UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Qualifying Facility Rates and Requirements	**Docket No. RM19-15-000**
Implementation Issues Under the Public Utility Regulatory Policies Act of 1978	**Docket No. AD16-16-000**

COMMENTS OF THE SOUTHERN ENVIRONMENTAL LAW CENTER, NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION, ALABAMA INTERFAITH POWER & LIGHT, ALABAMA SOLAR INDUSTRY ASSOCIATION, INC., APPALACHIAN VOICES, ENERGY ALABAMA, GEORGIA INTERFAITH POWER & LIGHT, GEORGIA SOLAR ENERGY ASSOCIATION, GREATER-BIRMINGHAM ALLIANCE TO STOP POLLUTION, NORTH CAROLINA CHAPTER OF THE SIERRA CLUB, NORTH CAROLINA INTERFAITH POWER & LIGHT, NORTH CAROLINA JUSTICE CENTER, SOUTH CAROLINA COASTAL CONSERVATION LEAGUE, SOUTH CAROLINA INTERFAITH POWER & LIGHT, SOUTHERN ALLIANCE FOR CLEAN ENERGY, SOUTHFACE INSTITUTE, TENNESSEE INTERFAITH POWER & LIGHT, UPSTATE FOREVER, AND VOTE SOLAR

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The Southern Environmental Law Center ("SELC"), North Carolina Sustainable Energy Association ("NCSEA"), Alabama Interfaith Power & Light, Alabama Solar Industry Association, Inc., Appalachian Voices, Energy Alabama, Georgia Interfaith Power & Light, Georgia Solar Energy Association, Greater-Birmingham Alliance to Stop Pollution ("Gasp"), North Carolina Chapter of the Sierra Club, North Carolina Interfaith Power & Light, North Carolina Justice Center, South Carolina Coastal Conservation League, South Carolina Interfaith Power & Light, Southern Alliance for Clean Energy, Southface Institute, Tennessee Interfaith Power & Light, Upstate Forever, and Vote Solar (collectively, "Southeast Public Interest Organizations") offer the comments below based on our regional perspective, to emphasize the continued significance of the Public Utility Regulatory Policies Act of 1978 ("PURPA") and its implementation in the Southeast to achieve the Congressional goal to support the development of small power production facilities. These organizations work extensively on issues concerning energy resources and their impact on the people, culture, environment and economy across six Southeastern states—Virginia, North Carolina, South Carolina, Georgia, Alabama, and Tennessee. Several of the public interest organizations, including SELC and NCSEA have been actively involved in Docket No. AD16-16-000 and submitted several comments as part of the technical conference and other requests for comment.[1] In these comments, we respond to the Federal Energy Regulatory Commission's ("FERC" or the "Commission") notice of proposed

[1] *See*, *e.g.*, Supplemental Comments of the Southern Environmental Law Center, Environmental Law and Policy Center, Vote Solar, Pace Energy and Climate Center, North Carolina Sustainable Energy Association, Climate + Energy Project, Center for Biological Diversity and Sierra Club, Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, Docket No. AD16-16-000, FERC (Oct. 17, 2018) [hereinafter "SELC et al. Oct. 2018 Supplemental Comments to FERC"]; Comments of the Southern Environmental Law Center, Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, Docket No. AD16-16-000, FERC (June 21, 2016); Comments of the Southern Environmental Law Center, Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, Docket No. AD16-16-000, FERC (Nov. 7, 2016).

rulemaking ("NOPR").[2] Specifically, we submit these comments opposing the proposed changes due to their conflict with the congressional intent behind PURPA and the statutory language, and due to the expected adverse impacts of the proposal on the development of renewable energy resources in the Southeast. We thank the Commission for the opportunity to submit comments.

Introduction

Congress enacted PURPA in 1978 to encourage the development of small power production and cogeneration facilities (collectively "qualifying facilities" or "QFs") and reduce reliance on fossil fuels.[3] Congress directed the Commission to prescribe rules to achieve this statutory directive.[4] Congress amended PURPA in 2005, allowing utilities to request a waiver of their mandatory purchase obligation in areas of the country where QFs have nondiscriminatory access to certain markets to sell energy and capacity. However, Congress left intact its primary PURPA mandate to reduce reliance on fossil fuels and encourage the development of QFs, particularly where QFs lack access to nondiscriminatory competitive markets.[5]

Forty years after PURPA was signed into law, it continues to play an important role in encouraging development of QFs. In many states, PURPA is the only legal tool available to support the development of independent power producers that promote energy independence, reduce reliance on fossil fuel generation, support competition with monopoly utilities, and provide low-cost renewable energy to ratepayers.

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[2] Qualifying Facility Rates and Requirements; Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, 84 Fed. Reg. 53,246 (proposed Oct. 4, 2019) (to be codified at 18 C.F.R. pts. 292 and 375) [hereinafter "NOPR"].

[3] *FERC v. Mississippi*, 456 U.S. 742, 750 (1982); *Amer. Paper Instit., Inc. v. American Elec. Power Serv. Corp*, 461 U.S. 402, 417 (1983).

[4] 116 U.S.C. § 824a-3(a); *FERC v. Mississippi*, 456 U.S. at 750.

[5] Energy Policy Act of 2005, 16 U.S.C. § 824a-3(m).

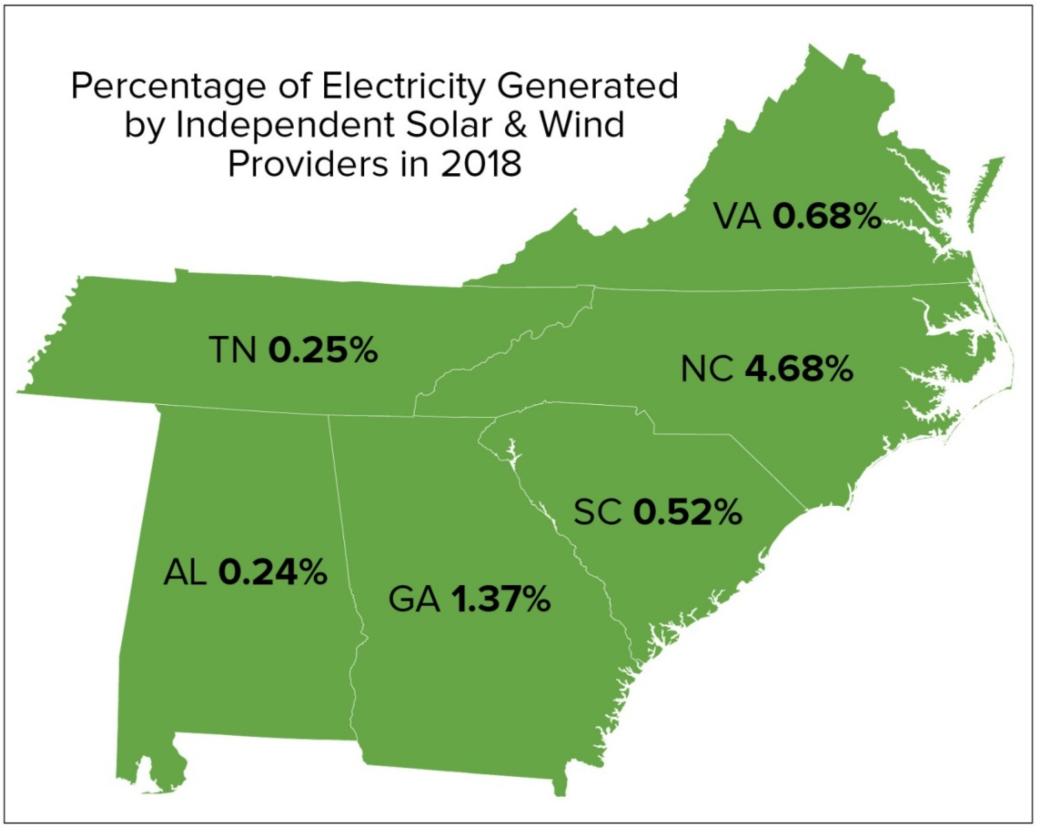
Contrary to arguments raised in the NOPR, [6] the same problems Congress enacted PURPA to remedy still exist in many states—especially in the Southeast. Many states and utilities in this region have failed to implement PURPA in a manner consistent with the congressional intent to encourage the development of QFs. While some utilities may claim that all QFs have nondiscriminatory access to markets, these claims ignore persistent barriers that discourage the development of QFs and frustrate Congress's intent in enacting and maintaining PURPA. In states without independent system operators ("ISOs") or regional transmission organizations ("RTOs"), QFs lack open, nondiscriminatory markets in which to sell their energy and capacity.[7] Throughout the Southeast vertically integrated monopoly utilities dominate the wholesale electric market and use their market power to shut out independent power producers.[8] Furthermore, states in the Southeast have not initiated efforts to promote carbon reduction by joining the Regional Greenhouse Gas Initiative ("RGGI") and only North Carolina has a mandatory renewable energy and energy efficiency portfolio standard.[9] As a result, state-initiated efforts have *not* influenced increasing investment in renewables in the same way they may have in other parts of the country.[10] PURPA is one of the only legal tools in this region to create any

[6] NOPR, *supra* note 2, at ¶¶ 19-32.
[7] Virginia and a portion of eastern North Carolina participate in PJM Interconnection, L.L.C. ("PJM"). All of the other states in our region do not have ISOs or RTOs.
[8] Vertically integrated utilities exist in all six Southeastern states—Virginia, North Carolina, South Carolina, Tennessee, Georgia and Alabama. As a result, the argument that "vertically integrated utilities no longer dominate the wholesale electric markets throughout the United States as they did in the past, and the participation of independently owned generation no longer is the exception but is the rule in much of the country" does not apply to the Southeast. NOPR, *supra* note 2, at ¶ 29.
[9] Galen Barbose, *U.S. Renewable Portfolio Standards 2018 Annual Status Report*, LAWRENCE BERKELEY NAT'L LABORATORY, 6 (Nov. 2018), http://eta-publications.lbl.gov/sites/default/files/2018_annual_rps_summary_report.pdf; *see* Robert Walton, *Virginia Entry to Regional GHG Initiative Blocked as Governor Declines to Veto Budget Language*, UTILITY DIVE (Apr. 23, 2019, updated May 3, 2019), https://www.utilitydive.com/news/virginia-entry-to-regional-ghg-initiative-blocked-as-governor-declines-to-v/553173/ (despite efforts to join, to date Virginia has not successfully joined RGGI).
[10] *See* NOPR, *supra* note 2, at ¶ 23 ("Another development pursued by regions (such as the Regional Greenhouse Gas Initiative) or states (like California and New York) has been state-initiated efforts to promote carbon reduction and through [renewable portfolio standard] programs require electric utilities to supply a specified percentage of their customers' loads from renewable resources or through the establishment of requirements to purchase renewable energy certificates (RECs).").

semblance of competition with vertically integrated monopoly utilities and to provide a market for power from QFs.

As a result of inadequate PURPA implementation and prohibitively high barriers to entry, independently produced renewable energy still represents only a small percentage of electricity generation across the Southeast. For example, in five of the six states shown in Figure 1 below, less than two percent of the total megawatt hours ("MWh") of electricity generation in 2018 was provided by independent solar and wind providers.[11]

Figure 1. Percentage of Electricity Generated by Independent Solar & Wind Providers in 2018



[11] *1990-2018 Net Generation by State by Type of Producer by Energy Source (EIA-906, EIA-920, and EIA-923)*, U.S. ENERGY INFO. ADMIN.: ELECTRICITY (Release Date: Oct. 22, 2019), https://www.eia.gov/electricity/data/state/. EIA data similarly shows relatively low percentages of total generation capacity in megawatts ("MW") for solar and wind QF facilities in the Southeast: Virginia: 1%, North Carolina: 10.5%, South Carolina: 1.4%, Georgia: 2.2%, Alabama: 0.6%, Tennessee: 0.8%. Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B), U.S. ENERGY INFO. ADMIN.: ELECTRICITY (Release Date: Sept. 3, 2019), https://www.eia.gov/electricity/data/eia860/.

While independent solar and wind providers, including QFs, continue to face prohibitively high barriers to entry, vertically integrated utilities in the South continue to burn fossil fuels and make the type of costly resource decisions that led Congress to enact PURPA in the first place. Massive utility-owned generation investments continue to make retail customers pay for billions of dollars of cost overruns, and in some cases, payment for facilities that will never achieve commercial operation. For example:

- Georgia Power's Vogtle nuclear plant is projected to cost over $27 billion, more than double its initial estimate, and is more than five years behind schedule;[12]
- In Virginia, Dominion's Atlantic Coast Pipeline project for natural gas is projected to cost between $7 and $7.5 billion, $1 billion more than its initial estimate, and is more than two years behind schedule;[13]
- In South Carolina, SCANA and Santee Cooper spent $9 billion for the partial construction of the V.C. Summer nuclear plant before cancelling construction, saddling ratepayers with the expense of a plant that will never generate a single kilowatt-hour;[14]
- In North and South Carolina, Duke Energy spent $541 million on the Lee Nuclear Station before cancelling construction of the plant.[15]
- In Mississippi, Southern Company spent $7.5 billion on the failed Kemper County coal gasification plant. The project is now under investigation from federal authorities.[16]

[12] *See* Darrell Proctor, *Georgia PSC Backs Additional Costs for Vogtle Nuclear Project*, POWER, Feb. 19, 2019, (Magazine), https://www.powermag.com/georgia-psc-backs-additional-costs-for-vogtle-nuclear-project/.

[13] REUTERS, *Dominion delays U.S. Atlantic Coast natgas pipe, boosts costs* (Feb. 1, 2019), https://www.reuters.com/article/us-dominion-us-pipeline-natgas/dominion-delays-u-s-atlantic-coast-natgas-pipe-boosts-costs-idUSKCN1PQ55W.

[14] *See* Mengqi Sun, *The $4.7 Billion Nuclear Bill That No One Wants to Pay*, WALL STREET JOURNAL (Aug. 25, 2018), https://www.wsj.com/articles/the-4-7-billion-nuclear-bill-that-no-one-wants-to-pay-1535194801.

[15] *See* John Downey, *Duke Energy Abandons Plans to Build the Lee Nuclear Station*, CHARLOTTE BUSINESS JOURNAL (Aug. 25, 2017, 10:37 AM), https://www.bizjournals.com/charlotte/news/2017/08/25/duke-energy-abandons-plans-to-build-the-lee.html.

[16] Giacomo Bologna, *Ex-Kemper Plant Manager Says Execs Ignored Her Warnings: 'It Was Essentially a Cover-Up'*, CLARION LEDGER (May 10, 2019, 3:00 AM), https://www.clarionledger.com/story/news/politics/2019/05/10/kemper-power-plant-ex-manager-calls-cover-up/1127749001/.

In the timeframe that the incumbent utilities developed these projects and passed on enormous costs to ratepayers, more modest and cost-effective PURPA QFs were hampered by inadequate state implementation of PURPA. North Carolina provides an exception, and has seen the most successful PURPA implementation in the Southeast due to a period of just and reasonable standard offer contract lengths, rates, and size thresholds. But in the Southeast's other states, the policy that Congress intended to promote through the enactment of PURPA is still yet to be achieved.[17] In fact, the Southeast is rife with examples of how FERC's proposals in this NOPR will further discourage QF development, contrary to PURPA. Although Georgia has begun to develop more solar capacity in recent years, the use of PURPA to facilitate this development has been limited.[18] In South Carolina, recent state legislation has the potential to bring more QFs online, but recent decisions by the South Carolina Public Service Commission implementing the new law seem likely to shut down rather than encourage QF development.[19] Despite Virginia being a member of an RTO, there has not been much renewable energy development by independent power producers through PURPA, most likely due to the low compensation for avoided energy benefits based on a methodology using Locational Marginal Price ("LMP").[20] Furthermore, FERC has exempted Virginia utilities within PJM from

[17] Southeast states have the following installed solar capacity: NC: 5,601.3 MW; GA: 1,571.35 MW; TN: 429.4 MW; VA: 802.75 MW; SC: 830.59 MW; AL: 282.8 MW. Solar Energy Industry Association, *Solar State by State* (2019), https://www.seia.org/states-map (select each state individually to see installed capacity; up to date as of Q2 2019).

[18] Georgia Power's Resp. to STF-PIA-7-24, Ga. Pub. Serv. Comm'n, Docket No. 42,515 (Sept. 13, 2019), https://psc.ga.gov/search/facts-document/?documentId=178360.

[19] *See, e.g.*, S.C. Public Service Commission, Directives, Docket Nos. 2019-184-E (Nov. 15, 2019), 2019-185-E, and 2019-186-E (approving decreases in the avoided cost rates paid by Dominion Energy and Duke Energy in South Carolina and limiting solar contracts to ten years); Robert Walton, *For South Carolina Solar, 'Things Look Bleak,' Advocates Warn, as Utilities Defend Lower Rates*, UTILITY DIVE (Nov. 25, 2019), https://www.utilitydive.com/news/for-south-carolina-solar-things-look-bleak-advocates-warn-as-utilities/567847/ ("South Carolina will now offer the lowest avoided cost rates for Public Utilities Regulatory Policy Act (PURPA) contracts in the nation… .").

[20] *See* Va. Elec. & Power Co., Schedule 19: Power Purchases from Cogeneration and Small Power Production Qualifying Facilities (filed on Mar. 15, 2019), https://www.dominionenergy.com/library/domcom/media/home-and-small-business/rates-and-regulation/residential-business-rates-shared/virginia/entire-filed-tariff.pdf?la=en

mandatory purchase obligations for QFs with a net capacity greater than 20 MW under the rebuttable presumption that QFs of this size have "non-discriminatory access" to PJM pursuant to 210(m)(1)(A).[21] The Tennessee Valley Authority's ("TVA") avoided cost program, which applies to almost all of Tennessee, offers (1) a miniscule avoided cost rate—subject to change monthly and determined by TVA rather than a state regulatory authority—that fails to accurately compensate solar generation for marginal avoided energy benefits or any other avoided cost components; and (2) onerous contractual terms that further suppress solar growth in the Valley.[22] As a result, only a small number of QFs sell power to TVA through this program.[23] In Alabama, short term contracts, variable pricing, a lack of avoided capacity rates, and other barriers have stymied QF development.[24]

Despite lackluster PURPA QF development in the past, the Southeast has enormous potential and many projects in queue for QF status and operation, if PURPA implementation is reasonably enforced at the federal and state level. In fact, in South Carolina and North Carolina, there are significant amounts of QFs under development. As of 2019, South Carolina has a reported 6,900 MW and North Carolina has 5,300 MW of QF capacity at some stage of

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("Purchase payments for the supply of energy by the QF to the Company will be based on an hourly energy purchase price (cents per kWh) that is calculated using the hourly $/MWh PJM Interconnection, LLC (PJM) Dom Zone Day Ahead Locational Marginal Price (DA LMP).").

[21] New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities, 71 Fed. Reg. 64,342 (proposed Oct. 20, 2006) (to be codified at 18 C.F.R. pt. 292); Xcel Energy Services Inc., Request for Reconsideration of Declaratory Order, FERC, Docket No. EL12-80-001, at 13, note 23 (Sept. 27, 2012) (stating that Virginia is one of the states in PJM that has set avoided costs at LMP); Va. Elec. & Power Co., *supra* note 20.

[22] Southern Environmental Law Center et al., Comments to Tennessee Valley Authority regarding Changes to Green Power Providers Program Draft Environmental Assessment (Nov. 8, 2019) at 2, 10, 12-13, https://www.southernenvironment.org/uploads/words_docs/2019_11_08_SELC_et_al_comments_on_TVAs_changes_to_the_GPP_program_draft....pdf.

[23] List of DPP Participants as of July 2018, obtained by SELC via Freedom of Information Act Request to the Tennessee Valley Authority.

[24] *See* Alabama Power, Rate Rider RGB (Jan. 10, 2013), https://www.alabamapower.com/content/dam/alabamapower/Rates/RGB.pdf; Proposed Modifications to Rate Rider RGB, *In re: Rate Rider RGB*, Ala. Pub. Serv. Comm'n., Docket No. U-4226 (June 15, 2019); Errata and Substitutes to the Direct Testimony, Reply Testimony, and Exhibits of Ala. Power Co., *In re: Rate Rider RGB*, Ala. Pub. Serv. Comm'n., Docket No. U-4226 (Nov. 15, 2019).

development, the majority of which is from solar projects.[25] In addition, Georgia and Alabama each have over 500 MW of QF capacity under development, the majority of which is also from solar projects.[26] Unfortunately, the NOPR as proposed will undermine this enormous potential. In particular, the NOPR's imposition of unfinanceable rates, terms, and conditions is expected to force independent power producers to abandon a significant number of pending QFs that would otherwise assist in fulfilling PURPA's intent.[27]

Monopoly utilities often characterize PURPA as an outdated statute that must be "modernized." These arguments for PURPA "reform" often overlook the majority of states that have failed to successfully implement PURPA to date and in which utilities fiercely defend their monopoly status and fight to stifle competition. Utilities also exaggerate opportunities for QFs to access existing wholesale markets, and ignore the benefits that ratepayers receive from QF development and from increased competition. There may be a time in the future when substantial competitive electricity markets have been developed in the Southeast that fulfill the Congressional policy goals that PURPA was intended to address. However, those conditions are far from existence today. In short, PURPA regulations need to be strengthened and protected in order to ensure states properly implement PURPA, consistent with Congress's policy goals embodied in PURPA and with PURPA's ongoing directive that the Commission encourage the development of QFs. Instead, what FERC has proposed in the NOPR would gut the heart of PURPA implementation where it is needed most.

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[25] Metin Celebi, Principal, Brattle Group, Address at Electric Utilities Consultant, Inc. Symposium: PURPA Resurgence and Avoided Costs (Sept. 9, 2019), https://brattlefiles.blob.core.windows.net/files/17081_purpa_resurgence_and_avoided_costs.pdf.

[26] *Id*.

[27] *See, e.g.*, Jeff St. John, *FERC Proposal Brings New Threat to Already-Suffering PURPA Solar Market*, GREENTECH MEDIA (Sept. 23, 2019), https://www.greentechmedia.com/articles/read/ferc-proposal-could-gut-already-suffering-purpa-solar-markets; Catherine Morehouse, *FERC Proposal Would 'Gut'PURPA, Could Lower Rates Utilities Pay to Solar Developers*, UTILITY DIVE (Oct. 8, 2019, 8:11 A.M.), https://www.utilitydive.com/news/FERC-PURPA-changes-solar-competition-market-flexibility-Chatterjee/563369/.

The following sections describe FERC's proposed changes to PURPA implementation and, in response, how each of these proposed changes would adversely impact QF development in the Southeast.

I. Abandoning Fixed Energy Rates Will Discourage Small Power Production from Renewable Energy QFs

The NOPR includes a proposal to change the long-standing rule that QFs may elect to sell their power pursuant to fixed long-term avoided energy and capacity rates, determined at the time the QF establishes a legally enforceable obligation.[28] In particular, the proposed rule would permit states to allow variable energy rates over the length of a QF contract.[29] The proposal to allow variable energy rates is a direct reversal of FERC precedent,[30] and it will undeniably discourage QF generation in contravention of Congressional intent. As discussed in comments submitted by SELC and other public interest organizations in the AD16-16 docket, "a qualifying facility's ability to choose whether to sell its output as-available or pursuant to a LEO, including the ability to enter into long-term fixed contract, is a foundational policy supporting qualifying facility development."[31] In particular, the long-term fixed rates are "necessary for QFs to be able to attract project financing."[32]

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[28] NOPR, *supra* note 2, at ¶ 66.

[29] *Id.*

[30] In FERC Order 69 and the *J.D. Wind* Orders, FERC made clear that a LEO must provide QFs a fixed long-term contract with the rates established at the time the LEO is created. *J.D. Wind, LLC*, 129 FERC ¶ 61,148, at ¶ 10 (2009), *reh'g denied*, 130 FERC ¶ 61,127 (2010). FERC emphasized that a QF that sells output under a LEO is entitled to a rate that is "determined at the time the obligation is incurred, even if the avoided costs at the time of delivery ultimately differ from those calculated at the time the obligation is originally incurred." *Id.* FERC's recent *Windham Solar* order further defines QF rights and utility responsibilities under PURPA. In *Windham Solar* FERC held that "a legally enforceable obligation should be long enough to allow QFs reasonable opportunities to attract capital from potential investors." *Windham Solar LLC*, 157 FERC ¶ 61,134, at ¶ 5.

[31] SELC et al. Oct. 2018 Supplemental Comments to FERC, *supra* note 1, at 18; *see also* Direct Testimony of Rebecca Chilton, S.C. Pub. Serv. Comm'n, Docket No. 2019-184-E, at 5-6 (Sept. 23, 2019), https://dms.psc.sc.gov/Attachments/Matter/74eb2db9-2b8a-4842-a692-ef5eea7a7ca3 (describing the importance of projected QF revenues for financing); Direct Testimony of Carson Harkrader, N.C. Utilities Comm'n, Docket No. E-100 Sub 148, at 15 (Mar. 28, 2017) (explaining that PPAs for less than 15-year durations "would have a much smaller pool of potential debt and equity investors" and that varying an avoided energy rate every two years during a contract term would likely have the same effect, especially for smaller QFs),

Congressional intent behind Section 210 of PURPA is clear: to encourage QF development.[33] Variable energy rates do not encourage QF development, particularly in states that lack competitive wholesale markets or other forms of competition with monopoly utilities. Disparate PURPA implementation in the Southeast makes this plain. In states where PURPA implementation has involved long-term, fixed energy and capacity rates, QF development has occurred. In states with variable energy and/or capacity payments, QF development has been virtually non-existent. These facts are undeniable, yet the Commission has proposed rules based on an alternative scenario in which QFs are somehow able to obtain financing without assured revenues.

In North Carolina, the Utilities Commission historically approved standard offer contracts of 15-year durations for projects of 5 MW or less, with energy and capacity rates both *fixed* at the time of the LEO.[34] This unquestionably encouraged QF development, meeting the Congressional intent of Section 210 of PURPA. North Carolina has been widely cited as first in the nation for solar QF development, and most of the state's solar power deployment has been pursuant to PURPA.[35] Only once this significant solar QF development occurred did the N.C.

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https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=5d120413-facf-4c4b-9fba-00645bfcd4b1; Direct Testimony of Kurt G. Strunk, N.C. Utilities Comm'n, Docket No. E-100 Sub 148, at 11 (Mar. 28, 2017), https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=b6449036-9361-4793-b87f-22bb131876f7 ("Lenders typically rely upon fixed pricing for assurance that the project will be in a position to service its debt.").

[32] SELC et al. Oct. 2018 Supplemental Comments to FERC, *supra* note 1, at 18-19.

[33] 16 U.S.C. § 824a-3(a) (FERC shall prescribe rules to "encourage cogeneration and small power production, and to encourage geothermal small power production facilities at not more than 80 megawatts capacity"); *FERC v. Mississippi*, 456 U.S. 742, 750 (1982) ("Congress believed that increased use of these sources of energy would reduce the demand for traditional fossil fuels" and it recognized that electric utilities had traditionally been "reluctant to purchase power from, and to sell power to, the nontraditional facilities."); *Amer. Paper Instit., Inc. v. American Elec. Power Serv. Corp*, 461 U.S. 402, 405 (1983) ("Section 210 of PURPA was designed to encourage the development of cogeneration and small power production facilities.").

[34] The Commission reduced the standard offer size to 1 MW and length to 10 years following enactment of legislation commonly known as "HB 589." N.C. Utilities Comm'n, Order Establishing Standard Offer Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 148 (Oct. 11, 2017).

[35] *See North Carolina Has More PURPA-Qualifying Solar Facilities Than Any Other State*, U.S. ENERGY INFO. ADMIN.: TODAY IN ENERGY (Aug. 23, 2015), https:// eia.gov/todayinenergy/detail.php?id=27632.

General Assembly and N.C. Utilities Commission, with the support of the QF community, shift gears to drive more solar deployment through a competitive bidding process.[36]

With the passage of the South Carolina Energy Freedom Act earlier this year, South Carolina is making a push to follow in North Carolina's footsteps,[37] but the proposed changes in the NOPR will undermine this effort. In recent years, Dominion Energy South Carolina ("DESC", formerly South Carolina Electric & Gas Co.) offered 15-year standard offer contracts for projects up to 80 MW in size, with the avoided cost values fixed at the time the LEO was incurred. The fixed energy rate and capacity rate encouraged solar QF development, leading the utility to sign interconnection agreements or power purchase agreements ("PPA"), or both, for over 1 GW of solar QF capacity.[38] However, when DESC eliminated capacity payments altogether in 2018, this effectively halted any new QF proposals.[39] The South Carolina Public

[36] N.C. Utilities Comm'n, Order Establishing Standard Offer Rates and Contract Terms for Qualifying Facilities, Docket No. E-100, Sub 148 (Oct. 11, 2017) ("[I]n implementing PURPA, the Commission should not 'slam on the brakes' in establishing rules for the development of QF resources. Rather, as the Commission's policies have resulted in North Carolina cresting the hill, it now is appropriate to moderately ease off on the regulatory accelerator and depend in part on momentum created so as to moderate the financial impact on electric rate payers."). Notably in the N.C. Utilities Commission decision in that proceeding, it rejected a proposal by Duke Energy to impose varying energy rates on QFs that would change every two years over the course of a 10-year contract, finding it inconsistent with FERC rulings and likely to impair the ability of QFs to secure financing. *Id*. at 69. "The Commission determines, for purposes of this case, that Duke's proposed two-year reset in the avoided energy rate component of the standard offer rate should not be adopted at this time. While some larger facilities may be able to negotiate for different terms and degrees of certainty with regard to securing capital and return on investment, the proposed two-year energy rate reset for facilities eligible for the standard offer rates adds an additional element of uncertainty to their ability to reasonably forecast their anticipated revenue, which may make obtaining financing more difficult than a longer term, fixed-rate PPA." *Id*.

[37] *See* South Carolina Energy Freedom Act, Act 62 (May 16, 2019), https://www.scstatehouse.gov/sess123_2019-2020/bills/3659.htm.

[38] *See* Direct Testimony of John H. Raftery, S.C. Pub. Serv. Comm'n, Docket No. 2019-184-E, at 13 (Aug. 23, 2019), https://dms.psc.sc.gov/Attachments/Matter/2e1cff06-5028-4208-802c-0b5739a0eefd ("As of August 8, 2019, 31 utility-scale solar facilities have interconnected with DESC's system which represent approximately 498 MW of solar generation. In addition, 14 utility-scale projects, totaling approximately 713 MW, have executed an interconnection agreement, a PPA, or both.").

[39] Proceeding to Establish Standard Offer, Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions, Tr. Vol. 1, p 338 lns 8-17, S.C. Pub. Serv. Comm'n, Docket No. 2019-184-E (Oct. 14, 2019) (DESC witness was asked: "How many PPAs has the Company executed under the -- under the [sic] avoided cost rates that were approved in 2018?" He responded: "There's none currently in effect. I don't know how many were signed, but there's none currently in effect that I know of." On follow-up, he was asked: "So the Company is not under contract with anybody under that -- that [sic] 2018 rate?" and responded: "I'm not aware of any of those.").

Service Commission recently required DESC to restore avoided capacity payments, but at a fraction of the amount previously offered.[40] DESC has now been authorized to offer QFs the lowest avoided energy rates in the nation at 10-year terms, according to industry groups.[41] Solar QF developers have signaled that this will again prevent new QF development in the state.[42]

Like DESC in 2018, other Southeastern utilities limit their avoided cost compensation to only energy rates, often variable energy rates, without any avoided capacity rate. This has resulted in little to no QF development in these states. The NOPR concludes, without sufficient evidentiary foundation, that QFs can be financed without fixed energy rates, if capacity rates remain fixed. However, the practical reality is that many incumbent utilities do not offer any avoided capacity rate, meaning QFs will only have a variable rate option.[43]

For example, Alabama Power limits standard offer contracts to QFs for only one-year terms, and only offers avoided energy rates.[44] Customers receive between 2.428 and 3.850 cents per kWh for energy generated, and some customers taking service under this tariff are subject to

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[40] *See* Commission Directive, S.C. Pub. Serv. Comm'n (Nov. 15, 2019), https://dms.psc.sc.gov/Attachments/Matter/2e0705e6-9cfe-4783-bbcc-0a4c07fcdc56.

[41] *See, e.g.*, Tom Kenning, *Lowest Solar Rates in US Spook South Carolina Industry – SEIA*, PV TECH (Nov. 20, 2019), https://www.pv-tech.org/news/lowest-solar-rates-in-us-spook-south-carolina-industry-seia. The Commission's recent approval of Duke Energy's rates, terms and conditions in South Carolina has also raised concerns. The Commission approved fixed-energy and -capacity contracts for 10 years, but the approved avoided cost rates are so low that developers have signaled they will not build QFs at those prices.

[42] *Id*.

[43] Even utilities that still offer avoided capacity cost rates have sought to drastically reduce such rates in recent years. *See supra* note 19 (describing recently decreased avoided cost rates in South Carolina); *see also* Late Filed Exhibit No. 4 of Duke Energy Carolinas and Duke Energy Progress, *In the Matter of Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018*, N.C. Utilities Comm'n Docket No. E-100 Sub 158 (Aug. 14, 2019), https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=17280072-f07b-49cb-90ef-f17970a5bbd4 (detailing decrease in Duke Energy's proposed avoided cost rates from those approved in 2016 proceeding, including significant reductions in estimated levelized annual capacity credits for10-year standard offer rates for 1 MW QFs).

[44] Alabama Power, Rate PAE (Purchase of Alternate Energy) (by Ala. Pub. Serv. Comm'n order dated Mar. 12, 2019), https://www.alabamapower.com/content/dam/alabamapower/Rates/PAE.pdf; Alabama Power, Rate CPE (Contract for Purchased Energy), (by Ala. Pub. Serv. Comm'n order dated Mar. 12, 2019), https://www.alabamapower.com/content/dam/alabamapower/Rates/CPE.pdf.

a monthly standby charge of approximately $5/kW.[45] The Alabama Public Service Commission also does not engage in any significant stakeholder process similar to the process used by North Carolina or South Carolina to establish avoided cost rates and standard offer contracts. As a result, solar development in the state lags far behind other states across the country and region. The Solar Energy Industries Association reports that Alabama installed only 46.1 MW of solar in 2018, for a cumulative installed solar capacity of 282.8 MW and a rank of 26th in the nation for installed solar capacity.[46]

Georgia Power's variable energy rates have similarly hampered PURPA QF development in Georgia. While Georgia has seen a significant increase in installed solar capacity in recent years, development of the vast majority of this new capacity has taken place through Public Service Commission-approved programs that are not offered in other Southeastern states and not developed pursuant to PURPA.[47]

Georgia Power offers a standard offer contract for QFs up to 30 MW; however, the contract does not differentiate between QFs of different sizes. This lack of differentiation results in commercial and industrial projects of a size appropriate for behind-the-meter tariffs being treated the same under Georgia Power's standard contract as 30 MW projects. Georgia Power's standard contract includes a number of features that pose unreasonable barriers for smaller QFs. One of the most significant is that the standard offer contract rate is based on the utility's

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[45] *See* Alabama Power, Rate Rider RGB (Jan. 10, 2013), https://www.alabamapower.com/content/dam/alabamapower/Rates/RGB.pdf. Alabama Power has proposed to raise the charge from $5/kW to $5.41/kW. *See* Proposed Modifications to Rate Rider RGB, *In re: Rate Rider RGB*, Ala. Pub. Serv. Comm'n, Docket No. U-4226 (June 15, 2019);
Errata and Substitutes to the Direct Testimony, Reply Testimony, and Exhibits of Ala. Power Co., *In re: Rate Rider RGB*, Ala. Pub. Serv. Comm'n, Docket No. U-4226 (Nov. 15, 2019).

[46] *Solar Spotlight – Alabama,* SOLAR ENERGY INDUSTRY ASSOCIATION (June 2019), https://www.seia.org/sites/default/files/2019-09/Factsheet_Alabama.pdf; *Alabama Solar*, SOLAR ENERGY INDUSTRY ASSOCIATION (2019), https://www.seia.org/state-solar-policy/alabama-solar.

[47] *See, e.g.*, Georgia's Renewable Energy Development Initiative (REDI), https://www.georgiapower.com/company/energy-industry/energy-sources/solar-energy/solar/c-and-i-redi.html.

"Territorial Hourly Avoided Energy Rate" which essentially results in a variable rate rather than a fixed rate. This variable energy rate, which is revised annually, creates significant uncertainty for QF developers and investors who intend to enter into long-term contracts with predictable returns. Due in part to these features of Georgia Power's standard contract and alternative renewable programs, QF development pursuant to PURPA has been minimal in Georgia, as shown by testimony in a recent Georgia Public Service Commission proceeding indicating that Georgia's PURPA QF program has only approximately nine participating QFs, with a total capacity of approximately 414.5 kilowatts.[48]

In Tennessee, the Tennessee Valley Authority ("TVA") has implemented PURPA primarily through its Dispersed Power Production ("DPP") program, including its DPP Guidelines that establish the purchase price and many of the terms under which QFs may sell their output. Rates under the DPP program are offered through two different parts, and QFs may elect to receive compensation under either "Part A" or "Part B" of the price schedule.[49] Under Part A, all QFs are paid the same fixed price, currently set at 2.235 cents per kWh.[50] Under Part B, QFs are paid a rate determined by the amount of electricity delivered to the grid in a given hour as well as demand at the time the electricity is delivered.[51] Significantly for project financing, the prices reflected in the October 2019 version of the DPP program guidelines are temporary and subject to change by TVA "from time-to-time as it deems appropriate," which

[48] Georgia Power's Resp. to STF-PIA-7-24, Ga Pub. Serv. Comm'n, Docket No. 42,515 (Sept. 13, 2019), https://psc.ga.gov/search/facts-document/?documentId=178360.
[49] Christopher W. Hansen, TVA, Letter to DPP Participant, Oct. 31, 2019, at A-1, https://www.tva.gov/file_source/TVA/Site%20Content/Energy/Renewables/Dispersed%20Power%20Program/dispersed.pdf [hereinafter "DPP Price Schedule"].
[50] DPP Price Schedule, *supra* note 49, at A-1.
[51] *Id.*

typically occurs monthly.[52] Moreover, the minimum length of PPAs signed under the DPP program is just one year, far from a contract length that would ensure that QF developers can secure financing on reasonable terms.[53] Both the low rates offered by TVA and the variable structure of the compensation have stifled development of small power production in the state. Only a small number of QFs sell power to TVA through the DPP program.[54]

Even more concerning is that recent analyses have shown that the limited and variable avoided energy rates offered by TVA fail to accurately compensate QFs for the utility's actual marginal avoided energy value. A recent analysis conducted by Greenlink Analytics ("Greenlink"), an energy technology, research, and advisory firm that specializes in energy policy analysis, on behalf of SELC showed that the avoided energy-only price TVA offers as compensation under the DPP program is significantly less than the cost of generating power from TVA's most expensive unit operating (*i.e.* the marginal unit) on an hour-by-hour basis.[55] In other words, the true marginal avoided energy value of solar generation is worth more than what

[52] TVA, Dispersed Power Production Guidelines, at ii, 1 (2019), https://www.tva.gov/file_source/TVA/Site%20Content/Energy/Renewables/Dispersed%20Power%20Program/dispersed.pdf [hereinafter "DPP Guidelines"].
[53] DPP Price Schedule, *supra* note 49, at A-3.
[54] List of DPP Participants as of July 2018, obtained by SELC via Freedom of Information Act Request to the Tennessee Valley Authority.
[55] Comments of the Southern Environmental Law Center, Appalachian Voices, Energy Alabama, green|spaces, Kentucky Chapter of the Sierra Club, Southern Alliance for Clean Energy, Tennessee Chapter of the Sierra Club, Tennessee Conservation Voters, and Tennessee Interfaith Power and Light to Tennessee Valley Authority regarding Changes to Green Power Providers Program Draft Environmental Assessment (Nov. 8, 2019) at 2, 10, 12-13, https://www.southernenvironment.org/uploads/words_docs/2019_11_08_SELC_et_al_comments_on_TVAs_changes_to_the_GPP_program_draft....pdf [hereinafter "SELC et al. Comments to TVA"]. Greenlink collected TVA plant data from form EIA-860 and hourly generation data from EPA's Air Markets Program Data (AMPD) for the years 2014–2018. Greenlink compiled fuel costs for each power plant from S&P Global's modeled production cost database for each plant in TVA territory. Fuel costs are not the only component determining the marginal cost (other variable costs associated with unit operations are also incorporated), but not all of those costs could be captured for every TVA unit. As a result, Greenlink's results are necessarily conservative estimates. By coupling generation costs with hourly generation data, Greenlink was able to produce a database of each plant on the margin for any given hour over the 2014–2018 period. Greenlink determined the cost for solar generation using Nashville as a proxy for average solar insolation over TVA's territory. Greenlink collected hourly solar data from the National Renewable Energy Laboratory's PVWatts tool. For the 2018 winter peak day, Greenlink used TVA's Off Peak pricing for January 2018 as the cost of solar ($22.26/MWh). Letter from Christopher W. Hansen, TVA, to DPP Participant, Dec. 28, 2017. For the 2018 low demand day, Greenlink used TVA's Off Peak pricing from October 2019 ($21.44/MWh). DPP Price Schedule, *supra* note 49, at A-1.

TVA offers under the DPP program. Greenlink found that for 2014–2018, the weighted average value of solar on the system on an hourly basis was about $49/MWh over the past five years, and was high in 2018, at almost $85/MWh.[56] Thus, exports of electricity generated by solar units could offset TVA's use of more expensive marginal resources (such as natural gas combustion turbines). Greenlink's analysis shows that through the DPP program, TVA has been undervaluing and undercompensating distributed solar. TVA's failure to adequately compensate solar even on a varying avoided-energy basis has undoubtedly contributed significantly to lower levels of customer investment in the resource.

TVA's failure to fully compensate for marginal avoided energy values is unfortunately not unique. Across the Southeast, the avoided cost methodologies and assumptions used are often so removed from reality as to provide perverse results. Figure 2 shows some of the most egregious examples of utilities using PURPA avoided cost rates that are well-below the levelized cost of energy from utility-built plants.[57] This is not a problem unique to our region, as depicted below by the inclusion of Mississippi Power's Kemper Plant and Duke Energy's Edwardsport Plant in Indiana, but it is prevalent. As a result, there is a strong argument that the avoided cost methodologies result in much lower rates than the utilities' actual "but for" avoided costs.

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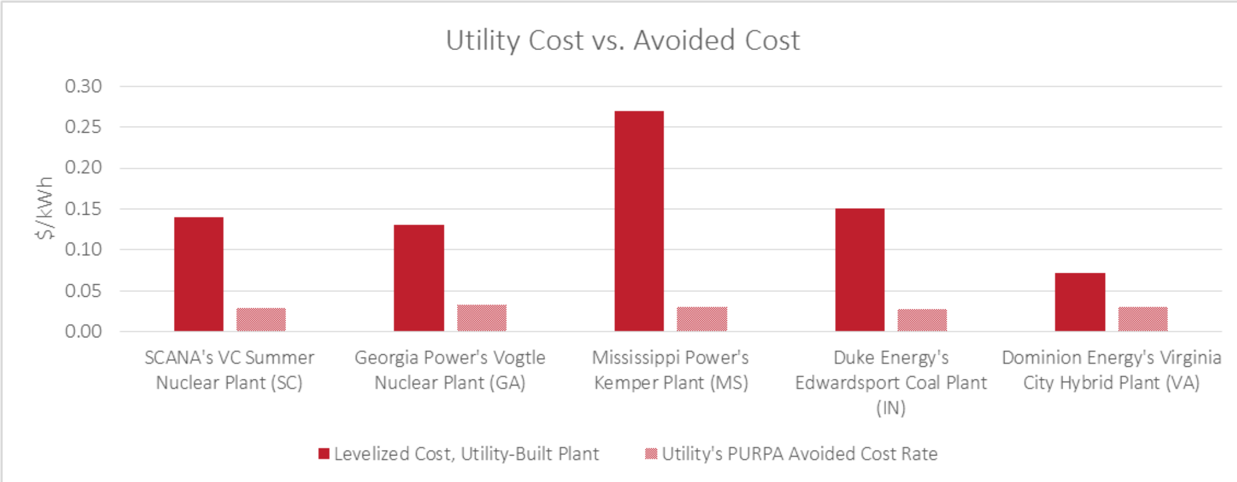
[56] SELC et al. Comments to TVA, *supra* note 55, at 10.

[57] Figure 2 compares the PURPA avoided cost rate used by each utility against costs incurred by the utility for specific generation projects using FERC Form 1 data from 2012. SELC et al. Oct. 2018 Supplemental Comments to FERC, *supra* note 1, at 21. The chart has been updated to include Dominion Energy's Virginia City Hybrid Plant. *See Form 1 – Electric Utility Annual Report* . FEDERAL ENERGY REGULATORY COMMISSION, https://www.ferc.gov/docs-filing/forms/form-1/data.asp; Va. Elec. & Power Co., *supra* note 20. *See also* Direct Testimony of Dr. William M. Cox, Ph. D. and Karl R. Rábago, Ga. Pub. Serv. Comm'n, Docket Nos. 42310, 42311, at 10-17 (Sept. 23, 2019), https://psc.ga.gov/search/facts-document/?documentId=176709 (describing the failure of Georgia Power to accurately compensate solar QFs for avoided costs).

Figure 2. Utility Cost vs. Avoided Cost



There is a stark contrast in the Southeast between QF development in states with long-term fixed avoided cost rates and those without them. By proposing to allow varying energy rates, the NOPR is locking in a policy approach that has been shown to actively discourage QF development, rather than encourage it as PURPA requires. There may be a time in the future in which PURPA is truly no longer needed to encourage the development of small independent power producers. If the Southeast develops competitive markets that provide truly nondiscriminatory access to QFs and allow QFs to compete directly with incumbent utilities, the policy goals Congress intended to achieve through PURPA may no longer be needed.[58] However, QFs in traditionally regulated states in the Southeast currently have no access to markets that would remove the need for PURPA, and the NOPR has provided no evidence to the contrary. Until and unless those changes take place, PURPA, including the requirement for utilities to offer long-term fixed pricing to QFs, remains a critical tool to fulfill the Congressional

[58] Certain existing markets that nominally provide "nondiscriminatory access" to QFs may, in fact, contain limitations that make it difficult for QFs to access and participate in those markets. This issue is addressed in part in the discussion of the NOPR's proposal to decrease the threshold for waivers of the mandatory purchase obligation from 20 MW to 1 MW.

mandate to encourage QF development. We urge the FERC to rescind the proposal to allow varying energy rates.

II. Using Competitive Prices for As-Available QF Energy Rates Outside of RTO/ISO Markets Lacks Justification and Fails to Fully Account for Utilities' Avoided Costs

FERC proposes to revise PURPA regulations to permit a state to set the as-available energy rate paid to a QF by electric utilities located outside of RTO/ISO markets at a competitive price calculated at the time of delivery. In this context a competitive price could be either (i) energy rates established at liquid market hubs, or (ii) energy rates determined pursuant to natural gas price indices and a proxy heat rate for efficient natural gas combined-cycle generating facility.[59] No Southeast state could credibly identify a particular market hub that is reasonably accessible and has competitive prices that actually relate to the costs an electric utility would avoid but for the purchase from the QF.[60] That being said, there are very few proposed requirements in the NOPR regarding what "reasonably accessible" would actually entail and as a result, we are forced to consider what this proposed change would mean for the Southeast.

Under this proposal, states would be allowed to set the avoided cost at the price a QF would otherwise receive on a merchant basis or establish other approaches for determining avoided cost. FERC is essentially equating the natural gas spot market with a utility's avoided cost. As a threshold matter, it is important to note that the avoided energy prices that FERC proposes in the NOPR are inconsistent with the standard that Congress established in its Section 210(m) amendments. In order to be eligible for a waiver of its mandatory purchase obligation, a utility must demonstrate that QFs have access to markets for long-term energy sales.[61] Congress, therefore, expressed its clear intent that in all instances QFs must have access to long-term

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[59] NOPR, *supra* note 2, at ¶¶ 51-60.
[60] *Id*. at ¶ 56. The closest liquid market hub to our region appears to be the Henry Hub in Louisiana.
[61] 16 U.S.C. § 824a-3(m)(1)(A) and (B).

energy prices rather than short-term or spot market prices. Liquid market hubs are simply spot markets for energy and do not represent long-term energy rates. These spot market prices also do not reflect the other costs associated with that energy including, but not limited to, congestion, transmission, and capacity costs. As a result, it is a poor substitute for a determination of avoided cost and contrary to the statute and the developed case law.[62] This proposal would make the revenue stream for most projects more unpredictable and, as a result, would undermine the ability of projects to find financing.

The NOPR does not include any justification for this proposal or any case analysis of whether the liquid market hubs accurately represent a utility's avoided energy costs or if they are just and reasonable and nondiscriminatory. It is conceivable that if a utility solely relies on the liquid market hub for all incremental energy purchases, then the liquid market hub may represent just and reasonable and non-discriminatory rates. But, it is highly doubtful that this occurs anywhere. Most utilities, particularly vertically-integrated monopoly utilities in the Southeast, rely on self-owned generation to serve the vast majority of their load. As a result, the liquid market hub would not represent the utility's avoided energy costs. FERC's proposal does not require states to perform this analysis, and therefore FERC's proposal would allow liquid market hubs to set avoided energy costs even when they do not represent such avoided costs.

Similarly, FERC's proposal to allow states to set energy rates determined pursuant to natural gas price indices and a proxy heat rate for efficient natural gas combined-cycle

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[62] *See Exelon Wind I, LLC*, 140 FERC ¶ 61,152 ¶ 52 (2012), *reconsideration denied*, 155 FERC ¶ 61,066 (2016)) (denying reconsideration of Commission's finding that the Texas Commission's approval of "avoided cost rates linked to the locational imbalance price of the QF's node…was inconsistent with the requirements of PURPA and the Commission's regulations implementing PURPA." *Id*. at 3, 6.); *Plymouth Rock Energy Assoc. v. Dep't of Pub. Util.*, 648 N.E.2d 752, 756 (Mass. 1995) (holding that the "statute and its implementing regulations clearly mandate that the rate to be paid by utilities for electric energy be determined by the avoided cost to the utility of generating that energy or purchasing it elsewhere."); *Amer. Paper Instit., Inc. v. American Elec. Power Serv. Corp*, 461 U.S. 402, 417 (1983) (holding that the words "in the public interest" take meaning from the purposes of the regulatory legislation and since that purpose is to encourage development of QFs, this purpose should be reflected in the purchase rates required pursuant to PURPA).

generating facility is misguided and troubling. Again, these metrics do not reflect a complete avoided cost methodology as required by statute and case law.[63] Natural gas fuel prices and heat rate alone do not reflect the full avoidable energy costs associated with a proxy combined cycle gas plant. For example, FERC's proposal does not require states to include variable operations and maintenance costs ("O&M") in the proxy combined cycle plant. A utility-owned combined cycle gas plant would be allowed to recover O&M costs, so the failure to require states to include variable O&M in the avoided cost calculation for QFs results in discriminatory rates against QFs. The result of this proposed change would therefore be in direct conflict with PURPA.[64] Similarly, FERC's proposal does not require states to include an adjustment for natural gas transportation. If a purchasing utility is hundreds of miles away from a natural gas price index hub, then it would incur avoidable transportation costs associated with purchasing from that hub. Again, a utility would always recover its own costs for transporting natural gas from other utility-owned facilities, so allowing states the ability to exclude such transportation costs from avoided cost methodologies results in discriminatory rates in conflict with PURPA. Finally, FERC has not provided any analysis or reasoning for breaking with precedent to make this change.[65] This change, if enacted without adequate justification, would be arbitrary and capricious.[66]

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[63] *Id*.

[64] 16 U.S.C. § 824a–3(c)(2).

[65] *See* 18 C.F.R. § 292.304(B)(2) (1982) (requiring a utility to purchase electricity from a qualifying facility at a rate equal to the utility's full avoided cost); *Exelon Wind I, LLC*, *supra* note 62; *Amer. Paper Instit., Inc. v. American Elec. Power Serv. Corp*, 461 U.S. 402, 406-07, 415 (1983) (finding that "these ratepayers and the nation as a whole will benefit from the decreased reliance on scarce fossil fuels, such as oil and gas, and the more efficient use of energy" and therefore the purchase rate from QFs should be set accordingly to encourage QF development.)

[66] *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.'" (quoting *FCC v. Fox Television Stations*, 556 U.S. 502, 515 (2009))); *Perez v. Mortgage Bankers Ass'n* 135 S. Ct. 1199, 1209 (2015) ("[T]he APA requires an agency to provide more substantial justification when 'its new policy rests upon factual findings that contradict those which underlay its prior policy; or when its prior policy has engendered serious reliance interests that must be taken into account. It would be arbitrary and capricious to ignore such matters.'" (quoting *FCC v. Fox Television Stations, Inc*. 556 U.S. 502, 515 (2009)).

III. Using LMP as a *Per Se* Rate for As-Available QF Energy Sales is an Overly Restrictive Departure from Precedent

FERC has proposed to allow a state the flexibility to set the as-available energy rate paid to QFs by an electric utility located in an RTO/ISO at LMPs calculated at the time of delivery.[67] LMPs relate to the fact that the cost of energy from a particular location varies due to changes in the local energy markets. Since this proposal would apply to utilities located in RTO/ISOs, only Virginia and a portion of eastern North Carolina are the Southeastern states currently impacted by this change. Virginia and a portion of eastern North Carolina participate in PJM Interconnection, L.L.C. ("PJM").

Under PURPA, state commissions must set rates paid to independent renewable power producers at a rate that is just and reasonable, in the public interest and not discriminatory against QFs.[68] In addition, the rate cannot be more than the utility's avoided cost of the next incremental unit of electricity that, but for the purchase from power from an independent renewable producer, the "utility would generate or purchase from another source."[69] Avoided costs should reflect avoided capacity and/or energy costs that the utility would generate or purchase but can avoid by purchasing from the QFs.[70]

Currently, a state commission could find that a LMP of a facility reflects the "but for" avoided energy cost to a utility and legally set rates paid to independent renewable power producers using LMP as a proxy for avoided energy cost.[71] But, in making this determination, a

[67] NOPR, *supra* note 2, at ¶¶ 43-50.
[68] 16 U.S.C. § 824a–3.
[69] 16 U.S.C. § 824a-3(d).
[70] 18 C.F.R. § 292.101(b)(6) (2016).
[71] *See Exelon Wind I, LLC*, 140 FERC ¶ 61,152 ¶ 52 (2012) (holding that the Texas Commission Order incorrectly accepted the locational market price instead of calculating what the costs to the utility would have been "but for" the presence of the QF), *reconsideration denied*, 155 FERC ¶ 61,066 (2016) (contrary to the holding stated in the NOPR, *supra* note 2, at ¶ 50 note 84, the Commission actually states in this case: "We note that the Commission to date has not been asked to, and so has not, opined on whether LMP may be used to calculate avoided costs." *Id*. ¶ 11, note 19.).

state would be required to consider the full range of avoided costs in order to determine whether the LMP is the same as the price "but for" the presence of the QF. While it may be appropriate for avoided costs to reflect the locational and/or time value of QF output, these factors may not always represent just and reasonable and nondiscriminatory rates. FERC has even stated that *ideally* LMPs would reflect "the true marginal cost of production," but this may not always be the case.[72] Additional considerations and circumstances should also be taken into account to confirm whether a LMP in fact reflects just and reasonable and nondiscriminatory rates in a certain circumstance.[73] The NOPR proposed change creates a *per se* rule finding that LMPs reflect a utility's avoided cost, when in reality utilities may rely primarily on self-owned generation, and LMPs may not represent just and reasonable and nondiscriminatory rates. In fact, the methodology for calculating the LMP is very important and as proposed the NOPR does not provide sufficient guardrails for computing a LMP that would result in reasonable and just and nondiscriminatory rates. For example, the proposed avoided cost methodology does not take into account any long-term or seasonal purchases made from third parties or affiliates, adjustments for transmission and distribution losses, capacity deferrals, avoided environmental compliance costs, or dispatchability of the QF.[74] Broadly setting the as-available energy rate at LMPs does not reflect the true avoided cost of a utility—instead, it is a simplification that under-values the benefits independent power producers provide.

[72] Offer Caps in Markets Operated by Regional Transmission Organizations and Independent System Operators, Order No. 831, 157 FERC ¶ 61,115, at 7 (2016), *order on reh'g and clarification*, Order No. 831-A, 161 FERC ¶ 61,156 (2017) ("LMPs and market-clearing prices used in energy and ancillary services markets *ideally* 'would 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.'" (emphasis added).

[73] Comments of the Southern Environmental Law Center, Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, Docket No. AD16-16-000, FERC (June 21, 2016) at 10.

[74] *See e.g.*, NOPR, *supra* note 2, Commissioner Glick Dissent, at ¶10; Comments of Elizabeth Whittle, Technical Conference Transcript at p. 158.

The impact of this proposed rule is all too clear. Virginia Electric and Power Company ("Dominion"), the largest vertically integrated utility in Virginia, already uses the current LMP as the basis for the State Corporation Commission-approved avoided cost rates for QFs.[75] Specifically, Dominion calculates QFs' avoided cost rate for energy by dividing the average of the hourly $/MWh Dom Zone DA LMP for the QFs' billing month by 10, and multiplying the quotient by the net generation as recorded on the Company's non-time differentiated meter.[76] In short, Dominion is using the average monthly LMP to determine the avoided cost rate, which obscures the temporal aspects of QF generation. This methodology does not distinguish between a QF providing energy at peak and avoiding expensive generation options or a QF providing energy in the middle of the night when the energy is not needed. Dominion then adds 2.8% to account for line losses avoided by the Company, though Virginia had a higher percentage of 5.13% in transmission and distribution losses in 2017.[77] In addition, Dominion allows for contracts with QFs to be as short as one year.[78] Dominion's approved avoided cost rate arguably violates PURPA's current regulation which plainly allows QFs the option of receiving long-term, forecasted rates at avoided cost.[79] This offer has enticed little to no QF development in Virginia. In fact, QFs make up only one percent of total electricity generation capacity in the state.[80] Dominion's avoided cost methodology in Virginia should not be the model for the rest of the United States. Instead of changing the regulations to make illegal PURPA implementation legal, FERC should recognize and remedy non-compliant PURPA implementation.

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[75] Xcel Energy Services Inc., *supra* note 21 (stating that Virginia is one of the states in PJM that has set avoided costs at LMP.)
[76] Va. Elec. & Power Co., *supra* note 20.
[77] *Id*.
[78] Va. Elec. & Power Co., *supra* note 20. *State Electricity Profiles*, U.S. ENERGY INFO. ADMIN. (2017), https://www.eia.gov/electricity/state/virginia/state_tables.php.
[79] 18 C.F.R. § 292.304(d)(2).
[80] Form EIA-860 Detailed Data with Previous Form Data (EIA-860A/860B), U.S. ENERGY INFO. ADMIN.: ELECTRICITY (Release Date: Sept. 3, 2019), https://www.eia.gov/electricity/data/eia860/.

Today in Virginia many of the same problems Congress enacted PURPA to solve still exist. As a result of inadequate PURPA implementation and prohibitively high barriers to entry in Virginia, small power production QFs still represent only a small percentage of generation capacity. With one percent of the overall generating capacity from QFs in Virginia it is evident that the QFs lack adequate markets in which to sell their energy and capacity. Instead, vertically integrated utilities maintain their monopoly and suppress independent power generators. PURPA is one of the only legal tools to create any semblance of competition and to provide a market for QFs. "Reforming" PURPA regulations to allow LMP as essentially a *per se* "accurate measure of avoided costs" undercuts the goals of PURPA and would leave QFs in many states in the same dire position as QFs in Virginia. The Commission has been directed to prescribe rules which "encourage cogeneration and small power production."[81] As proposed, the NOPR would exacerbate problems with current implementation of PURPA and would do nothing to achieve the Congressionally-mandated purposes of PURPA. At a bare minimum, this should be a case-by-case consideration by state commissions, taking into account any other relevant factors. Although this alternative would be a more reasonable approach than the proposed *per se* rule, our primary recommendation is to rescind the NOPR proposal and enforce the current law where utilities are presently in violation of those regulations.

Finally, in making this proposal, the Commission fails to explain its rationale for reversing precedent.[82] This change, if enacted without adequate justification, would be arbitrary

[81] 16 U.S.C. § 824a-3(a).

[82] This would break from established precedent. Congress required FERC to ensure that the prices paid to QFs "encourage cogeneration and small power production" and "not discriminate against qualifying cogenerators of qualifying small power producers." 16 U.S.C. § 824a-3(a), (b)(2). Since PURPA's adoption, FERC has consistently met those criteria by setting the QF price at the statutory maximum price equal to full avoided cost in order to maximize incentives for QF development and this standard has been upheld by the courts. *See* 18 C.F.R. 292.304(b)(2) (1982) (requiring a utility to purchase electricity from a qualifying facility at a rate equal to the utility's full avoided cost); *Plymouth Rock Energy Assoc. v. Dep't of Pub. Util.*, 648 N.E.2d 752, 754 (Mass. 1995) ("[I]n essence, the statutory ceiling price has become the floor price."); *Amer. Paper Instit., Inc. v. American Elec.*

and capricious. [83] Furthermore, while the Commission has the authority to revise PURPA regulations "from time to time" it does not have the authority to determine whether PURPA has achieved its stated goals or revise those goals.[84] The impact of this change, if enacted as proposed, on the ability of QFs to enter the market would contradict the Congressionally-mandated purposes of PURPA to reduce reliance on fossil fuels and to encourage the development of QFs.

IV. Permitting the Energy Rate Component of a Contract to Be Fixed at the Time of the LEO Using Forecasted Values of the Estimated Stream of Market Revenues is an Unjustified Departure from Precedent

The NOPR proposal to permit the energy rates to be fixed at the time of the Legally Enforceable Obligation ("LEO") using forecasted values of market revenues[85] suffers the same deficiencies as the LMP and liquid market hub value proposals. In particular, no analysis is provided in the NOPR as currently drafted as to how and whether the forward price curves represent just and reasonable and non-discriminatory rates as required by PURPA. A departure from past precedent without adequate justification would be arbitrary and capricious.[86]

V. Using Competitive Solicitations to Determine Avoided Costs Can Be Difficult and Discriminatory in Practice

The NOPR proposes to allow states to consider using competitive solicitations to set avoided cost rates.[87] Southeast Public Interest Organizations urge caution with this proposal and

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Power Serv. Corp, 461 U.S. 402, 406-07, 417 (1983) (upholding requirement that QFs receive full avoided costs rate.).

[83] *Encino Motorcars, LLC, supra* note 66; *Motor Vehicle Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co.*, 463 U.S. 29, 42 (1983) ("If Congress established a presumption from which judicial review should start, that presumption . . . is not against safety regulation, but against changes in current policy that are not justified by the rulemaking record.").

[84] 16 U.S.C. § 8241-3(a).

[85] NOPR, *supra* note 2, at ¶¶ 61-62.

[86] *Id.*

[87] NOPR, *supra* note 2, at ¶¶ 82-88.

raise a number of concerns that should be considered. As first raised in SELC et al. Oct. 2018 Supplemental Comments to FERC, competitive solicitations are not currently required in many states, and in the states that do require some form of competitive solicitation, many utilities do not regularly hold competitive solicitations, do not make competitive solicitations open to all QFs, or do not provide QFs the ability to sell to the utility outside of a competitive solicitation process.[88] Further, the competitive solicitation process can be overly burdensome and costly for smaller facilities, depriving them of an opportunity to compete on equal terms because the administrative costs of participating in such a solicitation represent a higher percentage of a facility's costs than for larger facilities.

The Commission has previously considered whether competitive solicitations comply with PURPA. In *Hydrodynamics Inc.*, 146 FERC ¶ 61193 (2014), the Commission found that requiring a qualifying facility to win a competitive solicitation as a condition to obtaining a long-term contract imposes an unreasonable obstacle to obtaining a LEO and noted that a qualifying facility's ability to negotiate a contract outside of a competitive solicitation was not a sufficient alternative because "a utility may refuse to negotiate with a qualifying facility at all."[89]

The argument that competitive solicitation will always satisfy the intent of PURPA also ignores the fact that competitive solicitation implementation varies widely. Not only do many states not require competitive solicitation, only a small number of states with competitive solicitation require all capacity expansions or additions to undergo a request for proposal ("RFP") process where both the utility and independent power producers bid to meet future capacity needs and an Independent Evaluator not affiliated with the utility runs the RFP. And to

[88] SELC et al. Oct. 2018 Supplemental Comments to FERC, *supra* note 1, at 16.
[89] *Hydrodynamics Inc.*, 146 FERC ¶ 61,193, 61845 (2014); *see also Windham Solar LLC*, 156 FERC ¶ 61,042 (2016) (reiterating the Commission's holding that a QF's ability to negotiate a contract outside of a competitive solicitation was not a sufficient alternative.)

our knowledge, no state requires, and no utility conducts, a competitive solicitation to determine how best to meet the ongoing energy needs that it currently meets through the operation of its existing generation fleet and market purchases.[90]

Many states that do require some form of competitive solicitation do not provide a robust process or equitable playing field for non-utility power producers like QFs to bid and, if successful, to construct, own, and operate a generating facility. Florida, for example, does not require an Independent Evaluator as part of its competitive solicitation process.[91] Other states, like Colorado[92] and Oklahoma,[93] allow utilities to apply for waivers of the competitive solicitation requirement. In North Carolina, the incumbent monopoly utility has been allowed to participate in a competitive bidding process and has received preferential treatment in the form of waiving post bid security required for any independently owned projects.[94]

While a well-designed and well-implemented competitive solicitation process could be an appropriate procurement and rate-setting tool in some cases, competitive solicitations should never be the only way to set rates or for QFs to sell their output, and close consideration should be given to determinations of utility capacity need that could be manipulated to limit renewable energy procurements.[95] Absent clear, enforceable guidelines that prevent monopoly utilities from

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[90] *See also* Solar Energy Industries Association, Supplemental Comments of the Solar Energy Industries Association, FERC, Docket No. AD16-16-000, at 22 (Aug. 28, 2019) (recommending that "any utility seeking to deploy a competitive solicitation in lieu of its PURPA obligation to pay QFs for capacity be required to procure all new resources, as identified in a state commission-approved IRP through the competitive solicitation process, and not artificially segment the market by limiting the solicitation to a fraction of identified capacity needs or limit the solicitation to a single technology, a single program, or a single build type.").
[91] Fla. Admin. Code § 25-22.082.
[92] 4 Colo. Code Regs. 723-3:3611(c).
[93] Okla. Admin. Code § 165:35-34-3(e).
[94] *See* Solar Energy Industries Association, Supplemental Comments of the Solar Energy Industries Association, FERC, Docket No. AD16-16-000, at 29-32 (Aug. 28, 2019) (describing North Carolina competitive bidding process and unfair monopoly utility advantage in greater detail).
[95] For example, a recent bill, H.R. 4476—the "PURPA Modernization Act of 2017"— proposed to eliminate the mandatory purchase obligation in states that held competitive procurements or in which the utility's integrated resource plan ("IRP") indicated the utility had no capacity need. However, tying PURPA obligations to utility integrated resource planning overlooks the fact that although some states engage in robust IRP proceedings that bind

implementing discriminatory bidding processes, the deference to "competitive solicitations" undercuts the Congressional intent behind PURPA, the mandatory purchase obligation, and the federal agency's responsibility to adopt regulations to successfully implement the law. Without adequate guardrails, incumbent utilities may propose and state commissions may approve competitive solicitation processes that are not fully transparent or fair, artificially suppressing avoided cost rates in a way that discourages QF development, in contravention of PURPA.

VI. Relief from Purchase Obligation in Competitive Retail Markets Will Discourage QF Generation

The Commission proposes to modify the current requirement that utilities purchase "any energy and capacity which is made available from a qualifying facility" for those utilities whose supply obligations are reduced by a state's retail choice program.[96] Currently, electric utilities are generally required to be Providers of Last Resort ("POLR") and serve customers that are not obtaining electricity from competitive electric retail suppliers.[97] The Commission is proposing to reduce electric utilities' PURPA capacity purchase obligations to the extent retail choice reduces their supply obligations and to thus remove state commissions' authority to set PURPA contract term lengths by requiring QF contracts with a POLR match the term of the POLR's other supply contracts.[98] The Commission does not cite to any legal authority to effect this change, and the proposal fails to encourage cogeneration and small power production as directed by PURPA since the proposal will reduce utilities' mandatory purchase obligation. Finally, we are concerned

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future utility resource decisions, many IRPs are procedural exercises that do not obligate the utilities or create presumptive validity for future resource decisions. This is especially true in states in which utilities simply file IRPs without review by state regulators or opportunities for stakeholder input, and for nonregulated electric utilities that are not regulated by a state utilities commission. Tying resource procurement to IRPs or other similar planning documents without sufficient vetting of the actual capacity need would give utilities yet another tool to undermine PURPA. *See Legislation Addressing LNG Exports and PURPA Modernization: Hearing Before the Subcomm. on Energy of the H. Comm. on Energy and Commerce,* 115th Cong. (2018) (testimony of Karl R. Rábago, Senior Policy Advisor, Pace Energy and Climate Center).

[96] 18 C.F.R. § 292.303(a); NOPR, *supra* note 2, at ¶ 89.

[97] NOPR, *supra* note 2, at ¶ 90.

[98] *Id*. at ¶ 91.

that the proposal reduces state commissions' ability and authority to establish longer QF contracts as appropriate.

VII. Evaluation of Whether QFs are Separate Facilities

A. Revisions to the One-Mile Rule Will Burden and Discourage Existing and Proposed QFs in the Southeast

The NOPR includes significant changes to FERC's longstanding rule that QFs more than a mile apart are considered separate QF facilities, commonly known as the "one-mile rule."[99] These changes will have burdensome consequences and should be reconsidered.

The NOPR changes the previous *irrebuttable* presumption that facilities more than a mile apart are separate facilities to a *rebuttable* presumption for facilities between one and ten miles apart.[100] Certification or recertification of facilities in this one-to-ten mile range would be subject to challenge by the Commission, incumbent electric utilities, or any "others."[101] Under the current one-mile rule, facilities located within one mile, using the same energy resource, and owned by the same person(s) or its affiliates are considered to be "at the same site."[102] Southeast Public Interest Organizations believe the previous one-mile rule, especially with regard to solar facilities applying for QF status or recertification, provided a much clearer test with less potential for confusion, expense, and litigation than the proposed rule.

FERC has proposed changes to the one-mile rule based on its understanding that "some QF developers of small power production facilities are circumventing the one-mile rule, and thereby circumventing PURPA, by strategically siting small power production facilities that use the same energy resource—primarily wind farms made up of multiple individual wind turbines —slightly more than one mile apart in order to qualify as separate small power production

[99] *Id*. at ¶ 94, 96.
[100] *Id*. at ¶¶ 94, 96.
[101] *Id*. at ¶ 102.
[102] *Id*. at ¶ 96.

facilities that are protected by the irrebuttable presumption that facilities more than a mile apart are separate QFs."[103] FERC singles out wind facilities for apparently circumventing the PURPA one-mile rule but does not allege that other QFs such as solar facilities seeking QF certification are similarly attempting to circumvent the rule.[104] In the Southeast, the overwhelming majority of QFs are solar facilities, and the NOPR's proposed one-mile-rule "fix" has significant implications for existing solar QFs. In particular, the proposed rule is expected to impose a costly burden on certain developers and QFs seeking QF status or recertification, particularly in states like North Carolina and South Carolina with substantial QF development under the current one-mile rule.

As previously noted herein, North Carolina is rich in PURPA QF solar projects. In fact, as of August 2018, North Carolina had the most PURPA-qualifying solar capacity in the United States, with 2.9 GW of qualifying solar capacity and only 0.4 GW of utility-scale solar capacity not certified as qualifying.[105] What is particularly troubling about the NOPR's proposal for a rebuttable presumption for facilities spaced between one and ten miles apart is that it will be applied not only to facilities seeking certification, but also those seeking *recertification*.[106] As displayed in the map below,[107] the effect of this proposed change on recertification would significantly burden the utility-scale solar market in North Carolina as existing PURPA PPAs expire and project owners begin the process of recertification.

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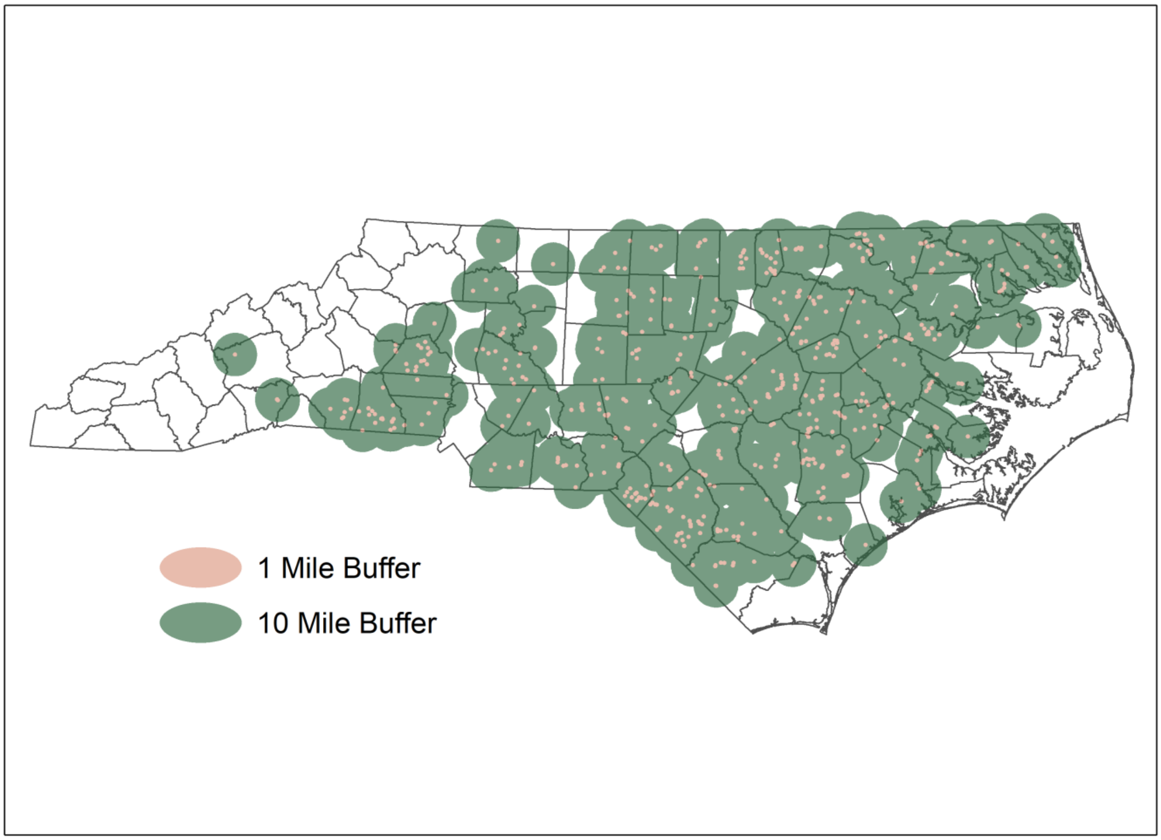
[103] *Id*. at ¶ 97.
[104] *Id*.
[105] *PURPA-qualifying capacity increases, but it's still a small portion of added renewables*, U.S. ENERGY INFO. ADMIN.: TODAY IN ENERGY (Aug. 16, 2018), https://www.eia.gov/todayinenergy/detail.php?id=36912.
[106] NOPR, *supra* note 2, at ¶ 100.
[107] This map, produced internally at North Carolina Sustainable Energy Association through the use of GIS mapping analysis, provides approximate boundaries for solar facility sites with some small variance from the true geographic edges of the solar facilities.

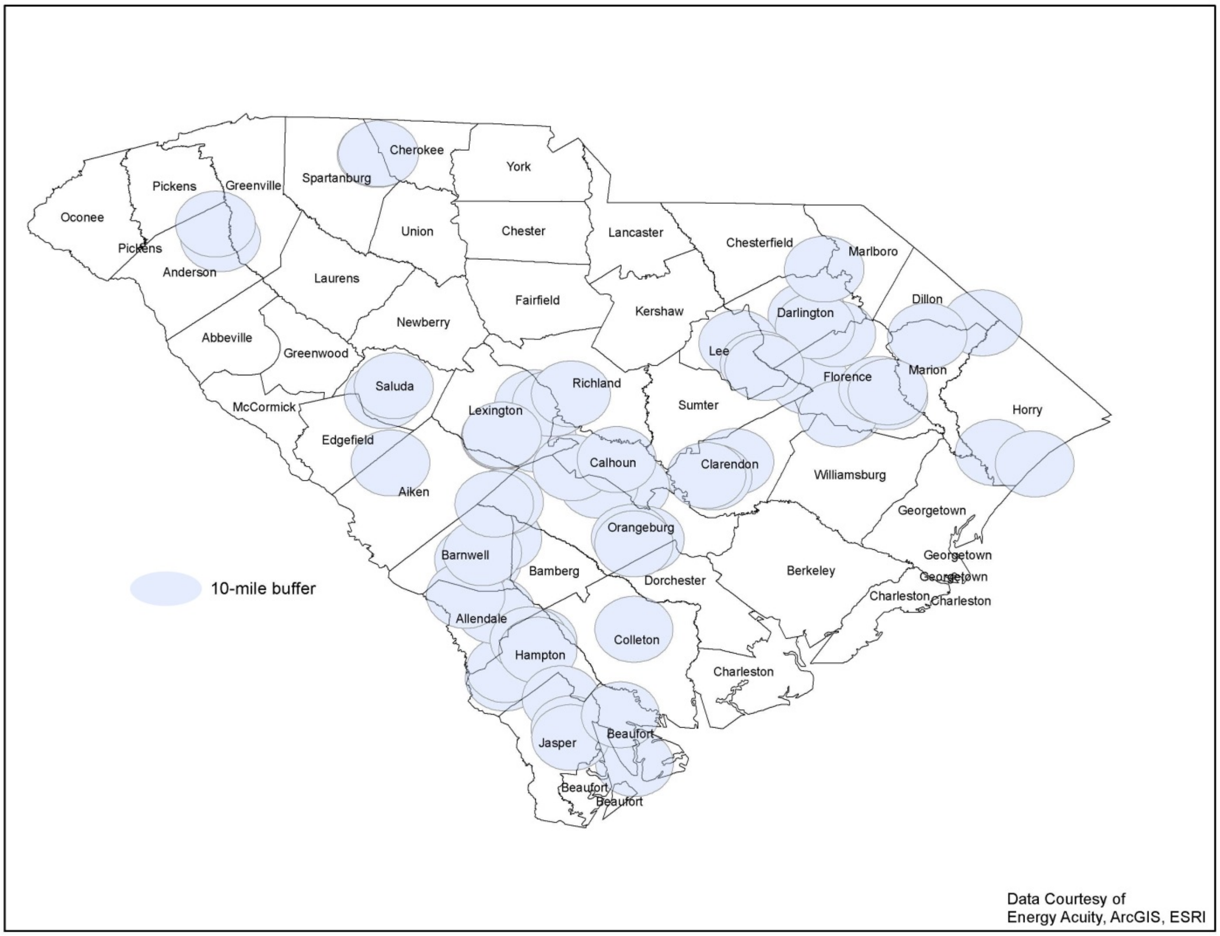
Figure 3. North Carolina Utility-Scale Solar Buffer Map – 2019



As the Utility-Scale Solar Buffer Map in Figure 3 shows, the increase of radius from 1-mile to a 10-mile buffer causes nearly all of the currently online utility scale solar sites in North Carolina to overlap with other facilities. In some cases, these overlap with *multiple* other facilities. There is a very large number of utility scale solar projects in North Carolina that are likely to be impacted by the proposed rulemaking change and QF developers in the state will be threatened with considerable costs and burden associated with such changes. Southeast Public Interest Organizations are not aware of any of the sort of "circumvention" that the NOPR seeks to eliminate through this amendment occurring in North Carolina, despite the fact that North Carolina leads the country in PURPA QF solar capacity.

South Carolina, with its nascent but growing QF development, will also be negatively impacted by the proposed ten-mile rule, particularly for any QF recertification. The map below shows all of the ten-mile zones surrounding existing and under-construction solar QF facilities in South Carolina. At best, QFs will have to undertake the time and expense to report to FERC any other facilities within these zones. At worst, QFs' certification or recertification will be subject to challenge under the proposed rule and QFs could lose their rights under PURPA.

Figure 4. South Carolina Utility-Scale Solar Buffer Map – 2019



In contrast to the proposed ten-mile rule in the NOPR, the current one-mile rule sets an appropriate limit with clear guidance while still encouraging the development of renewable resources as required by PURPA. The proposed rule does not appear targeted at solar QF projects in the Southeast, but the implications are significant and should be considered. The proposed ten-mile rule has the potential to subject operational and pending projects to a whirlwind of litigation without public benefit. The bare administrative law stricture of "reasonableness" mitigates against a ten-mile rule and in favor of the tested and bright-line one-mile rule.

i. Undefined Third Parties

The NOPR proposal to allow undefined third parties or "others" to challenge a QF's status under the rebuttable presumption ten-mile rule is also problematic.[108] The NOPR allows the Commission, *sua sponte*, to challenge certification, along with incumbent utilities, and also leaves open the possibility for undefined "others" to challenge QF status.[109] As the Commission has long recognized, certainty is essential for QF project financing. Opening the door for any number of challenges to QF status such as proposed will inject unnecessary uncertainty for QF developers seeking project financing, and it will most certainly have the impact of discouraging, rather than encouraging QF development.

ii. Factors Test

The NOPR includes a set of physical and ownership factors that a challenging entity or a QF may rely upon when arguing over separation of facilities located between one and ten miles from each other.[110] In general, it is reasonable and defensible that QFs should have the opportunity to proactively show they are separate facilities and defend against challenges to their QF status. However, the NOPR proposes that no single factor would be dispositive to defend a rebuttal action, and this is concerning. Ownership of facilities should be a dispositive factor. In other words, facilities that are shown to be owned by two separate entities should immediately, without further challenge, be considered separate facilities for the purposes of QF certification

[108] NOPR, *supra* note 2, at ¶ 102.
[109] *Id*.
[110] *Id*. at ¶ 105.

and recertification. There is no rational basis for assuming that two separately owned facilities may be trying to "circumvent" the PURPA regulations. Therefore, *lack of common ownership* should be a dispositive factor in the analysis.

Furthermore, facilities previously certified as "separate" within the parameters of PURPA QF certification should be allowed to show previous certification as a dispositive factor in the analysis on recertification unless some significant change has occurred at the facility. This dispositive factor should be allowed for QFs certified under any adopted new rules and those certified under the one-mile rule currently in effect. This would be a significant improvement to the rule as proposed and would serve to limit the amount of litigation or other challenges associated with legacy PURPA projects seeking recertification under changes to the one-mile rule.

Regarding the remaining proposed factors, several are problematic. Key factors that *should be* considered include whether the project(s) at issue may have a common point of interconnection or a single real estate parcel or owner. Factors beyond these two are overly expansive. In particular the list of "physical characteristics" is far too broad and unclear.[111] For instance, "infrastructure" is undefined and ambiguous, lending itself to different interpretations and scrutiny. Similarly, "control facilities", "access and easements", "collector systems or facilities", and "property leases" are all problematic insofar as they are too vague and could be construed in different ways.

The long list provided under "*ownership/other characteristics*" as written is perhaps the most problematic and heightens a standard beyond comparable legal precedent in determining whether two entities are legally separate.[112] For example, "control and maintenance," particularly

[111] *Id*.
[112] *See id.*

in North Carolina where there are many utility scale solar facilities, is often contracted for by a limited number of solar maintenance companies.[113] To that end, allowing for the *maintenance company* of neighboring solar facilities to be in any way determinative of QF status opens the door for frivolous certification challenges. Likewise, the sale of electricity to a common utility, the financing of a project through a mutual lender, the construction of a facility through a mutual contractor, the timing of contract execution, and the timing of facilities being placed into service are all factors listed in the NOPR which do not provide relevant evidence as to common ownership requiring facilities to be considered a single unit.[114] The use of these factors will likely prejudice solar facilities constructed nearby each other that used common associates, contractors, or partnering organizations or entities. This is especially troubling given the significant number of projects developed under the previous one-mile rule and potentially impacted by this proposed rule due to its application to the recertification process. These factors are expected to increase regulatory burden and expensive litigation, while failing to support the intent of PURPA to encourage QF development.

Many of the factors identified by the Commission are routinely present in the case of facilities that are unquestionably not located at the same site. For example, because of the costs and complexity of financing the construction of QFs, developers frequently secure financing for a portfolio of distinct projects that may be hundreds of miles apart or even located in different states.[115] Since common financing regularly occurs in the case of clearly distinct facilities, it

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[113] *See id.*
[114] *See id.*
[115] *See e.g.*, STOEL RIVES SOLAR ENERGY TEAM, THE LAW OF SOLAR: A GUIDE TO BUSINESS AND LEGAL ISSUES ch. 7 at 2-3 (5th ed. 2017) http://files.stoel.com/files/books/LawofSolar.PDF (explaining that solar developers may finance projects through a portfolio in which “multiple different projects can be financed together by transferring ownership of multiple project SPVs to the same holdco …” this “allows an investor to diversify its risk among multiple different projects through a single point of investment.”); Chris Groobey et al., *Project Finance Primer for Renewable Energy and Clean Tech Projects*, WILSON SONSINI GOODRICH & ROSATI 11(Aug. 2010), https://www.wsgr.com/PDFSearch/ctp_guide.pdf (suggesting that “in connection with the time consuming nature of

sheds no light on whether two facilities claimed to be distinct are in fact one facility and should be treated as such. Simply put, common financing has no rational link to a determination that two facilities are co-located. All these factors that are frequently present in the case of separate facilities should be eliminated as they add no value and are likely to be used by utilities to mount unjustified challenges to QF certification.

The NOPR proposes to use the same problematic factors when evaluating whether two companies are "affiliates" as defined by 18 CFR § 35.36(a)(9).[116] Facility owners or representatives must be provided with due process, but the heightened factor analysis outlined in the NOPR is expected to needlessly increase litigation and create more problems than it seeks to solve. The specter of increased litigation will also add to the underlying costs for project planning and budgeting, ultimately discouraging QF development and negatively impacting those who seek competitively priced renewable and cogeneration PURPA energy. For all these reasons, we urge the FERC to rescind the currently proposed revisions to the one-mile rule.

iii. Form 556

Related to changes to the one-mile rule, some of the changes proposed to Form 556 regarding facility reporting are problematic.[117] For example, the NOPR includes a separate line item on Form 556 to be completed during facility certification which lists "facilities whose nearest electrical generating equipment is *greater than 1 mile and less than 10 miles* from the electrical generating equipment of the instant facility."[118]

This added requirement will needlessly increase costs associated with certification of a facility. Requiring a developer to draw out a radius line 10 miles wide from the newly-defined

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complying with the covenants set forth in project financing documentation that there may be certain economies of scale, particularly where the individual projects are smaller, to arranging project financing on a portfolio basis.").
[116] NOPR, *supra* note 2, at ¶ 106.
[117] *Id.* at ¶¶ 107, 111-17.
[118] *Id.* at ¶ 112.

edge of each of its electrical generating equipment and report on other projects within that zone will undeniably increase time, effort, and costs required for certification. Furthermore, this reporting requirement directly conflicts with the "rebuttable presumption" proposal that otherwise places the burden on a challenger to rebut the presumption that facilities more than a mile apart are considered separate facilities. The added Form 556 requirement greatly increases the burden on a QF that is already presumed to be separate from other QFs more than a mile away.

Requiring facility owners to show how distances were calculated as proposed in Paragraph 114 of the NOPR also needlessly increases burden on the facility presumed to be separate.[119] Identifying specific electrical generating equipment and "associated geographic coordinates" will require substantial work to be done by the applicant facility above and beyond what should be necessary for a presumed "separate" facility to show it is indeed distinct from nearby facilities.[120]

B. In the Alternative, Should FERC Implement the Rebuttable Presumption Amendment to the One-Mile Rule, Certain NOPR Proposals Should be Adopted to Mitigate Negative Impacts

Some of the suggestions in the NOPR regarding separate facilities should be implemented. For instance, the explanation of how to measure the distance between generation facilities is expected to be helpful.[121] A clarifying amendment to 18 CFR § 292.02 to include a definition of "electrical generating equipment" and 18 CFR § 292.04(a)(2)(i) to specify how to measure the distance between facilities that have multiple separate sets of "electrical generating

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[119] *Id.* at ¶ 114.
[120] *Id.*
[121] NOPR, *supra* note 2, at ¶¶ 108-10.

equipment" appears reasonable.[122] This includes clarifying the issue "as to whether the one-mile is measured from the edge of the panels at one solar facility to the edge of the panel at the next facility, or from the center point of each array."[123]

Southeast Public Interest Organizations support the NOPR suggestion of an irrebuttable presumption that facilities over ten miles are separate, and as described earlier, we assert that facilities below this threshold should continue to have an irrebuttable presumption that they are separate from nearby QFs.[124] We further see as reasonable an amendment to Form No. 556, item 8, wherein the applicant need only include affiliate QFs and may exclude non-QFs affiliates.[125]

As described in more detail in the previous section, Southeast Public Interest Organizations oppose the proposed amendments regarding the rebuttal presumption for facilities between one-to-ten miles apart. If, however, FERC moves forward with this proposed change, the following provisions could provide a minimal check on the rebuttable presumption process:

1) the provision "allowing an entity seeking QF status to provide further information in its certification (both self-certification and Commission certification), to preemptively defend against rebuttal by asserting factors that affirmatively show that two facilities are indeed separate facilities at separate sites"[126];
2) the requirement that challenging entities make a "prima facie" case when alleging that QFs more than a mile apart are the same facility[127]; and

[122] *Id.*
[123] *Id.* at ¶ 99.
[124] *See id.*at ¶ 101.
[125] *Id.* at ¶ 115.
[126] *Id.* at ¶ 103.
[127] *Id.* at ¶ 104.

3) the determination that earlier certified QFs have the benefit of presumed status with the onus on the challenging entity to prove a change of circumstances occurred which calls to question the nature of the facility.[128]

VIII. PURPA Section 210(m) Rebuttable Presumption of Nondiscriminatory Access to Markets – Reducing the Rebuttable Presumption from 20 MW to 1 MW Will Discourage QF Development

The FERC proposal would reduce the rebuttable presumption for nondiscriminatory access in RTOs from 20 MW to 1 MW.[129] The Commission first established in Order No. 688 the rebuttable presumption that QFs with a capacity at or below 20 megawatts ("MW") do not have nondiscriminatory access to markets.[130] The Commission's determination was based on recognition of market barriers that smaller QFs often encounter.[131] The Commission found that such difficulties supported a rebuttable presumption that smaller QFs have "substantially less ability to access wholesale markets than do larger QFs."[132]

The presumption that smaller QFs have substantially less ability to access wholesale markets remains valid today in Virginia and a portion of eastern North Carolina, which participate in PJM. In fact, the Commission has found in recent years that utilities in PJM have failed to rebut the presumption of nondiscriminatory access of QFs, citing market barriers

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[128] *Id*.

[129] *Id.* at ¶¶ 118-30.

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

[131] These barriers include constraints based on QF interconnection at the distribution level rather than the transmission level, as well as obstacles that larger QFs would not have to overcome, such as jurisdictional differences, pancaked delivery rates, and administrative burdens to obtaining access to distant buyers. Order No. 688-A, FERC Stats. & Regs. ¶ 31,250 at ¶¶ 94-103; *see also PPL Elec. Utilities Corp.*, 145 FERC ¶ 61,053 at ¶¶ 3-4, 23-24; (Oct. 17, 2013) (affirming FERC's findings in Order Nos. 688 and 688-A).

[132] Order No. 688-A, FERC Stats. & Regs. ¶ 31,250 at ¶ 96. The Commission further explained that it set this rebuttable presumption at 20 MW, rather than at a much smaller size of one or two MW, to reflect its understanding of "the general nature of QFs' interconnection practices and the relative capabilities of small entities" to participate in markets. *Id*. at ¶ 101.

espoused in Order 688.[133] The Southeast market is not as mature as assumed in the NOPR.[134] Small QFs are still part of a nascent market in this region and there is no evidence in the record to support a conclusion that they have meaningful, nondiscriminatory market access. The Commission should maintain the 20 MW presumption, as many of the same barriers to market access at the time the Commission promulgated Order 688 continue to hamper access for smaller QFs today.

Significantly, the rest of the Southeast does not have an RTO. As a result, QFs of *any* size lack nondiscriminatory access to markets. This lack of access to markets for QFs exemplifies the continued need for PURPA's mandatory purchase obligation for all QFs, even those above 20 MW. Further, if FERC were to reduce the threshold from 20 MW to 1 MW, and an RTO was established in the Southeast, particularly in North and South Carolina, existing PURPA QFs could potentially be stranded at the end of their existing contracts. If small QFs continue to lack nondiscriminatory access to markets, even in RTOs, as FERC determined in Order 688 and 688-A, it is highly likely that the large number of 5 MW QFs in North Carolina and 2 MW QFs in South Carolina would not have sufficient access to markets in which to sell their output after the expiration of their initial contract.[135] The stranding of these assets would be an unjust and unreasonable outcome. FERC should not support this outcome and should instead strengthen and

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[133] *See e.g., PPL Elec. Utilities Corp.*, 145 FERC ¶ 61,053 ¶ 24 (Oct. 17, 2013) (denying PPL Electric Utilities Corporation's petition to terminate its purchase obligation for QFs at or below 20 MW because PPL failed to overcome the rebuttable presumption that these facilities lacked nondiscriminatory access to the PJM markets); *Virginia Elec. & Power Co.*, 151 FERC ¶ 61,038 ¶ 21 (Apr. 16, 2015) (denying Virginia Electric and Power Company's petition to terminate its purchase obligation for QFs up to 20 MW). FERC *has* found the presumption rebutted on at least two occasions, after the QFs at issue had already sold power into the incumbent RTO. *See Fitchburg Gas and Elec. Light Co.*, 146 FERC ¶ 61,186 ¶¶ 32-33 (Mar. 14, 2014); *City of Burlington*, 145 FERC ¶ 61,121 ¶ 36 (Nov. 13, 2013).

[134] NOPR, *supra* note 2, at ¶ 126.

[135] For a number of years the North Carolina Utilities Commission approved a standard offer for QFs up to 5 MW in size, and South Carolina now has a 2 MW size limit for standard offers, which was previously the standard offer limit for QFs in Duke Energy's South Carolina territory. These standard offer thresholds result in projects being built at or just below that size.

protect PURPA implementation to meet the purposes for which the law was enacted, to reduce fossil fuel use and encourage small power production.

IX. Proposed Commercial Viability Requirements for LEOs Lack Adequate Justification and Will Discourage QF Development

Obtaining project financing remains a major hurdle for QF developers, including those in the Southeast. While it may be appropriate to develop modest parameters to screen out frivolous LEO solicitations to utilities, the Commission's proposed commercial viability requirement pushes the timeline for getting a LEO too far back in the "development cycle."[136] There are two primary issues with this proposed revision: (1) the NOPR fails to provide sufficient evidence to show that unviable QFs obtaining LEOs is a problem in need of solution; and (2) it will discourage QF development since achieving some of the indicia suggested by the Commission often circularly requires that QF developers have *already* obtained financing.

A. The Commission Has Not Sufficiently Demonstrated that this is a Problem in Need of a Solution

The right to a LEO is a core promise of PURPA. LEOs represent both a utility's commitment to pay for QF electricity and a QF's ability to lock in a particular avoided cost rate. They are relied on by QF developers to demonstrate financial certainty.[137] Before implementing a proposal that would burden QF developers, the Commission first needs to show that a problem exists. While it may be plausible that LEOs could be sought by QF developers for economically unviable QF projects and encumber the utility resource planning process, neither the

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[136] *See* NOPR, *supra* note 2, Commissioner Glick Dissent, at ¶ 24.

[137] NOPR, *supra* note 2, Commissioner Glick Dissent, at ¶ 11 (quoting Todd Glass, Attorney, Wilson Sonsini Goodrich & Rosati, Remarks on behalf of the Solar Energy Industries Association, Federal Energy Reguatory Commission's Technical Conference on Implementing Issues Under the Public Utility Regulatory Act of 1978 (June 29, 2016), Docket No. AD16-16-000 Technical Conference Tr. at 26:22-25, 27:1-3 ("The Power Purchase Agreement is the single most important contract of the development and financing of an energy project that's not owned by a utility. Without the long-term commitment to buy the output of that agreement at a fixed price, there is no predictable stream of revenue. Without a predictable stream of revenues, there is no financing. Without any financing, there is no project.")).

Commission nor other commenters have provided sufficient evidence to show that this is the case. In its proposal, the Commission asserts that "some" QFs have argued that a LEO is created when they merely communicate that they "intend" to supply power to their incumbent utility at some point in the future.[138] The only "evidence" cited in the NOPR to this effect are Comments from Xcel Energy Services Inc. and Supplemental Comments from the Edison Electric Institute ("EEI") but, because EEI only cites to a single example in its Comments, this evidence, at most, only reflects the experiences of two utilities.[139] Moreover, Xcel and EEI failed in their comments to cite to any specific examples of unviable QF projects encumbering the utility resource planning process.[140]

B. The Commission's Proposed Requirements Will Discourage QF Development by Permitting States to Establish Indicia that Are Too Burdensome

Beyond a lack of evidentiary support for more stringent LEO requirements, the proposed commercial viability and financial commitment requirements should not be enacted because they are inconsistent with the Congressional intent behind PURPA to encourage QF development. In order to obtain project financing, QFs must be able to demonstrate commercial viability to investors in the form of predictable, quantifiable revenue streams.[141] Some of the "indicia" suggested in the NOPR for state adoption cannot reasonably be undertaken by QFs until they have a known contract price and can thus assess the economic viability of their project. The reality is that there is a range of time and steps between when a QF's LEO solicitation might truly be specious (*i.e.* before *any* steps are undertaken) and when a state's condition precedent

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[138] NOPR, *supra* note 2, at ¶ 138.
[139] *See Id.*; EEI Supplemental Comments, Docket No. AD16-16-000, attach. A at 7 (June 25, 2018) (citing *Western Water and Power Production Limited LLC* (*Western Water*), Notice of Petition for Enforcement, Docket Nos. EL17-17 and QF11-516 (Nov. 7, 2016)); Xcel Comments, Docket No. AD16-16-000, at 15-16 (Nov. 7, 2016) (citing to case law regarding LEO obligations but not providing specific examples of unviable QF projects encumbering the utility resource planning process.).
[140] *Id.*
[141] NOPR, *supra* note 2, Commissioner Glick Dissent, at ¶ 11.

requirements for getting a LEO are unreasonable under current FERC precedent (*i.e.* a fully executed contract or interconnection agreement).[142] The three suggested indicia in the NOPR—"(1) obtaining site control adequate to commence construction of the project at the proposed location; (2) filing an interconnection application with the appropriate entity; [and] (3) securing local permitting and zoning"—span this range.[143] Further, the inclusion of an open-ended, catch-all fourth indicium means that states are free to set requirements all the way up to, but not including, fully executed agreements.[144] While these indicia all ensure the utility's interest in screening out frivolous LEO solicitations, they do not all reasonably protect QFs' interests. Indeed, this proposal is not meaningfully narrowing the range of "wildly divergent LEO tests that have been adopted by states across the country" since it only really precludes expression-of-interest LEOs.[145] Some suggested indicia are reasonable and allow for a showing of commercial viability without burdening QF development. Site control typically occurs early in the development cycle, often being one of the first concrete actions undertaken by developers.[146] A site control indicium should both address the potential problem while not unduly burdening project development.

Other indicia proposed, however, are expected to significantly discourage QF development. The suggested local zoning and permitting requirement is particularly problematic. Securing these permits can be time-consuming and costly, especially if some members of the community are opposed to a project. Pre-financing QFs may not have the resources to wait out a lengthy permitting process. As one QF developer testified in a recent South Carolina proceeding,

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[142] *See*, *e.g.*, *Murphy Flat Power, LLC*, 141 FERC ¶ 61,145, at ¶ 24 (2012) (holding that requiring a signed and executed contract with an electric utility as a prerequisite to a LEO is inconsistent with PURPA Regulations).
[143] NOPR, *supra* note 2, at ¶ 141.
[144] *See id*.
[145] Solar Energy Industries Association Comments, Docket No. AD16-16-000, at 49 (Aug. 28, 2019).
[146] *See*, *e.g.*, *Key Steps of the Utility-Scale Solar Project Development Process*, URBAN GRID, (Jan. 16, 2019), https://www.urbangridsolar.com/solar-project-development-process-understanding-the-steps/ (listing identifying and acquiring land for the site as the first steps in the development cycle).

"[o]btaining environmental permits and land-use approvals can be an expensive and time consuming process, sometimes costing in the hundreds of thousands of dollars. It is unreasonable to expect a QF to incur these expenses until it has secured a price for its output so that it can in turn secure financing for the project."[147] The South Carolina Commission ultimately rejected Dominion Energy South Carolina and Duke Energy's proposals to impose such a permitting condition on LEO formation.[148] FERC should likewise abandon the proposed permitting indicium given the likelihood that it will discourage rather than encourage QF development.

Conclusion

The Southeast Public Interest Organizations appreciate the opportunity to provide input on the NOPR. We urge the Commission to reconsider the NOPR in its entirety, and particularly the portions that will discourage rather than encourage QF development, as described in these comments. In the Southeast, PURPA continues to serve a critical role in the encouragement of qualifying facilities to address many of the same issues that led Congress to enact the statute in 1978. In many of these states, PURPA is the only legal tool available to support the development of independent power producers that promote energy independence, reduce reliance on fossil fuel generation, and provide low-cost renewable energy to ratepayers.The majority of the Southeastern states still have a nascent renewable energy market due to inadequate implementation of PURPA. Thus, the varying levels of success of PURPA provide a guidepost for how the NOPR will impact PURPA implementation going forward. If the experiences of the

[147] Direct Testimony of Steven Levitas, S.C. Public Service Commission, Docket No. 2019-184-E, at 27-28 (Sept. 23, 2019), https://dms.psc.sc.gov/Attachments/Matter/c35e8fd7-a16e-49ed-af19-143f29baadf8 (explaining the difficulties with requiring QF to secure all required land-use approvals and environmental permits prior to LEO formation).

[148] S.C. Public Service Commission, Directive, Docket No. 2019-184-E at 6 (Nov. 15, 2019), https://dms.psc.sc.gov/Attachments/Matter/2e0705e6-9cfe-4783-bbcc-0a4c07fcdc56; S.C. Public Service Commission, Directive, Docket No. 2019-185-E, at 6 (Nov. 15, 2019), https://dms.psc.sc.gov/Attachments/Matter/f9205af9-fdf1-40ed-afc4-c00c348659ad; S.C. Public Service Commission, Directive, Docket No. 2019-186-E, at 6 (Nov. 15, 2019), https://dms.psc.sc.gov/Attachments/Matter/cb3458f1-6f5d-4a0d-a6b8-b02d354fc2c9.

independent power producers in the Southeast can be the guide, the proposed changes in the NOPR will not satisfy the policy objectives of PURPA.

As a result, the Southeast Public Interest Organizations urge the Commission to rescind the NOPR. For the Southeast, one of the most problematic provisions is the proposal to vary energy rates, which will directly and negatively impact QF project financing, and has already led to failed PURPA implementation in a number of states in our region. The proposed changes to the one-mile rule are expected to have significant and wide-reaching impacts in North and South Carolina, and potentially other states, particularly for QFs seeking recertification. Other NOPR proposals aimed at using market-oriented rates for QF compensation raise concerns and warrant closer scrutiny. The proposals regarding commercial viability and the LEO standard will further discourage QF development through overly burdensome and costly indicia like obtaining local and environmental permits prior to obtaining a LEO. The aggregate weight of these concerns and implications warrant withdrawal of the NOPR and consideration of changes to FERC regulations that would instead strengthen and protect PURPA implementation in places where it is most needed, such as the Southeast.

Finally, Southeast Public Interest Organizations reiterate a previous recommendation made in the SELC et al. Oct. 2018 Supplemental Comments to FERC. Namely, that any Commission review of its PURPA regulations include a survey of existing implementation by state regulatory authorities and nonregulated electric utilities in order to determine where current state implementation does not comply with PURPA and the Commission's regulations, to investigate existing barriers in wholesale markets that prevent nondiscriminatory access for qualifying facilities, and to evaluate opportunities to strengthen and protect PURPA implementation.

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