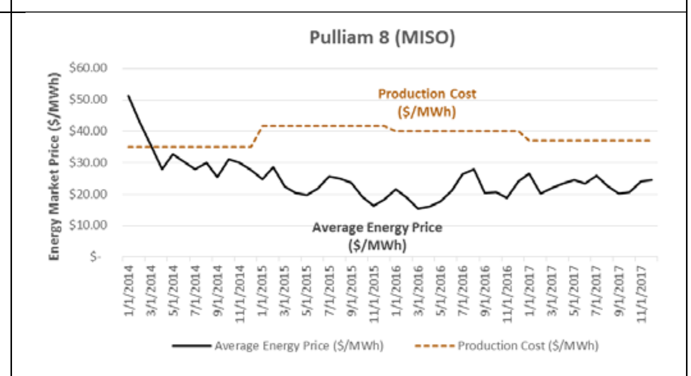
economic dispatch relative to the procurement of energy and capacity on the market."[149]

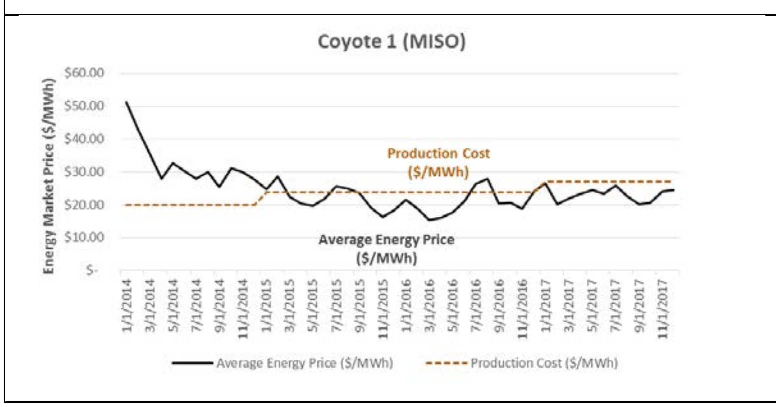
Utilities incurring variable production costs that exceed the LMP value of their energy is typically limited to those that are allowed to recover their costs from captive ratepayers, either because of cost-of-service regulation or because they are outside of regulatory supervision and have long-term all requirements customers. The Other People's Money report and underlying data attached as exhibits to these comments contains information for each plant. A few examples are shown in the figures below:

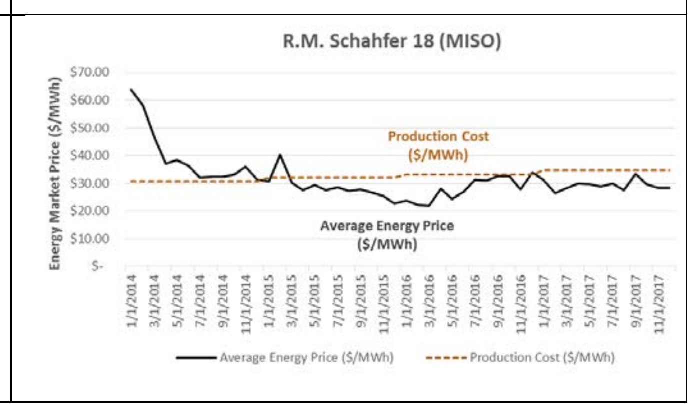




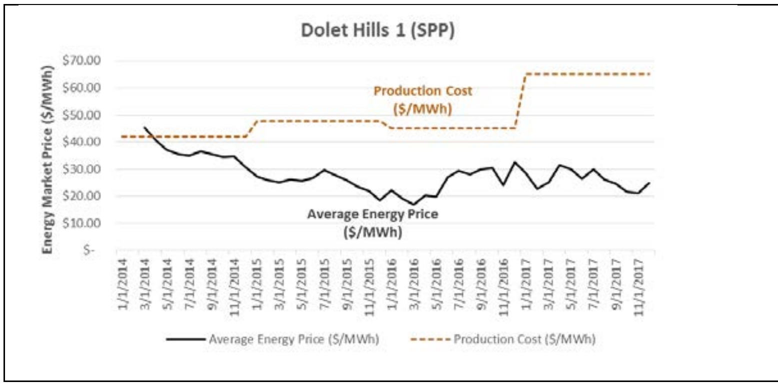


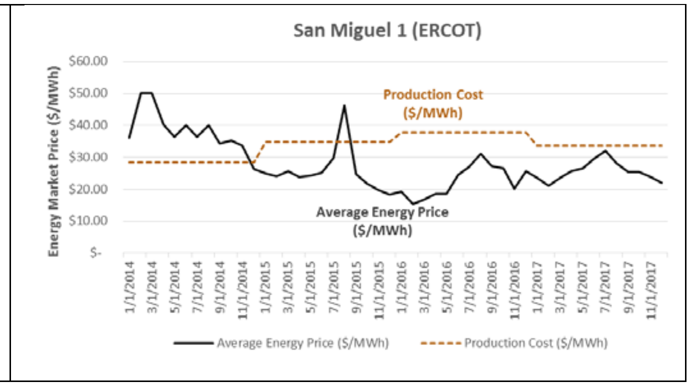






149 *Id.*





The brown dashed line indicates the internal fuel and variable operation and maintenance cost of generation and the black solid line indicates the contemporaneous value at the regional hub. The plants in the examples above produced negative margins between production costs and RTO/ISO market energy value.

Energy Market Gain / (Loss) (M$)								
Market Region	**Power Plant Unit Code**	**Primary Owner**	**Capacity (MW)**	**2014**	**2015**	**2016**	**2017**	**2014-2017**
ERCOT	San Miguel 1	San Miguel Electric Coop, Inc	410	$18.7	($15.4)	($31.7)	($19.1)	**($47.6)**
MISO	Coyote 1	Otter Tail Power Co	450	$39.7	($2.4)	($3.0)	($9.1)	**$25.2**
MISO	Genoa ST3	Dairyland Power Coop	346	$6.4	($13.1)	($11.8)	($11.0)	**($29.6)**
MISO	Presque Isle 6	Wisconsin Electric Power Co	90	$3.0	($2.2)	($2.5)	($2.6)	**($4.3)**
MISO	Pulliam 8	Wisconsin Public Service Corp	150	($0.6)	($3.7)	($3.2)	($3.2)	**($10.7)**
MISO	R.M. Schahfer 18	Northern Indiana Pub Serv Co	424	$24.5	($2.1)	($2.5)	($9.7)	**$10.1**
PJM	Conesville 6	AEP Generation Resources Inc	444	$27.6	($7.4)	($13.6)	($10.1)	**($3.4)**
SPP	Asbury 1	Empire District Electric Co	213		($4.2)	($4.1)	($5.6)	**($13.9)**
SPP	Dolet Hills 1	Cleco Power LLC	721		($94.6)	($66.5)	($72.1)	**($233.2)**
SPP	John Twitty ST1	City Utilities of Springfield - (MO)	194		($3.0)	($3.9)	($4.0)	**($10.9)**
SPP	Pirkey 1	Southwestern Electric Power Co	721		($39.8)	($38.7)	($31.9)	**($110.4)**

As the figures above indicate, and as further demonstrated in the attached Sierra Club analysis, generators owned by utilities that are either rate regulated or which have captive long-term customers are able to pass along above-market costs through higher than market prices.[150] Within MISO, alone, there were 31 terawatt

150 Sierra Club's estimated net energy market revenues for selected utility-owned power plant electric generating units ("EGUs") operating in wholesale

hours of generation by coal-fired units in 2017 for which production cost exceeded market price, 93% of which was attributable to rate regulated utility generation.[151] That represents $1.29 billion in energy production costs in excess of market rates.[152] Because utilities—especially state regulated utilities and wholesale generators with all-requirements customers outside of any regulator's jurisdiction– are able to recovery those above-market-price energy generation costs, it would violate 16 U.S.C. § 824a-3(b)(2) to limit QFs seeking to sell to those utilities and displace that energy generation to only the LMP.

b. Additional evidence confirms utilities incur generation costs exceeding LMP.

Other available information confirms that limiting QFs to LMP values would discriminate against QFs because the production cost of utilities' own generation

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market regions for the years 2014 through 2017by subtracting estimated hourly cost of production (fuel plus variable operations and maintenance) from the hourly market price of energy in $/MWh, multiplied the result by hourly net generation the unit.

$$R_{y,EGU} = \sum_{h=1}^{h_y} \left(Pe_{h,hub} - \left(Pc_{y,EGU} + Pvom_{y,EGU}\right)\right) * G_{h,EGU}$$

Hourly cost of production was developed from reported annual weighted average fuel costs ($Pc_{y,EGU}$) and estimated variable operations and maintenance ("O&M") costs ($Pvom_{y,EGU}$). EGU-specific fuel costs, reported by S&P Global, were derived from fuel receipts, self-reported by generators to the Energy Information Administration ("EIA") through EIA Form 923. Hourly price of energy is the day-ahead clearing price of energy at the nearest wholesale market hub to the generator ($Pe_{h,hub}$). Individual hub prices, extracted from S&P Global, reflect reported day-ahead prices for each relevant hub in MISO, SPP, ERCOT, and PJM. The market hub best approximates expected LMP values since the NOPR does not specify which LMP price at existing generation connections should be used. Utilities will obtain generation from various generation and interconnection points, each with a slightly different LMP. The market hub price approximates those various values for the relevant utility. Sierra Club's analysis indicates that any variation between different LMPs and the hub price is minimal compared to the above-market cost of generation compared and, therefore, has no impact on the results. Additional information on methodology, data, and assumptions are included in the attached Other People's Money report.

151 *Id.* at 4.

152 *Id.*

and the cost of long-term contracts other than QF generators is not limited to the LMP.

Bloomberg New Energy Finance ("BNEF") conducted an analysis similar to Sierra Club's Other Peoples' Money analysis. Like Sierra Club, BNEF found a number of plants in organized markets—especially those that are rate regulated or have captive ratepayers—regularly have short-run marginal production costs greater than the value of the energy they produce in the RTO/ISO market.[153]

Similarly, in 2017, an analysis for the Greater Springfield Chamber of Commerce determined that the City of Springfield's City Water Light and Power ("CWLP") operates its generation resource in an uneconomic manner. The analysis shows that during 2016 the full marginal cost of the utility's generation was higher than the regional market price in more than 98% of hours.[154] According to that analysis, the CWLP utility produced generation at an average cost of $76.98/MWh (including fuel, production O&M, and debt service) or $56.18/MWh (fuel and production O&M) but received average market prices of $33.71/MWh, resulting in a net loss of $45.97 or $33.71/MWh.[155] That net loss was passed on to captive ratepayers, who collectively paid $82.8 million or $40.5 million (depending on whether debt service is included as production cost) above market value for the energy.[156] In fact, market prices were barely sufficient to cover just the fuel cost, alone, for the utility's own generation.[157] The following figures from that report[158] summarize that analysis:

153 William Nelson & Sophia Liu, Half of U.S. Coal Fleet on Shaky Economic Footing; Coal Plant Operating Margins Nationwide, Bloomberg New Energy Finance (March 26, 2018) (hereinafter "BNEF 2018") (attached as Ex. 17).

154 The Power Bureau, Analysis of Market Impact for Proposed EmberClear Generation Facility in Pawnee Illinois (2017) (attached as Ex. 18). The analysts determined that the utility was already operating its generation out of market order before the impact from a proposed natural gas generating plant being analyzed as the primary focus of the report.

155 *Id.* at 1-2, 25-26.

156 *Id.* at 2, 26-27.

157 *Id.* at 23-24.

158 *Id.* at 21, 23.

Figure 18: Cost of Generation for CWLP Primary Generation Resources (2016)

Cost Variables		Dallman Unit 1	Dallman Unit 2	Dallman Unit 3	Dallman Unit 4
Plant Thermal Efficiencies					
Plant Heat Rate (MMBtu/MWh) [A]	A	12.72	12.58	11.94	12.15
Heat Content of Coal (MMBtu/Ton) [A]	B	21.15			
MWh Generation/Ton Coal	C = B / A	1.66	1.68	1.77	1.74
Fuel Cost (Coal)					
Average Cost per Ton of Coal [B]	D	$39.00			
Fuel Cost per MWh of Net Generation	E = D / C	$23.46	$23.20	$22.02	$22.40
Production O&M Cost					
Annual Production O & M Cost [C]	F	$52,913,000			
MWh Generated (Net) [C]	G	1,765,383			
Production O&M Cost per MWh	H = F / G	$29.97			
Marginal Cost per MWh of Net Generation					
Fuel Cost per MWh	I = E	$23.46	$23.20	$22.02	$22.40
Production O&M Cost per MWh	J = H	$29.97	$29.97	$29.97	$29.97
Marginal Cost of Generation	**K = E + H**	**$53.43**	**$53.17**	**$51.99**	**$52.37**

[A] Annual Average for 2016 per EIA-923 Report

[B] "CWLP seeking to slash coal expense by more than $6 million," State Journal Register, January 30, 2016

[C] 2016 Continuing Disclosure Reports for the Water Fund and the Electric Fund (CWLP)

Figure 19: Hours when CWLP Cost of Generation was less than MISO Marginal Energy Cost (2016)

Cost Basis	Dallman Unit 1	Dallman Unit 2	Dallman Unit 3	Dallman Unit 4
Marginal Cost of Generation ($/MWh)	**$53.43**	**$53.17**	**$51.99**	**$52.37**
# Hours in 2016 when MISO hourly Marginal Energy Cost was above the CWLP Marginal Cost of Generation	155	160	169	166
# Total Hours in 2016	8784	8784	8784	8784
% of Total Hours when CWLP Marginal Costs were less than MISO hourly Marginal Energy Cost	**1.8%**	**1.8%**	**1.9%**	**1.9%**

Figure 23: Cost of Generation for CWLP Primary Generation Resources (2016)

Cost Variables	Dallman Unit 1	Dallman Unit 2	Dallman Unit 3	Dallman Unit 4
Marginal Cost of Generation				
Fuel Cost per MWh	**$23.46**	**$23.20**	**$22.02**	**$22.40**
Production O&M Cost per MWh	$29.97	$29.97	$29.97	$29.97
Total Cost per MWh	**$53.43**	**$53.17**	**$51.99**	**$52.37**
Range of Generation Resource Energy Dispatch Price				
Annual Maximum	$27.65	$29.65	$26.10	$31.00
Annual Average	**$24.05**	**$24.26**	**$23.36**	**$23.30**
Annual Low	$21.33	$21.20	$21.90	$18.22

In yet another example, the captive ratepayers of Alliant Energy's two monopoly utilities in the Midwest cover the utility's own generation production costs when they exceed the short term market price.[159] During 2016, the average day ahead LMP for the Interstate Power and Light Company ("IPL") zone was $28.75.[160] IPL's 2016 FERC Form 1 disclosed "Expenses per Net KWh" higher than that average LMP for nearly all of its utility-owned generation.[161] In fact, the fuel costs, alone, for several of the utility's steam units (Prairie Creek 4, Dubuque, Lansing 4, and Fox Lake) were higher than the LMP value of the energy produced. And the utility's above-market costs of generation were not limited to its own generation. During the same year, IPL paid NextEra for energy from the Duane Arnold Energy Center (formerly owned by IPL) under a long-term PPA at approximately $45/MWh in 2016.[162] Across the state line, Alliant Energy's Wisconsin subsidiary, Wisconsin Power and Light Company ("WPL"), also incurred production costs that exceeded the LMP value of the energy.[163] Similar to IPL, WPL also incurred purchase power costs from non-QFs during 2016 that exceeded the LMP value of the energy.[164]

Another Wisconsin utility, Wisconsin Electric Power Company, similarly incurred production costs that exceed the LMP value of energy from its large Elm

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159 Ironically, the NOPR relies on Alliant Energy's complaint in 2016 that an unspecified QF received above-market prices for its energy. NOPR at P 64, n.101

160 This is consistent with, although somewhat higher than, what an Alliant subsidiary filed with the Iowa Utilities Board in 2016 as its avoided energy cost. *See* Interstate Power and Light Co., Cogeneration and Small Power Production Tariff, Docket No. TF-2016-0290 (Iowa Util. Bd., June 30, 2016) (representing $28.10/MWh as an avoided cost) (attached as Ex. 19). Around the same time in 2016, it sought regulatory approval to build and rate base wind generation based on the utility's calculated all-in "levelized" price of $28.44/MWh and a second rate-based wind farm at $28.43/MWh. *See* Interstate Power and Light Co., Direct Testimony of James E. Niccolls at 10, Docket No. FCU-2017-0004 (Iowa Util. Bd., July 17, 2017) (attached as Ex. 20).

161 IPL 2016 FERC Form 1 (attached as Ex. 21).

162 IPL 2016 FERC Form 1 at 326-27 (IPL paid $154,959,894 in energy charges for 3,443,553 MWh in 2016) (Ex. 21).

163 *See generally* Other People's Money (Ex. 16).

164 Wisconsin Power and Light Company, 2016 Annual Report to Public Service Commission of Wisconsin, at Copy 1 of Pages E-10 and E-11 (Apr. 27, 2017) (purchased 878,400 MWh from Minnesota Power for $30,853,800 in energy charges, 44,007,840 MWh from Morgan Stanley Capital Group for $1,317,600; 9,262 MWh from Wisconsin Public Power Inc. for $953,448). The Wisconsin Power and Light MISO zone ALTE average day ahead LMP was $25.88 in 2016.

Road coal plant and its sister utility, Wisconsin Public Service Corporation's Pulliam plant.[165] In addition, Wisconsin Electric Power Company contracts with non-QF power producers and pays higher prices through PPAs than the LMP value for the energy. Specifically, it paid NextEra Energy Point Beach, LLC, approximately $47 per MWh for generation from the Point Beach nuclear plant in 2018.[166] As reflected in the utility's own filing,[167] those prices will escalate dramatically in future years:

165 *See generally* Other People's Money (Ex. 16).

166 Wisconsin Electric Power Company, 2018 Annual Report to the Public Service Commission of Wisconsin, Copy 1 of Pages E-10 to E-11 (Apr. 30, 2019) (attached as Ex. 22).

167 Wisconsin Energy Corporation Form 10-Q, For the Quarterly Period Ended March 31, 2008, Exhibit A to Exhibit 10.1 (Point Beach Nuclear Plant Power Purchase Agreement between FPL Energy Point Beach, LLC and Wisconsin Electric Power Company, dated as of Dec. 19, 2006) (attached as Ex. 23).

EXHIBIT A

Delivered Energy Charges

Year	Delivered Energy Charge (in $/MWh)
2007	31.37
2008	39.23
2009	40.40
2010	41.62
2011	42.87
2012	44.15
2013	44.59
2014	45.04
2015	45.49
2016	45.94
2017	46.40
2018	46.87
2019	49.68
2020	52.66
2021	55.82
2022	59.17
2023	62.72
2024	66.48
2025	70.47
2026	75.51
2027	80.91
2028	86.69
2029	92.89
2030	99.53
2031	106.65
2032	114.28
2033	122.45

For comparison, the average day ahead LMP value for the Point Beach Nuclear Plant Node during 2018 was only $29.31/MWh.[168]

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168 Wisconsin Electric Power Company reflects these payments as energy payments, and the Exhibit A to the Power Purchase Agreement identifies them as energy payments. Even if capacity is included, the maximum value of capacity—based on cost of new entry multiplied by rated capacity—can be backed out of the values in the PPA. MISO determined the cost of new entry for capacity in 2019—a maximum capacity value—as $89,610/MW. Filing of the Midcontinent Independent System Operator, Inc. Regarding Local Resource Zone CONE Calculation, Docket No. ER19-____-000 (Sept. 10, 2019). The capacity of the plant is 1,054 MW. At 95% capacity factor, $89,610/MW-yr translates to $10.77/MWh. Subtracting that high bookend for capacity value from the PPA price still exceeds the LMP value for the energy by $6.79/MWh in 2018, or 23%. That above-market value will increase in

As demonstrated by the foregoing examples, utilities incur costs for energy that exceeds the LMP value of the energy. Because the price of that energy is not limited to the LMP, it discriminates in violation of 16 U.S.C. § 824a-3(b)(2).

c. The Commission's attempt to rely on LMPs as the "true" measure of avoided also arbitrarily fails to account for price depression from uneconomic dispatch.

Even if FERC's proposal to limit QF energy prices to LMPs did not otherwise violate PURPA's requirement for just and reasonable rates and prohibition against discriminatory rates (which, as explained above, it does), the proposal would still be arbitrary, capricious, and contrary to the evidence in the record. The Commission proposes to find that *LMP is an accurate measure of avoided costs. . . ."*[169] because "*LMPs 'reflect the true marginal cost of production, taking into account all physical system constraints, and these prices would fully compensate all resources for the variable cost of providing service."*[170] Additionally, the Commission claims that use of LMPs could also "promote the more efficient use of the transmission grid, promote the use of the lowest-cost generation, and provide for transparent price signals."[171] The Commission's conclusory assertions are wrong, and insufficient to support the use of LMPs as a "true" measure of avoided costs.

As explained in Sierra Club's recent analysis of self-commitment behavior in the RTOs, pervasive utility self-commitment practices (which often lead to units operating out of merit) suppresses energy market prices. Briefly, in a competitive electricity market, prices are set by the most expensive power plant that has to run to meet demand at a given point in time (this is typically called the "marginal" unit). That is, the price is set where the demand curve and the cost curve meet. However, when more costly units are forced into the dispatch order regardless of cost, it displaces other units and drives the price down. This is depicted in the diagrams below. In the diagram on the right, all power plants bid their actual cost of producing power. The market price (P') is set at the cost of the last unit that

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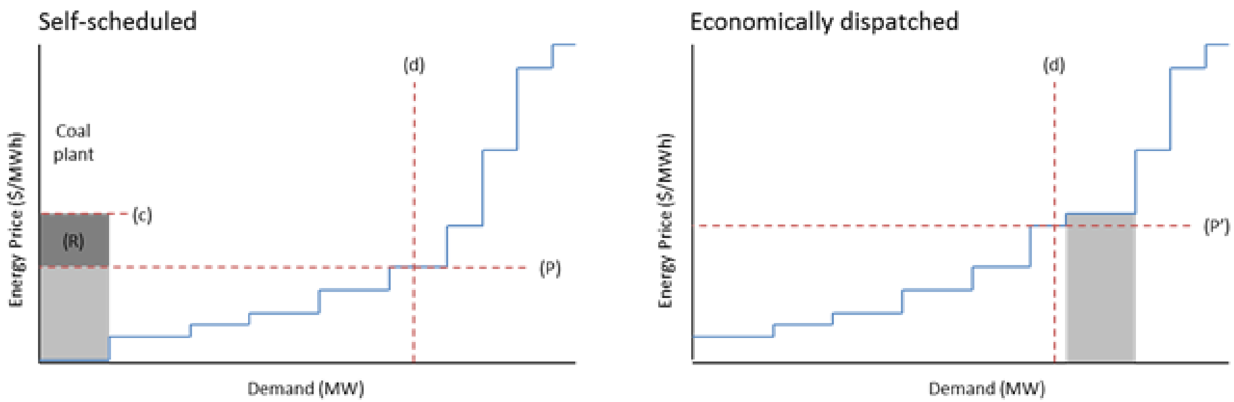
future years. Notably, Wisconsin utilities do not offer QFs capacity value based on cost of new entry. Instead, they provide either no capacity value (Wisconsin Electric) or the value of the Planning Resource Auction (Wisconsin Power and Light, Madison Gas and Electric) which is nominal. Midcontinent Independent System Operator, Inc., 2019/2020 Planning Resource Auction (PRA) Results (Apr. 12, 2019), https://cdn.misoenergy.org/20190412_PRA_Results_Posting336165.pdf. If that value is subtracted from the PPA price, instead of the cost of new entry, the remaining energy portion of the PPA price for the Point Beach plant is even higher than the LMP value.

[169] *Id.*

[170] 84 Fed. Reg. at 53,253.

[171] *Id.*

needs to run to meet demand (d), and the coal plant (gray bar) is too expensive to run. In contrast, the diagram on the left shows an uneconomic plant forced into the supply curve (i.e., the plant is self-scheduled). This artificially pushes the rest of the supply curve out to the right and results in the price and load curve intersecting at a lower price. The higher cost plant forced into the supply curve recovers its costs from captive retail electricity customers of the utility but outside the competitive market. Thus, the true costs are hidden from the market and the ratepayer subsidy to the higher cost unit depresses prices for the units in the market.



Sierra Club's *Other People's Money* analysis estimates that, in 2017, self-commitment practices depressed MISO wholesale market prices by approximately 30%, resulting in average energy prices across the region that were approximately \$7.7/MWh *less* than they would be had all units in the system dispatched economically. The increase in market prices is consistent across both low- and high-cost hours.[172]

The SPP Market Monitor has raised the same concerns in its *State of the Market* report, in which it states: "Self-commitment of generation continues to be a concern because it does not allow the market software to determine the most economic market solution. Furthermore, it can contribute to market uplifts and low prices."[173] The SPP Market Monitor's report further states that self-scheduling can contribute to distorting market price signals, suppressing real-time prices, and affecting revenue adequacy for all resources.[174]

Thus, contrary to the Commission's assertion that LMPs reflect true marginal costs of generation and fully compensate generators, LMPs are consistently and

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[172] Fisher, Playing with Other People's Money at 4-5.

[173] Southwest Power Pool - Market Monitoring Unit, *State of the Market 2018* at 5 (May 15, 2019), *available at*: https://www.spp.org/documents/59861/2018%20annual%20state%20of%20the%20market%20report.pdf.

[174] *Id.*

artificially depressed due to self-commitment behavior. The Commission cannot support its proposed findings that LMPs are a true and accurate measure of avoided energy costs. Allowing states to limit QF energy prices to LMPs fails to reflect the true marginal costs being recovered by rate regulated utilities, and results in QFs being *undercompensated* for the energy they provide to the grid. FERC arbitrarily fails to provide any factual support to the contrary.

ii. Restricting QF rates to "other competitive prices" is also discriminatory.

The NOPR would allow states and nonregulated utilities to set QF prices outside of an organized RTO/ISO market at a "Competitive Price," defined as energy rates established at a liquid market hub,[175] or rates based on gas price indices and a proxy heat rate for an efficient natural gas combined cycle ("NGCC") unit.[176] The Commission proposes that states must determine that the "Competitive Price" does not *exceed* the utility's incremental cost.[177] Notably, the NOPR would not impose the symmetrical requirement that the utility's incremental cost not exceed the "Competitive Price."

This proposal is discriminatory to QFs for all the same reasons that restricting QF rates to LMP is discriminatory. Because non-QF generators are not limited to the "Competitive Price" and utilities can, and regularly do, pay effective prices for energy that exceed the purportedly "competitive" price determined by a regional trading hub or calculation from natural gas price and assumed combined cycle heat rate, the NOPR fails to restrict discriminatory rate treatment. Specifically, unless a utility caps the price it pays for non-QF generation at the hub price or calculated NGCC cost, applying that price to QFs violates 16 U.S.C. § 824a-3(b)(2) by discriminating against the QF.

Rate regulated utilities and unregulated wholesale generators with captive all requirement customers regularly incur production costs for their own generation and PPAs that exceed the trading hub value of the energy received. To commenters' knowledge, those costs are all passed through to ratepayers, effectively pricing the energy that could be displaced with QF generation higher than the trading hub or indexed NGCC price.

a. Analysis by BNEF demonstrates that utility-owned generation and other generation with long-term captive customers receive prices above regional hub pricing.

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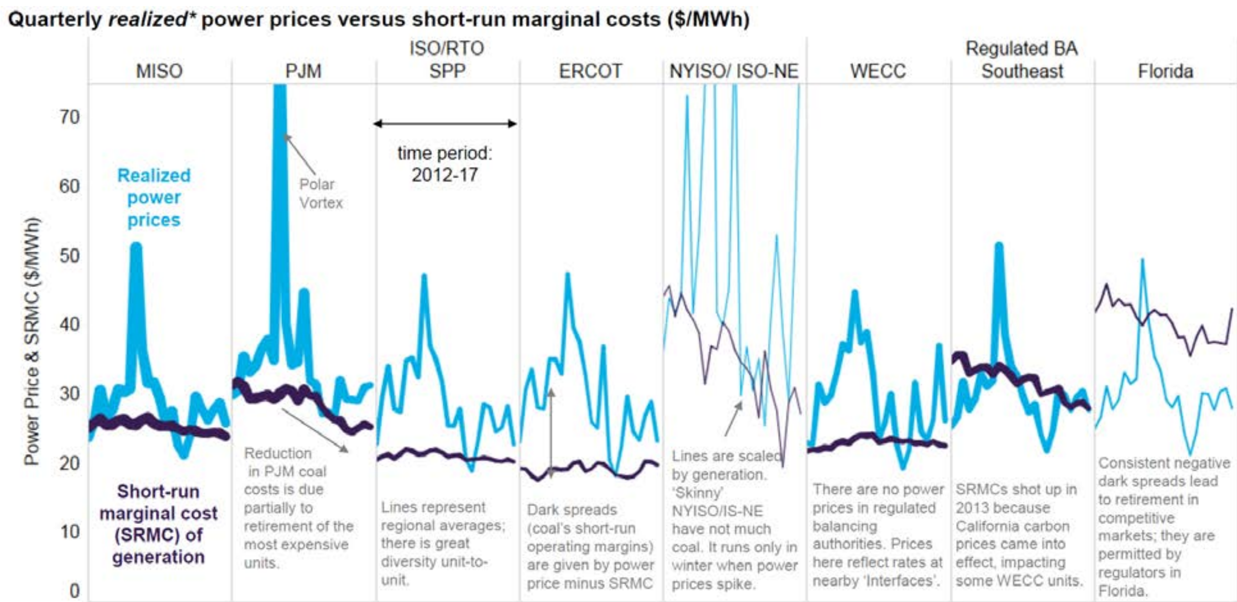
175 The NOPR specifically identifies the Mid-Columbia (Mid-C) and Palo Verde hubs as liquid markets that reflect competitive prices at those hubs. NOPR at P 52.

176 NOPR at P 51.

177 *Id.*

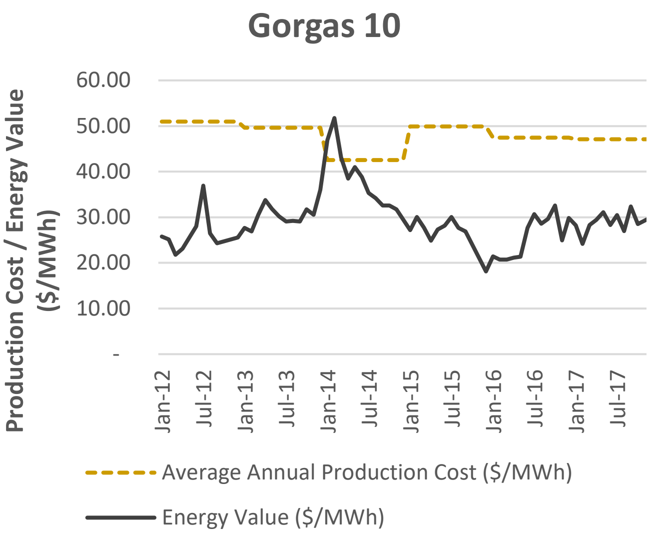
BNEF analysis indicates that some coal plants in all balancing areas, but many coal plants in the Southeast and Florida, have short-run marginal production costs that exceed the price for energy at the corresponding trading hub (what BNEF calls "Interfaces").[178] As demonstrated in the attached report and data, and depicted in the figure below,[179] the short-term production cost of the utility-owned generation exceeds the trading hub price across the Southeast region as a whole.

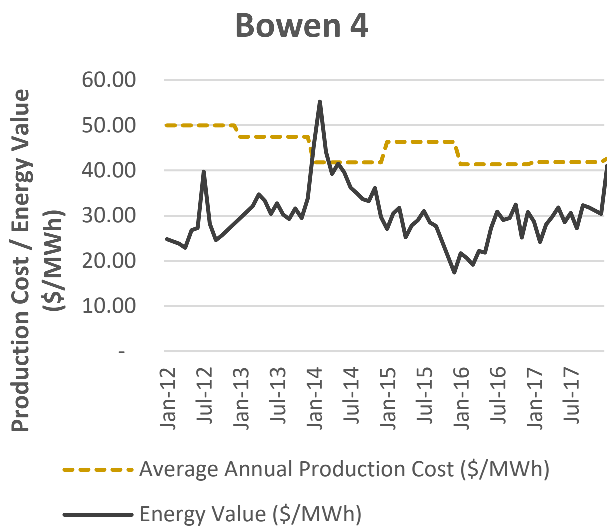


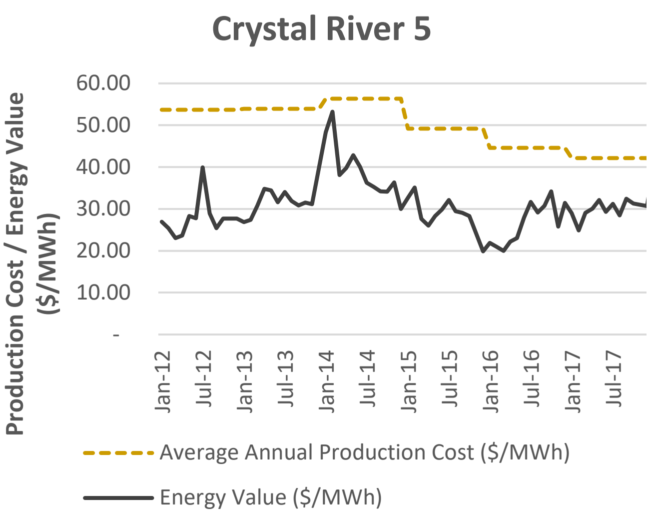
Individual examples from the BNEF analysis confirm that, as with generators in RTO/ISO regions, non-QF generators incur production costs higher than the market hub price value of the generation. As reflected in the difference between the solid black line and the dashed line, the production cost for the utility's generator diverges significantly from the regional hub market price. The utility recovers the full production cost from captive ratepayers, even where it is higher than the short-term regional energy market price.

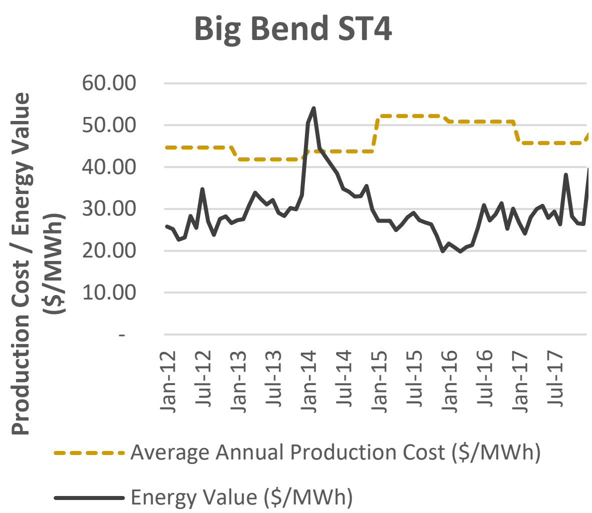
178 BNEF 2018, *supra* note 153.

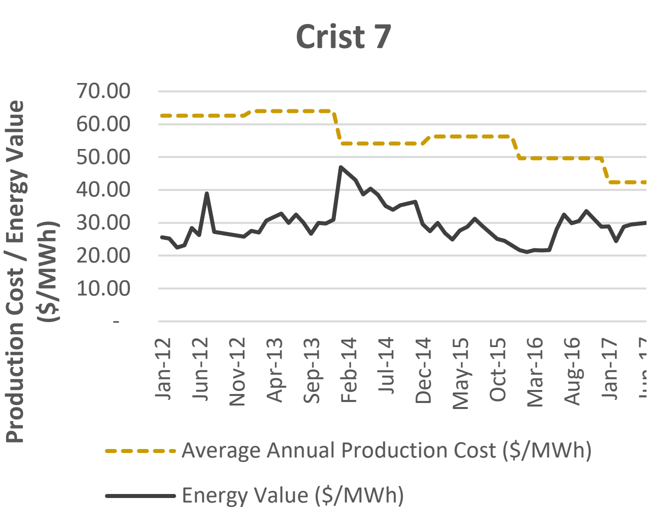
179 *Id.* at 29.

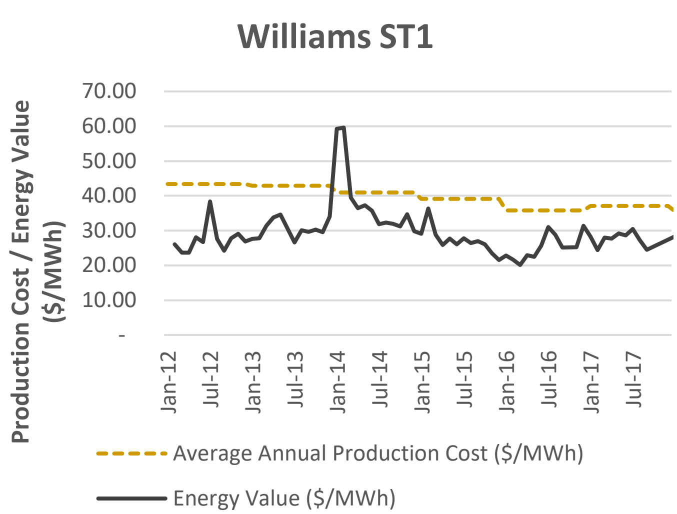

Gorgas 10
Production Cost / Energy Value ($/MWh)
60.00
50.00
40.00
30.00
20.00
10.00
-
Jan-12 Jul-12 Jan-13 Jul-13 Jan-14 Jul-14 Jan-15 Jul-15 Jan-16 Jul-16 Jan-17 Jul-17
Average Annual Production Cost ($/MWh)
Energy Value ($/MWh)

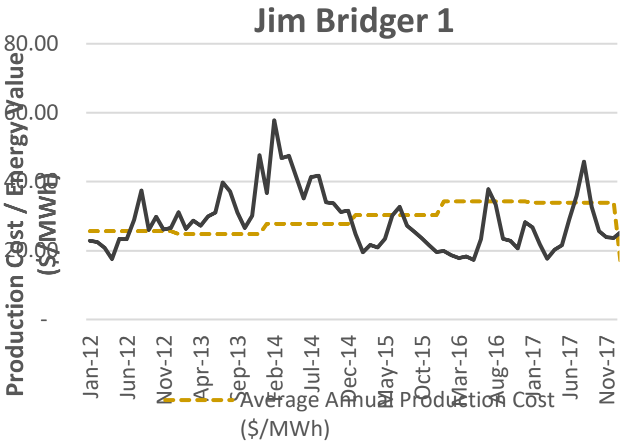

Bowen 4
Production Cost / Energy Value ($/MWh)
60.00
50.00
40.00
30.00
20.00
10.00
-
Jan-12 Jul-12 Jan-13 Jul-13 Jan-14 Jul-14 Jan-15 Jul-15 Jan-16 Jul-16 Jan-17 Jul-17
Average Annual Production Cost ($/MWh)
Energy Value ($/MWh)


Crystal River 5
Production Cost / Energy Value ($/MWh)
60.00
50.00
40.00
30.00
20.00
10.00
-
Jan-12 Jul-12 Jan-13 Jul-13 Jan-14 Jul-14 Jan-15 Jul-15 Jan-16 Jul-16 Jan-17 Jul-17
Average Annual Production Cost ($/MWh)
Energy Value ($/MWh)

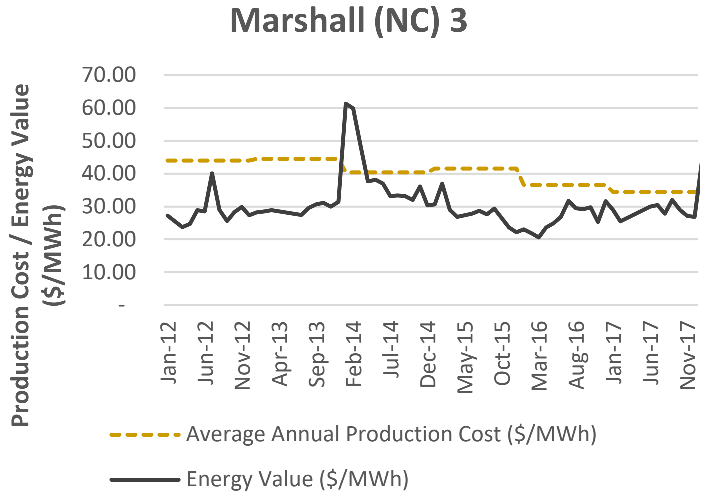

Big Bend ST4
Production Cost / Energy Value ($/MWh)
60.00
50.00
40.00
30.00
20.00
10.00
-
Jan-12 Jul-12 Jan-13 Jul-13 Jan-14 Jul-14 Jan-15 Jul-15 Jan-16 Jul-16 Jan-17 Jul-17
Average Annual Production Cost ($/MWh)
Energy Value ($/MWh)


Crist 7
Production Cost / Energy Value ($/MWh)
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
Jan-12 Jun-12 Nov-12 Apr-13 Sep-13 Feb-14 Jul-14 Dec-14 May-15 Oct-15 Mar-16 Aug-16 Jan-17
Average Annual Production Cost ($/MWh)
Energy Value ($/MWh)

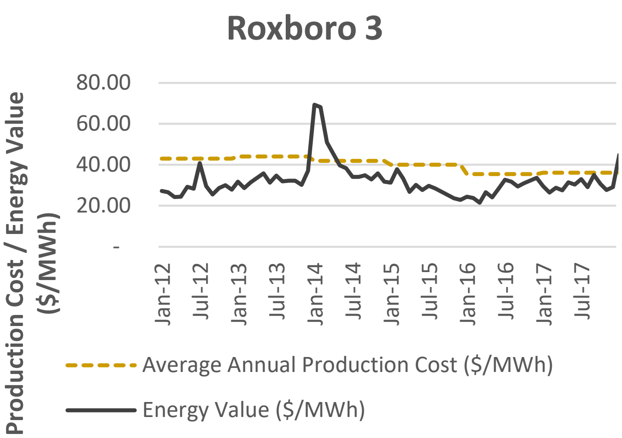

Williams ST1
Production Cost / Energy Value ($/MWh)
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
Jan-12 Jul-12 Jan-13 Jul-13 Jan-14 Jul-14 Jan-15 Jul-15 Jan-16 Jul-16 Jan-17 Jul-17
Average Annual Production Cost ($/MWh)
Energy Value ($/MWh)



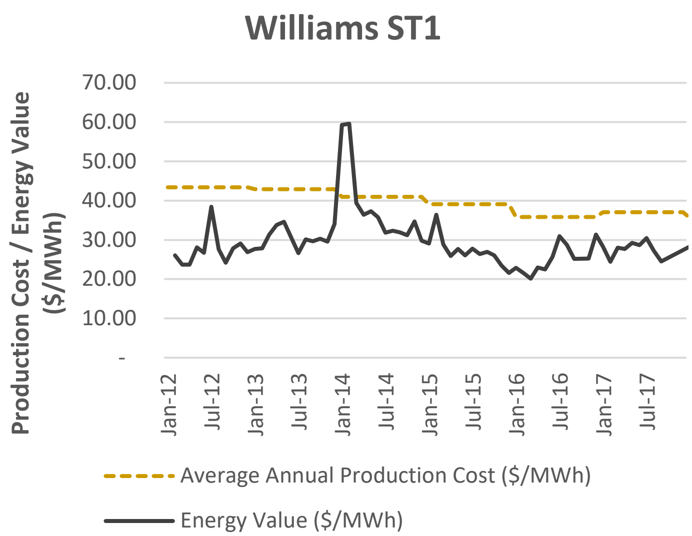
Jim Bridger 1
80.00
60.00
40.00
20.00
-
Production Cost / Energy Value ($/MWh)
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Jan-17
Jun-17
Nov-17
Average Annual Production Cost ($/MWh)



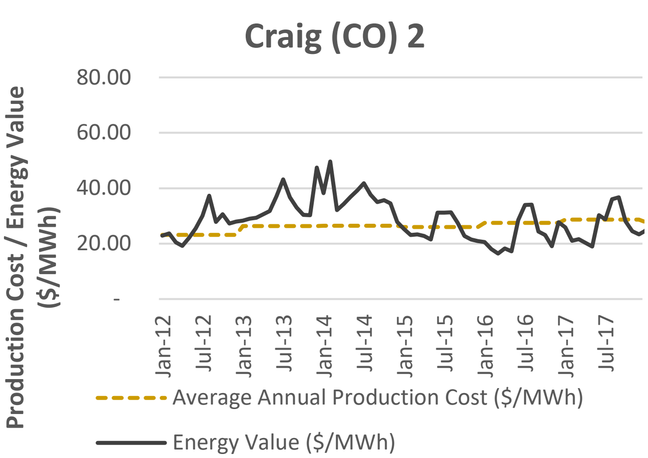
Marshall (NC) 3
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
Production Cost / Energy Value ($/MWh)
Jan-12
Jun-12
Nov-12
Apr-13
Sep-13
Feb-14
Jul-14
Dec-14
May-15
Oct-15
Mar-16
Aug-16
Jan-17
Jun-17
Nov-17
Average Annual Production Cost ($/MWh)
Energy Value ($/MWh)



Roxboro 3
80.00
60.00
40.00
20.00
-
Production Cost / Energy Value ($/MWh)
Jan-12
Jul-12
Jan-13
Jul-13
Jan-14
Jul-14
Jan-15
Jul-15
Jan-16
Jul-16
Jan-17
Jul-17
Average Annual Production Cost ($/MWh)
Energy Value ($/MWh)



Williams ST1
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
Production Cost / Energy Value ($/MWh)
Jan-12
Jul-12
Jan-13
Jul-13
Jan-14
Jul-14
Jan-15
Jul-15
Jan-16
Jul-16
Jan-17
Jul-17
Average Annual Production Cost ($/MWh)
Energy Value ($/MWh)



Craig (CO) 2
80.00
60.00
40.00
20.00
-
Production Cost / Energy Value ($/MWh)
Jan-12
Jul-12
Jan-13
Jul-13
Jan-14
Jul-14
Jan-15
Jul-15
Jan-16
Jul-16
Jan-17
Jul-17
Average Annual Production Cost ($/MWh)
Energy Value ($/MWh)

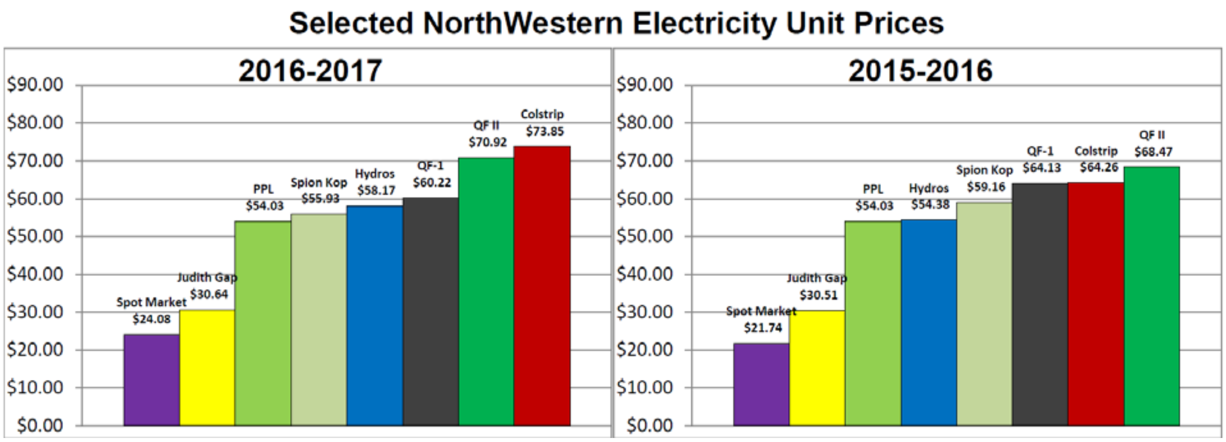
The plants in the examples above produced negative net margins during the four years studied.

			Net Energy Margin / (Loss) $M				
Plant	Parent	Capacity (MW)	2014	2015	2016	2017	2014-2017
Gorgas 10	Alabama Power	789	(14.4)	(87.1)	(90.0)	(65.1)	(256.5)
Crystal River 5	Duke Energy Florida	739	(75.5)	(62.6)	(65.0)	(41.1)	(244.1)
Bowen 4	Georgia Power	952	(9.2)	(65.9)	(77.7)	(48.5)	(201.1)
Big Bend ST4	Tampa Electric Company	486	(11.5)	(63.3)	(56.3)	(37.7)	(168.8)
Crist 7	Gulf Power	578	(26.2)	(49.7)	(35.7)	(25.3)	(137.0)
Williams ST1	SCANA Corp	660	(9.9)	(42.8)	(29.8)	(22.3)	(104.9)
Marshall (NC) 3	Duke Energy Carolinas	711	2.6	(35.2)	(37.8)	(17.3)	(87.7)
Roxboro 3	Duke Energy Progress	745	3.9	(19.0)	(12.0)	(12.1)	(39.2)
Jim Bridger 1	PacifiCorp	406	37.2	(19.6)	(28.6)	(15.4)	(26.4)
Craig (CO) 2	PacifiCorp / Multi-Owned	86	33.9	(1.5)	(10.1)	(2.2)	20.1

b. Other evidence confirms the above-market price received by utility-owned and contracted generation.

The pattern of utility-owned generation operating at higher than "competitive" prices demonstrated in the BNEF data also persists with NorthWestern Energy in Montana. A comparison of the utility's generation and purchase power costs to the Mid-Columbia trading hub price conducted by the Montana Consumer Counsel indicates that the price of the utility's internal generation costs exceeds the trading hub price.[180]

180 Jason Brown, Residential Electricity Rates of NorthWestern Energy Through June 2017, Montana Consumer Counsel, at 7 (attached as Ex. 24).



The analysis reflects that, as required by existing PURPA rules, the cost of the utility's current QF generation and utility-owned generation is similar. The spot market price, however, is significantly lower. This analysis from the Montana Consumer Counsel confirms that rate regulated vertically integrated utilities receive a higher effective price for their generation and non-QF purchases—by passing them along through retail rates—than the regional spot market price value of that generation.

As demonstrated by the foregoing examples, utilities incur costs for energy that exceeds the LMP value of the energy. Because rate regulated utilities with generation and wholesale providers with long-term, all requirements contracts, are able to collect a higher price for energy from captive ratepayers than the regional spot market hub price for their electricity, allowing states to limit QF rates to the regional hub price discriminates against QFs in violation of 16 U.S.C. 824a-3(b)(2).

4. **Using competitive solicitation to determine QF pricing violates 16 U.S.C. § 824a-3(b) unless the utilities' own generation and alternative sources of supply are subjected to the same competition and all of a utility's load is available for QF generation to supply.**

The NOPR suggests that states may use "set avoided energy and/or capacity rates using competitive solicitations (i.e., RFPs [Requests for Proposals]), conducted pursuant to appropriate procedures."[181] However, rather than identifying those appropriate procedures, the NOPR seeks comments on factors states will have to consider when setting avoided cost rates based on competitive solicitations.[182] At the outset, the Commission's proposal does not require, that state solicitation

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181 NOPR at P 82.

182 *See id.* at PP 86-87.

procedures for competitive solicitation actually meet the statutory floor established through PURPA that rates (1) encourage small power producers and (2) not discriminate relative to the utility's own generation and non-QF generators. To ensure competitive solicitations actually meet statutory criteria, the Commission must ensure that competitive solicitations meet certain minimum standards.

First, solicitations must account for utility-owned and non-QF generation and cannot be a limited competition between QFs without the ability to displace non-QF generation. The NOPR cites the National Association of Regulatory Utility Commissioners' supplemental comments in Docket No AD16-16-000 that suggests that "competitive solicitations, or requests for proposals (RFPs), would be open to all QFs . . . ." [183] The NOPR also cites the Commission's 1988 notice of proposed rulemaking.[184] The Commission's 1988 proposal recognized that states cannot carve out portions of a utility's load for QFs and reserve the rest for non-QF generation. That is true despite using competitive solicitation procedures.

> Regardless of whether capacity is obtained through bidding or through other means, no capacity may be exempted from QF offers, *i.e.*, set aside for either the utility's own construction program or purchases of power for sources other than QFs.
>
> . . .
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> A bidding procedure that reserves some portion of needed capacity for certain suppliers, such as utilities, would not satisfy the statutory obligation that a utility must offer to purchase QF power at rates equal to the cost that would be incurred absent the QF. A practice of reserving capacity needs to be met only by a particular supplier would appear to be systematically discriminatory against QFs. If a utility needs capacity, and would be building capacity itself or purchasing capacity from another wholesale source, it must offer to buy such capacity from QFs. Utilities would not be permitted to withhold purchasing from QFs any portion of their capacity needs, provided QFs are offering power that is comparable to the capacity that the utility would otherwise obtain from alternative sources.[185]

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183 *Id.* at P 83.

184 *Id.* at P 84.

185 Regulations Governing Bidding Programs, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,455, 32,030-32,031, 2015 WL 8610975 (Mar. 16, 1988) ("Bidding NOPR"); *see also id.* at 32,031 ("[B]idding can be used to satisfy a portion

Such safeguards are missing from the current NOPR. In fact, the Commission fails to ensure that utilities do not bifurcate their load and allow QFs to bid for only a portion of the utility's energy requirements, despite previously stating that such treatment would constitute illegal discrimination. "[T]the extent that QFs are not even given an opportunity to sell power of comparable quality to the purchasing utility at a price comparable to the source from which the utility is actually purchasing, such a capacity reservation would appear to run afoul of the section 210(b) proscription against rates that discriminate against QFs."[186] While the Commission's prior statements refer to capacity, the same reasoning applies equally to energy. Thus, at a minimum, a non-discriminatory competitive solicitation must allow QFs to meet any and all portions of a utility's energy requirements, including the portion otherwise served by the utility's own generation or by other non-QF generation.[187]

Nevada's implementation rule at NAC 704.9496 is an example of an incorrectly-conducted, and unlawfully-discriminatory, bidding process. In Nevada, utilities conduct a request for proposals that is limited to QFs to meet a small, segregated portion of the utility's energy and unmet capacity requirements. The QF rate is then set at the lower of the lowest bid or an administratively determined avoided cost rate.[188] Because only a portion of the utility's energy and unmet capacity requirements are segregated and subjected to the QF bidding process, the rest of the utility's supply requirements are withheld from competition by QFs and filled by market purchases and the utility's own generation at higher marginal costs

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of a utility's capacity needs, while at the same time another process is used, such as negotiations, to satisfy the remainder of the utility's needs. However, in such situations, QFs must be given an opportunity to offer to satisfy the portion of the utility's capacity needs that has not been subjected to bidding.").

186 Bidding NOPR at 32,031.

187 *Id.* ("The legality of bidding requires that the bidding process take into account all potential sources of supply. This would include the purchasing utility's own capacity expansion program as well as those wholesale sources that the utility would have purchased from absent the QF purchase, such as other QFs, IPPs and other utilities."). The Commission's 1988 NOPR indicates that failing to include non-QFs could lead to paying QFs too high of rates because a non-QF could have supplied the same generation for less. *Id.* Allocating some of the utility's load to the utility's own generation or non-QF generators, without making that generation compete in the solicitation with QFs to meet all portions of the utility's load, results in two-tiered pricing where the QF could get paid less than the non-QF generation.

188 NAC 704.9496(7).

than the lowest QF bids in the RFP.[189] That withholding of most of the utility's load from QF competition and payment of higher prices to the non-QF generation meeting the withheld portion of load discriminates against QFs and results in higher customer prices.[190] If the Commission allows competitive solicitation to set QF rates, it must ensure that practices like Nevada's are clearly prohibited so that all of a utility's load is open to competition from QFs.

Second, to ensure that QFs receive the same price that other generation receives, all sources of supply must compete in the competitive solicitation—including the utility's own generation. As demonstrated above, rate regulated utilities are able to collect their own generation costs from captive ratepayers regardless of whether those costs are competitive with other suppliers of electricity. Setting QF pricing through a competitive process, while allowing utility-owned generation to receive cost-of-service compensation outside the competitive process, discriminates against QFs.[191]

Third, the solicitation process cannot be used in any way to curtail or delay a utility's obligation to purchase from QFs. As the NOPR indicates, FERC held in 2014 that Montana could not "curtail" a utility's obligation to purchase power from a QF "on a failure of the QF to win an only occasionally-held RFP."[192] In that order, the Commission held that "requiring a QF to win a competitive solicitation as a

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189 NV Energy shows between 840 MW and 1,886 MW of unmet requirements, or "Open Position" that it intends to fill with market purchases or other procurement. Hr'g. Ex 11, Docket No. 18-06003, at Figure EA-15 (Nev. Pub. Utils. Comm'n, Sept. 17, 2018) (attached as Ex. 25); Docket No. 18-06003 Vol. 3 Hr'g Tr at 191-93 (Nev. Pub. Utils. Comm'n, May 1, 2019) (attached as Ex. 26). For comparison, the most recent full solicitation conducted under NAC 704.9496 sought bids from QFs up to 25 MW in size for a total solicitation capacity of only 50 MW. Vote Solar, Direct Testimony of Rick Gilliam, Docket No. 18-06003, at 10-14 (Nev. Pub. Utils. Comm'n, Oct. 8, 2018) (also admitted as Hr'g Ex. 40) (attached as Ex. 27); Hr'g Ex. 11, Docket No. 18-06003, at 152-53, 163 of 309 (Nev. Pub. Utils. Comm'n, Sept. 17, 2018) (Ex. 25); Hr'g Ex. 28, Docket No. 18-06003, at 17-19 (Nev. Pub. Utils. Comm'n, Nov. 13, 2018) (market energy and capacity cost calculations) (attached as Ex. 28); Docket No. 18-06003 Vol. 3 Hr'g Tr at 190:13–194:24 (Nev. Pub. Utils. Comm'n, May 1, 2019) (Ex. 26).

190 Bidding NOPR at 32,028, 32,031.

191 *Pub. Serv. Co. of New Hampshire*, 83 FERC ¶ 61,224, 62,001 (May 29, 1998) (explaining that price paid to QFs must be based on "all potential sources of capacity in determining avoided costs"); *S. Cal. Edison Co.*, 70 FERC ¶ 61,215, 61,677 (Feb. 23, 1995) (avoided cost must be based on all potential sources of generation that the utility could purchase).

192 NOPR at P 85.

condition to obtaining a long-term contract imposes an unreasonable obstacle to obtaining a legally enforceable obligation particularly where, as here, such competitive solicitations are not regularly held. The Montana Rule is therefore inconsistent with PURPA and the Commission's regulations implementing PURPA to the extent that it offers the competitive solicitation process as the only means by which a QF . . . can obtain long-term avoided cost rates."[193] That is, while the infrequency of solicitations exacerbated the problem, the Commission found the requirement to win a competitive solicitation, itself, to be an unreasonable obstacle "and contrary to the express goal of PURPA to 'encourage' QF development."[194] In other words, PURPA requires utilities to purchase from QFs and pay a price at least as high as what the utility or any non-QF would receive for the same energy. To the extent competitive solicitation procedures would excuse a utility from procuring anything less than all energy provided by all QFs at those non-discriminatory rates, it violates PURPA.

For example, imagine a scenario where a utility has an existing generating unit totaling 500 MW and an avoidable cost of $50/MWh. Now, imagine that each year's solicitation is capped at 400 MW, and the clearing price is $25/MWh. If there was no cap set, the clearing price would have been $30/MWh. If there was no cap, that existing generating unit could be completely avoided (retired) and replaced by the 500 MW at $30/MWh (a savings of $20/MWh). Because that existing generating unit is avoidable with no cap, the state would violate PURPA's nondiscrimination doctrine if it still capped the RFP at 400 MW and set the utility's avoided cost rate at $25/MWh instead of what it should have been, which was $30/MWh.

Fourth, the "required operating characteristics of the needed capacity" factor suggested in the NOPR cannot be used as a surrogate to define characteristics of only non-QF generation or to allow a utility to pick among favored generators. While two different generators with different operating characteristics may have different capacity contributions and different quantities of energy production, a megawatt of accredited capacity and a megawatt-hour of energy are fungible. Criteria that would preclude the megawatt of accredited QF capacity or megawatt-hour of QF-produced energy in favor of another supplier violate PURPA. For example, the QF-only competitive solicitation run by NV Energy, referenced above, applied various criteria—such as whether the QF was in litigation with NV Energy—to preclude disfavored bidders.[195] There is no lawful basis for a utility to apply any criteria that would preclude any QF from exercising its right under PURPA to sell to the utility.

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193 *Hydrodynamics Inc.*, 146 FERC ¶ 61,193 at PP 32-33 (Mar. 20, 2014).

194 *Id.*

195 Vote Solar, Direct Testimony of Rick Gilliam, Docket No. 18-06003, at 14 and Ex. RG-2 at § 2.7 (Nev. Pub. Utils. Comm'n, Oct. 8, 2018) (Ex. 27).

If the Commission allows competitive solicitation to set QF prices, it must ensure that utility-owned and other non-QF generation is subjected to the same competition requirements and the utility is not compensated for generation outside of the competitive process, that the entire amount of a utility's load is available to be met by QF generation, that no caps or other constrains are placed on the amount of QF generation that can be acquired to meet load, and that no constraints are placed on any bidder that discriminate against any QF.

III. The favorable treatment of cogeneration violates the prohibition on discrimination.

The NOPR proposes to revise the Commission's regulations to remove support for renewable energy generation but leave rules unchanged for cogeneration. The NOPR's premise for that different treatment is that cogeneration has stagnated or declined in recent years.[196] However, that fails to justify different treatment for cogeneration technology that delivers the same fungible MWh of energy as renewable energy generation. Both provide the same energy and displace the same alternative source of that energy. The fact that cogeneration technology matured sooner, and therefore has seen slower recent growth, does not justify different prices for the same MWh of energy.

IV. The Commission lacks statutory authority to waive the must-purchase obligation for retail utilities serving in competitive retail markets.

The Commission lacks statutory authority, acts arbitrary and capriciously, and contravenes PURPA's non-discrimination provision with its two proposals regarding PURPA and Providers of Last Resort ("POLR"). The Commission proposes to reduce a POLR purchase obligation to the extent retail choice reduces their supply obligation and remove state authority to set PURPA contract term lengths.[197] The Commission proposes to remove state authority by requiring QF contracts with a POLR match the term of the POLR's other supply contracts.[198]

The purchase obligation under PURPA can only be waived through the specific provisions in section 210(m).[199] However, the Commission does not rely on section 210(m) for authority to limit a POLR's purchase obligation. Lacking statutory authority for the exemption or waiver, the Commission's proposal to limit

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196 NOPR at P 24.

197 *Id.* at P 91.

198 *Id.* at P 90.

199 *Raleigh & Gaston R. Co. v. Reid*, 80 U.S. 269, 270, 20 L.Ed. 570 (1872) ("When a statute limits a thing to be done in a particular mode, it includes a negative of any other mode.").

POLR contract term lengths with QFs conflicts with PURPA's requirement that utilities purchase electric energy from QFs.[200]

Moreover, even if the Commission had authority to waive POLR purchase obligations, there is no rational basis supported in the record for doing so here. The only rationale provided by the Commission for its proposal to match QF contract lengths with a POLR's other supply contracts is that "POLR load often is procured through a competitive solicitation process with contracts of one year or less."[201]

The Commission does not cite to any record evidence to support how POLRs "often" procure their supplies. The Commission's rationale lacks record evidence support.

Furthermore, to the extent the Commission's proposal would fail to treat QF contracts in parity with any of a POLR's other supply contracts, it unlawfully discriminates against QFs.[202]

V. The Commission proposes to unlawfully extinguish the must-purchase obligation of small QFs.

In implementing section 210(m) of PURPA, the Commission adopted a rebuttable presumption that QFs 20 megawatts and below ("Small QFs") do not have non-discriminatory access to any market of the type described in section 210(m)(1)(A), (B), or (C), and therefore maintained the mandatory purchase obligation for those facilities.[203] The Commission now proposes to revise the capacity level at which this presumption attaches from 20 MWs to 1 MW.[204] According to the Commission, organized electric markets are now "more mature, and the mechanics of participation in such markets are improved and better understood," and therefore Small QFs "should be able to participate in such markets under most circumstances."[205] The Commission also asserts that certain utilities located outside of an organized RTO/ISO could satisfy the requirements of

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200 16 U.S.C. § 824a-3(a)(2).

201 NOPR at P 90.

202 16 U.S.C. § 824a-3(b)(2).

203 *New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities*, Order No. 688, FERC Stats. & Regs. ¶ 31,233, at P 72, *et seq.* (Oct. 20, 2006) (hereinafter "Order No. 688"), *order on reh'g*, Order No. 688-A, FERC Stats. & Regs. ¶ 31,250, at P 94, *et seq.* (2007) (hereinafter "Order No. 688-A"), *appeal denied sub nom. Am. Forest & Paper Ass'n. v. FERC*, 550 F.3d 1179 (D.C. Cir. 2008).

204 NOPR at PP 10, 118, 126; 84 Fed. Reg. at 53,262-63.

205 NOPR at P 126; 84 Fed. Reg. at 53,263.

section 210(m)(1)(C) and will be able to receive an exemption on a case-by-case basis.[206]

The Commission's proposal is unlawful for several reasons. First, the record makes clear that Small QFs do not possess the "nondiscriminatory access" to these markets that is a statutory prerequisite to issuing an exemption to the must-purchase obligation under section 210(m). Contrary to the Commission's conclusory assertion that it is "fair to expect that small power production facilities above 1 MW can acquire the administrative and technical expertise necessary to obtain nondiscriminatory access to a market,"[207] the record demonstrates the opposite—significant practical barriers, routinely acknowledged by the Commission in other proceedings, prevent Small QFs from accessing these markets on an equal footing with large facilities. Indeed, many of the barriers faced by Small QFs are prohibitive, making project development solely based on market access unviable. Moreover, access for Small QFs varies significantly by RTO/ISO, and the Commission's categorical conclusion about access across *all* of these markets is untenable.

Second, the Commission's proposal is contrary to PURPA's mandate to encourage the development of QFs. Proper implementation of section 210(m) ensures that an exemption only applies where QF development will be stimulated by market forces; otherwise Congress intended QF development to continue to be encouraged by the mandatory purchase obligation.[208] Yet, the record is barren of evidence that could reasonably allow the Commission to conclude that Small QF development will be stimulated by market forces. The Commission's implied conclusion that access to RTO/ISOs is sufficient to ensure Small QF development is irrational in light of its own prior showing of the multitude of barriers these facilities face to access a buyer through the organized markets. The Commission neither acknowledges nor addresses these barriers, which very much remain in place for Small QFs today. Nor is the ostensible possibility of a Small QF rebutting the presumption of access sufficient to reduce the impact of QF development. As discussed more fully in section V below, placing the burden on Small QFs to prove its lack of access is itself a substantial barrier to QF development.

Third, the Commission must make clear that the NOPR continues to place the burden on utilities to petition to eliminate the must-purchase obligation for Small QFs—even for utilities that have previously made such a showing for QFs larger than 20MWs. In particular, utilities located within section 210(m)(1)(B) and

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206 NOPR at P 133.

207 84 Fed. Reg. at 53,263.

208 Order No. 688 at P 6 (recognizing Congress did not eliminate the obligation to encourage QFs in the Energy Policy Act of 2005 and concluding that its final section 210(m) rules must show QF development will continue to be encouraged by either market forces or the mandatory purchase obligations).

(C) type markets have not met the separate factual showings that are statutorily required to eliminate the mandatory purchase obligation, including showings of an actual and meaningful opportunity to sell both capacity and energy that must be made specifically with respect to Small QFs.

Finally, in light of the barriers that persist to QFs within even the most competitive organized markets and the substantial evidence that regulated utilities outside of RTO/ISOs continue to generate new and innovative ways to limit access by QFs of all sizes to markets, the Commission's suggestion that QFs have nondiscriminatory access to markets within the meaning of section 210(m) merely because of the issuance of a request for proposal ("RFP") and the existence of liquid market hubs is absurd. The Commission's interpretation of section 210(m) is so divorced from the statutory text as to effectively grant it the unconstrained authority to eliminate the must-purchase obligations anywhere, and is unlawful.

A. Small QFs lack nondiscriminatory access to markets.

In Order No. 688, the Commission recognized that QFs may lack nondiscriminatory access to wholesale markets, notwithstanding apparent eligibility to interconnect under an open access transmission tariff or the competitive quality of the market, because of operational characteristics, transmission limitations, and facility size.[209] Indeed, the Commission acknowledged that "[s]maller QFs are also 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."[210] In addition, QFs that connect on the distribution system can face a host of additional practical barriers to access, ranging from direct denial of access due to control by a distribution system operator to the need for technical enhancements to enable power to be able to flow from low voltage facilities to the transmission system.[211] As the Commission explained, the facilities connected through the distribution system facing such additional barriers are most often Small QFs.[212] In light of these significant challenges faced by Small QFs, the Commission established its 20 MW rebuttal presumption. In addition to the barriers faced particular to their size, the Commission recognized that setting the threshold at 20 MW would help to address the potential operational barriers to access, which could be more acute for small facilities.[213] In short, the Commission concluded that "nondiscriminatory access"

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209 Order No. 668 at PP 52, 82.

210 Order No. 688-A at P 96.

211 Order No. 688 at P 89.

212 Order No. 688-A at P 96; *see also* Order No. 688 at P 89.

213 Order No. 688 at P 82 (the 20 MW threshold "in effect capture[d] some of the operational issues expressed by commenters").

must mean more than mere legal or formal eligibility, but rather that practical barriers to market access are relevant to a finding of nondiscriminatory access under section 210(m).

The Commission now contends that Small QFs can "obtain nondiscriminatory access" and no longer need the benefit of the rebuttable presumption.[214] But the Commission offers little reasoning and no evidence in support of the claim.

To support its proposal to eliminate the must-purchase requirement for certain Small QFs, the Commission asserts that relative to when the Commission adopted the rebuttable presumption for all QFs under 20 MW, "the markets are more mature, and the mechanics of participation in such markets are improved and better understood."[215] The Commission fails, however, to cite any evidence supporting that premise. Likewise, the Commission does not explain what it means by "in light of the maturation of organized electric markets" or how such "maturation" is relevant to determining whether QFs smaller than 20 MW have nondiscriminatory access to those markets. The Commission also suggests that QFs smaller than 20 MW can now participate in markets on a nondiscriminatory basis "under most circumstances," but does not explain what those "circumstances" are, or whether they apply as a general matter to most Small QFs.

The Commission cites to its Fast-Track interconnection process for projects up to 5 MW, but does not explain its relevance to Small QF access. The Commission does not elaborate on which of the many barriers that it has recognized Small QFs face are purportedly alleviated by the process. If FERC's position is that the Fast-Track process reduces barriers for smaller projects, then the Commission must explain how that helps projects between 5 to 20 MW, which would still face significant barriers to accessing the market.[216]

Similarly, the Commission cites to its energy storage Order No. 841[217], but it does not explain how that is relevant to determining whether Small QFs have nondiscriminatory access to markets. Indeed, FERC has previously found that energy storage, standing alone, can never qualify as a QF, so FERC's reliance on

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214 NOPR at P 127.

215 *Id.* at P 126.

216 *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 43 (1983) (an agency's failure to consider the relevant factors and supply a "rational connection between the facts found and the choice made" renders its decision arbitrary and capricious) (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)).

217 Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,121 (Nov. 17, 2016) (Order 841).

Order No. 841 to establish Small QFs access to markets is misplaced.[218] Rather, that the Commission felt the need for Order 841 to explicitly grant storage resources located on the distribution system market access, and that that portion of Order 841 is currently under appeal highlights the current lack of non-discriminatory market access for all resources located on distribution systems.[219]

Remarkably, the Commission does not examine whether the barriers identified in Order No. 688, which the Commission previously found relevant to and relied upon in determining whether a presumption of nondiscriminatory access should apply, remain today. Strangely, the Commission does not even mention its ongoing investigation of the barriers that may limit distribution-connected resources (distributed energy resources or DERs) from participating in the organized wholesale markets.[220] Nor does FERC explain why it chose 1 MW as the new threshold, or offer factual support for its rationale.[221] The Commission's failure to provide a rational explanation of its proposal, supported by evidence in the record is, in itself, the hallmark of arbitrary and capricious agency decisionmaking.[222]

Contrary to the Commission's conclusory assertion that it is "fair to expect" that Small QFs can acquire the "administrative and technical expertise necessary to obtain nondiscriminatory access to a market,"[223] there is substantial record evidence demonstrating that numerous practical and logistical barriers to market access persist, and preclude Small QFs' nondiscriminatory access to wholesale markets. First, there is substantial record evidence of two broad sets of barriers to

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218 *See Luz Dev. & Fin. Corp.*, 51 FERC ¶ 61,078, 61,172 (Apr. 26, 1990) (denying stand-alone energy storage resource certification as QF).

219 Order 841 at 29.

220 *See* Order 841 at 5.

221 *See, e.g.*, *Luminant Generation Co. v. EPA*, 675 F.3d 917, 926 (5th Cir. 2012) ("bald assertions" are not sufficient to affirm agency action); *Texas v. EPA*, 690 F.3d 670, 678 (5th Cir. 2012) (judicial review "requires more than the [agency's] bare conclusion"); *La. Envtl. Action Network v. EPA*, 382 F.3d 575, 586–87 (5th Cir. 2004) (rejecting an agency's "naked assertion[s]" regarding the threshold for regulating a particular pollutant, and remanding because agency "fail[ed] to mention or show any evidence" to support its conclusions); *see also In re Bell Petroleum Servs., Inc. v. Sequa Corp.*, 3 F.3d 889, 905 (5th Cir. 1993) ("[j]udicial review 'must be based on something more than trust and faith" in the agency's assertions) (internal citations omitted).

222 *State Farm*, 463 U.S. at 43 (an agency's failure to consider the relevant factors and supply a "rational connection between the facts found and the choice made" renders its decision arbitrary and capricious) (quoting *Burlington Truck Lines, Inc. v. United States*, 371 U.S. 156, 168 (1962)).

223 NOPR at P 127; 84 Fed. Reg. at 53,263.

Small QF participation in the markets: (1) technical and logistical barriers to interconnection that disproportionally and adversely affect smaller projects, and (2) financial costs that do not scale with the size of the interconnecting resource, and thus have disproportionate impacts on Small QFs.

Second, the differing rules applicable to distributed energy resources in each of the RTOs illustrate the fundamental barriers that still exist for Small QFs: developers cannot readily predict, let alone confirm in advance, what the process will look like, how much it will cost, or how long it will take. The costs, delays, and uncertainty of the process are significant enough to make participation in wholesale markets commercially infeasible for many projects. Small QFs do not have "nondiscriminatory access" when they face such disproportionate barriers simply to completing the steps necessary to access wholesale markets; and the widespread lack of such distributed-connected resources participating in RTO/ISOs further demonstrates that these barriers remain substantial. "Nondiscriminatory access" surely *cannot* mean no access.

B. Small QFs face significant barriers to accessing the markets.

Small QFs face significant and discriminatory barriers to accessing markets. Indeed, as described in the attached affidavit of Thomas A. Rutigliano, based on years of experience representing developers of distributed energy resources, including PURPA QFs, in both commercial and regulatory matters, Small QFs face at least two broad sets of barriers that disproportionately and discriminatorily affect their ability to be eligible to participate in and to legally and physically access wholesale markets.[224]

First, small QFs often face disproportionate technical and logistical difficulties interconnecting to the transmission or distribution system, depending on whether the QF is connecting through the FERC-jurisdictional or non-jurisdictional state process. [225] Small QFs located behind retail meters or on distribution systems and seeking to sell their output to their local utility, for example, generally interconnect through relatively straight-forward state[226] jurisdictional tariffs, which typically impose nominal charges, have fixed, relatively brief timelines for completing the interconnection process, and have standardized "screening" procedures for rapid review of engineering studies.

Small QFs connecting through FERC-jurisdictional processes to sell into the wholesale market, on the other hand, face significant uncertainties, administrative

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224 Direct Testimony of Thomas A. Rutigliano at 2:1-11; 4:5-15 ("Rutigliano Testimony") (attached as Ex. 29).

225 *Id.* at 8-13.

226 Or municipal utilities and electric co-operatives, which are similarly situated to states.

hurdles, and delay. PJM's interconnection process, for example, has nine phases. Costs are unknown in advance.[227] For Small QFs, they can range between near zero up to $20,000, with little correlation between the size of the project and the total cost. Costs are even less predictable for 10 to 20 MW projects, which range between near zero up to $100,000.[228] Time to complete the PJM interconnection process is also unknown in advance, and the PJM process requires more detailed interconnection studies than typically required in the retail context. The process generally takes between 150 and 500 days for projects between 1 and 15 MW, with no clear relationship between project size and study duration.[229] For projects between 15 and 20 MW, the process can take over 1,000 days. In other words, once the application is filed, it may take nearly three years before construction can even begin.[230] To put those delays in context, for Small QFs the time needed to go through the PJM queue is often longer than the rest of the project development cycle combined.[231]

The Commission has previously found that "the mere fact that a QF can pay for upgrades to the transmission system"[232] is insufficient to demonstrate nondiscriminatory access, yet that is exactly the situation requiring Small QFs to go through FERC jurisdictional interconnection will create. Once the interconnection study is complete, the Small QF may have to finance expensive transmission upgrades just to access the market. These costs can be prohibitively expensive, sometimes exceeding the cost to build the Small QF facility itself.[233] Transmission upgrades and interconnection costs that exceed the cost of the Small QF itself effectively preclude *access* to buyers through the RTO market because, as a practical matter, they preclude construction of the QF itself. Conversely, the same Small QF would not face those same upgrade costs if it simply sold energy thorough the distribution system.

RTO administered FERC-jurisdictional interconnection processes create significant barriers for small QF projects, and those barriers become disproportionately more onerous for smaller projects. The majority of those small projects must go through the same process as very large generation projects,[234] but

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227 Rutigliano Testimony at 9-10.

228 *Id.*

229 *Id.*

230 *Id.* at 10:8.

231 *Id.* at 11.

232 *Northern States Power Company, a Minnesota corporation,* 151 FERC P 61110 at 35.

233 Rutigliano Testimony at 4:11.

234 *Id.* at 11-12.

smaller developers typically lack access to the same financing mechanisms as large developers, who can afford to wait many months or years to begin developing a project. These issues are compounded by PJM's requirement that the developer have site control prior to filing their interconnection request. Since many Small QFs are located at end-use customer sites, this creates an untenable situation where a developer must enter into a binding contract with the QF host site, then convince the host to wait for as long as several years, before any progress is observed toward realizing the benefit of the project.

The unknown delay also creates issues for QFs that wish to sell capacity. PJM's capacity market requires suppliers to make commitments three years in advance in order to realize their full capacity value. However, small generators will not have any firm idea of when they can start construction. Once they are presented an interconnection agreement, they will generally be able to be in service in much fewer than three years. Small generators thus face the nearly unavoidable loss of capacity value for the first few years of their projects.

The disparities between FERC-jurisdictional and non-jurisdictional interconnection processes are further compounded for Small QFs interconnecting and selling wholesale power through local distribution facilities, because they must go through *both* the PJM New Services Queue and the non-FERC jurisdictional entities' interconnection process. As a result, those Small QFs have to go through another layer of duplicative and sometimes inconsistent interconnection processes that do not apply to large QFs—effectively doubling the administrative burden that disproportionately affects (and applies *only* to) Small QFs. And while the Commission points to an Order adopting a Fast Track interconnection process for some small generators, PJM has concluded that those procedures only apply when a generator connects to a FERC-jurisdictional facility – which excludes the majority Small QFs which connect via non-FERC jurisdictional facilities.[235]

In sum, the interconnection process itself introduces delays that disproportionally affects smaller projects, and in some cases, leaves operating facilities unable to sell their power. Finally, the interconnection process may force Small QF's to pay for transmission upgrades that cost far more than the Small QF itself.

Second, small QFs face an additional array of *financial* barriers to accessing markets, primarily as a function of their size. Participation in PJM's markets brings fixed costs, financial risk, operation responsibilities, and technical requirements. Because these costs do not scale with the size of a project, they have exaggerated impacts on Small QFs.

By way of example, to participate in any PJM market, an entity must become a PJM member, satisfy PJM's credit policy, and maintain a control center in accordance with PJM manuals. Although becoming a member of PJM and selling

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235 *Id.* at 13.

only energy into the market may have only nominal costs, to sell capacity from a QF, which is critical to obtaining financing for Small QF, the resource may have to post financial surety up to $60,000 per MW-year of capacity offered. Because PJM's capacity market is a three-year forward auction, a generation owner will need to post up to $240,000 per MW just to sell the capacity from their facility's initial four years of operations. This can translate into as much as a 23% increase in project financing requirements, putting Small QFs at a significant disadvantage to existing generators.[236]

Similarly, Small QFs face significant cost disadvantages in accessing PJM's financial products, such as "virtual transactions" and "financial transmission rights," which are critical to managing energy price and congestion risks. Participants in PJM who wish to make virtual transactions or obtain financial transmission rights must meet more complex and onerous credit requirements regardless of size. This requirements include minimum capitalization requirements, explicitly discrimination against smaller entities. Those QF owners that cannot access these financial tools are not able to access energy markets, manage transmission risks, or sell to distant buyers on the same terms as other generation owners.[237] Finally, Small QFs participating in PJM face unavoidable financial risks of the cost of other members defaulting-- costs which, again, disproportionately impact Small QFs due to their size.[238]

There are similar operational barriers to access that disproportionately impact Small QFs. A generation owner participating in PJM must establish a Market Operations Center, which meets specific physical security, computer security, and redundant communication requirements. This not only imposes overhead costs but actually requires all market participants to be able to respond to telephone questions about their scheduled transactions within *one minute* of a phone call from PJM. To cover those requirements through third parties, a 20 MW facility may have to pay costs equivalent to up to 25% of its gross revenues, putting those Small QFs at significant disadvantage compared to larger, more financially entrenched generation.[239] These requirements may make sense for large resources, but they create prohibitively expensive administrative barriers to the development of projects, and thus effectively preclude access to markets.

C. Differing market rules applicable to distributed energy resources in the RTOs illustrate the fundamental barriers that still exist.

236 *Id.* at 6-10.

237 *Id.* at 6-7.

238 *Id.* at 8.

239 *Id.* at 8.

The particular challenges to access to wholesale markets faced by resources interconnected on the distribution system, first documented in Order No. 688[240] but separately identified in the Commission's ongoing DER rulemaking,[241] widely persist in markets today. Small QFs typically qualify as DERs within the meaning of FERC's ongoing rulemaking.[242] And the differing rules applicable to DERs in each of the RTOs illustrate the fundamental barriers that still exist for Small QFs.

1. MISO

MISO's filings in the Commission's concurrent distributed energy resource docket[243]indicate that the ISO has a "single Generator Interconnection Procedure ('GIP') and Generator Interconnection Agreement ('GIA') for Interconnection Requests of all sizes."[244] Accordingly, DERs and Small QFs must still incur the same costs of any transmission upgrades and must still choose between the two interconnection studies applicable to all resources, regardless of size. Perhaps because of these difficulties, MISO has not received any requests to interconnect aggregated distributed energy resources, and "has not yet developed rules that specifically address the challenges of such interconnections, including how the unit to be studied would be defined and studied."[245] Small QFs in MISO therefore lack certainty about the requirements for interconnection and they face the same administrative and interconnection barriers applicable to large generation sources, which impose significant financial and administrative barriers to entry.

2. ISO-NE

Although it is one of the more advanced RTOs with respect to distributed energy resource access, the ISO-NE imposes similarly problematic barriers to meaningful market access. The Massachusetts Department of Public Utilities ("MA

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240 Order No. 688 at P 89.

241 *Elec. Storage Participation in Markets Operated by Reg'l Transmission Orgs. and Indep. System Operators*, 157 FERC ¶ 61,121 at P 13 (Nov. 17, 2016) (In spite of their technical capabilities, DERs "can at times be too small to participate in these markets individually" and market rules can impose "prohibitively expensive or otherwise burdensome requirements.")

242 *See generally Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators*, FERC Docket No. RM18-9-000.

243 *Id.*

244 *See Data Request Comments of the Midcontinent Indep. System Operator*, FERC Docket No. RM18-9-000, at 3 (Oct. 7, 2019).

245 *Id.* at 11.

DPU"), for example, has initiated an investigation of delays in transmission interconnection for resources location on the distribution system, which revealed that there are more than 200 proposed small resource interconnections, totaling more than 900 MW, that have been unable to interconnect to the transmission system, with no certainty as to when, if ever, they will have access to wholesale buyers.[246] That amount of capacity is about one quarter of the currently installed distributed energy resource capacity in Massachusetts, and about half the state's solar capacity goal.[247]

The implications for that kind of uncertainty are significant. First, and most immediately, the uncertainty surrounding the ability to interconnect creates uncertainty about the financial viability of Small QF projects. Moreover, it demonstrates that contrary to the Commission's assertions, those projects do not, in fact, have access to the market. Second, the delay in the interconnection process for smaller sources demonstrates that Small QFs face unique administrative barriers to access. RTO/ISOs are generally structured and staffed to process and manage a smaller number of large-sized interconnections that occur relatively infrequently. It is becoming increasingly clear, however, that the RTOs/ISOs lack sufficient resources to process and manage the rapid increase in volume of distributed energy resource connection requests. Thus, even if Small QFs developed the "administrative and technical expertise necessary to obtain nondiscriminatory access to a market"[248] (and there is no evidence in the record that they actually have that expertise), those Small QFs still lack access to the market because the interconnection process cannot be implemented at the scale necessary to process all of the incoming requests.

Moreover, there are significant challenges in determining whether a particular distributed energy resource falls within the jurisdiction of a federally- or state-regulated entity. In ISO-NE, for example, whether a Small QF falls within a wholesale or retail jurisdiction is made on a "case by case" basis, and there is no guidance on how that inquiry is conducted.[249] As a result, small resources have no way of knowing or predicting how they will be treated until they actually start the interconnection process. This administrative and jurisdictional uncertainty injects

[246] *Joint Comments of the Mass. Dep't of Pub. Utils., Mass. Dep't of Energy Resources, and the Attorney General of the Commonwealth of Mass.*, FERC Docket No. RM18-9-000, at 8-9 (Nov. 6, 2019).

[247] *Id.*

[248] NOPR at P 127.

[249] *ISO New England, Response to Letter Dated Sept. 5, 2019 Regarding Participation of Distributed Energy Resource Aggregations in Markets Operated by Reg'l Transmission Orgs. and Indep. System Operators*, FERC Docket No. RM18-9-000, at 9-10 (Oct. 7, 2019).

further operational and financial uncertainty into the value proposition for small generation projects with relatively little room for error.

3. PJM

Despite the availability of certain processes intended to expedite interconnection for small resources, PJM's own studies show that there are significant barriers for distributed energy resources attempting to access the market, and that FERC-jurisdictional and non-jurisdictional resources are treated differently—sometimes significantly so. These differences tend to the benefit of FERC-jurisdictional resources. Indeed, PJM's own study shows that interconnection study costs are non-linear with size, meaning that small resources can effectively pay higher costs/MW for interconnection studies, relative to larger sources. Although PJM has an expedited interconnection process, eligibility depends on whether DER qualifies as interconnecting to wholesale or retail jurisdictional facility, and there is significant uncertainty as to how that decision is made.

There are additional differences in PJM's interconnection process for small sources, which vary depending on whether the resource is FERC-jurisdictional. The differences tend to accrue the benefit of FERC-jurisdictional resources:[250]

	FERC-jurisdictional process	non-FERC jurisdictional process
Documentation	PJM's Tariff outlines the procedure for FERC-jurisdictional Small Generator interconnections.	The PJM Tariff does not address non-FERC jurisdictional interconnection. Although the process is referred to in PJM's Manual 14G, actual practice in PJM has varied considerably over time, resulting in uncertainty for the interconnection customer.
Studies and screening	FERC-approved pathways use screens rather than studies to assess safety and	Under the existing process, all non-FERC-jurisdictional resources under 20 MW apply

250 *See Comments of University of Delaware, et al.*, FERC Docket No. RM18-9-000, at 3-4 (Oct. 7, 2019); *see also DER Interconnection Study Cost Analysis*, presented at the Oct. 4, 2018 DER Subcommittee meeting, *available at* https://www.pjm.com/committees-and-groups/subcommittees/ders.aspx.

	reliability. These screens use criteria based only on the local distribution system, not the transmission system.	through the Attachment N process. Even the smallest resources are required to undergo at least a Feasibility Study, and sometimes a System Impact Study, before approval.
Time	If the resource passes the screen, PJM must provide interconnection customers with an Interconnection Service Agreement within 15 business days of receipt of the initial request.	Small QFs must wait up to six months for the queue study process to begin. The Feasibility Study and System Impact Study are expected to each take three months.
Cost	Resources smaller than 1o kW are charged a set fee of $500. Resources up to 5 MW are required to supply a deposit, which varies from $2,000 - $5,000 depending on the timing of the request.	Upfront deposits required for the Feasibility and System Impact studies vary with the size of the project and the transmission owner. Small QFs have faced deposits of $27,000—nine times the deposit they would have been charged if the interconnection were under FERC jurisdiction.

The great variation in DER access from RTO to RTO only underscores the egregiousness of the Commission's sweeping finding that Small QFs have nondiscriminatory access to *all* section 210(m) markets, without any inquiry into the particular interconnection processes or other requirements to obtain access in individual RTOs.

Given that there is no evidence to support that the host of challenges faced by Small QFs to access the organized markets have been alleviated, the Commission cannot reasonably reduce the rebuttable presumption to 1MW. The sound reasoning and evidence the Commission based its initial determination to set the threshold at 20MW apply with equal force today.[251]

D. The Commission lacks factual basis to conclude Small QF development will be stimulated by market forces.

While the Commission has rejected interpretations of section 210(m) that require the "'economic and technical equivalent to the mandatory purchase'" through a competitive market or an obligation to "ensure a QF's commercial viability,"[252] it has also recognized that the adoption of section 210(m) "did not repeal PURPA section 210(a)'s directive that the Commission prescribe, and from time to time revise, such rules as it determines necessary to encourage cogeneration and small power production."[253] Thus, though market access need not provide precise equivalency of outcomes, the Commission has explained that proper implementation of section 210(m) will ensure that "QF development will, as determined by Congress, be stimulated by market forces." But where section 210(m) requirements have not been met, "QF development will continue to be stimulated as it is today through the mandatory purchase obligation."[254] Thus, the Commission recognizes that its implementing rules must "continue[] to support QF development."[255]

Here, the Commission lacks the factual underpinnings to conclude its new rules will continue to encourage QF development. As described at length above, the Commission failed to undertake the necessary factual inquiry to assess the barriers that remain in place for Small QFs, which remain significant in all RTO/ISOs and particularly acute in some organized markets. The Commission cannot reasonably conclude that market forces are capable of stimulating development of Small QFs today. To the contrary, the overwhelming evidence before it shows that, if limited solely to market access, Small QF development will wither away to virtual nonexistence.

Nor is the fact that the Commission is setting a rebuttable presumption, which may be reversed on a case-by-case basis, sufficient to ensure that its rules

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251 *FCC v. Fox Television Stations*, *Inc.,* 556 U.S. 502, 515 (2009) (Where, as here, a "new policy rests upon factual findings that contradict those which underlay its prior policy," the agency must "provide a more detailed justification than what would suffice for a new policy created on a blank slate."); *see also, Encino Motorcars, LLC v. Navarro*, 136 S. Ct. 2117, 2125-26 (2016) ("[T]he agency must at least 'display awareness that it is changing position' and 'show that there are good reasons for the new policy.'")

252 Order No. 688 at P 37.

253 *Id.* at P 6.

254 *Id.*

255 *Id.*

enable QF development. As discussed in Section V, if Small QFs must first take on the heavy administrative and legal task of first reversing the rebuttal presumption before it can ensure access to a buyer, the presumption itself serves as a significant deterrent to QF development.

E. The Commission must clarify that utilities retain the obligation to petition to eliminate a must purchase obligation, and provide specific factual information to support a finding under section 210(m).

While Public Interest Organizations contend that the only outcome consistent with the statute is to abandon the Commission's proposal to reduce the presumption, to the extent that the Commission proceeds with the proposal it must clarify certain aspects of its implementation.

First, the Commission must clarify that utilities located within section 210(m) (1)(A), (B), or (C) markets retain the obligation to petition the Commission to eliminate the must-purchase obligation. This must be true even for utilities that have previously successfully petitioned to eliminate must purchase obligations for QFs 20MWs or larger. This is the approach applied in the Commission's previous rule, and the Commission has offered no basis for departing from it.[256] Small QFs must be afforded adequate opportunity to rebut the presumption before it applies. In addition, in the case of section 210(m)(1)(B) (i.e., "Day 1" markets) and (C) markets, additional, more specific factual findings are required by the statute before the exemption can be granted. [257] As the Commission explained, "it is best to address on a case-by-case basis whether non-RTO/ISOs and RTO/ISOs that do not have both auction-based real-time and day-ahead markets satisfy those statutory requirements" that a QF have a meaningful opportunity to sell capacity and energy to buyers other than the interconnected utility.[258]

Second, the Commission must retain the obligation placed upon utilities petitioning to eliminate the must purchase obligation to present information about the transmission system that is not readily available to QFs.[259] Small QFs, more so than large QFs—due to their sophistication, smaller number of staff, and that they are typically interconnected on the distribution system—lack information they would need in order to rebut the presumption that they have nondiscriminatory access to the wholesale market. The Commission previously required utilities located within RTO/ISOs designated as "Day 2" markets under section 210(m)(1)(A) to include within their filing "information about transmission constraints within its service territory," recognizing that potentially affected QFs would lack such

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256 Order No. 688-A at P 30; Order No. 688 at PP 102-103.

257 Order No. 688-A at PP 38-39.

258 *Id.* at P 38.

259 Order No. 688 at P 102.

information. For filings that target Small QFs, the Commission should extend this requirement to include information about the (i) interconnection process, including study requirements and the range and average costs faced by Small QFs, range and average lengths of each stage for Small QFs, range and average costs of the transmission upgrades required for Small QFs to interconnect, and the rules, if any, that apply for determining whether a distribution-connected facility is jurisdictional or not; (ii) eligibility requirements to participate in any energy and capacity markets, including financial assurances; and (iii) the operational requirements to obtain access to the market. As described above, Small QFs face substantial barriers due to these various eligibility and interconnection related requirements, and it is the RTO/ISOs that have ready access to this information, not Small QFs.

While Public Interest Organizations believe that the Commission intends to maintain its existing approach of implementing the rebuttable presumption in the NOPR, the proposal is not terribly clear on the point. Confirmation that the Commission is not departing from its existing practice of implementing the rebuttable presumption will clarify the rule's implementation.

F. The Commission cannot apply section 210(m) to utilities outside of organized RTO/ISOs on the basis of access to a liquid market hub and the utilities use of a Request for Proposal.

The Commission requests comments on whether competitive solicitations coupled with market hubs could satisfy the requirements of section 210(m)(1)(C).[260] They cannot. The Commission lacks the authority to approve such a framework as a wholesale market pursuant to section 210(m)(1)(C).

When Congress amended PURPA in 2005 to allow utilities to request a waiver of the mandatory purchase obligation, it provided for such a waiver only for utilities located in areas in which qualifying facilities have "nondiscriminatory access" to:

- (i) independently administered, auction-based day ahead and real time wholesale markets and (ii) wholesale markets for long-term sales

  of capacity and electric energy; or
- (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

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260 NOPR at P 132.

determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

- wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described above.[261]

There is no statutory authority for FERC to eliminate the mandatory purchase obligation except under the specific criteria outlined in section 210(m)(1)(A)-(C). In adopting Order No. 688 implementing the amendments, the Commission made clear the "most reasonable interpretation of section 210(m)(1) is that Congress, in setting forth discrete tests for three different types of markets, was requiring the Commission to differentiate among these markets, and the differing circumstances they present, in determining whether a utility must be relieved of the mandatory purchase obligation."[262] Moreover, utilities seeking to apply section 210(m) in markets that "have less formalized structures" such as those under section 210(m)(1)(C) will "bear a heavier evidentiary burden to obtain relief."[263]

Competitive solicitations for capacity combined with a market hub for energy do not meet the requirements of section 210(m)(C), because this combination fails to afford the comparable competitive quality to either Day 1 (section 210(m)(1)(B)) or Day 2 (section 210(m)(1)(A)) markets. As a threshold matter, without an independent entity such as an RTO/ISO to manage the interconnection process, it is madness to presume that QFs possess "nondiscriminatory access" to the transmission system. The record is rife with regulated utilities' imposition of discriminatory costs and onerous, unnecessary technical requirements on QFs who seek access to the transmission system; costs and requirements which fundamentally will never apply to regulated utilities because they are in a position to rate-base their transmission costs. Indeed, the sheer lack of any information about the transmission system constraints, level of congestion, and interconnections itself become discriminatory barriers to QFs located in service territories without an independent transmission system operator. While the transmission owner knows precisely where to site its generation to avoid costly upgrades, it withholds this information on a variety of grounds from QFs, which then face discriminatory

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261 16 U.S.C. § 824a-3(m)(1)(A)-(C).

262 Order No. 688 at P 38.

263 *Id.*; *see also Order Denying Application to Terminate Mandatory Purchase Obligation, in re Public Service Company of New Mexico*, 140 FERC ¶ 61,191 at P 29 (Sept. 12, 2012) ("the evidentiary showings required in section 210(m)(1)(C) are higher than the evidentiary showings required in section 210(m)(1)(B)") ("PNM Order").

barriers to siting in the most commercially sensible manner. It is perhaps for this reason that the Commission has concluded that, to the extent a utility seeks to show QFs in its service territory have access to a wholesale market that is of the same competitive quality as a Day 1 market, it must show that the transmission and interconnection services afford the "functional equivalent" of that of a Commission-approved regional transmission entity.[264]

Second, access to a liquid market hub is not of comparable competitive quality for sale of energy to either section 210(m)(1)(A) or (B) markets. Both the provisions to exempt "Day 1" and "Day 2" type markets contain crucial safeguards to ensure a backdrop level of competition and access to multiple buyers, which are not available to a QF simply through access to a liquid market hub. Section 210(m)(1)(A) requires competition to a degree that it compares to "independently administered auction-based day ahead and real time wholesale markets." The Commission has described the level of competition in these markets as, "allow[ing] *all* competing generators to submit bids to participate in the market on a nondiscriminatory basis."[265] In other words, a seller in such a market has confidence that it will be able to sell so long as its energy is the lowest priced offer both in the real time and in a day-ahead timeframe, while also having the ability to enter into long-term energy contracts. Access to a liquid market hub provides nothing like this level of competition. A QF with access to a liquid market hub seeking to sell does not know it will in fact find buyers for its energy when its price is the lowest on any given day, hour or other interval.

Likewise, section 210(m)(1)(B) requires "competitive wholesale markets that provide a meaningful opportunity to sell . . . electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected." A QF selling into a market meeting such qualifications must have actual, not theoretical, opportunity to sell energy to multiple buyers, both in spot markets at real time, but also for short and long-term sales.[266] Accordingly, such a market must "exist on a territory-wide basis," providing access to buyers beyond the utility.[267] Moreover, to show such a "meaningful opportunity to sell" will typically require actual evidence of QF transactions in the market.[268] Liquid market hubs simply do not meet these competitive characteristics.

Finally, a request for proposals, presumably based upon the utility integrated resource plan, is in no way of comparable competitive quality to a Day 1 market

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264 PNM Order at P 34.

265 Order No. 688 at P 38 (emphasis in original).

266 Order No. 688-A at P 38.

267 PNM Order at P 35.

268 Order No. 688-A at P 38.

with respect to long-term capacity and energy sales. To be of comparable quality to a Day 1 market, there must be access to multiple buyers – not just the single utility buyer. Competitive solicitations to meet a single utility's long-term resource planning needs clearly fail in that regard. Further, to be of suitable competitive quality to meet the definition of either Day 1 or Day 2 markets, any such requests for proposals must address the anticompetitive behavior of buyers (favoring affiliates or self-owned generation; gaming requirements in a manner to portray resource needs in a manner that disfavors competitor; etc). As described in the section on competitive solicitations above, substantial safeguards are required to ensure such solicitations, in fact, represent real "markets" that result in long-term capacity and energy sales.

II. The NOPR would erect new administrative barriers to QFs development, hindering QF development and upending PURPA's express purpose.

In addition to injecting significant uncertainty around rates, the NOPR would also erect new administrative barriers to QF development. These include reducing the size threshold for the rebuttable presumption that QFs lack non-discriminatory access to RTO/ISO markets from 20 MW to 1 MW, making it easier for utilities to oppose QF self-certification, diluting the "one-mile rule," and requiring QFs to demonstrate commercial viability before obtaining a legally enforceable obligation (LEO). These changes to the Commission's PURPA regulations would hinder small power production from QFs by imposing unjustifiable new administrative burdens on such facilities, contravening the statute's express purpose of encouraging power production by QFs by removing barriers to their development.

A. Congress intended to encourage QF power generation by removing barriers to QF development.

Statutory language, legislative history, and subsequent rulemakings all show that Congress passed PURPA intending to increase QF power production, including through the removal of barriers to QF development. Section 210 not only charges the Commission with prescribing "such rules as it determines necessary to encourage cogeneration and small power production," it also directs the Commission to exempt QFs from the FPA, the Public Utility Company Holding Act, and/or relevant state laws if it determines that such "exemption is necessary to encourage cogeneration and small power production." [269] Or in the words of the Supreme Court, Congress enacted section 210 of PURPA in 1978 to "encourage the development of cogeneration and small power production facilities."[270] The

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269 16 U.S.C. §§ 824a-3(a), (e).

270 *FERC v. Mississippi*, 456 U.S. 742, 750 (1982).

Mississippi Court's discussion of PURPA's statutory history is worth quoting at length:

> Congress believed that increased use of [small power production and cogeneration] would reduce the demand for traditional fossil fuels. But it also felt that two problems impeded the development of nontraditional generating facilities: (1) traditional electricity utilities were reluctant to purchase power from, and to sell power to, the nontraditional facilities, and (2) the regulation of these alternative energy sources by state and federal utility authorities imposed financial burdens upon the nontraditional facilities and thus discouraged their development.[271]

In light of these problems, Congress directed the Commission to act to remove barriers to QF development, recognizing that existing regulations imposed unreasonable burdens for such facilities.[272]

Removing barriers to QF development has thus been central to PURPA's regulatory scheme since the statute was passed in 1978. This principle has guided many of the Commission's subsequent rulemakings. Among other things, Order No. 69 implemented PURPA section 210(e) by exempting QFs from certain provisions of the FPA, all of the Public Utility Holding Company Act relating to electric utilities, and from state laws regulating electric utility rates and financial organization.[273] More recently, in 2010 the Commission issued Order No. 732, which included a number of changes to reduce administrative burdens on QFs applying for self-certification—such as exempting "generating facilities with net power production capacities of 1 MW or less from the requirement that a generating facility, to be a QF, must file either a notice of self-certification or an application for Commission certification" and the "elimination of the requirement for applicants to provide a

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271 *Id.* at 750-51, *citing* 123 Cong. Rec. 25848 (1977) (remarks of Sen. Percy); *id.*, at 32403 (remarks of Sen. Durkin); *id.*, at 32437 (remarks of Sen. Haskell); *id.*, at 32419 (remarks of Sen. Hart); Nat'l Energy Act: Hearings on H.R. 6831 et al. before the Subcommittee on Energy and Power of the House Committee on Interstate and Foreign Commerce, 95th Cong., 1st Sess., 552–553 (1977); H.R. Conf. Rep. No. 95–1750, at 98 (1978); H.R. Rep. No. 95–496, pt. 4, at 157 (1977); 123 Cong. Rec. 32399 (1977) (remarks of Sen. Cranston); *id.*, at 32660 (remarks of Sen. Percy).

272 *See, e.g.*, H.R. Conf. Rep. No. 95–1750, at 98 (1978) ("Conferees do not intend cogenerators or small power producers to be subject, under the Commission's rules, to utility-type regulation").

273 45 Fed. Reg. at 12,215.

draft notice suitable for publication in the Federal Register."[274] In short, Congress passed PURPA intending to encourage QF power generation by removing barriers to QF development, and the Commission's regulations implementing the statute reflect this intent.

In stark contrast to PURPA's statutory language, legislative intent, and regulatory history, the Commission now proposes a suite of unjustified new administrative barriers for new and existing QFs.

B. Shifting the burden to QFs to prove their lack of access to wholesale buyers imposes an onerous burden on QFs

The Commission's proposal to lower the threshold for the rebuttable presumption that QFs lack non-discriminatory access to RTO/ISO markets from 20MW to 1MW for small power production facilities defies PURPA's mandate to remove barriers to QF development. As an initial matter, the Commission fails to support its assertion that all QFs between 1 – 20MWs "can acquire the administrative and technical expertise necessary to obtain nondiscriminatory access to a market."[275] Indeed, as described in section IV, numerous barriers continue to significantly impede access and impact development of QFs smaller than 20MWs in RTO markets. These difficulties are reflected in the fact that the Commission did not grant a utility's application to terminate an obligation to purchase from a small (under 20MW) QF under section 210(m)—rebutting the presumption that such facilities lack non-discriminatory access to RTO markets—until 2013.[276]

To overcome the rebuttable presumption currently in effect, "Order No. 688 placed the burden of proof on the electric utility to demonstrate that a small QF has nondiscriminatory access to the markets of which the electric utility is a member," requiring that such "an application for relief must be fully supported by documentation upon which it can make the required finding."[277] Few utilities have been able to muster evidence sufficient to overcome the rebuttable presumption. In the rare cases the Commission has allowed a utility to terminate its must-purchase

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274 *Revisions to Form, Procedures, & Criteria for Certification of Qualifying Facility Status for A Small Power Prod. or Cogeneration Facility*, 130 FERC ¶ 61214 at P 3 (Mar. 19, 2010).

275 NOPR at P 127.

276 *City of Burlington, Vermont*, 145 FERC ¶ 61121 at P 37 (Nov. 13, 2013); s*ee also PPL Elec. Utilities Corp.*, 145 FERC ¶ 61053 at P 4 (Oct. 17, 2013) (noting just one month before the *City of Burlington* order, "To date, the Commission has not granted any utility relief from the mandatory purchase obligation for a QF that is 20 MW or smaller.").

277 *PPL Elec. Utilities Corp.*, 145 FERC ¶ 61053 at P 4.

obligation for a small QF under section 210(m), it has generally relied on showings that the QF had in fact already sold power to the relevant wholesale market.[278]

It is unclear how small QFs greater than 1 MW would be able to rebut the presumption that they have non-discriminatory access RTO/ISO markets. The NOPR notes, "like QFs over 20 MW today, small power production facilities over 1 MW would be able to rebut the presumption of access due to operational characteristics or transmission constraints."[279] Yet the Commission's orders since section 210(m) was added to PURPA provide only *one* readily ascertainable example of a QF greater than 20 MW successfully rebutting this presumption[280]: *N.Y. State Elec. & Gas Corp.*, 130 FERC ¶ 61,216 (2010) (*"NYSEG"*). In *NYSEG*, the Commission found that a cogeneration facility owned and operated by Cornell University lacked nondiscriminatory access due to its very unusual operating characteristics—it supplied heat to the university campus, resulting in highly variable need for its thermal output that made it incompatible with "how NYISO's markets operate."[281] The dearth of precedent for QFs demonstrating lack of nondiscriminatory access to RTO/ISO markets beyond this single case involving a sui generis cogeneration facility suggests that vanishingly few small power production QFs of less than 20MW but greater than 1MW that will be able to surmount the high bar the Commission has set for them.

Where shifting the burden of proof to QFs functions only to stymie QF development, it is inconsistent with PURPA. The fact that this presumption is "rebuttable" is of little value to small QFs that lack nondiscriminatory access. To rebut the presumption, a QF is put in the impossible position of having to access detailed, specific information about the conditions of the market (such as the existence of transmission constraints) or how its unusual operating characteristics affecting its ability to participate in markets, and then presenting sufficient evidence about an unfamiliar RTO/ISO interconnection process to demonstrate that its access is limited. This administrative burden—including concomitant legal and

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278 *See City of Burlington, Vermont*, 145 FERC ¶ 61121 at P 32 ("Burlington relies on the fact that VEPPI was able to resell energy from Chace Mill in the ISO-NE markets."); *Fitchburg Gas & Elec. Light Co.*, 146 FERC ¶ 61186 at P 33 (Mar. 14, 2014) ("Pinetree does not dispute that energy from Pinetree was sold into the ISO-NE markets subsequent to the expiration of its power purchase agreement.").

279 NOPR at P 129.

280 *See Entergy Servs., Inc. Entergy Arkansas, Inc.*, 154 FERC ¶ 61035 at P 79 (Jan. 21, 2016) ("To date, the Commission has found only once that a QF had rebutted the presumption of nondiscriminatory access to the markets due to operational characteristics.").

281 *NYSEG*, 130 FERC ¶ 61,216 at P 21.

transaction costs—will fall more heavily on QFs less than 20MW compared to QFs greater than 20 MW. The need to overcome the presumption itself will become an insurmountable barrier to QF development for many. This result is plainly contrary to PURPA's mandate to encourage QF generation.

C. The NOPR invites a flood of new challenges to QF certification.

The NOPR proposes changes to facilitate challenges to QF self-certification. Current regulations allow a party to challenge a QF's self-certification through a petition for declaratory order, and the Commission may also revoke self-certification sua sponte.[282] Noting that the filing fee for a declaratory petition presents a "burden" to potential objectors, the Commission proposes to allow third parties to intervene and challenge a QF's self-certification without filing a separate petition.[283] While this provision removes the "burden" of filing a petition from utilities or competitors wishing to challenge a self-certification, it imposes a new burden on QFs to defend their self-certification. Frivolous challenges are all but inevitable. QFs will have to defend their qualification from any entity that can raise a prima facie challenge under this proposal, leading to increased legal fees. There is no indication that ineligible facilities are abusing QF self-certification under the current system, which already empowers the Commission to revoke self-certification on its own motion. The Commission's solicitousness towards those who would challenge self-certification comes at the expense of the very facilities PURPA has charged the Commission with encouraging.

Similarly, the NOPR's proposal to dilute the "one-mile rule" will subject QF developers to increased uncertainty and additional legal fees. Under current PURPA regulations, the "one-mile rule" provides a clear test for determining whether separate generation facilities under common ownership should be considered a single facility for the purpose of QF eligibility: facilities within one mile of each other are deemed a single facility "at the same site" and facilities more than a mile apart are not.[284] Under the NOPR, facilities within one mile of each other would still be irrefutably considered the same facility, but facilities within one and ten miles apart would now have a *rebuttable* presumption that they are not the same facility.[285] The purpose of this change is to allow utilities or others to challenge QF certification for facilities within this range.[286] The Commission states

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282 18 C.F.R. § 292.207(d).

283 NOPR at P 148.

284 *N. Laramie Range Alliance,* 139 FERC ¶ 61,190 at PP 22-24 (June 8, 2012); 18 C.F.R. § 292.204(a).

285 NOPR at PP 101-102. Facilities more than ten miles apart would be irrebuttably considered separate. *Id.*

286 *Id.* at P 102.

that it would examine a plethora of physical and ownership characteristics to determine whether two facilities between one and ten miles apart are the same facility, noting that "no single factor would be dispositive."[287] Forcing QFs to defend their separateness according to an indefinite standard adds an additional layer of uncertainty and legal cost for such facilities.

D. Requiring a finding of commercial viability prior to vesting of a legally enforceable obligation creates a substantial barrier to QF development.

Finally, the Commission's proposal to require a finding of commercial viability as a condition precedent to a QF obtaining a legally enforceable obligation ("LEO") further undermines PURPA's intent to promote QF development.

The LEO is a backstop to prevent utilities from circumventing their must purchase obligation through delay tactics and other forms of bad faith negotiations.[288] The proposed changes undermine this important tool because requiring commercial viability as a condition precedent to a LEO will significantly hinder QFs' ability to obtain a LEO at all. To show commercial viability, a QF must be able to obtain financing, which requires some assurances of future revenue—typically in the form of a LEO or a PPA. Yet QFs will be unable to obtain a LEO without demonstrating commercial viability first. Many QFs will thus be caught in a Catch 22: they cannot obtain financing unless they obtain a LEO, but they cannot obtain a LEO until they obtain financing. Put another way, the Commission's proposal to require QFs to demonstrate commercial viability in order to obtain a LEO will prevent many QFs from ever attaining commercial viability at all. Creating a new administrative obstacle to QF financing in this way flies in the face of PURPA's mandate to reduce barriers to QF development.

Imposing a nationwide requirement of commercial viability undoes Commission precedent holding that PURPA delegates to States—and not the Commission—the role of determining when a LEO arises under PURPA.[289] "For purposes of our regulations, the critical date is the date on which a legally enforceable obligation is incurred, and choosing that date for a specific QF *is* the responsibility of the States, not of this Commission" (emphasis added).[290] The Commission offered no reasoned explanation for its proposal to limit State authority

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287 *Id.* at P 105.

288 *See id.* at P 137.

289 *See, e.g.*, *W. Penn Power Co.*, 71 FERC ¶ 61153, 61496 (May 8, 1995)

290 *Id.*; Order No. 688 at P 212 ("When a utility refuses to enter into a contract with a QF and the QF seeks state regulatory authority help to enforce its PURPA regulations, a non-contractual legally enforceable obligation may be created *pursuant to the state's implementation of PURPA.*") (emphasis added).

under PURPA, and such a reasoned explanation is necessary to support reversing prior Commission precedent.

Taken together, lowering the rebuttable presumption for small power provider QFs in section 210(m) markets, enabling challenges to QF self-certification, diluting the one-mile rule, and requiring a demonstration of commercial viability as a condition precedent for obtaining a LEO will increase the administrative burdens QF developers face. Increased legal expenses and regulatory uncertainty will follow, hindering QF development. Given that PURPA charges the Commission with promulgating regulations to encourage QF development and reduce regulatory barriers, this result is plainly contrary to the statute.

CONCLUSION

For the foregoing reasons, Public Interest Organizations respectfully request that the Commission reject the NOPR.

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