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State Feed-in-Tariffs: Recent FERC Guidance for How to Make Them FiT under Federal Law

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This article first appeared in a slightly different form in the May 2011 issue of *The Electricity Journal* (www.elsevier.com).

Introduction

Governments seeking to advance the development of renewable energy in their jurisdictions have a variety of policy options. In the United States, the most popular has been so-called renewable portfolio standards (RPS). Generally, these are state mandates that require the state's utility companies to obtain a minimum percentage of the power they sell to consumers from specified resources; precise obligations vary significantly by RPS. In contrast, European governments have generally favored feed-in-tariffs (FITs). Essentially, FITs have two components – a set price for a specified source of energy and over a purchase term, and access to the grid for the purpose of delivering the energy.¹ Like RPS, however, they can differ dramatically. Variables in designing a FIT include, for example, the length of the term of the FIT, the

frequency at which prices are set during the term, the facilities which qualify (potentially based on size, resource type, location, and other criteria) and the allocation of costs, which typically need to exceed market rates in order to encourage the desired renewable energy development and investment.

Notwithstanding the sometimes aggressive requirements of RPS (e.g., the recently increased 33% in California), FITs are widely viewed as having a greater potential to encourage the development of renewable generation than RPS, and have therefore been the subject of considerable interest and advocacy within the renewable energy industry. A commonly held view is that a FIT regime leaves more initiative in the hands of generators, as compared to a RPS program administered by a utility pursuant to state rules. In addition to policy and economic obstacles, however, governments in the United States seeking to implement FITs have also faced significant legal impediments under federal law – principally, the risk of federal preemption.

In recent orders analyzing California Assembly Bill 1613 (AB 1613), which required California investor-owned utilities (IOUs) to purchase excess energy generated by combined heat and power (CHP or cogeneration) systems meeting certain energy efficiency and environmental compliance requirements, at rates to be set by the California Public Utilities Commission (CPUC), the U.S. Federal Energy Regulatory Commission (FERC) may have significantly altered the preemption analysis, at least for certain categories of generators. At the very least, it has raised the regulatory hurdles for many participants in FIT projects. Although renewable generation does not qualify for AB 1613, FERC's orders have direct implications for states considering comparable renewable energy policies.

Summary of CPUC Proceedings Before FERC

The risk of federal preemption of state FITs arises principally under the Federal Power Act (the FPA), which prohibits any generator of power from *selling* such power for resale (i.e., selling the power “wholesale”) without FERC approval of the contract pursuant to which the *sale* is made. Consequently, states cannot impose mandatory FITs under the FPA unless FERC reviews and approves the rates for each FIT contract, which would almost certainly undermine the most important element of the FIT – economic certainty for generators. This review can take place in one of three ways: (1) the FIT contract may qualify for “avoided cost” pricing, as discussed in more detail below, with minimal regulatory action on the part of the FIT generator; (2) FERC can review the rates charged for each individual FIT contract; or (3) a seller can undertake the effort and expense to qualify to charge market-based rates for power it generates and sells.

In the United States, several states have introduced FITs to encourage the development of small-scale generation facilities, often with a focus on renewable energy, cogeneration and other distributed generation. Introduced in 2008, California's AB 1613 establishes a FIT for CHP facilities of 20 megawatts (MW) or less. In implementing regulations, CPUC established the FIT price – \$0.096/kWh – based on the avoided cost of a base-load combined-cycle gas turbine, and added to that cost the likely future costs of compliance with

state greenhouse gas emissions-control requirements. In addition to the greenhouse gas adder, CPUC increased the FIT price by 10% for sales by generators located in transmission-congested areas as a proxy to reflect the avoided cost of distribution and transmission upgrades that would otherwise have been necessary. In May 2010, facing threatened litigation regarding the constitutionality of the AB 1613 FIT by Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E) and others, CPUC applied to FERC for a declaratory order that the FIT was not preempted by federal law.²

Among CPUC's legal arguments against preemption was that the FIT did not set wholesale costs for sellers of power, which it effectively conceded would violate the FPA; rather, it only mandated a cost at which California utilities were required to *purchase* power in order to comply with state law.³ CPUC reasoned that the FIT did not require generators actually to *sell* at that price. CPUC also argued that requiring utilities to offer to *purchase* power at a set price is an extension of a state's authority over the procurement decisions of such utilities – the same authority which allows states to implement RPS and which is not preempted under the FPA. State regulators frequently mandate open procurement for generating capacity and power by regulated utilities; typically, the procurement process includes an auction, often with independent oversight, that establishes the rates and the winning bidders, while the winning bidders must obtain rate approval from FERC, as discussed below, as a condition to the ultimate sales of energy.

CPUC defended the FIT under AB 1613 without arguing that it was an implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA). PURPA provides an exception from the FPA requirement for FERC approval for sales at wholesale made by a “qualifying facility” (QF) pursuant to a state program implementing PURPA. In setting the price at which sales by QFs will be made, the state implementing programs may not set a price in excess of “avoided cost” – that is, the cost at which the purchasing utility would have had to purchase power but for the transaction with the QF. QFs are limited to cogeneration facilities and renewable energy facilities, with both fuel and size limitations, and, as

CPUC recognized, the facilities targeted by AB 1613 would be eligible for QF status, making PURPA an option for employing the FIT without violating the FPA. One may speculate that at least one reason CPUC initially avoided arguing that the FIT was an implementation of PURPA may have been the concern that the FIT price exceeded the purchasing utilities' avoided cost. When CPUC did finally address PURPA, it argued that amendments to PURPA under the Energy Policy Act of 2005 (EPA2005) allowed states to set prices for purchases from cogeneration systems smaller than 20 MW without restriction,⁴ and later that the FIT price did not, in fact, exceed avoided cost.⁵

PG&E, SCE and SDG&E (collectively, the California IOUs) argued in response that there was no substantive difference between requiring California utilities to "offer" to purchase power at a specified price and setting a wholesale price.⁶ Consequently, they reasoned that the FIT did not regulate procurement decisions but rather set wholesale power prices, in violation of FPA, PURPA and FERC's regulations. The only way for the CPUC to set wholesale prices without violating federal law would be to establish a program implementing PURPA, which would have required that the FIT price not exceed the purchasing utilities' avoided cost. The California IOUs objected to the argument that CPUC could, without violating PURPA, set a price for the purchase of power from generators smaller than 20 MW other than in accordance with PURPA's avoided cost scheme. The California IOUs concluded that, because the FIT price exceeded avoided cost (and because the CPUC had not set the FIT price with the intention that it reflect avoided cost), the FIT was outside the bounds of PURPA and thus preempted by federal law.

In the resulting order, FERC sided with the California IOUs on the principal issue, holding that AB 1613 and the CPUC regulations constituted wholesale rate setting rather than setting an offering price, and rejecting CPUC's argument that the threat of global warming allowed it to enact the FIT without complying with the FPA and PURPA.⁷ FERC also rejected CPUC's argument that it was permitted under EPA2005 to set prices above avoided cost for generators under 20 MW without violating the FPA or PURPA. FERC also held, however, that CPUC could implement the FIT in

accordance with PURPA, as long as the participating generators were required to be QFs and the FIT price did not exceed avoided cost. Despite the reasoning set forth by the California IOUs for concluding that the CPUC's pricing formula violated avoided cost requirements, FERC noted explicitly that it had not been asked to, and it was not, reviewing whether the FIT price in fact exceeded avoided cost.

Following FERC's order, CPUC altered its approach, agreeing to implement the AB 1613 FIT under PURPA but seeking clarification from FERC on how it could calculate avoided cost.⁸ CPUC argued generally that it should be given considerable discretion in calculating avoided cost so as to pursue the policy objectives of AB 1613. More specifically, it argued that avoided cost should not be limited to short-term avoided cost but instead should vary to reflect the length of FIT contract, the location of the generator and the resulting differences in transmission and distribution costs, and the compliance costs of new state environmental laws. CPUC envisioned establishing two avoided cost rates – a higher rate for generators that are QFs and also meet the stricter requirements of AB 1613, and a lower rate for all other QFs.

In their answer to CPUC's request for clarification, the California IOUs agreed that PURPA regulations already permit differentiation in avoided cost based on the length of the purchase contract, but they argued that differentiation based on the location and efficiency of the generator are not in the PURPA regulations and should be rejected.⁹ The California IOUs conceded that the costs of compliance with state laws – including actual, documented environmental costs and laws like RPS – could be included in the determination of avoided cost but argued that CPUC had not established that state laws had increased utilities' avoided cost in the context of a proper avoided-cost proceeding. Similarly, it conceded that while actual transmission and distribution costs which are avoided should be included, CPUC could not simply include a blanket transmission adder as a proxy for calculating such costs. Finally, the California IOUs objected to CPUC's proposed two-tier avoided rate structure, arguing that a utility's avoided cost is the same irrespective of the efficiency of the QF from which it purchases power.

In October 2010, FERC largely endorsed the CPUC's arguments, at least in the abstract. While reiterating that it was not determining whether the AB 1613 FIT price was consistent with the avoided cost requirements of PURPA, FERC held that CPUC could implement a multi-tiered avoided cost rate structure in accordance with PURPA and confirmed that the avoided cost calculation may include all actual costs of complying with state procurement and environmental laws.¹⁰ Specifically, FERC held that, in determining avoided cost, the alternative generation sources which would be able to sell to the purchasing utility in the absence of a sale to a QF – i.e., the procurement costs being avoided – can be limited by state procurement laws such as RPS. Finally, FERC rejected CPUC's proposed 10% distribution and transmission adder, holding that the calculation of avoided cost must be based on actual costs, not proxies.

The California IOUs objected to FERC's ruling, arguing that PURPA does not permit states to establish different avoided cost rates to reflect varying resource procurement requirements.¹¹ According to the California IOUs, PURPA requires that the avoided cost analysis consider all available alternatives; allowing multiple avoided cost rates to reflect differentiated procurement requirements under state law would render the very notion of an "avoided" cost meaningless. Plainly stated, the California IOUs failed to convince FERC. In a January 2011 "clarification" order, FERC rejected the argument that a multi-tiered avoided cost rate structure was inconsistent with PURPA, reiterating that state procurement laws impact the assessment of the costs which a utility avoids by purchasing from a QF.¹² FERC noted again, however, that it was not reviewing the AB 1613 FIT price for conformity with PURPA's avoided cost requirement (since this had not been briefed and argued and that, accordingly, required information was not available to FERC to make this determination); it was simply providing guidance to CPUC on how it *could* implement AB 1613.

Where Does this Leave FITs?

Since the guidance provided in this case by FERC is general only and not based on the details of a specific PURPA implementing program, it is speculative to predict what might action a state might take in

reliance on the guidance. However, there are some interesting opportunities that now appear available or that at least can be investigated further.

First, FERC has clearly indicated that a PURPA-compliant avoided cost can reflect state requirements for particular types of energy resources and can reflect avoided congestion and similar benefits provided. Thus, a state conceivably could require a utility to implement a RPS for a specified portion of its supply portfolio (as noted, RPS differ considerably and may specify dozens of combinations of input source, facility size, efficiency and location, among others). Although it is unclear whether states would be required to do so, they apparently could establish an avoided cost standard for PURPA-qualifying generators within each discrete supply tranche. Similarly, a state facing major congestion charges could specify a particular type of energy resource at a particular location and set an avoided cost rate reflecting avoided congestion debottlenecking costs. Either approach would seem to be consistent with FERC's guidance.

There are other possible options to consider. Could a state offer additional incentive incremental rates of return for a project's difficulty? For a project's novelty? For carbon reduction or other environmental or similar benefits? FERC has found these rate of return "adders" to be appropriate in certain cases. Would a competitive auction for the project (which might still have an effective rate of return in excess of a traditionally set rate, especially if higher than traditional utility leverage is employed) support a PURPA-compliant determination? It would appear so. However, in addition to the caution that the guidance by FERC is advisory and not binding, taking the guidance to its (il)logical extreme indicates that it raises some problems as well. For example, if a state required a specific resource at a specific location, wouldn't the utility's "avoided cost" be self-defining (i.e., there would be a certain cost to the utility to build that specific resource at that specific location, and, in an endless loop, the "avoided costs" would be the costs proposed by the only entity able to serve that location)?

Taken to its logical extreme, FERC's guidance in this case does appear to vitiate the limitation that "avoided cost" was thought (at least as loudly proclaimed by

the CA IOUs, EEI and others in this case) to represent – namely, that the concept of avoided cost was intended to ensure that QFs, having become favored sources of energy under PURPA, would not be entitled to receive prices in excess of those available to non-QFs. This strongly suggests that this will not be the final word from utilities and other industry participants (and therefore from FERC) on this subject.

Where Do These Orders Leave FIT Programs?

First, there appears to be considerable room to craft future FIT programs into the PURPA guidelines established by FERC.

Second, states could take a direct route to support such projects. Nothing in the decision affected the ability of a state to provide “supplemental payments” to eligible facilities as authorized by FERC if the related funds to make the supplemental payments are collected separately from a utility’s general rates – e.g., through a special charge to customers or if the utility is “made-whole” by a tax credit or other effective taxpayer-funded means¹³ for any above-avoided cost payments. Indeed, FERC has specifically allowed such payments, but widespread use of such supplemental payments seems unlikely given the revenue constraints faced by many states and the general opposition to new taxes that might support such payments.

Third, FERC’s orders left unaddressed (because not raised) another key issue – whether a FIT program could work outside of PURPA. FERC has jurisdiction over the sale for resale of electricity in interstate commerce, which practically means any sale to a utility (outside of certain areas in Texas, Alaska and Hawaii). Any entity that seeks to make such sales must have a tariff on file with, and approved by, FERC. While many such tariffs, particularly for traditional utilities, reflect traditional cost-of-service ratemaking, most new generation is developed on the assumption that FERC would authorize the generator to charge market-based rates.¹⁴ This raises the question of whether a state could require its local utilities to source a portion of their respective supply portfolios from FIT sources, establish the rates to be paid such sources, and then require each participating generator to obtain contract-specific or market-based rate authority from FERC. In this manner, the states

would not be circumventing the “avoided cost” limits of PURPA, and they also would not be exercising FERC’s exclusive jurisdiction under the FPA to regulate wholesale rates. This would impose greater burdens on participating utilities, as compared to the regulatory burden imposed on QFs selling under a PURPA-implementing program.

For example, while almost any FIT participant likely would qualify for market-based rates and FERC has allowed parties seeking such rates to, in effect, borrow the analyses submitted by others, there are additional costs associated with preparing and filing a tariff in FERC’s e-filing format. Each seller under the revised FIT program, therefore, would have to file a tariff with FERC and would become subject to plenary regulation by FERC as a “public utility.” While many QFs are exempted from specified provisions of the FPA, a seller into a FIT program that is not a QF, or that is otherwise selling power other than pursuant to a PURPA implementing program, would bear additional compliance costs. However, given that a generator may be both a QF and sell power in a non-QF sale, this could be a route for states to explore – they would not create FIT programs that arguably conflict with PURPA standards, but they could still use an auction or other process to set the rates paid by the utilities they regulate.

If FERC is committed to encouraging renewable and distributed energy, it could take several concrete steps to encourage FITs and net-metering arrangements that raise related issues.

First, FERC could clarify that its jurisdiction over the rates charged by generators subject to its jurisdiction does not extend to jurisdiction over the rates imposed by state regulators on power purchases by utilities, or at least purchases destined to serve their retail loads. That would enable the states to pursue the option described above – an FIT program that exists outside of PURPA, to the extent necessary to meet state objectives.

Second, to ease the way for non-PURPA participation in FIT programs, FERC could make it easier for companies to manage the process of qualifying for market-based rates. For example, FERC could (a) post screen results that an applicant could rely on, and (b) allow at least some entities with market-based rate

authority to file a tariff by filing in a PDF form, rather than incurring the expense of hiring a contractor to prepare an e-tariff. This would reduce the regulatory burdens imposed on participants, who might otherwise shy away from any additional regulation because of their expectations of lightened regulation under PURPA.

Third, FERC could adopt standards that allow the use of financing techniques that are consistent with the statutory intent of PURPA, but that allow an array of ownership structures to be used by parties who want to sell power to a utility under a FIT (or, for that matter, net-metering) program. For example, in some cases, whether under a FIT or a net-metering program, there may be additional tax or other benefits if the generation facility is owned by an entity other than the entity that enters into a contract with local utility. However, currently, only the entity that actually owns or controls the generating facility is a QF. In such event, FERC could waive, to the maximum extent possible, its regulations to the extent an entity purchases power from a QF and commits to re-sell, in a FIT or net-metering program, only the power that it purchases from a specified QF. Such tight pairing could prevent any circumvention of FERC's rules on the source of the power sold under PURPA.

Finally, dealing precisely with issues raised in the FERC orders discussed above, FERC could commit to act expeditiously – as it has to date – to provide states and interested parties with guidance on the approaches to defining avoided costs that it will accept as consistent with PURPA. These issues, of course, need to be addressed well in advance of the commitment of capital by FIT participants – a FERC ruling long after the fact could leave investments stranded.

Whatever path FERC elects to take, FITs and affected industry participants face interesting times until these fundamental structural issues are resolved. ♦

Endnotes

¹ A related means of encouraging renewable energy production is the use of “net metering” regimes, pursuant to which a facility can generate power, using a favored energy source, bank production in excess of its requirements for use in a future period, and receive a payment at the end of the netting period, generally a year, for any net power delivered to the local utility. Net metering raises many of the same regulatory issues discussed herein with respect to FIT regimes.

² *Petition of the Public Utilities Commission of the State of California*, filed in FERC Docket No. EL10-64, May 14, 2010.

³ *Id.* CPUC's petition also relied heavily on arguments that the immediate threat of global warming allowed it to enact AB 1613, which it characterized as environmental in nature rather than economic in nature, like the FPA.

⁴ *Id.*

⁵ *Answer of the Public Utilities Commission of the State of California to California Utilities' Answer*, filed in FERC Dockets EL10-64 and EL10-66, July 2, 2010.

⁶ *Petition of So. Cal. Ed., PG&E, SDG&E*, filed in FERC Docket No. EL10-66, May 11, 2010.

⁷ 132 FERC ¶61,047 (Docket Nos. EL10-64-000 and EL10-66-000, issued July 15, 2010).

⁸ *Request of the Public Utilities Commission of the State of California for Clarification or, In the Alternative Request for Rehearing of July 15, 2010 Order under EL10-64*, filed in FERC Docket No. EL10-64, August 16, 2010.

⁹ *Answer of the California Utilities to the Request of the Public Utilities Commission of the State of California for Clarification or, In the Alternative Request for Rehearing of July 15, 2010 Order under EL10-64*, filed in FERC Docket No. EL10-64, August 31, 2010. In addition to the substantive arguments described in the body of this article, the California IOUs claimed that the process pursuant to which CPUC had set the FIT price was not the normal avoided cost rulemaking process, and it could not be retroactively deemed to have been such.

¹⁰ 133 FERC ¶ 61,059 (Docket Nos. EL10-64-001 and EL10-66-001, issued October 21, 2010).

¹¹ *Petition of So. Cal. Ed., PG&E, SDG&E for Clarification or, In the Alternative Request for Rehearing or, in the Alternative, Reconsideration, Partial Vacature, or Clarification*, filed in FERC Dockets EL10-64 and EL10-66, November 22, 2010. In addition to the substantive arguments described in the body of this article, the California IOUs made numerous procedural arguments regarding the ripeness questions before FERC and the scope of its order.

¹² 134 FERC ¶ 61,044 (Docket Nos. EL10-64-002 and EL10-66-002, issued January 20, 2011).

¹³ See *CGE Fulton, L.L.C.*, 70 FERC 61,290 (1995).

¹⁴ FERC has well-established standards, based on measures of market power, to determine whether a generator lacks market power. If a generator lacks market power, FERC has concluded that there is not a need to set that generator's rates, subject to the reporting of changed circumstances and, for some generators, filing every three years to re-establish the eligibility to charge market-based rates. An entity that has been authorized to charge market-based rates must report its transactions to FERC, but is not required to seek specific approval from FERC for each contract.

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