

The Urgency of PURPA Reform to Assure Ratepayer Protection

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1 | Introduction

The Public Utility Regulatory Policies Act (or “PURPA”), just celebrated its 40th anniversary in the midst of controversy and debate over some of its hallmark regulatory requirements. One of these requirements is the provision that utilities purchase electricity from certain types of non-utility generators at rates that purportedly reflect the utility’s costs, not those of the renewable generator. Renewable generators are taking advantage of this federal legislation by attempting to force utilities, and their state regulators, to purchase their energy at inflated rates, over long contract durations, regardless of whether the energy is needed or not.

An estimated 45,000 MW of renewable PURPA “Qualifying Facility” (QF) capacity has been developed over the past decade. It is reported that another 24,000 MW of QF capacity is under development and about 75 percent of that is solar.¹ The cost of these new wholesale power purchase requirements would be in addition to the estimated \$108 billion of PURPA-related renewable energy purchases already incurred over the past decade. It is not surprising, therefore, that the need to reform PURPA is both important and controversial.

Some renewable energy developers are trying to frame the PURPA reform debate as a fight between themselves and the monolithic monopoly utility industry. Setting up the debate like this may make for good politics, but it intentionally obscures the true victims of PURPA abuse which is not regulated utilities, or their shareholders, but rather the captive ratepayers of these utilities that are stuck servicing these over-priced long-term renewable power agreements. Utilities, while often sympathetic and supportive of PURPA reform, simply pass along the excessive costs associated with PURPA-related renewable energy purchases to their ratepayers.

Thus, PURPA reform is not one that seeks to benefit regulated utilities as much as it is a public policy initiative that should eliminate a set of regressive and excessive subsidies that benefit large renewable generation developers and their investors and burden retail ratepayers. Continuing to allow these renewable developers to abuse these PURPA provisions is: (1) inconsistent with its original legislative goals; (2) will create long-term ratepayer cost recovery burdens; (3) will continue to incent excessive, uneconomic renewable energy capacity development; and (4) will increase ratepayer costs.

¹ Mudge, R., et al. New technologies and old issues under PURPA. Norton Rose Fulbright. February 20, 2018.

2 | Understanding PURPA's Original Goals

In 1978, Congress passed the National Energy Act (“NEA”) as a legislative response to the 1973 energy crisis. The purpose of the NEA was to ensure sustained economic growth during a period in which the availability and price of future energy resources was becoming increasingly uncertain. The NEA was composed of five different statutes.² While many aspects of the NEA affected the electric power industry, PURPA was its most significant component. PURPA’s intent was to encourage: (1) the conservation of energy supplied by electric utilities; (2) optimal efficiencies in electric utilities facilities and resource use; and (3) that equitable rates were established for electric consumers (ratepayers).^{3,4} Nowhere in the PURPA’s electric provisions is there a requirement or specification to explicitly “promote” renewable energy, an often misrepresented and misstated claim made by renewable energy advocates in the PURPA reform debate.

To accomplish its goals, PURPA established a new class of generating facilities that would receive special rate and regulatory treatment.⁵ These facilities are known as “non-utility generators” or more commonly “qualifying facilities” (“QFs”). PURPA requires utilities to purchase electricity generated by QFs at the utility’s avoided cost, not the QF generator’s cost of service. A utility’s avoided cost is the cost a utility would incur if it chose to generate the electricity itself or purchase it from another source.⁶ PURPA charged the Federal Energy Regulatory Commission (“FERC”) with administering its provisions and developing a set of regulations under which QFs operate. Equally important are the provisions in PURPA that left implementation of these regulations up to the individual states, and states have done so in a number of ways including setting specific terms for utility purchases of QF generation, such as the avoided cost calculation, contract terms, and capacity thresholds.

3 | Why PURPA's Buy-back Provisions Are Unnecessary

PURPA effectively changed the regulated utility monopoly model by mandating QF purchases from all types of generation, including renewable and that associated with combined heat and power (“CHP”) or cogeneration applications. Wholesale markets have been in a frequent state of reform ever since that time period rendering many PURPA

² The Public Utilities Regulatory Policy Act (PURPA); the Energy Tax Act; the National Energy Conservation Policy Act; the Power Plant and Industrial Fuel Use Act (FUA); and the Natural Gas Policy Act.

³ 16 U.S.C. § 2611.

⁴ PURPA also included provisions for natural gas utilities, small hydroelectric power projects, crude oil transportation systems and other miscellaneous provisions.

⁵ Federal Energy Regulatory Commission. 2018. What is a qualifying facility? Available at: <https://www.ferc.gov/industries/electric/gen-info/qual-fac/what-is.asp>.

⁶ 18 C.F.R. § 292.101(b)(6).

provisions unnecessary. In fact, in a 2017 letter to FERC recommending comprehensive changes to PURPA, the National Association of Regulatory Utility Commissioners (“NARUC”) noted a number of important industry changes^{7,8} that support PURPA reform.

First, NARUC noted that while PURPA initiated the development of wholesale electricity competition, it was the Energy Policy Act of 1992 (“EPAAct”) that fundamentally changed the industry by granting FERC the authority to open electric transmission systems on a non-discriminatory basis and allowing wholesale generators to provide power in direct competition with utilities. EPAAct, in conjunction with a series of subsequent FERC Orders such as Order 888, Order 889 and Order 2000, outlined the methods by which wholesale competition would be achieved and defined the institutions that would facilitate and govern wholesale market interactions.⁹ These collective statutory and administrative actions eliminated many market access issues faced by non-utility generators, fossil fuel-fired generators and renewable energy projects alike.

Second, and as a corollary to competition, is the fact that FERC required all electricity utilities, as part of Order 888 and Order 889 to file what are today known as Open Access Transmission Tariffs (or “OATTs”). These OATTs govern the terms and conditions of non-utility access, among other things, to the wholesale electricity grid. One of the primary requirements of an OATT is to explicitly outline non-discriminatory terms for generator interconnection. Utilities are required to provide interconnection and pricing terms to non-affiliate entities on the same terms and conditions as those they provide to their own affiliates.

Third, a number of initiatives at both the federal and state level have been implemented to specifically promote renewable generation. Federal initiatives, comprised primarily of a series of tax credits and other tax breaks, have been successful in promoting the development of renewable energy capacity. More important has been a series of state-level initiatives, starting in 2005 (a year of high natural gas prices), that have led to heavily subsidized and guaranteed markets for renewable generation. The establishment of “renewable portfolio standards,” or “RPS” polices, have propelled renewable capacity development throughout most of the U.S. as seen in Figure 1.

In addition to state-level initiatives, state policy decisions have been made to give rate preference to renewable generation over traditional fossil fuel generation. For instance, in Oregon, the Public Utility Commission requires investor-owned utilities to offer a QF renewable price depending on whether the power is “green,” meaning QFs are selling their power with attached renewable energy attributes; or “brown,” meaning QFs are selling just

⁷ NARUC is a non-profit organization that represents state public service commissions who regulate energy, telecommunications, power, water and transportation utilities.

⁸ In re: Public Utilities Regulatory Policies Act of 1978 Regulator Reform. NARUC letter

⁹ FERC Order 888 was actually a series of orders that promoted wholesale competition by requiring all public utilities to have open access non-discriminatory transmission tariffs; Order 889 set standards regarding information that utilities must make available to the market; and Order 2000 advanced the formation of Regional Transmission Organizations (“RTOs”).

power, without renewable energy certificates.¹⁰ Originally, the assumption underlying this choice between prices was the idea that renewable resources would be more expensive than traditional resources. However, updated avoided cost filings show that renewable prices are actually lower than non-renewable prices, giving renewable QFs the opportunity to select prices that are not reflective of actual avoided costs.¹¹

While PURPA was not specifically intended to promote renewable energy, state policies, nonetheless, have filled in this gap so there is no need to use PURPA to duplicate what state policies have already accomplished.

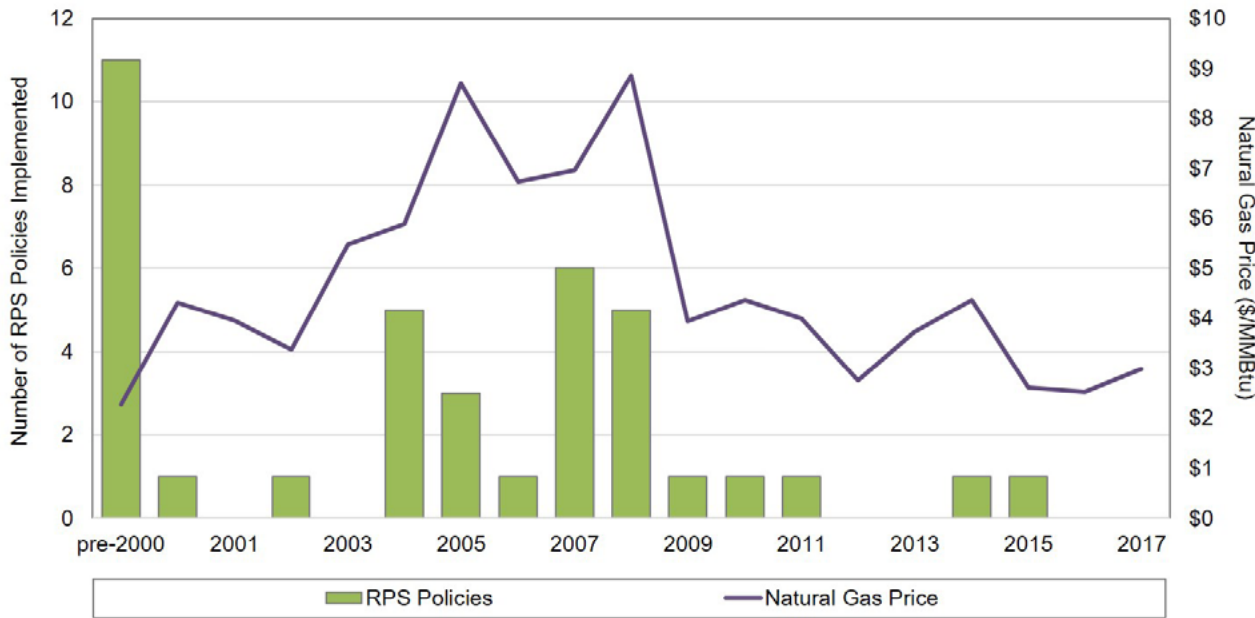


Figure 1: State RPS Adoption and Annual Natural Gas Prices.

Source: U.S. Energy Information Administration; and NC Clean Energy Technology Center.

Finally, the current electric power industry is made up of a large number of competitive suppliers; something not imaginable back in the early 1980s when PURPA was originally being implemented. Today, a regulated utility of any kind, as well as any large wholesale purchaser, can access a variety of spot markets, forward markets, financial derivatives and other tools to secure and hedge electricity purchases. States can now conduct competitive solicitations for large amounts of renewable capacity and can expect numerous responses

¹⁰ Sanger Thompson PC. 2018. Oregon Commission requires PacifiCorp to purchase renewable power from large independently owned generators. Available at: <http://www.sanger-law.com/oregon-commission-requires-pacifcorp-to-purchase-renewable-power-from-large-independently-owned-generators/>.

¹¹ In the matter of PacifiCorp, dba Pacific Power, updates standard avoided cost purchases from eligible qualifying facilities. Public Utility Commission of Oregon, Docket UM1729. Order. August 9, 2018, p. 3; and In the matter of PacifiCorp, dba Pacific Power, application to update Schedule 37 qualifying facility information. Public Utility Commission of Oregon, Docket UM1729. Motion for emergency interim relief. April 26, 2018.

and bids from creditworthy market participants. Again, something that was a challenge back in the early days of PURPA implementation is, today, simply commonplace.

4 | Ratepayer implications

Renewable energy advocates often dismiss arguments for PURPA reform as being motivated by utilities wanting to maintain their monopoly privileges by shunning competition and customer empowerment that is purportedly facilitated by renewable QFs. This kind of argument makes for good press, and potentially good politics, but fails to recognize that utilities are more-or-less indifferent to long-term QF contracts because the costs of these over-priced contracts are simply passed on to ratepayers through fuel adjustment clauses (“FACs”) and/or a utility’s overall cost of service.

A reimbursement rate that is equivalent to the utility’s “avoided cost” sounds reasonable since prices in competitive markets are often set by cost, and in particular, the marginal costs that these rates are intended to represent. However, the similarity between what is envisioned by PURPA and what happens in real markets is conceptual only. Avoided costs are rarely reflective of the actual cost-based prices that characterize wholesale electricity markets, and the pseudonym “administratively-determined,” when used in conjunction with avoided costs, is simply political-speak for “set by regulators, not markets.” Regulators attempting to “promote” renewable energy through the manner in which they set these prices, and QF contract terms, often do so at the expense of ratepayers in a number of different ways.

First, ratepayers are often burdened with paying for renewable QF generation at “administratively-determined” (i.e., “set by regulators”) avoided cost rates that are higher than market prices. These avoided “cost” rates can be out of sync with markets for a number of reasons. For instance, many states allow for premiums or “adders” to be included as part of the avoided cost payment to “encourage” the development of a particular resource type or to reward a resource for its environmental attribute. This was the original intention in Oregon for setting different QF rates for “green” or “brown” power.

In other states, these premiums can be added to administratively-determined avoided cost rates in order to ensure a QF’s ability to secure financing. Most often, the calculation of avoided cost reflects the “all-in” capital cost of developing a new natural gas-fired resource, which includes the capacity, operation and fuel costs, on a levelized basis. Even though this calculation is “cost-based” and unitized, it often results in a rate that is higher than market prices, particularly when markets are long on capacity, which is the case in many of today’s regional wholesale markets.

State approaches for calculating avoided costs can vary. Many states use a “proxy method” where a particular type of generating facility (e.g. combined cycle gas turbine) is used as a proxy for comparison to measure avoided fixed and variable costs. This method assumes that a regulated utility is building a hypothetical natural gas unit and that: (a) the estimated fixed cost can be used to establish an avoided capacity cost; and (b) the estimated variable costs can be used to determine the avoided energy cost. Other states use a “peaker unit” methodology that assumes a QF will allow the utility to avoid paying the marginal generating unit on its system (usually a combustion turbine). Both of these methods however, can overstate the true market cost, particularly if the proxy or peaker “reference” generators cost more to build and operate than a renewable resource, or if the costs of developing these reference units are out of sync with current market conditions, particularly in markets that have excess generation capacity.

Second, QF provisions require ratepayers to fund QF capacity regardless of whether the capacity or generation is needed. Today’s electric utilities are already suffering from a number of growth-related challenges – and those challenges involve not enough growth, or too much growth. Consider that most states have passed legislation or promulgated rules and/or regulations requiring utilities to promote energy efficiency and demand-reduction programs. These government-mandated electricity demand reduction requirements, coupled with ongoing technological innovation facilitating end-use efficiency, have led to considerable reductions in electricity use per customer (UPC”) and overall electricity growth. Requiring utilities to purchase QF electricity in the face of this flat electricity growth outlook simply requires ratepayers to pay for electricity that they do not need.

Third, and likely less appreciated, is the fact that many states are subsidizing renewable QF projects through their contract terms that afford project developers a high degree of ratepayer “underwriting” or “securitization.” For instance, very few developers will go out into today’s market and develop a multi-million dollar, if not billion-dollar generation asset without having the benefit of some form of long-term contract to “back-up” that asset. PURPA-related, mandatory QF contracts in some states span 10, 15 or 20 years, which are lengthy periods that afford renewable projects a high degree of security in terms of revenue streams. The experience in Montana is a good example of a state attempting to reign in these overly-generous contract terms only to find this reform challenged in court.

Even further, these revenue streams are “backed” by a set of captive utility customers (ratepayers) that will make up any short falls in cost recovery for this QF-contracted capacity. This represents a set of financial and contracting benefits not usually afforded to other traditional fossil-fuel generation resources. To make matters worse, QF developers usually do not have to compete for these contracts through any form of competitive bidding requirement: the contracts are often offered strictly on a standard-offer basis.

While some states do require competitive bidding for QF contracts, unclear guidelines from FERC can muddy the waters. For instance, in Colorado, Xcel Energy issued a competitive solicitation for renewable QF capacity in 2017 that resulted in 430 bids and some of the lowest-cost renewable offers reported.¹² The utility's energy portfolio included a number of these bids and was approved by the state commission. However, a developer that was not awarded a contract in the competitive solicitation claimed that it had a legal right to sell the output of almost 1,400 MW of capacity based on a 2016 avoided cost that was calculated when it had previously established a legally enforceable obligation ("LEO") to the company (before the solicitation).¹³ According to FERC, the date a LEO is formed is the date a QF may have its avoided cost rate determined.¹⁴ As a result, the Colorado Public Service Commission amended its QF provisions effectively removing the rule that a QF can only obtain an LEO through competitive bidding.¹⁵

Fourth, renewable QF contracts can serve as financial liabilities to utilities, in the form of long-term payment requirements that are recorded on a utility's financial statements and evaluated by ratings agencies. An increasing level of these obligations are comparable to adding more debt, thereby increasing utility risks and, more importantly, their overall cost of capital. Increases in a utility's cost of capital are another type of cost that flows directly to ratepayers; yet another financial burden created by what are often unnecessary and expensive QF renewable energy contracts.

Finally, these renewable QF contracts, and their often-overstated avoided cost payments, represent a regressive wealth transfer from ratepayers to unregulated renewable energy developers and their shareholders. These contracts take valuable financial resources away from ratepayers in the form of above-market payments, payments for unnecessary capacity, and the provision of financial underwriting, and effectively transfer those financial resources to QF developers and their shareholders under the guise of "promoting renewables." These wealth transfers are often regressive since they hit lower and fixed-income households harder than they do for the wealthy.

¹² NARUC. 2018. Aligning PURPA with the modern energy landscape. Available at: <https://pubs.naruc.org/pub.cfm?id=E265148B-C5CF-206F-514B-1575A998A847>.

¹³ *Id.*

¹⁴ 18 CFR § 292.304(d)(2)(ii).

¹⁵ In the matter of the proposed amendment to rules regulating electric utilities in relation to qualifying utilities, 4 code of Colorado regulations 723-3-3902(c). Colorado Public Utilities Commission, Proceeding No. 18R-0492E. Decision Adopting Rule Revision, October 31, 2018,

5 | Recent state initiatives

A number of states have attempted to reform the manner in which PURPA has been implemented, particularly with regards to QF contract terms and prices. Recent decisions in Idaho, Montana, and North Carolina have started to set the stage for state-level PURPA reform. These efforts have been controversial with some resulting in federal legal challenges. Thus, the success of state-level reform may be dependent upon changes to federal statute.

In January 2015, Idaho Power filed a petition with the Idaho Public Utilities Commission to reduce QF contract terms from 20 years to two years.¹⁶ Idaho Power noted at the time that it had 1,302 MW of PURPA QF capacity under contract, and another 885 MW of PURPA solar capacity requesting interconnection into its system (often referred to as entering into the utility’s “interconnection queue”).¹⁷ Idaho Power indicated that its current QF contracts totaled \$4.2 billion in ratepayer liabilities and the projects in the queue represented an additional \$2.1 billion in potential liabilities.¹⁸ Idaho Power also stated that the additional capacity of the proposed projects would cause it to exceed its operational need.¹⁹ It is important to remember that these contracts are not backstopped by utilities and their shareholders, but rather by ratepayers and their ability to pay off these generally unnecessary purchase requirements over two decades for each QF project.

Soon after, Idaho’s other regulated electric utilities (Avista and Rocky Mountain Power) filed similar requests.²⁰ The Idaho utilities based their requests for PURPA QF relief on three arguments related to PURPA’s shortcomings:

- ▶ It is unreasonable to require utilities to enter into long-term contracts when there is no need for additional capacity and energy.²¹
- ▶ It is unreasonable to sign long-term fixed-price contracts when wholesale market prices have been falling and are not volatile.²²
- ▶ Avoided costs are recalibrated on a periodic basis to reflect market conditions, customer growth and fuel price forecasts.²³ However, a PURPA QF project receives a 20-year fixed price set at the then-current price with no reopening clauses.²⁴

¹⁶ In the matter of Idaho Power Company’s petition to modify terms and conditions of prospective PURPA energy sales agreements. Idaho Public Utilities Commission Case No. IPC-E-15-01. Idaho Power Company Petition. January 30, 2015.

¹⁷ *Id.*, p. 18.

¹⁸ *Id.*, pp. 3, 20.

¹⁹ *Id.*, pp. 3-4.

²⁰ In the matter of Idaho Power Company’s petition to modify terms and conditions of prospective PURPA energy sales agreements. Idaho Public Utilities Commission Case No. IPC-E-15-01. Order No. 33357. August 20, 2015, pp. 4-5.

²¹ In the matter of Idaho Power Company’s petition to modify terms and conditions of prospective PURPA energy sales agreements. Idaho Public Utilities Commission Case No. IPC-E-15-01. Idaho Power Company Petition. January 30, 2015, pp. 13-16.

²² *Id.*, pp. 14-15

²³ In Idaho, these avoided costs are updated and filed before the Commission every two years.

²⁴ In the matter of Idaho Power Company’s petition to modify terms and conditions of prospective PURPA energy sales agreements. Idaho Public Utilities Commission Case No. IPC-E-15-01. Idaho Power Company Petition. January 30, 2015, p. 16.

A number of renewable energy organizations opposed the utility petitions citing the need to “do what’s right,” “foster solar,” and “promote renewable development.”²⁵ Renewable developers asserted that they would not be able to secure financing without the long-term QF contracts.²⁶ Similarly, one renewable developer cited the lack of attractive state incentives as a need for the long contract length afforded under the state’s QF contracting provisions.²⁷ Developers also stated that investment recovery for utility-owned resources can be up to 50 years and that PURPA resources should be placed on an “equal footing” with these regulated assets.²⁸ These arguments simply underscore the uneconomic nature of some of these renewable QF contracts. In fact, the Sierra Club explicitly argued that reducing contract lengths, and declining avoided cost rates, were “likely to make uneconomic QFs that could be developed at avoided cost prices with a long-term agreement.”²⁹

The Idaho Commission ruled in favor of the utilities’ request to reduce the QF contract term from twenty years to two years. It concluded that it was “self-evident” that long-term avoided cost rates set at the beginning of a contract term would overestimate future avoided costs collected from ratepayers and that 20-year contracts “exacerbate overestimations to a point that avoided cost rates over the long-term period are unreasonable and inconsistent with the public interest.”³⁰

A similar QF contracting controversy arose in Montana, a western state that, like Idaho, is not part of an RTO or ISO. In May 2016, NorthWestern Energy requested approval for new avoided cost rates for QF facilities of three MW or less. NorthWestern noted in its application that its existing QF rates were out of date, notably higher than current avoided costs, and providing “inappropriate incentives” to QF developers.³¹

NorthWestern’s proposed new rate structure was about \$34 per MWh for solar facilities and \$30 per MWh for wind facilities. The avoided cost rates in place were almost double at \$66 per MWh for solar and \$54 per MWh for wind.³² These old prices were set in 2013, and since then, the development of regional excess capacity and low natural gas prices resulted in fundamental changes in the Northwestern’s avoided costs.³³

More importantly, NorthWestern claimed these dated avoided cost rates were unnecessarily

²⁵ *Id.*, pp. 8-9.

²⁶ *Id.*, p. 8.

²⁷ *Id.*, p. 19.

²⁸ *Id.*, pp. 20-21.

²⁹ *Id.*, p. 20.

³⁰ *Id.*, p. 23.

³¹ In the matter of NorthWestern Energy’s application for interim and final approval of revised Tariff No. QF-1, Qualifying Facility Power Purchase. Montana Public Service Department. Docket No. D2016.5.39. Direct Testimony of John D. Hines, p. JDH-3.

³² NorthWestern Energy files to update avoided cost rate for qualifying facilities; change could save customers millions. NorthWestern Energy News. May 4, 2016. Available at: <http://www.northwesternenergy.com/news/2016/08/10/NorthWestern-Energy-files-to-update-avoided-cost-rate-for-qualifying-facilities-change-could-save-customers-millions>.

³³ In the matter of NorthWestern Energy’s application for interim and final approval of revised Tariff No. QF-1, Qualifying Facility Power Purchase. Montana Public Service Department. Docket No. D2016.5.39. Order No. 7500. June 16, 2016. ¶17; and Green Tech Media. 2017. Once an obscure law, PURPA now drives utility-scale solar. Available at: <https://www.greentechmedia.com/articles/read/purpa-is-causing-conflict-in-montana#qs.qfgjXXq>.

stimulating a considerable degree of uneconomic QF generation. In fact, NorthWestern stated that since the beginning of the year it has had “two out-of-state developers propose 43 three-MW QF solar projects, projects which our electric system does not need.”³⁴ NorthWestern made an additional emergency filing soon after its original request, asking to suspend its QF tariff for new solar QFs greater than 100 kW.³⁵

The Montana Commission ultimately ruled in favor of NorthWestern’s emergency request recognizing that “avoided cost rates that reflect outdated market price expectations can convey improper price signals.”³⁶ To avoid this problem and still allow QFs contracts at fixed prices based on avoided costs, the Commission ordered NorthWestern to update its QF tariff every six months.³⁷

Unhappy with this decision, solar developers filed a petition with FERC arguing that the Montana Commission and NorthWestern “failed to implement PURPA in a manner consistent with the statute and the Commission’s [FERC] regulations.”³⁸ Renewable QF developers also took the unusual step of petitioning FERC to actually exercise its enforcement powers against both NorthWestern and the Montana Public Service Commission.

The FERC ruled in favor of the QF developers, at least in terms of a finding that the Montana Commission had acted in a manner inconsistent with PURPA. The FERC also found that the Montana Commission’s attempt to grandfather the terms and conditions of certain projects that were in the process of signing QF contracts was inconsistent with PURPA since those terms and conditions could, in theory, be manipulated by the utility and are, therefore, inconsistent with PURPA.³⁹ However, despite the admonition, the FERC stopped short of launching an enforcement action, telling developers that they could pursue such matters in the courts.⁴⁰

The solar developers and advocates also filed reconsideration requests with the Montana Commission arguing that the 10-year contract length is inconsistent with the law; negatively affects a QF’s financing abilities; and that PURPA requires contract lengths that allow for “reasonable opportunities to attract capital.”⁴¹ Upon further review the Commission recognized that “long-term” is defined by Montana law as “a time period at least as long as a utility’s electricity supply resource planning horizon.”⁴² And it recognized that Montana has

³⁴ NorthWestern Energy files to update avoided cost rate for qualifying facilities; change could save customers millions. NorthWestern Energy News. May 4, 2016. Available at: <http://www.northwesternenergy.com/news/2016/08/10/NorthWestern-Energy-files-to-update-avoided-cost-rate-for-qualifying-facilities-change-could-save-customers-millions>.

³⁵ *Id.*, ¶7.

³⁶ In the matter of NorthWestern Energy’s application for interim and final approval of revised Tariff No. QF-1, Qualifying Facility Power Purchase. Montana Public Service Department. Docket No. D2016.5.39. Order No. 7500c. June 22, 2017. ¶38.

³⁷ *Id.*

³⁸ In re: FLS Energy, Inc. FERC Docket No. EL17-5-000. Notice of Intent and Declaratory Order. Issued December 15, 2016.

³⁹ *Id.* ¶23-26.

⁴⁰ *Id.* ¶20.

⁴¹ In the matter of NorthWestern Energy’s application for interim and final approval of revised Tariff No. QF-1, Qualifying Facility Power Purchase. Montana Public Service Department. Docket No. D2016.5.39. Order No. 7500d. November 24, 2017. ¶14 and ¶15.

⁴² *Id.* ¶26.

a legislative mandate to encourage long-term contracts to “enhance economic feasibility” of QFs.⁴³ Thus, the Commission reversed its ruling, set a 15-year maximum contract length for QFs, and eliminated its previous requirement for a five-year rate adjustment.⁴⁴

A third example of recent state-level QF reform comes from North Carolina. While not part of an organized RTO or ISO, North Carolina has had almost 3 GW of solar QF capacity installed in recent years.⁴⁵ In a recent biennial review of utility avoided costs, the state’s largest utility, Duke Energy, stated that it was overpaying solar developers an estimated \$1 billion over the remaining life of its existing 15-year QF contracts.⁴⁶ The utility also sought a reduction in the size of projects that qualify for QF contracts (from five MW to one MW or less) as well as a reduction in contract length to 10 years with biennial updates to the energy component of their QF tariff.⁴⁷ Duke contended that generous state rules have resulted in too many solar farms, with little utility input on whether these resources are needed, and had previously proposed moving to a competitive bidding process to allow “more orderly addition of new solar power” to its system.⁴⁸

The North Carolina legislation, recognizing the problems associated with uneconomic renewable QF development, revised the statutes governing QF contracts with HB 589, passed in July 2017. The legislation limited fixed-price PURPA contracts from five MW to one MW or smaller and shortened contract lengths from 15 years to 10 years.⁴⁹ Payments to QF projects larger than one MW are still based on avoided cost, but are to be negotiated between the developer and utility and cannot extend longer than five years. Larger projects will be procured through a competitive auction process. An order from the North Carolina Utilities Commission incorporated the changes brought by HB 589 and called for a recalculation of avoided cost rates paid to QF facilities. The order also required QF capacity payments to be based on a utility showing of need in its integrated resource plan (“IRP”).⁵⁰

⁴³ *Id.* ¶15 and ¶26.

⁴⁴ *Id.* ¶30.

⁴⁵ Form EIA-860, U.S. Energy Information Administration.

⁴⁶ In the matter of biennial determination of avoided cost rates for electric utility purchases from qualifying facilities – 2016. North Carolina Utilities Commission Docket No. E-100, Sub 148. Direct testimony of Lloyd M Yates. February 21, 2017, p. 9; and Henderson, B. 2017. Duke Energy says solar power will cost N.C. customers \$1 billion too much. The Charlotte Observer. February 26, 2017.

⁴⁷ In the matter of biennial determination of avoided cost rates for electric utility purchases from qualifying facilities – 2016. North Carolina Utilities Commission Docket No. E-100, Sub 148. Direct testimony of Lloyd M Yates. February 21, 2017, p. 11.

⁴⁸ *Id.*, pp 7, 10.

⁴⁹ Roselund, C. 2017. North Carolina governor signs PURPA overhaul bill. PV Magazine. Available at: <https://pv-magazine-usa.com/2017/07/27/north-carolina-governor-signs-purpa-overhaul-bill/>; and Maloney, P. 2017. New North Carolina regulatory order trims PURPA avoided cost rates. Utility Dive. Available at: <https://www.utilitydive.com/news/new-north-carolina-regulatory-order-trims-purpa-avoided-cost-rates/507505/>.

⁵⁰ In the matter of biennial determination of avoided cost rates for electric utility purchases from qualifying facilities – 2016. North Carolina Utilities Commission Docket No. E-100, Sub 148. Order Establishing Standard Rates and Contract Terms for Qualifying Utilities. October 11, 2017; and New North Carolina regulatory order trims PURPA avoided cost rates. Utility Dive. Available at: <https://www.utilitydive.com/news/new-north-carolina-regulatory-order-trims-purpa-avoided-cost-rates/507505/>.

6 | Uneconomic Capacity Development

Renewable QF capacity development has expanded considerably over the past decade (2007-2017) in large part due to the favorable terms extended by many states on contract terms and/or generous QF electric purchase rates, which are ultimately passed along to retail electric customers. A look at the empirical trends over the past decade underscores the degree to which PURPA has facilitated, if not been abused, by renewable developers.

Figure 2 shows that development of renewable QF capacity surged in 2007 with over 2,000 MW of new wind capacity installed in that year alone. Renewable QF capacity continued to increase through much of the decade. After a brief downturn from 2013 to 2015, renewable QF capacity growth rebounded. In fact, installations in 2016 and 2017 totaled more capacity than the two-decade period from 1980 through 1999.

Figure 2 also shows that the composition of renewable QF development has changed over the past decade, reflecting the types of renewable resources taking advantage of generous contracting terms under PURPA. Wind resources were the primary renewable QFs being developed from 2007 through 2012. Changes in the wind production tax credit likely had some impacts during 2013 to 2015, and renewable QF development flipped to solar installations. Almost 11 GW of solar capacity has been installed since 2013, compared to 8 GW of wind capacity. Solar capacity development has been considerable, averaging over 2 GW per year during this period.

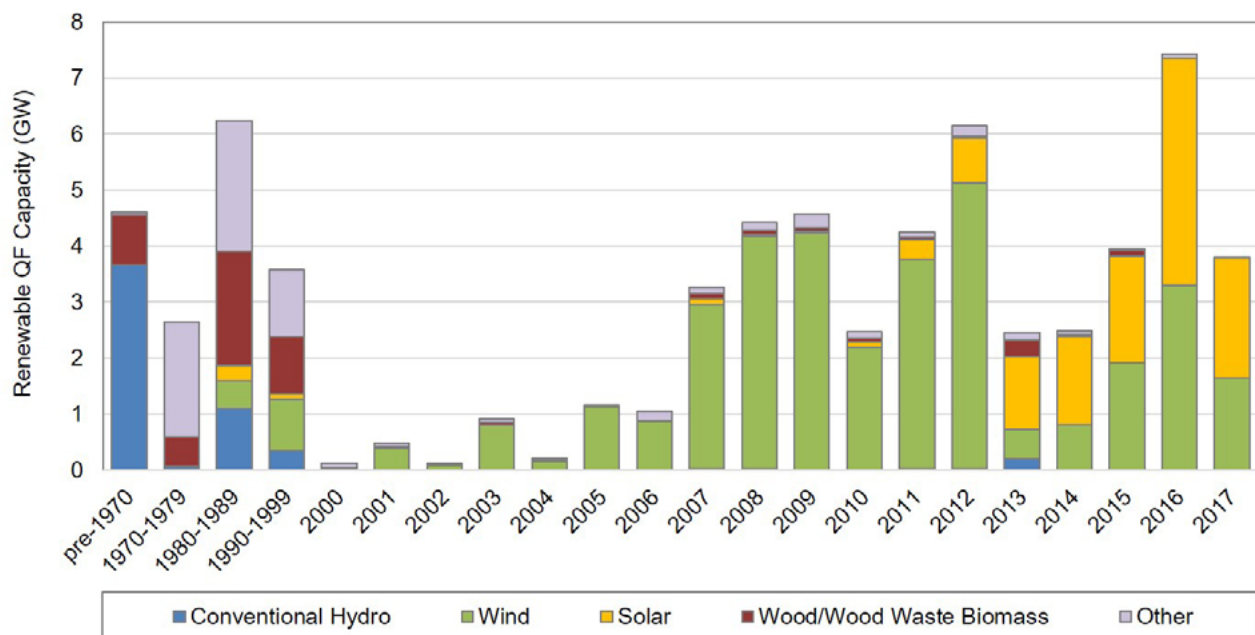


Figure 2: Renewable QF Capacity by Type and Installation Year.

Source: U.S. Department of Energy, Energy Information Administration.

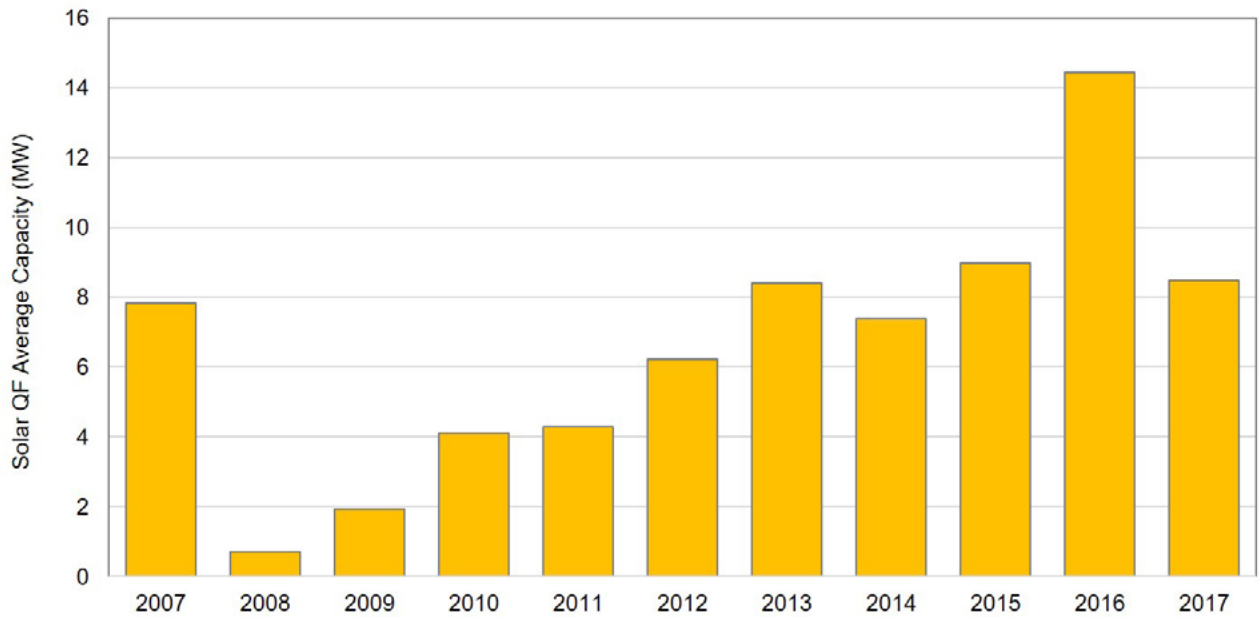


Figure 3: Average Solar QF Capacity per Installation.

Source: U.S. Department of Energy, Energy Information Administration.

Renewable QF capacity growth is becoming problematic in many parts of the country and development continues to increase. Figure 3 highlights the fact that not only is the total amount of capacity increasing, but the average size of the typical renewable generators taking advantage of the PURPA provisions is increasing as well. In 2007, the average size of a solar QF facility was under 8 MW. A decade later, average capacity has increased by almost 85 percent to over 14 MW for a typical solar QF project.

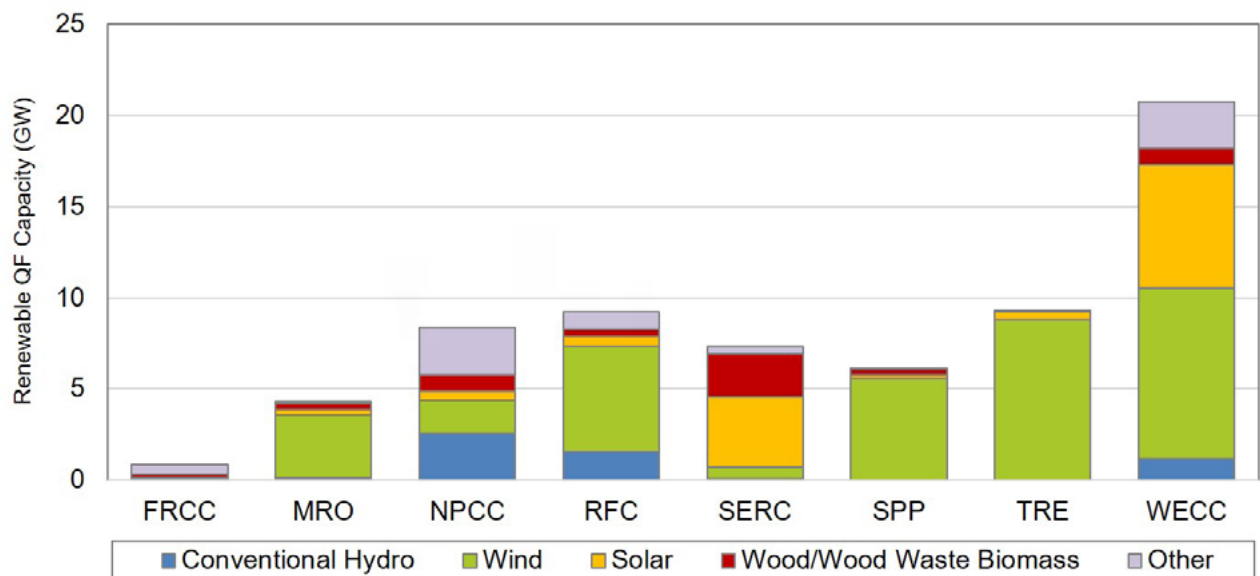


Figure 4: Active Renewable QF Capacity by NERC Region (2017).

Source: U.S. Department of Energy, Energy Information Administration.

Not surprisingly, the location of renewable energy QF capacity development is concentrated in states that have some of the more generous QF pricing and contracting policies (e.g., Oregon, Montana, Idaho). Figure 4 shows that a large amount of both wind and solar installations are located in the WECC (western) region of the country.⁵¹ Wind QF capacity development dominates NERC regions, with the exception of the SERC which is heavily dominated by solar QF capacity development.

Figure 5 shows the required reserve margins for each NERC region. Most NERC regions use planning margins between 13 percent and 15 percent, to ensure that the region has enough spare capacity to serve over and beyond its peak demand. Reserve margins above the planning margin can be thought of as excessive relative to a region’s reliability needs. Figure 5 shows that every NERC region in the U.S. is currently well above its standard reserve margin meaning that, at least from a forward looking capacity requirements perspective, additional PURPA-stimulated renewable QF capacity is unneeded and unnecessary to meet regional reliability needs.⁵²

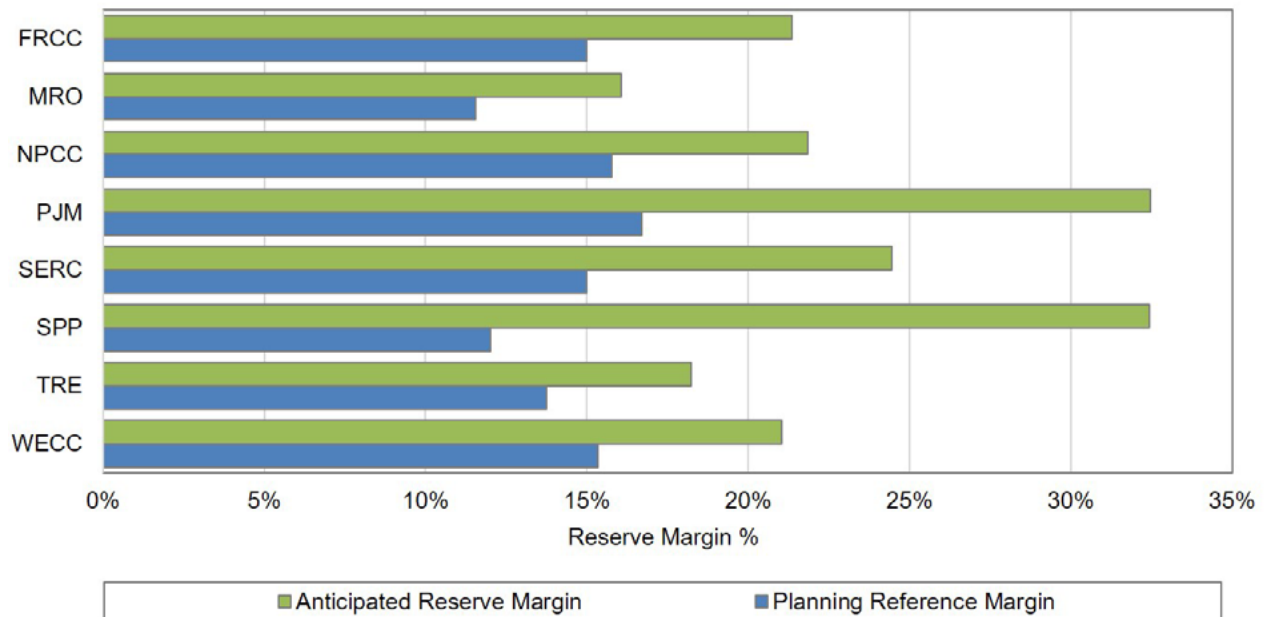


Figure 5: Active Renewable QF Capacity by NERC Region (2017).

Source: NERC.

⁵¹ The North American Electric Reliability Council (“NERC”) has eight reliability regions in North American that include: the Florida Reliability Coordinating Council (“FRCC”); the Midwest Reliability Organization (“MRO”); the Northeast Power Coordinating Council (“NPCC”), the ReliabilityFirst Corporation (“RFC”); the SERC Reliability Corporation (“SERC” where SERC is the former abbreviation for the region and stands for the Southeast Electric Reliability Coordinating Council); the Southwest Power Pool (“SPP”); and Texas Reliability Entity (“TRE”); and the Western Electric Coordinating Council (“WECC”).

⁵² This is a generous conclusion since many Regional Transmission Organizations (“RTOs”) and Independent System Operators (“ISOs”) discount the capacity contribution made by renewables given their intermittency and the fact that these renewable resources provide peak generation at times that are usually different than most system demand peaks.

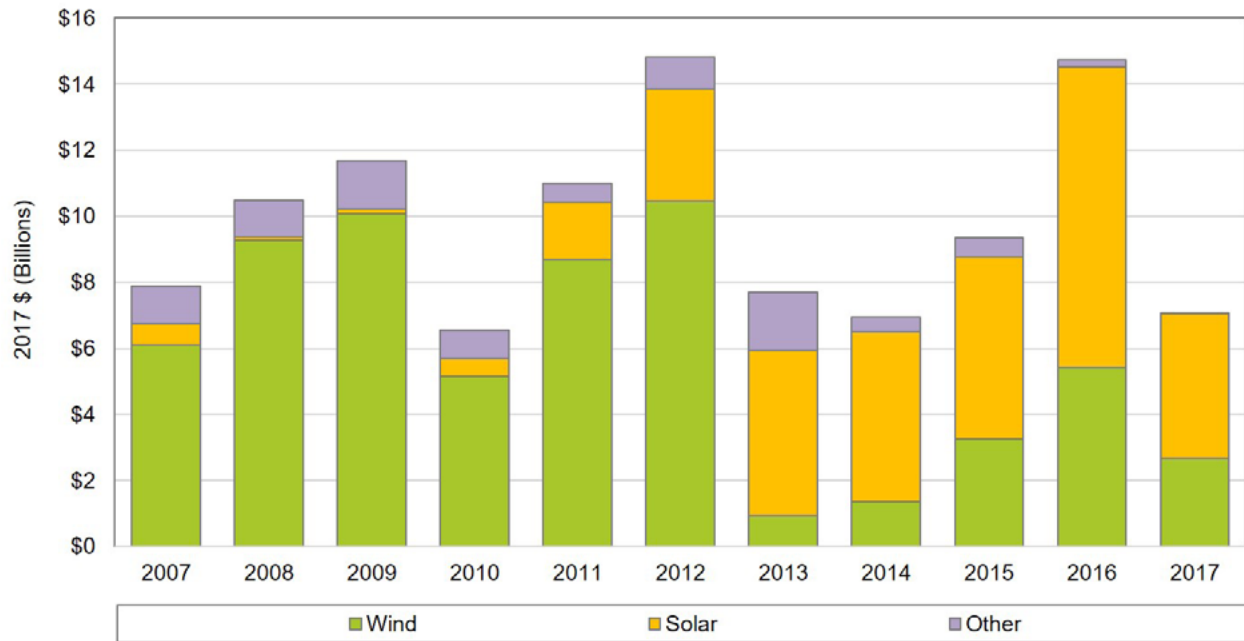


Figure 6: Estimated Annual QF Renewable Installation Capital Investments.

Source: Authors construct with information from: U.S. Energy Information Administration; Lawrence Berkley National Laboratory; National Renewable Energy Laboratory and Lazard.

Excess renewable QF capacity development is not costless since utilities are forced to purchase this electricity under current law, regardless of whether or not the generation is needed. Further, it is often the case that the QF generation secured under these PURPA contracts is above prevailing market prices. Consider, for instance, the earlier-cited case of Montana that originally had a \$66 per MWh rate that was dated and well in excess of going market prices around \$34 per MWh: in other words, the costs paid to QF renewable generation in Montana, at one time, were double going market rates. On a more general basis, for the U.S. overall, the excess cost of this QF renewable generation can be estimated using a number of assumptions.

Figure 6 for instance, estimates the annual installed capital costs for each QF renewable generator installed over the past decade (2007-2017). Estimates by generator type and year were calculated and summed to represent the overall capital requirement that will be needed to be recovered by the renewable QF generator that came on line in each of these years. These capital investment costs, over the decade, sum to around \$108 billion in 2017 dollars. The installed costs just over the past five years sum to over \$45 billion. These are all costs that will ultimately be recovered directly from ratepayers for capacity that is likely not needed to meet reliability requirements.

Figure 7 provides an estimate of the potential payments that have been made to renewable QF generators over the past several years. These estimates are made at the individual generator level and are “rolled-up” to get an annual total. The annual QF payment estimates

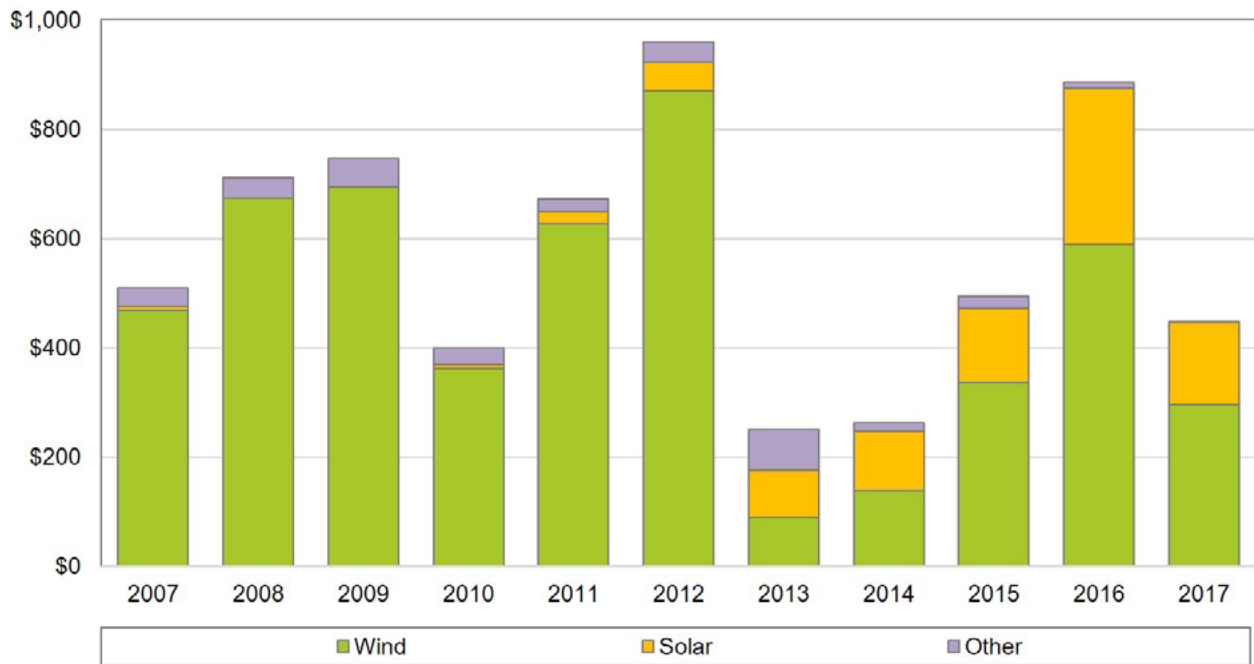


Figure 7: Estimated Annual “Avoided Cost” Payments to QF Renewable Installations.

Source: Authors construct with information from: U.S. Energy Information Administration.

provided in Figure 7 are based upon a number of conservative assumptions. The first assumption is that these generators perform at levels comparable to the averages for that resource type. That is, solar or wind generators will produce electricity at capacity factors comparable to the industry average for the size and year in which the particular renewable QF facility came on line. Second, the estimates assume that renewable QF generators receive annual “avoided cost” payments that are comparable to the levelized cost of energy (“LCOE”) for a combined cycle natural gas facility. The LCOE estimate is developed using capital, operating, and fuel cost drivers from the EIA’s *Annual Energy Outlook*, 2018.

Figure 7 shows that the estimates of the payments likely needed to support new renewable QF generation are considerable, on average about \$468 million per year for the last five years, for a cumulative total of about \$2.3 billion over a five-year period. These renewable QF payments are likely underestimates (of the total payments) since the valuation is done at a natural gas-based estimate of avoided cost that does not include any mark ups, premiums, or “adders” that can often be tacked on top of an avoided cost reimbursement rate. For instance, the estimated avoided cost utilized in developing the estimates in Figure 7 is around \$48 per MWh, an amount much lower than the prior Montana payments of \$66 per MWh.

Estimating how much of these payments are “excessive” admittedly requires knowledge about of the specific avoided cost for each renewable QF contract and the current market conditions at the time in which each renewable QF contract was executed. However, it

is likely that a good portion of these estimated renewable QF payments are in fact, excessive since most regions do not need this electricity and the renewable QF payments simply represent an excessive cost burden that must be recovered by someone; and that “someone” is utility ratepayers.

7 | Conclusions and Recommendations

Clearly the time has come to reform PURPA in order to eliminate the abuses that have taken hold over the past decade or more by speculative QF renewable energy generation developers. The most important and obvious reform should be the elimination of the 20 MW threshold for QF renewable energy purchases. Today, all utilities, even those that are part of a presumptively competitive RTO, are still required to purchase QF renewable energy offers for generators with a capacity of 20 MW or less. This provision needs to be removed, since at this point in time there are no barriers to entry for getting bona fide renewable energy projects to the market.

Further, and in fairness, if the PURPA buy-back provision is repealed, such a repeal should continue to uphold the sanctity of existing contracts, and should only apply on a forward-going, not retrospective basis. Contracts that expire, however, like the QF resources secured under the current two-year contracts utilized in Idaho, should be allowed to expire without any mandatory contract renewals or evergreen provisions that are not otherwise embedded in the original contract. Utilities should not be required to purchase electricity, on behalf of their ratepayers, from any resource that is: (a) not needed; and (b) not competitively priced. If, however, the PURPA buyback provisions are not eliminated, there are a number of other reasonable reforms that can help to dampen the already experienced QF excesses and abuses.

First, utilities should not be required to purchase unneeded electricity. The PURPA “buy-back” provisions, if “reformed,” should be changed in a fashion that allows utilities to reject PURPA “puts” if the capacity is unnecessary. This need can be determined separately, on an annual basis, a stand-alone basis, or as part of a utility’s integrated resource planning (“IRP”) process.

Second, utilities should not be required to enter into long-term contracts for periods that are longer than those necessary and/or prevailing in the current market unless it can be shown that the QF resource is: (a) needed to meet utility long term capacity needs; and (b) more competitive than other offers in the market and tested through a competitive bidding process.

Third, eliminate the one-mile disaggregation loop-hole. This loop-hole has been allowed for far too long and allows what are, in effect, large projects to disaggregate themselves for QF contracting purposes. Renewable developers use their often large geographic footprints to qualify as several “smaller” projects rather than a single, larger integrated project that otherwise would be ineligible for the PURPA mandatory buy-back provision.

PURPA reform is an important ratepayer protection issue that needs to be addressed immediately. In its day, PURPA represented a disruptive piece of federal legislation that ultimately helped to show that electric power generation was not a natural monopoly and that competition could be sustained in the electric power industry. But at the time PURPA was passed, electric utilities were vertically integrated and highly regulated monopolies. Non-utility generation of any type (renewable, small scale distributed, industrial on-site generation), represented less than five percent of total U.S. power generation in the year in which PURPA was passed. PURPA’s goal was to break this monopoly model by removing barriers to entry, by facilitating trades between utilities and non-utility parties, and to weaken any vertical market power abuse a utility could impose on a nascent set of competitive generators. The goal in doing this was to increase electricity diversity, overall supply-side efficiency, and reliability through more competition. The needs for those protections, however, are unnecessary since that world simply does not exist anymore.

The irony is that today, renewable QF generators are abusing the very provisions of PURPA that helped to create today’s competitive electric marketplace. These speculative renewable energy developers are forcing utilities to purchase electricity that is not needed, for contract terms that are beyond what most generators can secure in today’s market, and for contract prices that are far in excess of market costs. The entire financial liability of these abuses are paid for by one party, and one party only – not utilities, but ratepayers. It will be utility ratepayers (customers) who will carry the burden of these contracts, on an unavoidable basis, as long as they are customers of the regulated utilities that are being forced to execute these special, out-of-market contractual arrangements. Thus, ratepayer protection is the primary and fundamental reason why PURPA needs to be reformed quickly and comprehensively to stem what otherwise will be a continued, very costly, and long-term financial liability for a large number of U.S. electricity customers.

About the Author

David E. Dismukes is Professor, Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University. He also serves as a professor in the Department of Environmental Sciences, and as the director of the Coastal Marine Institute, both of which are in the College of the Coast & Environment at LSU.

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