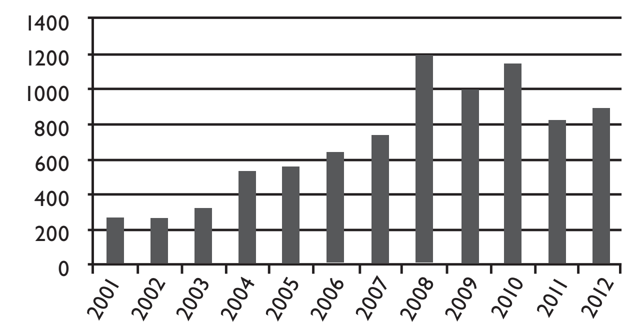
ARTICLES

PURPA's Public Power Impact (And What to Do About It)

By Donna M. Attanasio*

Congress enacted the Public Utility Regulatory Policies Act of 1978 ("PURPA"),[1] over 35 years ago on November 9, 1978 to encourage energy conservation and efficiency.[2] It set off a revolution that changed the electric industry. Section 210 of PURPA[3] created a class of generating facilities known as qualifying facilities ("QFs") which became the advance guard for the competitive generation industry as we know it today and participated in the early battles to open the transmission grid. Now, competitive generation and open access transmission have been firmly established pursuant to sections 205 and 206 of the Federal Power Act ("FPA"),[4] but PURPA remains on the books. Indeed, the number of applications for QF status from 2008–2012 was greater in every year than in any of the years 2002–2007.[5]

QF Applications Filed



This Article explores the relevance of PURPA section 210 in today's market from the perspective of both QF owners and public power companies,[6] which are increasingly likely to find QFs in their service territories. It concludes by discussing ways in which a public power company might use PURPA as part of its toolkit for addressing the many changes resulting from the growth of distributed energy resources ("DER").[7]

I. Background

PURPA and the regulations implementing PURPA that were developed by the Federal Energy Regulatory Commission

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1. Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95–617, 92 Stat. 3117 (1978). Sections 201 and 210 of PURPA, which are the primary focus of this Article, are codified at 16 U.S.C. § 796(17)–(22) and § 824a-3 (2012), respectively.
2. Public Utility Regulatory Policies Act of 1978 § 2(1) (codified at 16 U.S.C. § 2601(1) (2012)).
3. *Id.* § 210 (codified at 16 U.S.C. § 824a-3).
4. Pub. L. No. 74-333, 49 Stat. 851–852 (1935) (codified as amended at 16 U.S.C. § 824 (2012)).
5. The number of QF applications from 2002–2012 received by FERC are found in FERC congressional budget requests for fiscal years 2003–2014. *See* Fed. Energy Regulatory Comm'n, FY 2014 Congressional Performance Budget Request 74 (2013), *available at* https://www.ferc.gov/about/strat-docs/budget.asp; Fed. Energy Regulatory Comm'n, FY 2013 Congressional Performance Budget Request 96 (2012), *available at* https://www.ferc.gov/about/strat-docs/FY13-budg.pdf; Fed. Energy Regulatory Comm'n, FY 2012 Congressional Performance Budget Request 83 (2011), *available at* https://www.ferc.gov/about/strat-docs/FY12-budg.pdf; Fed. Energy Regulatory Comm'n, FY 2011 Congressional Performance Budget Request 98 (2010), *available at* https://www.ferc.gov/about/strat-docs/FY11-budg.pdf; Fed. Energy Regulatory Comm'n, FY 2010 Congressional Performance Budget Request 61 (2009), *available at* https://www.ferc.gov/about/strat-docs/FY10-budg.pdf; Fed. Energy Regulatory Comm'n, FY 2009 Congressional Performance Budget Request 127 (2008), *available at* https://www.ferc.gov/about/strat-docs/FY09-budg.pdf; Fed. Energy Regulatory Comm'n, FY 2008 Congressional Performance Budget Request 105 (2007), *available at* https://www.ferc.gov/about/strat-docs/FY08-budg.pdf; Fed. Energy Regulatory Comm'n, FY 2007 Congressional Performance Budget Request 99 (2006), *available at* https://www.ferc.gov/about/strat-docs/FY07-budg.pdf; Fed. Energy Regulatory Comm'n, FY 2006 Congressional Performance Budget Request 81 (2005), *available at* https://www.ferc.gov/about/strat-docs/FY06-budg.pdf; Fed. Energy Regulatory Comm'n, FY 2005 Congressional Performance Budget Request 62 (2004), *available at* https://www.ferc.gov/about/strat-docs/FY05-Budg.pdf; Fed. Energy Regulatory Comm'n, FY 2004 Congressional Budget Request and Annual Performance Plan 69 (2003), *available at* https://www.ferc.gov/about/strat-docs/FY04-Budg.pdf; Fed. Energy Regulatory Comm'n, FY 2003 Congressional Budget Request and Annual Performance Plan 46 (2002), *available at* https://www.ferc.gov/about/strat-docs/Fy03-Budg.pdf.
6. Public power companies are community-owned utilities. Many are owned and operated by local governments, but some are owned and operated by states, counties and other governmental bodies. Public power companies are non-profit and generally are not subject to rate, financial, or organizational regulation by state commissions or the Federal Energy Regulatory Commission ("FERC"), as a for-profit company would be.
7. FERC is charged with developing the rules for implementation of PURPA. Implementation of FERC's rules is generally delegated to the states with respect to those utilities over which the state has ratemaking authority. 16 U.S.C. § 824a-3(f)(1). However, utilities that are not regulated by the state, such as public power companies, are identified in the statute as "nonregulated" and are obligated to implement PURPA themselves. *Id.* § 824a-3(f)(2). This Article addresses PURPA in the context of nonregulated public power utilities, but many of the same points are applicable to other types of utilities and the state regulators that implement PURPA on their behalf.

("FERC")[8] defined the criteria for, and thus created, qualifying small power production facilities ("QF-SPP," which produce electricity using biomass, waste, renewable or geothermal resources) and qualifying cogeneration facilities ("QF-Cogen," which produce electricity and thermal energy in a sequential process).[9] PURPA stimulated the growth of QFs by providing the owner of a QF-SPP or QF-Cogen with a package of rights that were not generally available as a matter of law to the owner of a non-QF during the 1980s and early 1990s. Generally, these rights consisted of (1) the right to interconnect on non-discriminatory terms as a matter of federal law[10]; (2) the right to sell the QF's power to any electric utility to which it is able to deliver the power, at the utility's avoided cost[11]; (3) the right to secure power from the utility for back-up, maintenance, supplementary, or interruptible uses at non-discriminatory rates[12]; and (4) exemption from certain federal and state laws otherwise applicable to utilities.[13]

Notwithstanding exemptions granted to public power companies from certain other aspects of federal power regulation,[14] the obligation to interconnect with a QF, purchase the QF's power, and sell power to QFs applies to any "electric utility," which is a defined term that includes public power entities.[15] Throughout PURPA's history, a number of public power companies have either purchased QF power or arranged to transmit QF power to their respective wholesale requirements suppliers, who fulfilled the purchase mandate on their behalf, as permitted under PURPA.[16]

PURPA was enacted in the years following the 1973 oil embargo, in an era when large power projects, often nuclear, were incurring cost overruns and straining utility budgets and the patience of ratepayers and regulators. Its purpose was to facilitate energy efficiency and innovation as a means to reduce the United States' dependence on foreign oil.[17] A QF was required to meet certain minimum technical criteria with respect to either size and fuel use or efficiency and operating standards, plus certain ownership restrictions, to receive the benefits of QF status.[18] Notwithstanding these requirements, many owners were able to successfully develop QFs.

In an era when non-utility generation was limited due to an absence of open access transmission and competitive markets and by the restrictive mandates of the Public Utility Holding Company Act of 1935 ("PUHCA"),[19] PURPA served as the wedge to break open the monopolization of the power industry. QFs demonstrated that independent generation could be interconnected and operated without impairing the reliability of the electric system and at costs competitive with, or lower than, those of many incumbent utilities. Since the rate for mandatory purchases made pursuant to PURPA must be set at the purchasing utility's avoided cost, QF development was most prevalent in areas served by high cost systems and in states in which the regulators implemented clearly defined methodologies for determining an avoided cost rate that provided QFs with the certainty needed for successful development and non-recourse project financing.

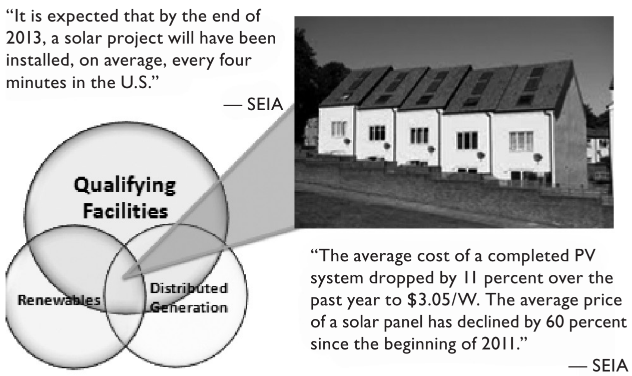
Notwithstanding its historical significance, PURPA's original purpose and effect are largely anachronistic. PUHCA is no longer a barrier to entry since it was largely repealed and restructured into a "books and records" requirement by the Energy Policy Act of 2005.[20] Thanks to FERC Order No. 888, issued in 1996, and its progeny, any wholesale power producer has a right to interconnect to the transmission system pursuant to federal law and to secure open access transmission service.[21] While the pro-

8. 18 C.F.R. pt. 292 (2013).
9. 18 C.F.R. § 292.203 (2013).
10. 16 U.S.C. § 824a-3(a); 18 C.F.R. § 292.303(c) (2013).
11. 16 U.S.C. § 824a-3(b), (d); 18 C.F.R. §§ 292.303(a), 292.304 (2013). "Avoided cost" is the incremental cost the purchasing utility would pay for energy, or energy and capacity, if it were to obtain it from a source other than the QF.
12. 16 U.S.C. § 824a-3(c); 18 C.F.R. §§ 292.303(b), 292.305 (2013).
13. 16 U.S.C. § 824a-3(e); 18 C.F.R. §§ 292.601, 202.602 (2013).
14. 16 U.S.C. § 824(f) (2012) (granting exemption from Title II of the FPA, except as otherwise specified, to "the United States, a State or any political subdivision of a State . . . or any agency, authority, or instrumentality of any one or more of the foregoing, or any corporation which is wholly owned, directly or indirectly, by any one or more of the foregoing, or any officer, agent, or employee of any of the foregoing acting as such in the course of his official duty. . . .").
15. For purposes of PURPA, an "electric utility" is explicitly defined by statute as "a person or Federal or State agency . . . that sells electric energy," including "the Tennessee Valley Authority and each Federal power marketing administration." 16 U.S.C. § 796(22) (2012). *See also id.* § 796(19) (defining "[f]ederal power marketing agency" as "any agency or instrumentality of the United States (other than the Tennessee Valley Authority) which sells electric energy."). The statute clearly states that the entities that are otherwise granted a broad exemption from the FPA pursuant to 16 U.S.C. § 824(f) are within the definition of "electric utility," and hence subject to the mandatory purchase requirement. 16 U.S.C. § 796(22); 16 U.S.C. § 824(f); *see* 16 U.S.C. § 824a-3(a).
16. *See* The City of Longmont, Colo., 39 FERC ¶ 61,301 (1987) (granting four cities waiver of the obligation to purchase QF power where such obligation would instead be fulfilled by their wholesale supplier, and determining that the proper measure of avoided cost is the cost avoided by the wholesale supplier, not the rate at which the cities purchase from the wholesale supplier); Cuero Hydroelectric, Inc. v. The City of Cuero, Tex., 85 FERC ¶ 61,124 (1998) (Commission denies reconsideration of notice of intent not to bring an enforcement action against The City of Cuero, Texas, on the basis that the City properly implemented PURPA in setting its avoided cost equal to its requirements supplier's avoided costs); Kootenai Elec. Coop., Inc., 143 FERC ¶ 61,232 (2013) (Commission provides notice of intent not to bring an enforcement action, asserting that "[a] utility is obligated under PURPA to purchase the output of a QF as long as the QF can deliver its power to the utility").

Note that FERC's interpretations of PURPA § 210 and the rules it promulgated pursuant to § 210 are not binding unless adopted by a district court, because enforcement of PURPA was entrusted to the district courts. *See* Niagara Mohawk Pwr. Corp. v. FERC, 117 F.3d 1485, 88–89 (D.C. Cir. 1997). However, FERC's interpretations are used liberally throughout this Article as they provide the most comprehensive and informed interpretations available.
17. *See, e.g.*, FERC v. Mississippi, 456 U.S. 742, 745–46 (1982).
18. 18 C.F.R. § 292.203 (2013). The ownership restrictions were eliminated by the Energy Policy Act of 2005. Pub. L. No. 109-58, § 1253(b), 119 Stat. 972 (2005) (amending 16 U.S.C. §§ 796(17)(C), (18)(B)).
19. PUHCA placed multistate utility holding companies under federal regulation. Among other things, a holding company within PUHCA's jurisdiction was limited with respect to activities it could undertake outside the electric power and natural gas distribution sectors and its ability to enter into mergers with noncontiguous companies, and also subject to strict oversight with respect to its securities issuances and intra-holding company transactions. Until the 1992 amendment that created an exemption for subsidiaries that were solely engaged in generating and selling electricity, it was difficult for multi-state companies (including, *e.g.*, companies engaged in non-power industries, such as paper or automotive manufacturing) to own and operate generation and sell excess power from their generators at wholesale without running afoul of PUHCA, except pursuant to PURPA.
20. Pub. L. No. 109-58, Title XII, Subtitle F, 119 Stat. 972 (Repeal of PUHCA).
21. 18 C.F.R. § 35.28 (2013). The obligation to offer open access transmission and interconnection service extends only to public utilities that are subject

cess for interconnection is still fraught with delays, issues of cost allocation, and occasional disputes about discrimination, having a federal *right* to interconnect and participate in wholesale electric markets is no longer the exclusive province of a QF relying on PURPA to defend its right. And, with the 2005 revisions to PURPA, a utility that can demonstrate that QFs in its footprint have access to a competitive market is relieved of the PURPA mandate to purchase QF power.[22] So, what then is the importance of PURPA on its 35th birthday? A starting point is to look at the benefit of holding QF status in today's market.

QF Growth



II. Today's QF and the Benefits of PURPA

State laws intended to counteract climate change have stimulated, and in some cases perhaps created, a vibrant market for renewable and alternative energy and other efficient forms of generation, such as combined heat and power ("CHP") and waste-fired generation. Of particular note, even though solar remains a small part of the market, distributed photovoltaic ("PV") solar power generation capacity in the United States is growing exponentially. A recent Department of Energy ("DOE") report states that since 2008, solar PV installations have grown approximately tenfold, "from about 735 megawatts to over 7200 megawatts"[23] and installed distributed PV is expected to double by 2015.[24] In addition, small and large users often opt to purchase power under tariffs that promise to source power from renewable resources, often called "green tariffs," and some larger users have sought to by-pass their local electric power distributor by contracting directly with independent power producers that can provide renewable energy either for direct delivery or to offset their usage.[25]

PURPA remains relevant in today's market because these renewable and efficient resources that have been encouraged under state and federal policies to advance achievement of carbon-reduction goals, including small rooftop PV, often meet the requirements for QF status and therefore qualify for PURPA benefits. Specifically:

- A QF-SPP may include a facility that is fueled by "biomass, waste, renewable resources, geothermal resources, or any combination thereof" provided that it receives no more than 25% of its fuel input from fossil fuels.[26] Generally, a QF-SPP must have a net capacity of no more than 80 MWs.[27] (Certain older renewable energy facilities, referred to herein as "Section 3(17)(E) QF-SPPs" have no size limit.)[28] Thus, common technologies for use in renewable or DER projects, including photovoltaic solar, on-shore wind, and landfill gas projects may be eligible for QF-SPP status. Technologies such as concentrating solar power or off-shore wind would also qualify based on technology, but the economics of such projects typically dictate a size larger than 80 MW, which would exceed the limit for QF status.
- A QF-Cogen unit is one that produces electricity and useful thermal energy sequentially and meets certain operating and efficiency standards.[29] The thermal energy must be used for industrial, commercial, heating, or cooling purposes.[30] There is no size limit. CHP facilities that meet the operating and efficiency standards qualify. Revisions to PURPA that were established through the Energy Policy Act of 2005 require that new cogeneration units seeking to avail themselves of the mandatory purchase provisions of PURPA meet a higher standard than previously required by demonstrating that "[t]he thermal energy output of the cogeneration facility is used in a productive and beneficial manner"[31] and "the electrical, thermal, chemical and mechanical output of the cogeneration facility is used fundamentally for industrial, commercial, residential

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to FERC's jurisdiction, but because FERC has implemented a reciprocity requirement to encourage non-jurisdictional transmission providers to provide comparable service, it is widely available throughout the interconnected grid.

22. *See* 18 C.F.R. §§ 292.309, 292.310 (2013).
23. U.S. Dep't of Energy, Revolution Now: The Future Arrives for Four Clean Energy Technologies 4 (Sept. 17, 2013), *available at* http://energy.gov/sites/prod/files/2013/09/f2/Revolution%20Now%20--%20The%20Future%20Arrives%20for%20Four%20Clean%20Energy%20Technologies.pdf.
24. Stephen Lacey, *Chart: 2/3rds of Global Solar PV Has Been Installed in the Last 2.5 Years*, Greentech Solar (Aug. 13, 2013), http://www.greentechmedia.com/articles/read/chart-2-3rds-of-global-solar-pv-has-been-connected-in-the-last-2.5-years?utm_source=Daily&utm_medium=Headline&utm_campaign=GTMDaily ("More than two-thirds of America's distributed PV (everything except for utility-scale projects) has been installed since January 2011. And by 2015, the country's distributed PV market is expected to jump by more than 200 percent.").
25. *See, e.g.*, James Montgomery, *Google, Facebook Up the Renewable Energy Ante*, RenewableEnergyWorld.com (Nov. 14, 2013), http://www.renewableenergyworld.com/rea/news/article/2013/11/google-facebook-up-the-renewable-energy-ante. *See also* Todd Woody, *Google Prods a Coal-Fired Utility Into Making Money on Green Power*, The Atlantic (Nov. 18, 2013), http://www.theatlantic.com/technology/archive/2013/11/google-prods-a-coal-fired-utility-into-making-money-on-green-power/281608/ (Duke Energy would contract on behalf of large users for renewable power and resell it under a Green Source Rider tariff designed to pass the cost through to the customers opting for such service).
26. 18 C.F.R. § 292.204(b)(1)(i) (2013).
27. *Id.* § 292.204(a)(1).
28. *Id.* § 292.204(a)(4).
29. 18 C.F.R. §§ 292.203(b), 292.205 (2013).
30. 18 C.F.R. § 292.202(h) (2013).
31. 18 C.F.R. § 292.205(d)(1) (2013).

or institutional purposes and is not intended fundamentally for sale to an electric utility."[32]

If a facility meets the criteria to be deemed a QF, then even with the 2005 revisions to PURPA, its owner reaps the following advantages[33]:

- All QFs that are smaller than 20 MW are exempt from federal rate regulation for wholesale power sales under sections 205 and 206 of the FPA.[34] In addition, QF-SPPs of 30 MW or less, geothermal QFs of 80 MW or less, section 3(17)(E) QF-SPPs, and QF-Cogen facilities may also be eligible for exemption from sections 205 and 206, if they sell their power pursuant to a state program implementing PURPA (that is, at avoided cost rates).[35] This exemption is important because most non-governmental sellers of power must file cost-based rates with FERC or be approved by FERC to sell power at market-based rates prior to making any sale.[36] Subsequently, such sellers become subject to various reporting requirements and periodic reevaluation of their ability to exercise market power.[37] This exemption removes those regulatory burdens, making it easier for such QFs to do business.
- FPA sections 203 and 204 limit the ability of public utilities to transfer certain utility assets or issue securities absent FERC approval.[38] QF-SPPs of 30 MW or less, geothermal QFs of 80 MW or less, section 3(17)(E) QF-SPPs and QF-Cogens are exempt from FPA sections 203 and 204 as well as certain other provisions of the FPA.[39]
- QF-SPPs of 30 MW or less, QF-SPPs of 80 MW or less fueled by geothermal or biomass, section 3(17)(E) QF-SPPs and QF-Cogens are also exempt from the requirements of the Public Utility Holding Company Act of 2005 (which is largely a record-keeping requirement) and from state laws and regulations respecting rates and the financial and organizational regulation of utilities.[40]
- Each electric utility has an obligation under federal law to sell QFs back-up, supplementary, maintenance, and interruptible power at non-discriminatory rates, unless FERC has exempted such utility after finding that competing retail suppliers are "willing and able to sell and deliver" such services and the electric utility is not required by state franchise laws to serve the QF.[41] Therefore, each QF is assured of its ability to receive electric service at non-discriminatory rate to power the load that is normally served by the QF during periods in which the QF is unable to generate the necessary power to serve that load directly.
- Although QFs generally are required to file a notice of their QF status with FERC, a QF with a net power production capacity of 1 MW or less is not required to make such a filing.[42]

These rights and exemptions reduce the QF owner's cost of regulation and certain transactional costs and therefore make it more economical and simpler for a QF owner to participate in the electric power market. In particular, a vast portion of the rooftop solar currently installed in the United States not only meets the requirements for QF status but is small enough to reap all the benefits PURPA has to offer, since such facilities are typically below the 30 MW threshold or even the more restrictive 20 MW or 1 MW thresholds.[43]

Small QFs receive a further benefit because, while an electric utility's obligation to purchase QF power may be terminated if it demonstrates that the QFs within its footprint have access to competitive markets[44] and non-discriminatory transmission and interconnection services under an open-access tariff, FERC's regulations include a rebuttable presumption that QFs of 20 MW or fewer do not have access sufficient to meet the criteria for termination of the utility's purchase obligation.[45] Thus, small QFs can continue to benefit from the mandatory purchase provisions of PURPA, even in areas where the utility has been relieved of its obligation to purchase the power of larger QFs.

III. Implications for Public Power Utilities

While early QF projects tended to congregate in the footprint of utilities that had higher avoided cost rates, the new trend toward DER and renewable resources is not necessarily driven solely by rates. Thus, even if a public power utility has lower rates than a neighboring, for-profit utility, it may still find a sudden growth spurt of DER, QFs and/or renewable power on its system. Several factors contribute to this trend.

- Owners of some renewable resources may profit from the sale of the related renewable energy credits

32. *Id.* § 292.205(d)(2). The revisions were instituted in reaction to an industry backlash against cogeneration units that had minimal thermal loads and whose primary business was to generate and sell electricity, which were derogatorily referred to as "PURPA machines." Press Release, Fed. Energy Regulatory Comm'n, Commission Finalizes Cogeneration Facilities Rulemaking; Ownership Limits Eliminated, Efficiency Underscored (Feb. 2, 2006), *available at* http://www.ferc.gov/media/news-releases/2006/2006-1/02-02-06-E-2.pdf.
33. A new QF-Cogen unit that meets the minimum operating and efficiency standards, but not the higher standards necessary to invoke the mandatory purchase provisions of PURPA, would still qualify for regulatory exemptions and the other benefits of PURPA afforded to QF-Cogen units as described in the following text. *See* 18 C.F.R. § 292.601(a) (2013).
34. *Id.* § 292.601(c)(1).
35. *Id.*
36. 16 U.S.C. § 824d (2012); 18 C.F.R. pt. 35 (2013) (setting forth the obligation of public utilities to file rates).
37. 18 C.F.R. pt. 35.
38. 16 U.S.C. §§ 824b, 824c (2012).
39. 18 C.F.R. § 292.601.
40. 18 C.F.R. § 292.602 (2013).
41. 18 C.F.R. §§ 292.303(b), 292.305, 292.312(b)(1) (2013).
42. 18 C.F.R. § 292.303(d).
43. Conversation with Staff, Office of Energy Mkt. Regulation, Fed. Energy Regulatory Comm'n (Sept. 19, 2013) (confirming that many of the recent QF applications are for rooftop solar).
44. All RTOs with day-ahead markets have been determined to meet these criteria, such that the utilities within their footprints may seek termination of the mandatory purchase obligation with respect to QFs of over 20 MW. 18 C.F.R. § 292.309(e)–(g) (2013).
45. 18 C.F.R. § 292.309(d)(1).

("REC"), that is, the revenue stream from the investment may not consist solely of power, or may be eligible to receive incentives under state or federal programs, such as grants, tax credits, or loan assistance. Thus, the owner looks at whether displacing the cost of its utility-purchased power (assuming it intends to consume its production) and/or the revenue received from sale of its power to the utility (if it intends to sell power into the grid), *plus* the revenue stream expected from the sale of RECs, justifies the up-front capital cost of installing and operating the proposed QF project after taking into account all incentives and tax benefits.

- In addition, DER in the form of renewable power (*e.g.*, rooftop solar) and purchases from an independent power producer of renewable power are often undertaken as a philosophical matter, including by companies that perceive a customer preference for environmentally friendly practices. Thus, the property owner may weigh intangible benefits that favor the use of a renewable source, as well as the comparative cost of utility-supplied power.
- In the wake of natural disasters such as Hurricane Sandy, there has been increasing interest in electric system resiliency and the ability to maintain electric service even in the absence of grid-support.[46] While not all QFs are capable of functioning independently of the grid, there are owners that place value on the ability to operate independently of the grid (for reasons such as the avoidance of lost revenue or safety concerns), and thus can justify the cost of a system with that capability.
- Further, when investing in DER (or any other long-term commitment to a non-utility supplier), the prospective owner necessarily has to make assumptions or projections as to its future cost for power from the new alternative source versus its cost for utility-purchased power. If the owner anticipates that its utility-purchased power costs will rise in the future, *e.g.*, because of either stricter environmental regulations or a carbon "tax" (in whatever form that might actually take), it may view the long-term prospects for a green alternative as more favorable than utility-sourced power. Or the prospective owner may anticipate that the cost of the new alternative source will be more predictable than its utility-purchased power, and place a value on avoiding price volatility or price risk.

In sum, a simple rate-to-rate cost comparison may not be determinative of an owner's decision to displace utility-purchased power. Thus, public power companies as well as other types of utilities may find an increasing amount of distributed, customer-owned generation on their grids, much of which is entitled to QF rights and benefits, for reasons that are not strictly related to their rates.

Across the United States, utilities of all types and their regulators are facing the implications of the growth of DER. This is sometimes referred to as "disintermediation," meaning that customers are procuring power without use of the utility as an intermediary. Utilities are raising the concern that load served by DER is not paying its fair share of the transmission and distribution system that is still required to support it.[47] Edison Electric Institute describes the current and expected increase in DER as "disruptive."[48] In *Smart Power*, Peter Fox-Penner posited that a new business model is needed, indeed emerging, in which utilities may transition from power providers to service integrators.[49] Many organizations are exploring the question of how "the utility of the future" should or will generate revenue and different regulatory models are being championed.[50]

There can be, however, positive effects from the addition of DER or other QF power to a system. First, it adds generation to the grid without requiring a capital investment from the utility or placing the utility at risk for completion or operation of the asset. Second, DER, depending on the configuration, could enhance grid reliability. For example, it may provide voltage support or relieve congestion. Or, DER can be part of a microgrid capable of being islanded during an outage, and either riding through the disturbance or perhaps being restored more quickly, thus assisting in the wider-area recovery.

The impact of DER, or the potential for a customer to contract directly with a non-utility generator for green power or other on-site power, has to be seriously evaluated by every utility and plans made to address this changing landscape and adapt. Among the logical steps that each utility should undertake are the following.

46. Resiliency projects and studies launched in the wake of Superstorm Sandy include ones conducted by the President's Hurricane Sandy Rebuilding Task Force, led by the Department of Housing, which recommended 69 measures including some related to energy resiliency, Press Release, U.S. Dep't of Hous. and Urban Dev., HUD No. 13-125, Hurricane Sandy Rebuilding Task Force Releases Rebuilding Strategy (Apr. 19, 2013), *available at* http://portal.hud.gov/hudportal/HUD?src=/press/press_releases_media_advisories/2013/HUDNo.13-125; Dep't of Energy and N.J. Transit, *DOE, New Jersey Study Reliability Improvements After Superstorm Sandy*, Elec. Light and Power (Aug. 27, 2013), http://www.elp.com/articles/2013/8/doe-new-jersey-study-reliability-improvements-after-superstorm-sandy.html; and Gridwise Alliance, *Improving Electric Grid Reliability and Resilience: Lessons Learned From Superstorm Sandy and Other Extreme Events*, Gridwise Alliance (June 2013), http://www.naseo.org/Data/Sites/1/documents/committees/energysecurity/documents/gridwise-superstorm-sandy-workshop-report.pdf. *See also* Nicholas C. Abi-Samra, *One Year Later: Superstorm Sandy Underscores Need for a Resilient Grid,* IEEE Spectrum (Nov. 4, 2013), http://spectrum.ieee.org/energy/the-smarter-grid/one-year-later-superstorm-sandy-underscores-need-for-a-resilient-grid (estimating storm damage at $65 billion and identifying four universities that were able to maintain power during the storm using on-site CHP plants).

47. Peter Kind, Edison Elec. Inst., Energy Infrastructure Advocates, Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business (Jan. 2013), *available at* http://www.eei.org/ourissues/finance/Documents/disruptivechallenges.pdf [hereinafter EEI Report].
48. *Id.* at 1.
49. Peter Fox-Penner, Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities 171–74 (2010).
50. *See, e.g.*, Ron Lehr & Bentham Paulos, *Three Regulatory Models That Could Help Utilities Embrace the Future*, Greentech Grid (Sept. 17, 2013), http://www.greentechmedia.com/articles/read/new-utility-business-models?utm_source=Daily&utm_medium=Headline&utm_campaign=GTMDaily.

A. Analysis

Each utility should analyze its system to determine why, where and whether (1) its customers might add DER (from QFs or other resources) to the system, and (2) the utility would find the addition of DER to be disruptive or helpful to its system. For example, a study done by Rocky Mountain Institute for Pacific Gas and Electric Company identified multiple drivers for customer-initiated DER.[51] State initiatives and financial incentives for rooftop solar played a large role.[52] But among the findings, the tiered rate structure for residential customers, intended to protect lower-income customers by maintaining artificially low rates for lower amounts of monthly consumption and to promote energy efficiency by charging sharply increased rates for larger users, had the effect of making DER quite cost effective for larger users.[53] Thus, a close system-by-system examination is necessary starting point.

B. Planning

Utility planning processes need to be expanded to anticipate and embrace the changing nature of electric service and guide it. Integrated resource planning needs to look beyond the old paradigm of seeing customers solely as load and recognize that they may become resources that deliver energy and ancillary services into the distribution system, and that the distribution system may serve a new function of moving power into the transmission system. Planners need to look to new and emerging technologies, such as community storage systems, home energy management technologies and storage (at the customer or utility level), when thinking about future system development. Because the utility does not directly control some of this growth, it might consider opening its planning process for stakeholder input, much as FERC required of transmission owners pursuant to Order Nos. 890 and 1000. This would help the utility better understand how stakeholders intend to use its generation, distribution, and transmission assets. Because public interest is at the core of public powers' economic model, public power is uniquely situated to be a progressive leader in rethinking the regulatory model.

C. Structuring

After determining how and where DER would be helpful or detrimental to the utility system, and incorporating customers into its planning process, the utility must also consider how to align incentives with desired result, or more euphemistically, how to "make lemonade out of lemons."

51. Rocky Mountain Inst., Net Energy Metering, Zero Net Energy and the Distributed Energy Resource Future: Adapting for the 21st Century 12–24 (Mar. 2012), *available at* http://www.rmi.org/rmi_pge_adapting_utility_business_models.
52. *E.g., id.* at 16.
53. *Id.* at 19–20.

IV. Making Lemonade Out of Lemons

The task of how a utility should proactively structure to survive change is not easily answered. There are numerous projects around the country working on this issue. Among them, the Energy Futures Coalition undertook "UTILITY 2.0 Piloting the Future for Maryland's Electric Utilities and their Customers," a project of the United Nations Foundation, to test "(1) the application of new technologies, strategies, and practices in the day-to-day functioning of electric utility service in a pilot project area; and (2) matching changes in utility business practices and reward structures as well as the regulatory scheme under which Maryland's utilities operate."[54] The report identified six areas in which utilities ought to focus:

- Reliability and resiliency, aimed at ensuring continuous, high-quality service;
- Residential customer optionality, centered on bringing smart grid information, analysis, control, and savings to small customers;
- Large customer optionality, optimizing costs and services for big customers;
- Utility system upgrades, making the grid's technical operations more visible, flexible, and able to convey and react to real-time information;
- Utility business model changes, keeping utilities financially viable even if they deliver less electricity; and
- Regulatory model adjustments, adapting the mechanisms for public-interest oversight, and consumer protection to new utility technologies.[55]

In another project, Edison Electric Institute commissioned Peter Kind of Energy Infrastructure Advocates to review the "disruptive" forces affecting the industry. He suggests that electric utilities adopt a number of short-term and long-term strategies, several of which focus on revising pricing structures to allocate costs without cross-subsidization as a defensive measure against revenue erosion.[56] Other significant work includes the Utilities 2020 project, led by Ron Binz and Ron Lehr, which examines three regulatory models that move beyond a defensive strategy and toward a new regulatory compact; the eLab work led by Rocky Mountain Institute; the e21 Project, which is working to develop new regulatory and business models for two of Minnesota's investor-owned utilities; and New York State's focused examination of the role of distribution utilities and, more generally, mechanisms for modernizing energy delivery.[57] Of note, much of the research and thought leadership

54. Energy Future Coal., UTILITY 2.0: Piloting the Future for Maryland's Electric Utilities and Their Customers 1 (2013), *available at* http://cleanenergytransmission.org/uploads/Utility%202-0%20Pilot%20Project-reduced.pdf.
55. *Id.* at 1.
56. EEI Report, *supra* note 47.
57. *See* Lehr & Paulos, *supra* note 50. *See also Utilities 2020: Exploring Utility Business Models and the Regulatory Changes Needed to Transform Them*, RBinz.com,

is focused on the regulation of investor-owned companies in this new economy, their business models and, as in New York State's Reforming the Energy Vision, the potential for a transformational change in the function of distribution utilities to platform providers.[58] While much of the thought emerging from such projects may be informative to public power, public power companies have an opportunity to address and bring leadership to these issues from a wholly different perspective that balances customer needs and desires with financial viability.

As utilities ponder the growing body of work surrounding potential future business models, given that DER technologies are among the important agents of change, it is critical to look at what PURPA requires and permits, since much of the new DER is entitled to PURPA rights and benefits. Further, electric utilities of all types should anticipate that QFs will demand their PURPA rights where it is advantageous to do so. Pricing and non-pricing issues inherent in possible new business models and strategies are discussed below, with emphasis on approaches that are compatible with PURPA.

A. *Price It Right!*

One obvious strategy is to better align the cost to the customer with the cost to the utility system. For QFs, this includes both the cost that the utility charges QFs for use of the grid and utility services and the rates that the utility pays for the power delivered to its system from QFs.

1. Rates for Service

Electric utilities remain obligated (sometimes in the capacity of "provider of last resort") to meet customer needs that exceed the customers' DER capability and, in connection, the distribution and transmission service necessary to deliver that service and receive power. A rising concern is that these costs are not being fully recovered. For example, during a highly contentious rate proceeding in which Arizona Public Service Company ("APSC") sought to revise the payment obligations of customers with rooftop solar, APSC explained on its website:

> Under the current rules, known as net metering, solar customers pay little or nothing to support the grid. Those costs are shifted to non-solar customers. As more people install solar on their homes, it becomes more important that everyone who uses the grid pays their fair share for the costs of keeping the grid operating.[59]

To the extent that cost recovery for transmission and distribution is rolled into the volumetric energy charge, customers installing DER will contribute less to the recovery of those costs than previously. Whether this is an undue burden, weighed against the overall benefits that DER providers bring to the system, would need to be considered on a system-by-system basis by each utility. However, if any rate restructuring is to be undertaken, there are some PURPA standards that must be considered.

PURPA mandates that electric utilities sell power to QF customers and, if requested, provide back-up, supplementary, maintenance, and interruptible power, unless exempted after FERC finds that the QF has a practical as well as legal right to procure such services from a competitive retail provider.[60] PURPA does not require that non-DER customers subsidize QFs (or other DER customers),[61] but PURPA does require that all rates for sales to a QF be "just and reasonable and in the public interest" and not discriminate against QFs as compared to other customers.[62] PURPA further requires that: "Rates for sales which are based on accurate data and consistent system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics."[63] PURPA also specifically provides that:

> The rate for sales of back-up power or maintenance power: (1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and (2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.[64]

Thus, PURPA does not prohibit restructuring of transmission, distribution, and service rates to assure that QF customers bear their fair and non-discriminatory share of the costs. Such changes could include, for example, allocating fixed costs related to distribution and transmission service for supplementary, maintenance, back-up, or interruptible power to a service charge based on peak usage rather than a volumet-

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http://www.rbinz.com/Utilities%202020.pdf (last visited June 17, 2014); *eLab*, Rocky Mountain Inst., http://www.rmi.org/elab (last visited June 17, 2014) (describing eLab work and associated publications); *e21 Initiative*, Great Plains Inst., http://www.betterenergy.org/projects/e21 (last visited June 17, 2014); N.Y. State Dep't of Pub. Serv., Case 14-M-0101, Reforming the Energy Vision (Apr. 24, 2014) (staff report and proposal appended to Order Instituting Proceeding); Advanced Energy Econ., Creating a 21st Century Electricity System for New York State (Feb. 26, 2014), *available at* http://info.aee.net/21st-century-ny-energy-industry-wg-position-paper.

58. N.Y. State Dep't of Pub. Serv., Case 14-M-0101, Reforming the Energy Vision (Apr. 24, 2014) (staff report and proposal appended to Order Instituting Proceeding); *supra* Part III.

59. Ariz. Pub. Serv. Co., Net Metering, AZ Energy Future, http://www.azenergyfuture.com/net-metering/ (last visited Oct. 17, 2013). *See also* EEI Report, *supra* note 47, at 17. Subsequently, the Arizona Corporation Commission ("ACC") authorized an interim fixed grid charge assessed on a per kW/month basis for all new residential distributed generation installations to be in effect until the next rate case, at which time the ACC could reevaluate the charge and further ordered a new proceeding for consideration of the value of distributed generation. In the matter of Ariz. Pub. Serv. Co.'s Application for Approval of Net Metering Cost Shift Solution*,* Ariz. Corp. Comm'n, Decision No. 74202 (Dec. 3, 2013).

60. 18 C.F.R. §§ 292.305(b), 292.312 (2013).

61. H.R. Rep. No. 113-4018 (2013), 2013 Wolters Kluwer 27 (Joint Explanatory Statement of the Committee of Conference).

62. 18 C.F.R. § 292.305(a)(1).

63. *Id.* § 292.305(a)(2).

64. *Id.* § 292.305(c).

ric charge and reassessing and potentially updating the rates for supplementary, maintenance, back-up, and interruptible power based on current usage patterns. *But, as set forth above, PURPA mandates comparable treatment of QFs and similarly situated non-QFs, cost allocations that are in accordance with the principles set forth in FERC's regulations, and rates that are otherwise just, reasonable and non-discriminatory. Any efforts to restructure are bound by these principles.*

2. Rates for Purchase

Obviously, a utility has a strong interest in attracting the optimal mix of customer investment in QF, DER, and other technologies to its system and may use rates and other non-rate incentives to do so. But unless an electric utility has been exempted from the obligation to purchase QF power under PURPA, it must offer QFs an opportunity to sell at avoided costs. Recent changes in FERC's understanding of how an avoided cost rate may be calculated (discussed below) and changes in the way in which QFs are being deployed, such as the rapid deployment of rooftop solar interconnected at the distribution level, suggest this is an opportune time for each public power utility to take a critical look at its avoided cost methodology and determine if it needs updating.[65]

It is also important to remember that QFs are not limited to selling only pursuant to PURPA's mandatory purchase provisions (sometimes called a "PURPA-put"); QFs have all the options of a non-QF also available to them. Thus, there are essentially three pricing models under which utilities can purchase power from QFs: (1) net-metering, which is being widely used for small DER, such as rooftop solar; (2) avoided-cost pricing under PURPA; and (3) negotiated prices. Feed-in tariffs ("FiT") are a possible means for implementing any of the three pricing structures and are also discussed below.

A baseline consideration with respect to any pricing discussion is the scope of federal preemption over wholesale rates. Generally, rates for wholesale sales in interstate commerce made by any person who is not exempt from the FPA must be filed with and accepted by FERC prior to the time the wholesale sales commence; sales not made in accordance with this requirement are in violation of the FPA.[66] FERC's authority to set wholesale rates for sales by entities subject to its jurisdiction is exclusive and has been found to preempt the field.[67] Thus, even though the public power utility-purchaser may be exempt from the FPA, the public power utility cannot set a wholesale rate for a seller of power who is subject to the FPA.[68] (Of course, not all sellers of power are subject to the FPA. Some privately owned QFs are exempt from FERC rate regulation, for example, because the facility is 20 MW or smaller and therefore has been exempted by regulation, as discussed above; because it is owned by a government entity exempt under section 201(f) of the FPA; or because it is located in Hawaii, Texas or the Electric Reliability Council of Texas and therefore not transacting in interstate commerce.) Thus, except within the confines of PURPA, as discussed below, a utility has to take care not to "set" a wholesale rate for a seller that is otherwise subject to the FPA.

a. Net Metering

Net metering, which is typically offered by tariff to smaller DER customers, has the inherent advantage of being customer-friendly. Net metering rules differ by state, and many configurations are possible. But to illustrate by reference to a simple example, a customer could install some type of DER, for example, roof top solar, at the same location as its load and on the customer's side of its retail meter. When the DER is generating, the customer load is served by the DER, with any customer needs in excess of the DER's output served from the grid. Power from the grid needed to serve the load is metered. If the output of the DER exceeds the load, then the excess power is fed back into the grid (also metered) and that contribution is "netted" from the total amount of power taken from the grid during the billing period at the same $/kWh rate at which the customer purchases power. The customer continues to get a monthly invoice from its utility, but due to its DER, its invoice is reduced to reflect its lower consumption of power from the grid. In other words, the customer consumes less power from the grid when the DER is meeting some or all of its load, and the meter is treated as "running backwards" during periods in which DER-production exceeds the load with which it shares a meter.[69] In some states, customers can opt to participate in a virtual net metering project, in which DER located off-site or not directly connected to specific customer loads is deemed to have delivered all or a portion of its output to the customer and the customer's bill reflects a credit for the energy produced, just as if the DER's output were delivered directly to and consumed by the customer's load.[70]

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65. The same point would be applicable to state regulators, who implement PURPA for electric utilities that are not "nonregulated" utilities. *See* 16 U.S.C. § 824a-3(f) (2012).
66. 16 U.S.C. § 824d (2012).
67. Montana-Dakota Co. v. Pub. Serv. Co., 341 U.S. 246, 255 (1951).
68. *See Conn. Light & Power Co.*, 70 FERC ¶ 61,012, at 61,029-31 (1995) (non-binding order, setting forth the Commission's views), *reh'g denied*, 71 FERC ¶ 61,035 (1999), *petition for review denied for lack of jurisdiction*, Niagara Mohawk Power Corp. v. FERC, 117 F.3d 1485 (D.C. Cir. 1997).
69. As described, the customer would receive a monetary credit for the power it delivers to the grid at the same retail rate it pays for power. However, to mitigate criticisms that the retail rate is too high, some utilities are moving to a "value of solar" concept in which the credit for rooftop solar power delivered to the grid is made at a rate that is specifically calculated based on the value the solar power delivers to the grid, and which will generally differ from the rate at which the customer purchases electricity. *See, e.g.*, City of Austin, *New Value of Solar Rate Takes Effect January*, Austin Energy (Dec. 6, 2013), www.http://austinenergy.com/ (follow "PowerSaver Program" hyperlink; then follow "About" tab; then follow "View all news" hyperlink; then follow "New Value of Solar Rate Takes Effect January" hyperlink); *Value of Solar Tariff Methodology*, Minn. Dep't of Commerce, http://mn.gov/commerce/energy/topics/resources/energy-legislation-initiatives/value-of-solar-tariff-methodology%20.jsp (last visited June 18, 2014).
70. *See, e.g.*, *Virtual Net Metering*, Cal. Pub. Utils. Commission, http://www.cpuc.ca.gov/PUC/energy/DistGen/vnm.htm (last visited June 18, 2014) (describing California's virtual net metering program for multi-tenant buildings); *Net Metering*, Energize Conn., http://www.energizect.com/government-municipalities/programs/virtual-net-metering (describing Connecticut's virtual net metering program); *Distributed Generation and Interconnection in Massachusetts*, Mass. Dep't of Energy Resources, https://sites.google.com/site/massdgic/home/frequently-asked-questions#question12 (last visited June 18,

Net metering arrangements can be structured such that the seller, whether it is a QF or not, avoids FERC jurisdiction, so long as the customer consumes more power from the grid than it delivers into the grid, over the applicable billing period. Specifically:

> Where there is no net sale over the billing period, the [FERC] has not viewed its jurisdiction as being implicated; that is, [FERC] does not assert jurisdiction when the end-use customer that is also the owner of the generator receives a credit against its retail power purchases from the selling utility.[71]

FERC also extended its disclaimer of jurisdiction over net metering to cover a third-party owner of the DER, in this case, Sun Edison LLC and its subsidiaries:

> SunEdison presents a case where the entities that own the generating facilities will not be the participants in the net metering program, but will sell their output to the net metering program participants. Sun Edison asks the Commission to declare that in these circumstances there is no sale for resale. We agree that, where the net metering participant (i.e., the end-use customer that is the purchaser of the solar-generated electric energy from SunEdison) does not, in turn, make a net sale to a utility, the sale of electric energy by SunEdison to the end-use customer is not a sale for resale, and our jurisdiction under the FPA is not implicated.[72]

But, if the customer does deliver more power into the grid from its DER than it consumes over the billing period—that is, it does make a net sale—FERC's jurisdiction is implicated:

> If the entity making a net sale is a QF that has been exempted from section 205 of the FPA by section 292.601 of our regulations, no filing under the FPA is necessary to permit the net sale; however, if the entity is either not a QF or is a QF that is not exempted from section 205 of the FPA by section 292.601 of our regulations, a filing under the FPA is necessary to permit the sale.[73]

Thus, a state or nonregulated utility can use net metering with respect to entities that are not net sellers to the grid.

Critics of net metering have alleged that since customers are credited with the retail rate for power rather than a wholesale price, they are overpaid.[74] Certainly, a retail price is more of an incentive than a wholesale price. Indeed, some utilities are moving toward a structure that credits the customer's bill for rooftop solar power, in particular, at a rate that is based on its value to the grid, which is called a "value of solar" rate.[75] (Under either structure, the adjustment is made to the customer's retail bill, and therefore FERC does not deem the transaction to include a FERC-jurisdictional sale.) However, each generation technology benefits from (or is limited by) government policies in some way. So from this author's perspective, the issue is not whether net metering is credited at a retail or "value of solar" price, or who owns or operates the facilities (assuming they are properly integrated into the grid). The issue is whether, taking into account the total cost of building and operating the net-metered DER compared to the total cost of building and operating alternative forms of generation or alternative solutions (*e.g.*, energy efficiency, transmission or distribution solutions, storage), the utility is attracting the optimal mix of resources to its system. Sending a positive pricing signal through net metering is appropriate for encouraging the technologies that lend themselves to net metering (*e.g.*, rooftop solar), if that results in the optimal mix of resources that meet customers' needs for electric power.

Net metering offers a significant advantage over a "buy all/sell all" transaction structure, which is sometimes promoted as an alternative to net metering, because net metering removes the transaction from FERC's jurisdiction, thus eliminating concern about whether the owner of the DER is authorized to sell power at wholesale.[76] Under a buy all/sell all structure, rather than just crediting the retail bill for power delivered to the grid, the customer would buy all of its power from the utility at retail and, separately, sell the utility power from its DER at wholesale. As with a "value of solar" rate, this transaction structure may send a more accurate price signal, which might the appropriate signal for optimizing the resource mix; and it allows for a customer to sell more than it consumes (on a net basis). But, with a buy all / sell all structure, the customer's sale of power to the utility is a wholesale sale. So unlike a net metering arrangement, which is viewed as an adjustment to a retail arrangement and is therefore under state jurisdiction or the direct jurisdiction of the public power utility, a customer/owner that sells power into the grid outside of a net metering arrangement is engaging in a FERC-jurisdictional sale, unless the sale is made as a PURPA-put or the customer/owner is otherwise exempt from FPA. Thus, if a utility does not offer net metering, or the DER owner/customer is a net seller, FERC's jurisdiction may be implicated. In other words, a buy all/sell all structure implemented by a public power utility would be accessible only to those generators that either have FERC authorization to sell at wholesale pursuant to the FPA or who are exempt from rate regulation under the FPA.

b. PURPA Avoided Cost Rate Sales

A QF-SPP or a QF-Cogen that meets the regulatory requirements may require an electric utility to purchase its power

2014) (describing Massachusetts's "neighborhood metering program" and customer rights to allocate metering credits to others in the state).

71. Sun Edison LLC, 129 FERC ¶ 61,146, at P 18 (2009) (notes omitted).
72. *Id.* at P 19.
73. *Id.* at P 18.
74. *See, e.g.,* Inst. for Energy Research, California Public Utilities Commission Report on Net Metering (Oct. 23, 2013), *available at* http://www.instituteforenergyresearch.org/2013/10/23/california-public-utility-commission-cpuc-report/ (alleging that by paying a retail rather than wholesale price for net metered solar, California utilities "are paying nearly 400 percent more than they would for energy from other sources").
75. *See supra* text accompanying note 69.
76. *See, e.g.,* Lawrence A. Gamble et al., American Solar Energy Society, ASES 2013 – 238: Farmers Electric Co-Operative, Kalona Iowa: America's Most Progressive Utility? 4 (2013) (describing comprehensive management strategy adopted by Farmers Electric Cooperative, which includes a buy all/sell all program).

pursuant to PURPA at the utility's avoided cost rate, unless the utility is exempt from PURPA.[77] This right exists regardless of whether the utility-purchaser or the QF would be subject to FPA rate regulation or not.[78] PURPA requires utilities regulated by state law to establish their avoided cost rate pursuant to rules established by the state regulator.[79] Electric utilities that are not rate regulated, including public power utilities, are required to make their avoided cost information available directly to potential sellers and implement their own avoided cost rates.[80] This ability of states and nonregulated utilities to set avoided cost rates for wholesale sales by QFs under PURPA is an express carve-out from FERC's otherwise pervasive preemption of the field.

A QF may be compensated at an avoided cost rate for capacity or capacity and energy if it commits to provide capacity or capacity and energy pursuant to a legally enforceable obligation over a specified period of time, for example pursuant to a contract.[81] FERC's rules specify a number of characteristics of the QF that are to be given consideration when determining a utility's avoided cost, including the following:

- Availability during daily and seasonal peaks;
- Availability for dispatch;
- Reliability;
- Ability to usefully coordinate scheduled outages with the utility;
- Usefulness in emergencies, including its ability to separate its load from its generation;
- The individual and aggregate value of the QF energy and capacity on the system;
- Smaller capacity increments and shorter lead times for construction;
- Other terms and conditions of the contractual arrangement pursuant to which the QF provides power, including the duration of the obligation, termination notice requirements, and sanctions for non-compliance.[82]

A recent paper commissioned by the Interstate Renewable Energy Council, Inc. takes a close look at how these factors, which have been in effect since 1980, can be applied to QFs that are DER.[83] For example, it points out that by locating close to load, DER can reduce line losses and may reduce transmission congestion (since the generation and load are both on the distribution system), each of which can produce avoided costs, which may be appropriately considered in setting compensation for QFs.[84] While the avoided cost rate cannot include "adders" or "bonuses" for traits such as avoiding greenhouse gases, it can appropriately include any costs that the purchasing utility would actually incur, such as environmental compliance costs.[85] Further, non-rate incentives such as tax benefits are not considered in the avoided cost calculation, and therefore, although neither nonregulated utilities nor states implementing PURPA have authority to set a rate that exceeds the avoided cost rate, a nonregulated utility (or state) can still encourage desirable forms of generation with non-rate incentives without violating PURPA or the FPA. Under certain circumstances, a utility may offer different avoided cost rates to reflect the respective values of the different resources that are avoided. Specifically, FERC has recognized that when a state determines an avoided cost rate, it "may take into account actual procurement requirements, and resulting costs, imposed on utilities [by the state.]"[86] Underlying this decision was FERC's acknowledgement that states have authority over a utility's procurement policies.[87] Thus, FERC determined that,

> [W]here a state requires a utility to procure energy from generators with certain characteristics, generators with those characteristics appropriately constitute the resources that are relevant to the determination of the utility's avoided cost for that procurement requirement—they are the sources that can sell to the utility, and thus the sources being avoided.[88]

So, for example, if a utility is subject to a state mandate to procure a particular type of resource, *e.g.*, energy and capacity from solar facilities, then the state may establish an avoided cost rate for solar QF-SPPs based on the avoided cost of purchasing energy and capacity from its next best alternative that is a solar facility. In this context, where only a solar facility could fulfill the state law mandate, the avoided cost would not be appropriately based on the cost of gas-fired energy and capacity, which by law would be unable to fulfill the same need. Thus, FERC's policy allows the avoided cost rate to reflect the value of a diversified portfolio or specific types of generation, where the state has embedded that requirement into law.

Where a public power utility is subject to a state renewable portfolio standard mandate,[89] the same logic would apply. But where the public power utility sets its own procurement goals, its ability to set resource-specific avoided cost rates is not yet clearly defined. The fact that the public power utility or the local government with which it is associated established the goal, rather than the state legislature or the state public utility regulator, would seem irrelevant, if the RPS is set using the adopting body's legislative or regulatory authority.

77. 18 C.F.R. § 292.303(a) (2013).
78. *Supra* text accompanying note 15.
79. 16 U.S.C. § 824a-3(f)(1) (2012).
80. *Id.* § 824a-3(f)(2).
81. 18 C.F.R. § 292.304(d)(2) (2013). If a QF has made a legally enforceable commitment to deliver energy or capacity over a period of time, the energy has a higher value than energy that is delivered "as available," since the utility can depend on it, and therefore the utility can avoid procuring an alternative resource.
82. 18 C.F.R. § 292.304(e) (2012).
83. Keyes, Fox & Wiedman LLP, Interstate Renewable Energy Council, Inc., Unlocking DG Value 7 (May 2013).
84. *Id.*
85. Cal. Pub. Util. Comm'n, 133 FERC ¶ 61,059, at P 31 (2012).
86. Cal. Pub. Util. Comm'n, 134 FERC ¶ 61,044, at P 32 (2011).
87. *Id.* at n.75.
88. *Id.* at P 33.
89. A renewable portfolio standard establishes the amounts of renewable energy, sometimes specified by type, that should be included in a utility's portfolio of generation resources.

Thus, a logical extension of the cases described above would permit a public power utility to offer a renewable resource the same avoided cost rate it would pay for a resource of the same type, (*e.g.*, wind for wind, or solar for solar) rather that the price it would pay for a fossil-fuel resource, if the purchase is made to fulfill a legally binding RPS requirement.

In sum, each electric utility should review its avoided cost methodology because the types of QFs entering the system and FERC's methodology, which now permits resource-specific avoided cost prices (where supported by an RPS requirement) have both evolved in recent years. Avoided cost pricing is an option through which a nonregulated utility can set wholesale rates targeted to attract specific resources needed to fulfill a legal mandate. Importantly, the nonregulated utility may fully incorporate into its avoided cost rate a wide range of factors, such as avoided line losses or avoided distribution investments. Perhaps even more importantly, QFs may demand that it do so. A nonregulated utility can also use non-rate incentives to encourage resource-specific development. Therefore, notwithstanding FPA's preemption of the area of wholesale rates, a nonregulated utility can use the PURPA avoided cost exception to FERC's FPA jurisdiction (coupled with procurement mandates and perhaps other incentives) to establish favorable economics designed to attract an optimal mix of QF power to its system.

c. Negotiated Rates

A QF may also elect to sell its power at negotiated rates.[90] When it does so, the sale is not made pursuant to PURPA (even though the QF may have a PURPA-put alternative, if the negotiation is not otherwise successful). When a QF sells pursuant to a negotiated rate, it must have authorization from FERC under section 205 of the FPA to make the sale, which would typically be in the form of market-based rate authority, unless the QF is otherwise exempt from the FPA requirement (*e.g.*, QFs of 20 MW or less). A non-exempt QF may secure market-based rates upon application to FERC, by showing that it, together with its affiliates, lacks market power.[91]

A utility seeking to buy power under negotiated rates may proceed through a competitive auction or targeted procurement, depending on its governing practice requirements, but typically such procurements would permit QFs and non-QFs to compete on equal footing. Some procurement mechanisms, such as California's Renewable Auction Mechanism ("RAM"),[92] rely on price competition among small generators, some of which may be QFs and/or DER. Larger QFs may elect to sell under unit-specific negotiated contracts. But, from the perspective of the purchasing utility, purchasing power from a QF pursuant to a negotiated rate is not substantively different than purchasing from a non-QF, except that the QF may have lower regulatory compliance obligations and therefore may incur lower costs, making it more competitive.

d. Feed in Tariffs

FiTs have been widely used in Europe and are generally deemed to be a highly effective means for promoting resource development, particularly of green power.[93] FiTs provide prospective sellers with assurance of a tariff price, which in some cases will be available over a specified number of years.[94] Thus, price-discovery is simple and financing for the new resource can be based on the tariff provisions. FiTs could be used in a targeted manner by offering the most lucrative pricing to generation resources that provide a commensurate benefit to the system. A FiT can be applied to a resource that generates all its power for delivery to the grid at all times (that is, does not serve a load) or to one that serves an on-site load and only delivers the excess. A number of states and utilities have implemented FiTs, but typically for very small facilities that are not subject to FPA rate regulation.[95]

As discussed above, FERC's exclusive jurisdiction to set wholesale rates for sales in interstate commerce, other than QF avoided cost rates, places a limit on the use of FiTs for wholesale sales. The only transfer of rate-setting authority granted by PURPA to states and to nonregulated utilities applies to the rates for QFs and the rates set must be no more than avoided cost. Thus, a nonregulated utility cannot set a wholesale rate pursuant to a FiT for any FERC-jurisdictional facility, other than an avoided cost rate for a QF.

While nonregulated utilities and state regulators may not set a wholesale price pursuant to a FiT (other than an avoided cost rate), QFs are not limited with respect to the rate at which they may sell. Since no QF is obligated to sell its power under a specified structure, there is a hazy line between "setting a rate" and "making an offer." In deciding the 2010–2011 cases involving California's CHP program, FERC rejected the arguments of the California Public Utilities Commission ("CPUC") that it was not setting prices in violation of the FPA because it was merely requiring, consistent with state law AB 1613, that the utilities under its jurisdiction *offer* to buy the output of CHP facilities at the tariff rates it had established, not requiring the CHP units to sell.[96] The CPUC argued that its action was consistent with its purview to direct the purchasing policies and generation mix of the utilities under its jurisdiction and within the state's right to implement policies to meet the state's envi-

90. Like any other seller of electric power at wholesale, a QF may seek authorization from FERC pursuant to Section 205 of the FPA to sell power at market-based rates pursuant to the regulations set forth at 18 C.F.R. § 35.36–35.42 (2013). However, as noted above, a QF of 20 MW or less is exempt from the obligation to do so.
91. 18 C.F.R. § 35.37 (2013).
92. *See Renewable Auction Mechanism*, Cal. Pub. Util. Commission, http://www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm (last modified Feb. 24, 2014).
93. *See* Toby D. Couture et al., Nat'l Renewable Energy Lab., A Policymaker's Guide to Feed-In Tariff Policy Design 1, 9–11 (2010), *available at* http://www.nrel.gov/docs/fy10osti/44849.pdf.
94. *See id.* at 6.
95. For a listing, see *Feed-In Tariffs*, U.S. Energy Information Admin. (June 4, 2013), http://www.eia.gov/electricity/policies/provider_programs.cfm.
96. Cal. Pub. Util. Comm'n, 132 FERC ¶ 61,047, at P 64 (2010).

ronmental goals.[97] FERC declined to find that the tariff was merely an offer, holding instead that "the CPUC's AB 1613 Decisions constitute impermissible wholesale rate-setting by the CPUC."[98]

In 2012, however, FERC declined to bring an enforcement action against Vermont's offering of an optional standard-offer purchase program, the SPEED program, which allowed QFs to supply power at an offered price that was not an avoided cost rate.[99] The Commission found that because Vermont had a long-standing program under which QFs were able to sell at avoided cost rates,

> [QFs] still have the option to participate in a program that has been found consistent with PURPA. Those Vermont QFs that choose to participate in the SPEED program are agreeing to the rates that result from that program. Nothing in the Commission's regulations limits the authority of either an electric utility or a QF to agree to rates for any purchases or terms or conditions relating to any purchases which differ from the rates or terms or conditions which would otherwise be required by the Commission's regulations.[100]

Thus, the distinction remains hazy between an impermissible FiT that sets a rate and a permissible FiT that provides an optional rate.

For an electric utility that is not subject to either the FPA or state law, the electric utility's ability to offer incentive rates through a FiT are even hazier. Certainly offering a rate (other than an avoided cost rate) through a FiT would not excuse a nonregulated utility from its PURPA obligation to purchase at an avoided cost, nor endow a QF that is not exempt from the FPA with a right to sell other than with FERC's authorization. However, in its capacity as a utility, a public power entity has discretion to purchase power from non-QF facilities and from QFs at rates that are mutually agreed to, regardless of whether the rate is above, at or below avoided cost. So, for example, a public power entity that desires to add DER to its system could publish a request for offers and select from among the competing offers based on price, which is a mechanism often used by utilities of all types. Such requests often reserve to the utility the right to reject any or all bids, if none are satisfactory. So, it is only a small (but untested) step for the nonregulated utility to make a request for offers, specifying both the terms and conditions *and the price* which it would be willing to pay for power of a specified quantity and kind through the publication of a FiT. Provided that the seller is in compliance with its FPA obligations (if any) and able to sell at a negotiated rate, it could accept the offer. Whether this would constitute impermissible rate-setting seems to balance on a fine line, but arguably, so long as the FiT is not the only available channel through which a seller may sell and the FiT tariff is offered directly by the (nonregulated) utility, not under a state-mandated or state-approved rate, it would appear to pass muster, since it's merely a voluntary option.

B. *Looking Beyond Rates: The Bigger Picture*

Other than looking at pricing, "making lemonade" requires considering the system as a whole to determine how to make it most hospitable to desirable investments. As discussed below, some additional measures that should be considered include the following: (1) remove non-price barriers to the addition of desirable resources that meet customer needs and desires; (2) build and retain load that complements the system; and (3) consider making direct investments in, or owning, DER or other resources that are desirable additions to the system.

1. Removing Non-Price Barriers

If a utility has selected the path of trying to facilitate desirable growth, it should look beyond rates to ways in which it can help smooth the entry of new, desirable DER and QF power. Some of the non-price barriers to development that may require attention include the following:

- A utility might be able to encourage placement of new generation facilities in desirable locations by making more data about its transmission and distribution system available. This would also reduce the cost to the developer of the new generation. For example, the California utilities make available maps of their distribution systems that show line voltages and capacity to facilitate planning for DER providers.[101] Publicizing information about where capacity is available, where voltage support is needed, or other pertinent data could direct developers to preferred locations. Of course, generators will likely seek compensation that is commensurate with the benefit they are bringing to the system.
- Clear interconnection procedures and easy to understand, standardized forms of interconnection agreements can reduce transaction costs and build the utility's reputation as a place where QFs and other DER or efficient generation is welcomed.
- Local laws may include zoning or other land use restrictions or processes that unnecessarily restrict or increase the cost of installing DER or other QF generation.[102] The utility can work with other public authorities to

97. *Id.* at PP 29–30.
98. *Id.* at P 64.
99. Otter Creek Solar LLC, 143 FERC ¶ 61,282 (2013) (declining to bring an enforcement action in opposition to Vermont's SPEED program).
100. *Id.* at P 4.

101. For explanations of the purpose, and links to the interactive maps created by Pacific Gas and Electric Company and Southern California Edison Company to facilitate the placement of new DER, see *Solar Photovoltaic (PV) and Renewable Auction Mechanism (RAM) Program Map*, PG&E, http://www.pge.com/b2b/energysupply/wholesaleelectricsuppliersolicitation/PVRFO/pvmap/ (last visited June 18, 2014); *Renewable Auction Mechanism (RAM)*, S. Cal. Edison, http://www.sce.com (last visited June 18, 2014) (follow "Energy Procurement" hyperlink; then follow "Renewable & Alternative Power Contract Opportunities" hyperlink; then follow "Renewable Auction Mechanism (RAM)" hyperlink).
102. *See, e.g.*, *Municipal Clean Energy Tool Kit*, ICLEI, http://www.icleiusa.org/action-center/tools/municipal-clean-energy-toolkit/ordinances (last visited June 24, 2014).

remove these restrictions and help educate consumers on how to navigate the applicable regulations. It is also appropriate and necessary to look more broadly at how increased QF or DER would affect the system and the community and work proactively to address any repercussions. For example, first responders' training may need to be expanded in light of the increased deployment of DER.[103]

State laws that limit third-parties from selling power at retail can inhibit the use of third-party equipment owners and operators. Particularly in the residential rooftop market, it is common to find third-party equipment owners and operators who sell power at a contract rate, collect "rent" in the form of a monthly payment for power, or engage in some form of shared savings structure.[104] These structures can make DER affordable to those for whom the up-front capital costs would be prohibitive. A non-regulated utility that wants to encourage capital investments in its footprint might look at ways to facilitate third-party owned generation and community-owned generation or storage.

2. Load Building

Part of the solution to customers leaving the system could be in the form of building new customer load or creating incentives that retain customer load that might otherwise leave the system. Public power has long relied on low rates as a competitive advantage to attract load, but as discussed above, rate-competition may not fully meet new customer needs. Combining low rates with programs that satisfy customers' desire for green power and asset control could be an attractive inducement to new load and economic development. Many large companies, including Apple, Google, Intel, Staples, Toyota and Wal-Mart, have committed to achieving environmental stewardship goals and have made the purchase of renewable power a part of their strategy.[105] The obstacles to realizing this goal can be daunting. As explained by IBM, which is also pursuing a sustainable energy policy:

> Currently, due to limitations in the market regulatory and procurement structures and in the distribution infrastructure, there is limited renewable energy available through the grid in most areas of the world. These restrictions limit the total quantity of renewable energy available for purchase directly from the grid for consumption at a facility. Continued advances are needed in renewable electricity generation, distribution and storage technologies to increase the availability of economically viable renewable electricity in the marketplace to supply electricity directly to consuming locations. IBM is working with industry peers, utilities, NGOs and other renewable energy industry participants to identify, develop and capture opportunities to procure electricity generated from renewable sources where it makes business sense. We also work to incorporate on-site solar energy, co-generation or tri-generation systems or geothermal systems on an individual location basis.[106]

Some of the obstacles that companies like these face may be within the power of a utility to remove or ease, thereby making the utility's service territory more attractive to such commercial or industrial customers. Among the strategies that may prove attractive to new load are:

- giving customers the option to be served under a green tariff in which the utility continues to provide power, but from sources with similar environmental characteristics to those that the customer would choose, and at a lower cost than the customer would incur if it purchased the power independently of the utility;
- allowing large consumers to "buy-through" so that their own green power wholesale purchases can be delivered at their retail locations, and the utility is compensated for providing scheduling and smoothing services; or,
- as discussed below, becoming a provider of green DER and partnering with customers to be their on-site "solution provider."

103. *See, e.g.*, Casey C. Grant, Fire Prot. Research Found., Fire Fighter Safety and Emergency Response for Solar Power Systems (Oct. 2013), *available at* http://www.nfpa.org/~/media/files/research/research%20foundation/research%20foundation%20reports/for%20emergency%20responders/rffirefightertacticssolarpowerrevised.pdf.

104. *See* April Lee, *Most New Residential Solar PV Projects in California Program Are Not Owned by Homeowners*, U.S. Energy Information Admin. (2013), http://www.eia.gov/todayinenergy/detail.cfm?id=12991.

105. *See* Environmental Responsibility—Climate Change, Apple, http://www.apple.com/environment/climate-change/ (last visited June 18, 2014) ("Our goal is to power all Apple corporate offices, retail stores, and data centers entirely with energy from renewable sources—solar, wind, micro-hydro, and geothermal. We're designing new buildings and updating existing ones to use as little electricity as possible."); *Renewable Energy*, Google, http://www.google.com/green/energy/ (last visited June 18, 2014) ("At Google, we're striving to power our company with 100% renewable energy. In addition to the environmental benefits, we see renewable energy as a business opportunity and continue to invest in accelerating its development."); *Intel and the Environment: Responsible Operations*, Intel, http://www.intel.com/content/www/us/en/corporate-responsibility/eco-responsible-operations.html (last visited June 18, 2014) (explaining Intel has "been the largest voluntary purchaser of green power in the U.S. since 2008 (according to the U.S. Environmental Protection Agency), and our commitment continues to grow. Our green power purchases in 2013 account for 100 percent of our U.S. electricity use, up from 50 percent in 2008."); *Using Renewable Energy*, Toyota, http://www.toyota-global.com/sustainability/environmental_responsibility/establishing_a_low_carbon_society/using_renewable_energy.html (last visited June 18, 2014) (explaining how Toyota is beginning to use renewable power in its manufacturing facilities); *Renewable Energy & Efficiency*, Staples, http://www.staples.com/sbd/cre/marketing/about_us/renewable-energy-efficiency.html (last visited June 18, 2014) ("While Staples' energy reduction efforts are contributing substantially to reducing the company's carbon footprint, we're shrinking that footprint even further by producing our own solar power, using fuel cell technology and participating in the EPA's Green Power Partnership. As of November 2013, Staples was ranked fourth among all retailers, sixth among Fortune 500 companies and seventh nationally on the Partnership rankings lists."); *Working Toward 100% Renewable Energy*, Walmart, http://corporate.walmart.com/global-responsibility/environment-sustainability/energy (last visited June 18, 2014) (explaining that Walmart is "[w]orking toward 100% renewable energy."). *See also Green Power Purchaser Awards List*, U.S. Envtl. Prot. Agency, http://www.epa.gov/greenpower/awards/winners.htm (last updated on Apr. 15, 2014) (recognizing a number of for-profit and non-profit organizations, including Cisco Systems, Inc., Microsoft Corporation, Apple, Inc., for their use of renewable energy).

106. *Increasing Renewable Energy*, IBM, http://www.ibm.com/ibm/environment/climate/renewable_energy.shtml (last visited June 18, 2014).

This is a non-exclusive list, and not suitable to every system, but utilities that thrive will be those that supply the choices consumers want.

3. Taking Ownership, Literally

While feasibility depends on the particular utility and project, one possible way to offset the loss of utility revenue due to DER is to become a provider of DER. But as Commissioner Peevey, President of the CPUC, explained, DER ownership may be outside of the comfort zone for utilities:

> "The California utilities would have been very smart, five, six, eight years ago to get into the solar business themselves and put the solar panels on people's homes. They could have done this, and put it into rate base[,]" [said Michael Peevey, chair of the California Public Utilities Commission.] Peevey, in fact, says he recommended they do just that, to no avail. "It's not their culture," he says. "They told me that. 'It's not our culture.'"[107]

Commissioner Peevey's view is consistent with a 2006 DOE study that found that electric utilities had not installed much distributed generation for several reasons, including their "lack of familiarity with DG [distributed generation] technologies."[108] DOE pointed out that a consequence of utilities' lack of direct involvement with DER is "a lack of standard data, models, or analysis tools for evaluating DG, or standard practices for incorporating DG into electric system planning and operations."[109]

However, if the utility were to own and operate DER, the additions could be planned to provide for operational benefits to the system and the financial benefits of the project would not flow exclusively to a single customer but to the utility and its ratepayers generally. The homeowner or business that makes its rooftop, parking lot, or land available would still benefit from lease payments as well as the personal psychological benefit of having made a contribution to sustainability, without the maintenance headache.

As the DOE study also pointed out, however, distributed generation benefits tend to be site-specific and therefore are often more readily identifiable by a customer than its utility.[110] Therefore, close cooperation with customers may be critical to identifying potentially cost-effective projects. A more open planning process, as referenced above, may assist in this regard.

V. Conclusion

PURPA continues to be relevant to today's market because many of the new generation additions to the electric system qualify for QF status. This growth, much of which consists of small DER, is being widely heralded as creating a need for thought leadership on how the utility of the future can make money and survive. While each utility will have to develop its own strategy, PURPA includes a great deal of flexibility that a utility can apply to encourage desirable customer-owned investments. Further, having QF status frees the QF owner/operator from certain regulatory burdens which can reduce the QF's costs.

However, both utilities and QFs have to be cognizant of the limitations as well as the opportunities posed by PURPA. For example, PURPA entitles QFs to sell power at an avoided cost rate (although they are not required to do so) to any utility that has not been excused from its PURPA-purchase obligations. Utilities may need to reassess their avoided cost methodologies and rates since some of the new QFs are deployed in ways that differ from prior generations of QFs. Utilities heeding the current trend to reassess the charges imposed on DER for transmission, distribution and additional power support need to be sure that any rate restructuring conforms to the non-discrimination provisions of PURPA. Notwithstanding the limitations of PURPA, public power entities have an opportunity to use this paradigm shift in generation sources to assess the role of DER, QFs and renewable energy on the overall electric system and business model. They can then develop strategies that provide opportunities for customers to achieve their goals for cleaner, reliable, and affordable energy.

107. Chris Martin et al., *Why the U.S. Power Grid's Days Are Numbered*, Bloomberg Businessweek 3 (Aug. 22, 2013), http://www.businessweek.com/articles/2013-08-22/homegrown-green-energy-is-making-power-utilities-irrelevant.
108. U.S. Dep't of Energy, The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion, 4 (Feb. 2007).
109. *Id.*
110. *Id.* at 3-4.