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PURPA: Making the Sequel Better than the Original

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I: INTRODUCTION AND OVERVIEW

The Energy Policy Act of 2005 (EPAct 2005) contains several provisions that direct regulators to encourage or offer incentives for particular kinds of generation development. In particular, it supports the development of small, onsite renewable generation by requiring electric utilities to purchase excess electricity produced by onsite generators. It also includes provisions advocating diversity of a utility's supply portfolio. Such policies presumably are intended to overcome imperfections in the choices that market participants otherwise would make, though this concern is not fully articulated, nor are the recommended policies framed with any guidelines as to how far and how fast to go in these directions.

While it is certainly plausible that some regulatory fine-tuning of the electricity markets may be desirable, it is also quite important that this be done carefully. The electric utility industry has been down a similar road before, with less than universally acclaimed success, under market circumstances that bear an eerie resemblance to the current situation. In the late 1970s, there was increasing frustration with the capacity choices and costs associated with the generation expansion plans of many utilities, as nuclear plants expected to be inexpensive were proving to be just the opposite. Concomitantly, the price of oil was quite high, pursuant to Middle East disruptions and terrorism, and the domestic supply of natural gas was thought to be inadequate (largely due to prior controls that suppressed its price relative to its energy-equivalent value). In this context, a sweeping new regulatory policy—the Public Utility Regulatory Policies Act of 1978 (PURPA)—was introduced to try to encourage more efficient generation development. This report reviews the history of how PURPA was implemented and how it performed, as a cautionary note about maintaining control over how well-intended regulatory interventions are set in motion. As explained further below, the report's key focuses are on how the avoided cost pricing standards of PURPA were set and on how the scope of the program was (or, more accurately, was not) kept in line with assumptions that originally motivated it.

Under Section 210 of PURPA, electric utilities were required to purchase energy offered by Qualifying Facilities (QFs), defined as cogenerators (generating units that simultaneously produce electricity and steam) and small power producers (maximum size of 80 MW that use a waste or renewable energy source as their primary fuel input). The statute requires utilities to purchase electric energy from QFs at rates that are just and reasonable to consumers and which reflect the incremental cost that the utility would have incurred to generate or purchase the energy supplied by the QF. The Federal Energy Regulatory Commission (FERC or Commission) subsequently issued regulations requiring utilities to purchase QF energy and capacity at rates equal to the utility's avoided cost, defined as the incremental energy and capacity cost the utility would have incurred but for the purchase from the QF. FERC's regulations were appealed and ultimately upheld by the U.S. Supreme Court.

The ensuing supply of QF capacity in the 1980s—over 20,000 MW of QF capacity was built and put into operation—greatly exceeded expectations.[1] In some regions of the U.S., QFs became a significant, and in some cases the primary, supplier of incremental generation capacity. This growth in QF capacity was not without controversy, particularly with respect to the prices that QFs received for their power. Utilities and others argued that some states—intentionally or inadvertently—set utility purchase rates at levels well in excess of avoided cost. These excessive rates effectively subsidized QFs, attracting entry in excess of system needs, and forced retail customers to pay too much, sometimes far too much, for the QF output. In some cases, utilities also were required to buy more QF capacity than was needed to reliably serve load in their

[1] *1988 Capacity and Generation of Non-Utility Sources of Energy* (Edison Electric Institute, April 1990), Table 29.

service territory. Problems with administrative determinations of avoided cost, coupled with the abundance of offered QF supply, persuaded some states to procure incremental QF capacity through a competitive procurement process. By the early 1990s, approximately 10 states had or were using some type of bidding mechanism to determine avoided costs and the QF projects that would be eligible for long-term contracts.

Concerns about methods for setting avoided cost payments to QFs largely were superseded starting in the mid-1990s by state interest in retail competition and restructuring. Indeed, restructuring itself may have been partly induced or encouraged by the sometimes imbalanced and uneconomic results of PURPA. There is a strong correlation between the states with the largest PURPA supply and their early pursuit of retail access. It was widely agreed that the mandatory purchase obligation was not sustainable in a competitive retail market, because the local utility would no longer have the obligation to serve, at least not as that obligation traditionally was defined, and would not have a captive customer base to which it could pass through the cost of QF purchases. Moreover, in a competitive market with open transmission access, the local utility was no longer the "monopoly" buyer for QF power—QFs potentially could market their power to many wholesale and/or retail customers. As a result, in the mid-to-late 1990s, there was discussion of eliminating the must-buy obligation and possibly replacing it with targeted incentives for renewable generation. Such a recasting of PURPA was common in the proposed federal energy legislation of that era.

There has been a retrenchment in retail restructuring, largely in reaction to the Western U.S. power crisis of 2000-2001. A portion of the U.S. has open retail markets, while the majority of the country does not. This "split" industry structure (though not always thriving) of rate-regulated monopoly service providers and open retail markets is likely to persist for the foreseeable future. Recognition of this split industry structure figured prominently in the provisions of EPAct 2005 that modify Section 210 of PURPA. Section 1253 of EPAct 2005 eliminates a utility's requirement to purchase QF power, but only if the utility demonstrates that QFs can sell their power in a competitive wholesale market for energy and capacity. If such a demonstration cannot be made, the mandatory purchase provisions of Section 210 of PURPA continue as before. Thus, it appears that in some states and regions electric utilities will continue to be obligated to purchase power from QFs at avoided cost rates. Such rates typically will be determined using a methodology (or competitive procurement process) specified by the utility's state regulators.

The purpose of the balance of this report is to review the methods used in the past by state regulators to determine a utility's avoided costs and to identify the conceptual and practical problems associated with some of these methods. This report does not delve into other controversial issues associated with QFs, such as QF efficiency standards and stand-by rates for QF purchases from utilities. After considering the conceptual strengths and weaknesses of commonly used methods of setting avoided cost, we will identify specific examples of mistakes made in the setting of avoided cost and the resulting cost and other impacts for utilities and their customers. In reaction to these mistakes, some state regulators adjusted their methods of setting avoided cost to prevent such overpayments in the future. We will discuss these "lessons learned" and provide recommendations as to how state regulators and utilities can minimize, if not entirely eliminate, problems with the measurement of avoided cost in the future. We also will note new products and other changes in today's wholesale power markets that provide useful benchmarks for avoided cost.

The report also examines the appropriate method of setting credits for net metering service. Many states require their utilities to offer such service, which is provided to retail customers who have small, onsite renewable generators that at times generate more electricity than the customer needs to serve its own requirements. Under net metering, the customer receives a credit for excess generation sold to the utility. As we will explain, these credits should be based on the utility's avoided costs, but some states are providing credits that over-compensate onsite generators for the power they sell to utilities. Appropriate compensation for energy provided by net metering customers also will require the use of advanced "smart" meters that track the time electricity is used and produced.

The report concludes with a brief discussion of peak demand reduction programs, which also are encouraged by EPAct 2005. Such programs provide large commercial and industrial customers credits in return for agreeing to curtail all or a significant portion of their load up to several times a year when requested to do so by the utility or system operator. Curtailable demand provides the utility or system operator with a resource to help balance supply and demand during system emergencies and can reduce a utility's installed generation capacity requirement. However, as with PURPA avoided cost pricing, care must be taken to ensure that credits provided to such customers accurately reflect the capacity and operating costs actually avoided by the utility as a result of the peak load reductions. In addition, to be eligible for credits, peak load reductions need to be measurable and verifiable.

II: DEFINITIONS OF AVOIDED COST

The enactment of PURPA was designed to further three fundamental goals: (1) conserve electric energy, (2) increase utility efficiency, and (3) achieve equitable rates for consumers. To help achieve these goals, Congress created a favored class of power generators known as Qualifying Facilities (QFs). These generators were exempted from much of the financial and rate regulation that applied to electric utilities. For example, QFs were exempt from the Public Utility Holding Company Act of 1935. In addition, neither state commissions nor FERC were allowed to review the books of QFs to determine their cost of service.

Section 210(b) of PURPA requires electric utilities to offer to purchase electric energy from QFs at rates that are: (1) just and reasonable to the electricity consumers and in the public interest, (2) non-discriminatory with respect to QFs, and (3) not in excess of the incremental cost to the electric utility of alternative electric energy. Section 210(d) of PURPA defines the incremental cost of alternative energy as “the cost to the electric utility of the electric energy which but for the purchase from such cogenerator or small power producer, such utility would generate or purchase itself from another source.”

FERC issued regulations implementing PURPA in February 1980. The Commission’s rules provided that the just and reasonable rate for purchases from a QF should be equal to the utility’s full avoided cost, which FERC defined as “the incremental costs of electric energy, capacity, or both, which, but for the purchase from the QF, such utility would generate itself or purchase from another source.” Some parties urged FERC to set purchase rates at something less than the utility’s full avoided cost, so that utility customers would receive a financial benefit from QF purchases. However, FERC rejected rate designs, such as a “split-the-savings” rate (i.e., a rate roughly between the utility’s avoided cost and the QF’s incremental cost) that provided a QF with payments less than the utility’s avoided cost. FERC reasoned that the customer benefit from a split-the-savings rate would be small, whereas payments equal to full avoided cost could provide a significant incentive for the development of QF technologies. In addition, FERC concluded that split-the-savings or similar rates would require a determination of the QF’s costs of production, which was inconsistent with the legislative intent to exempt QFs from cost-of-service regulation. At the same time, FERC emphasized that nothing in its regulations required a utility to pay more than its avoided cost for a purchase.

FERC’s regulations defined avoided cost generically and provided states and utilities with considerable flexibility in calculating avoided cost. While the Commission did not prescribe or endorse one or more specific approaches for determining avoided cost, it did offer the following guidance to the states:

- Utilities can be required to pay QFs for the “capacity value” of their projects only when the availability of such capacity allows the utility to reduce its own capacity-related costs by deferring construction of new plant or by deferring commitments to firm power purchase contracts.

- The avoided capacity and energy costs used to calculate QF purchase rates must be internally consistent. For example, to use the high capacity cost of a deferred baseload unit and the high energy cost of a peaking unit would exceed the utility’s true avoided costs. To avoid this problem, FERC required that data on the expected energy cost of the planned new capacity be considered in the formulation of avoided cost rates.

- Even if the purchasing utility has excess capacity, a QF should always be entitled to energy payments except during times when the utility actually would incur higher costs (i.e., negative avoided costs) as a result of purchasing from a QF because such purchases would cause the utility to operate an existing plant at a lower and less efficient level.

- Rates for QF purchases may be levelized over the life of a fixed-term contract rather than set equal to the utility's avoided costs at the time of delivery. Rates may be negotiated at levels below full avoided costs if the QF agrees to the arrangement, presumably in return for some contractual provisions not mandated under the applicable rules in that jurisdiction.

The FERC rules also provided a list of factors that should be taken into account when calculating the energy and capacity elements of avoided cost rates:

- The utility's ability to dispatch the QF
- QF reliability
- Duration and enforceability of a utility's contract with a QF
- Ability to schedule QF outages in coordination with the utility
- Usefulness of QF production during system emergencies
- Aggregate value of a QF's capacity and energy on a utility's system
- Smaller capacity increments and shorter lead time availability with QF capacity
- The relationship between a QF's production and a utility's ability to actually avoid costs
- Costs or savings from changes in line losses as a result of purchases from QFs

Another notable aspect of the Commission's regulations was that they permitted (but did not require) utilities to offer QFs long-term contracts based on projections of the utility's avoided costs. That is, at the option of the QF, purchase rates could be based on the utility's avoided costs at the time of delivery or its avoided costs calculated at the time the obligation is incurred (i.e., at the time a long-term contract is executed). FERC recognized that setting fixed, long-term payments based upon estimates of avoided cost could result in ratepayers making payments far in excess of their utility's actual avoided costs but reasoned that this risk should be roughly symmetrical and that, over time, "overestimations" and "underestimations" of avoided cost would balance out. In addition, FERC asserted that PURPA did not intend to require that rates established in long-term contracts be checked on a minute-by-minute basis against actual avoided costs. As we explain later, fixed-price, long-term contracts were at the core of much of the subsequent controversy surrounding PURPA and avoided cost pricing.

The Commission's regulations also required the states to establish "standardized" tariffs or rates for facilities with an installed capacity of 100 kW or less. FERC feared that the transaction costs associated with negotiating a project-specific rate could make a very small generation project financially untenable. Thus, standard offer rates were seen as a means of facilitating the development of very small QFs by giving them a published, "set" price that they could use to evaluate the economics of their project. Some states, however, extended the concept of standard offer rates to much larger facilities, in some cases with disastrous results. Moreover, these standard rates were set and maintained with no consideration of how many QF suppliers might take advantage of them—even though an excessive number would drive down the costs being avoided by the utility buyer.

Several aspects of the Commission's regulations were challenged by utilities in the U.S. Court of Appeals for the D.C. Circuit in American Electric Power vs. FERC.[2] In that case, the D.C. Circuit reversed and remanded the Commission's avoided cost rule on the ground that the Commission had not adequately justified the rule with specific reference to the statutory mandate requiring that rates paid to QFs must be just and reasonable and in the public interest. The court concluded that the benefits of QFs should be shared between project developers and the utility's customers.

The U.S. Supreme Court, however, subsequently reversed the D.C. Circuit in American Paper Institute vs. AEP, holding that the Commission had adequately explained its reasons for setting purchase rates at full avoided cost, had not unreasonably interpreted the statute, had adequately considered the interests of electric consumers, and, in general, had not acted unreasonably.[3] The Supreme Court based its decision primarily on the PURPA objective of encouraging cogeneration and small power production. It stated in its finding: "At this early stage in the implementation of PURPA, it was reasonable for the Commission to prescribe the maximum rate authorized by Congress and thereby provide the maximum incentive for the development of cogeneration and small power production."[4]

Relatively little QF development took place in the early 1980s as states, QFs and utilities waited to see how the legal challenges to FERC's PURPA regulations would play out. Once the Supreme Court issued its decision upholding the Commission's regulations, states began to move forward with their own regulations and, in some cases, their own PURPA statutes. These are discussed in the next section.

2 American Electric Power Service Corp. vs. FERC, 675 F.2d 1226 (1982), rev'd American Paper Institute vs. AEP, 461 U.S. 402, 103 S. Ct. 1921 (1982).

3 American Paper Institute vs. AEP, 461 U.S. 402, 103 S. Ct. 1921 (1982).

4 Ibid., at 1930.

III: METHODS USED TO DETERMINE AVOIDED COST

States took advantage of the ample flexibility afforded them under FERC's PURPA regulations and proceeded to establish many different methods of calculating avoided costs for the purpose of setting QF purchase rates. Perhaps the only common thread in these initial state methods for determining avoided cost was that all involved an *administrative* determination of avoided cost. That is, avoided cost was determined based on utility- or state-developed projections of the utility's incremental energy and capacity costs. Requests for Proposals (RFPs) or competitive procurement were not used initially to determine avoided costs. The absence of competitive procurement is not surprising because, at this time, vertically integrated utilities generally self-provided their own generating capacity.

In some cases, states established different methods to calculate short-term avoided costs and long-term avoided costs. Payments based on a utility's short-term avoided cost typically were provided to QFs that sold energy on a non-firm or "as available" basis. Examples of such QFs include some renewable generators that sold power on an intermittent basis and cogenerators that used most of their electricity output to serve a host industrial or commercial load. Short-term avoided cost payments for "as available" energy typically were based on the utility's incremental or marginal cost of energy, calculated variously on an *ex ante* or *ex post* basis. Some utilities set short-term avoided costs equal to their system lambda. Other utilities that were members of centrally dispatched power pools, such as the PJM Interconnection, set short-run avoided cost payments equal to the pool's hourly billing rate, typically a split-the-savings rate. Another approach involved the use of production cost models to estimate the utility's marginal energy cost for every hour in a forecast period. Avoided cost payments based on some measure of the utility's actual short-term incremental costs generally were not controversial because such payments, in theory, reflected the utility's actual avoided cost at the time the QF energy was purchased.

However, QFs desiring to sell most if not all of their electrical output to the local utility typically sought long-term contracts with fixed rates because such contracts were necessary to finance the project. QF projects usually were heavily debt-leveraged and could only obtain such financing if they had a stable, long-term revenue stream to back their loans. A fixed-price, long-term power sale contract with the local utility gave QFs the stable revenue source they needed to obtain project financing. Such contracts effectively transferred the financial risk of the QF project to the utility. Of course, fixed-price contracts raised the possibility that QFs would receive payments that could deviate significantly from the utility's avoided cost at any given time, but contracts with such terms were viewed as necessary to foster the growth of QFs.

Long-term contracts with fixed or pre-specified prices required long-term estimates of avoided cost. A variety of methods was used to develop such estimates, including: (1) the proxy unit or committed unit approach, (2) the component or "peaker" approach, (3) differential revenue requirement, (4) variants of these methods including expansion planning (generation resource plan) approaches, and (5) standard offers. Some of these approaches were relatively simple to implement whereas others required an extensive amount of data and modeling. Following is a brief description of each of these approaches.

Proxy or Committed Unit Method

The proxy or committed unit approach assumes that a QF enables a utility to delay or displace its next planned generating unit. As a result, the utility's avoided costs are based on the projected capacity and energy costs of this next planned generating unit. The proxy unit's estimated fixed costs set the avoided capacity cost and its estimated variable costs set the avoided energy cost. The capacity costs are annualized over the expected life of the generating facility to yield an annual capacity cost per kW. A fixed charge rate reflecting, among other factors, the utility's debt and equity costs and tax burden often is used to annualize the capacity costs.

This approach does not require the use of production cost or other models because avoided costs are unit-specific and do not depend on the utility's system marginal energy cost at any given time. The proxy unit approach should, however, account for any differences in the in-service date of the QF and of the proxy unit. This was typically done either by not providing the QF a capacity payment until the time the proxy unit would have come on line or by discounting the lump sum present value of the capacity payments at the time value of money so that customers (in theory) would be financially indifferent between the two payment streams.

The proxy unit typically is the next identified generating unit in the utility's integrated resource plan. In some cases, state regulators (e.g., in Florida) established a generic, state-wide "proxy" unit that each of the state's jurisdictional utilities was required to use as the basis for setting its avoided costs.

Component/Peaker Method

Under this approach, avoided costs are estimated as the annual equivalent of the utility's least-cost capacity option (as a capacity payment) and marginal energy costs in each year of the contract (as an energy payment). This method assumes that the QF output displaces the marginal, or most expensive, generation source on the utility's system at any given time for the duration of the contract. Capacity payments are provided only if the utility needs capacity and are set equal to the lowest-cost capacity option available to the utility, typically a peaking unit (e.g., combustion turbine). Hence, the component method assumes that the utility's long-term avoided cost is its projected system marginal cost of energy in any given hour (which could be from coal units off peak and oil units on peak) plus the fixed cost of a peaking unit. Note that this method does not calculate avoided cost based on the expected cost of a planned generation unit in the utility's resource plan. This method instead assumes that a QF, rather than displacing or delaying the need for a particular generating unit, allows the utility to reduce the marginal generation on its system and to avoid building a combustion turbine of the same size as the QF. Rather than assuming that the QF can help avoid a new utility-owned generating unit, this approach, according to an advocate, seeks to answer the question: What is the QF capacity worth in hours when the utility is short on capacity?[5]

This approach is fairly data-intensive, as it requires the use of a production cost simulation model to estimate the utility's system marginal energy costs with and without the QF in its resource portfolio. Through such modeling, detailed, time-differentiated avoided energy and capacity costs are developed for each year of the QF contract term.

Differential Revenue Requirement Method

The differential revenue requirement approach assumes an amount of QF capacity operating with given characteristics and calculates the utility's total generation cost (revenue requirement) with and without that QF capacity over a period of years, assuming that the QF energy and capacity are free. This "free" QF output reduces the utility's revenue requirement. The present value of the difference in total generation costs between the two cases is the lump sum of avoided cost for the hypothetical block of QF power.

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5 Parmesano, Hethie. Avoided Cost Payments to Qualifying Facilities: Debate Goes On, *Public Utilities Fortnightly*, September 17, 1987, pp. 34-39.

The differential revenue requirement method requires the use of two types of models. A planning expansion model is used to develop generation expansion plans both with and without the estimated QF output. The resulting two expansion plans then are used as inputs to a financial planning model that yields the utility's projected revenue requirement both with and without the QF output (assuming that the QFs are a "free" resource). The difference in the present value revenue requirements of these two expansion plans is the avoided revenue requirement made possible by the expected QF output. This avoided revenue requirement includes avoided energy and capacity costs as well as other factors (e.g., taxes).

The lump sum avoided revenue requirement often is transformed into a time-differentiated energy and capacity payment. This method differs from the component approach in that it uses models to simultaneously calculate both the energy and capacity cost (if any) avoided by the utility. The energy component may also be shaped over time in an administered fashion, which may differ from its pattern in a production costing analysis.

Other Methods

Variants of the above three methods were also used. For example, another method known as the expansion planning approach was used in some jurisdictions. This approach was a hybrid of the proxy unit and differential revenue requirement approaches: A planning model was used to establish a utility's expansion plan with and without an assumed amount of QF output. However, instead of using a financial model to determine revenue requirements, the differences in costs resulting from the planning model were used to set avoided costs. Another method was the "average incremental cost" method in which avoided cost was set equal to the average capacity and energy costs of the entire set of generating units or capacity upgrades included in the utility's long-term resource plan. As in the proxy unit method, the average incremental cost per kW of all of the utility's proposed capacity additions was annualized through use of a fixed charge rate.

Standard Offer

"Standard offer" describes a type of avoided cost payment rather than a method of calculating avoided cost. Standard offer refers to a fixed-price offer made available to a certain class or size of QFs. All QFs that meet the criteria for the standard offer can sell power for this rate. For example, if the standard offer rate was 6 cents/kWh, this means that all QFs eligible for the standard offer rate could receive 6 cents/kWh for all power sold to the local utility. While standard offer rates should, in theory, be based on a utility's avoided cost, they tended to reflect a generic, and in some cases a state-wide, measure of avoided cost. In contrast, the differential revenue requirement and the component method calculate a "customized" avoided cost for a QF or a block of QF capacity.

Strengths and Weaknesses of These Approaches

The three methods described above—the proxy unit approach, the component approach, and the differential revenue requirement—were the primary methods used by states to determine a utility's long-term avoided costs, at least prior to the advent of competitive procurement. All of these methods, if properly applied, can produce reasonable estimates of avoided cost. Of the three, the proxy unit method departs the most from a "theoretical ideal" of long-term marginal cost. One potential problem with the proxy unit approach is that it may not accurately reflect the utility's next planned unit, although this problem should be avoided if the identification of the proxy unit is tied to the utility's current integrated resource plan. But even assuming this condition is met, there remains the problem that, under its simpler applications, the proxy unit approach assumes that the output from a QF will be sufficient to permit the displacement of a baseload unit. For some utilities and QFs, this would be an unrealistic prospect. This method also ignores the timing of power deliveries from QFs and their effect on avoided energy costs. Finally, the use of estimated costs from a specific baseload plant does not provide for a reoptimization of the utility system based on the output of the QFs.

The differential revenue requirement and component methods are more sophisticated and conceptually correct ways of determining long-term marginal cost, relative to the proxy unit method. However, these methods rely on relatively complex modeling tools to determine costs and/or revenue, and this complexity makes them somewhat problematic, especially for state commissions that do not have access to or knowledge of such models. Avoided cost calculations become a "black box" to regulators, QFs, consumer groups and other market participants without access to or knowledge of the necessary models. This lack of transparency and inability to verify the model's inputs, structure and results could engender distrust of the utility's estimates. As with all aspects of price regulation, avoided cost determinations involve a trade-off between theoretical accuracy and practicality.

There are other issues associated with the differential revenue requirement and component methods, apart from modeling complexity. The former measures avoided costs only insofar as they affect the utility's revenue requirement. The danger is that factors that are unrelated to actual avoided cost may influence the calculation. For example, if the utility's allowed return on equity is lower than the cost of raising new funds, the differential revenue requirement method may systematically understate the avoided capacity costs made possible by purchases from QF capacity.[6] A key assumption underlying the component method is that the utility already has the "optimal" resource mix, which is not likely to be true much of the time and certainly will not be true for the entire duration of a long-term power purchase from a QF. Some also view the component method as a short-term method rather than a long-term method, because it assumes that the QF is perpetually the marginal resource on the utility's system.

More important, regardless of their conceptual elegance or lack thereof, *all* long-term estimates of avoided cost are critically dependent on underlying assumptions about fuel costs, demand growth, financing costs, labor and material costs, and permitting and siting costs, among other factors. Any long-term avoided cost forecast made in the mid-1980s, regardless of its analytical rigor or conceptual elegance, almost certainly would have overstated a utility's avoided costs in the 1990-1995 period because natural gas and oil prices during that era turned out to be far lower than projected in the mid-1980s vintage forecasts. In fact, the proxy unit method, if the proxy unit were assumed to be a coal-fired plant, would have been less sensitive to erroneous fuel price projections than the component method or the differential revenue requirement method, which base their avoided cost calculations in large part on projections of the utility's marginal energy cost. But all long-run estimates of avoided cost will be prone to forecast error regardless of the method used. Such error is inevitable; the only question is the significance and direction of the error over time.

In the mid-1980s, the error turned out to be very large and positive, i.e., with projected long-run avoided costs far in excess of realized avoided costs. There were at least three reasons for this error. First, PURPA was ushered in following the oil embargoes of 1973 and 1979, and in the midst of a period of very high, seemingly entrenched inflation. As a result, long-run projections assumed oil prices of $100/barrel, and borrowing costs of 10% or more per year. Fear of "running out" of oil (and natural gas) led to unduly pessimistic forecasts. Second, natural gas, which proved to be the primary fuel of choice for cogeneration QFs, and natural gas-fired generation technology, became extremely inexpensive by the mid-to-late 1980s, thanks in part to previous unduly high administrative estimates of gas development costs made in conjunction with the Natural Gas Policy Act of 1978. Overestimates of the prices needed to encourage gas

6 Robert Burns, William Pollard, Timothy Pryor and Lynne Pike. *The Appropriateness and Feasibility of Various Methods of Calculating Avoided Costs*, National Regulatory Research Institute, June 1982, p. 95.

development led to a huge "boom" in supply and a resulting collapse in prices. This in turn sparked much more development of gas-fired QFs, which drove down their capital costs significantly. Third, the endogeneity of the QF supply and long-run avoided cost (LRAC) pricing was not recognized. LRAC prices were estimated based on *marginal* expansion requirements, when often a much larger quantity of QF resources was offered than had been analyzed. An excess pool of QFs drove down the utility's marginal energy costs (since QFs were must-run, i.e., dispatched out of merit order) and eliminated or deferred capacity needs for much longer than was assumed in LRAC calculations. Relatedly, the financial assurances provided to QFs to help them obtain the aforementioned debt financing meant that their revenues and profits were much more assured than the utility's own capital recovery. So, an excessive rate of return was implicitly granted to the QFs, again encouraging over-development.

We once again are in an era of rising fuel prices, so today's long-term projections of avoided cost may impart a sense of déjà vu and fear of "running out" (e.g., the "peak oil" theory) to those who prepared or reviewed avoided cost calculations in the 1980s. The next chapter discusses and highlights some of the mistakes made during the 1980s and the resulting costs that were imposed on utility ratepayers.

Bidding

Starting in the late 1980s, some states replaced or supplemented their administrative determinations of avoided cost with RFPs or bidding mechanisms. These bidding mechanisms were adopted, in part, to find the most economical QFs to fill the utility's energy and capacity needs. Many utilities and states found an abundance of QF capacity willing to sell power at the utility's full avoided cost. Indeed, the capacity offered by QFs often was 10-20 times greater than the utility's capacity requirements.[7] To determine which QFs should receive long-term contracts with the utility, competitive procurement processes were sometimes established to rank the interested QFs in terms of price and other criteria. Given the difficulties associated with administrative determinations of avoided cost and the operating and planning problems associated with large-scale uncontrolled QF development, competitive bidding appeared to be a more efficient way to encourage QF electricity supply that is better matched to power system requirements.

Bidding systems varied fairly widely among states and utilities. The most fundamental distinction involved the scoring and ranking of projects. At one extreme, some utilities adopted "self-scoring" systems that provided bidders with explicit evaluation sheets where each relevant feature under consideration received a specified number of points depending on the project characteristics. Bidders added up their own scores and the utility verified the data and selected winners based on the highest scores. At the other extreme, some utilities only revealed the bid criteria in general terms. In these systems, the rank of any bid cannot be verified after the fact, and the utility possesses information about the evaluation process that the bidders do not. This latter approach affords more flexibility to the utility but is less transparent than self-scoring systems.[8]

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7 E.P. Kahn, C.A. Goldman, S. Stoft and D. Berman. Evaluation Methods in Competitive Bidding for Electric Power, Lawrence Berkeley Laboratory, June 1989, LBL-26924, p. 2-3.

8 Ibid., ex sum.

IV: LIMITATIONS OF ADMINISTRATIVE APPROACHES AND ABUSES IN THE SETTING OF AVOIDED COST PAYMENTS

Errors in the estimation of long-run avoided costs are inevitable. However, as PURPA was implemented by state regulators in the 1980s, a combination of questionable methods of setting avoided cost and/or poor application of these methods led to excessive avoided cost payments and forced utilities to buy QF capacity even when the utilities did not require more capacity. In addition, excessive, non-dispatchable QF output created operating problems for some utilities. Many complaints about PURPA's implementation were raised by electric utilities and others. These complaints can be grouped into six broad categories: (1) Deliberately setting rates above those permitted under FERC's regulations (i.e., above full avoided cost); (2) requiring the payment of capacity costs even though the utility does not need capacity and does not avoid any capacity costs; (3) placing no limit on the amount of QF capacity that could receive standard offer rates; (4) requiring utilities to sign long-term contracts at fixed rates based on long-term estimates of avoided cost; (5) making general errors in avoided cost methodology, such as the inclusion of sunk costs or failure to consider avoidable power purchases; and (6) requiring utilities to pay the same rate to all QFs, regardless of differences in the QFs themselves. Following is a discussion of these issues, including "real world" examples as described by electric utilities in comments submitted to FERC in 1987 in one of four regional conferences held that year by the Commission on PURPA and related topics (FERC Docket No. RM87-12-000).[9]

Intentionally Setting Rates Above Avoided Cost

A few states deliberately set rates above the utility's full avoided cost. Some states that did this believed that they had authority to do so under the FERC regulations. A few states passed laws that authorized purchase rates above full avoided cost. Perhaps the best known example of this is New York State. The New York state legislature enacted a law that provided that electric utilities must enter into long-term contracts to purchase electricity from QFs. The sales price was to be established by the New York Public Service Commission (NYPSC), but the legislation set a minimum price of 6 cents/kWh. This 6-cent price per kWh was applied irrespective of the avoided costs of the individual New York utilities or their need for additional capacity. In comments submitted in response to FERC's 1987 conferences on PURPA, one New York electric utility, Consolidated Edison Co. of New York (ConEd), pointed out that the NYPSC had determined that New York did not need capacity until 1999. Thus, the 6 cents/kWh minimum price created excess capacity that was not needed. ConEd further noted that in 1986 its avoided costs were slightly more than 3 cents/kWh, so it was paying QFs a rate well above its avoided costs. Other New York utilities raised similar objections to the 6 cents/kWh minimum rate in their comments to FERC. For example, Orange and Rockland Utilities asserted that it was paying QFs 6 cents/kWh even though its avoided costs in 1987 were 3.4 cents/kWh and were not projected to reach 6 cents/kWh until after 1995.

In her comments to FERC, Anne Mead, the chair of the NYPSC, conceded that all of the state's utilities had avoided costs below 6 cents/kWh and thus were providing a near-term subsidy to QF developers.

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9 These conferences helped establish the record for the FERC's subsequent Notices of Proposed Rulemaking on Avoided Cost Pricing and Bidding issued March 16, 1988.

Nevertheless, she asserted that New York's law had spurred QF development without causing substantial increases in rates.

Requiring Capacity Cost Payments Even Though the Utility Does Not Need New Capacity

For various reasons, utilities either were forced to accept new QF capacity that they did not need or more capacity than they needed. The most noteworthy example of the latter phenomenon was standard offer rates that placed no quantity limit on the amount of QF capacity that could sell power under the rate. This issue will be examined in the next section. In some cases, utilities were forced to accept capacity that they did not need because avoided cost rates based on long-term projections of marginal energy costs, which assumed significant increases in fuel costs, were sufficient to spur significant QF development. For example, in its comments to FERC, Pennsylvania Power & Light (PP&L) noted that it was forced to purchase the output of more than 500 MW from QFs despite the fact that the Pennsylvania Public Utility Commission determined, in 1985, that PP&L had 945 MW of excess generating capacity and, as a result, was denied full cost recovery for its Susquehanna 2 nuclear generating unit. Pacific Gas and Electric (PG&E) commented that in California QFs received a capacity payment even if the utility's resource plan did not have any identified need for additional capacity to meet load growth and maintain its target level of reliability. The California Public Utilities Commission (CPUC) reasoned that an additional generating unit always makes some contribution to reliability and therefore should receive a capacity payment. As a result, QFs received a capacity payment purportedly reflecting their incremental contribution to system reliability even though PG&E was not avoiding any capacity costs as a result of the purchase. As was noted above, the 6 cents/kWh minimum price in New York forced that state's utilities to buy capacity that they did not need.

Standard Offer Rates Without Quantity Limits

As noted above, FERC's regulations required that standard offer rates be made available to small QFs with an installed capacity of 100 kW or less. FERC's primary rationale for this provision was to reduce transaction costs for very small generation projects by giving them a posted, "no hassle" rate at which they could sell power to the local utility. The Commission's regulations did not, however, proscribe states from providing standard offer rates to larger QFs if they chose to do so. Some states decided to make generous standard offer rates available to a wide class of QFs, with the result that utilities were swamped with QF capacity.

California's experience with various standard offer rates is "Exhibit A" as to what can go wrong with making such rates widely available and not capping the amount of QF capacity eligible to sell under these rates. During the 1980s, California made several standard offer rates available to different types of QFs. The most notorious standard offer, and the one with the greatest financial impact on the state's utilities and their customers, was Standard Offer 4 (SO4). This standard offer was made available in September 1983 but, after fostering a huge amount of QF capacity, it was suspended in April 1985. SO4 provided for fixed energy payments for 10 years and fixed capacity payments for 10-30 years. Neither the energy nor the capacity payment was subject to any after-the-fact adjustment in the event that actual avoided costs deviated significantly from the projections. QFs had the choice of receiving either the forecast energy price for each year of the contract or a levelized forecast price. These energy payments were established at a time of high oil and natural gas prices and forecasts that assumed that the price of those fuels would increase significantly. Moreover, because the CPUC was unsure of the response to the SO4, no limit was placed on contract availability. The extended availability and open-ended nature of SO4 implied (incorrectly) that there was no limit on the amount of capacity needed by California's utilities.[10]

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[10] The standard offers, like other CPUC regulations, applied only to the state's investor-owned utilities.

In their comments to FERC, California's utilities complained that SO4 and California's other standard offers had forced them to purchase too much QF capacity at too high a price. For example, Southern California Edison (SCE) explained that the state's utilities had 16,000 MW of QF capacity under contract, with 7,000 MW of that capacity purchased by SCE. Slightly less than 2,000 MW of this total were operational at the time. SCE noted that if just half of the remaining QF capacity were built (approximately 2,500 MW), it would have no need for additional capacity for another 10 years. Approximately 3,700 MW of the 7,000 MW were under fixed-price contracts with prices well in excess of avoided cost. SCE estimated that by 1990, total payments to QFs would be about $1.4 billion per year, with more than $300 million of this total in excess of avoided cost.

Similarly, PG&E noted that it had purchased 5,625 MW of QF capacity under SO4 contracts and that the capacity prices under those contracts were well above PG&E's actual avoided costs. PG&E also claimed that its annual overpayments to SO4 QFs for energy alone were projected to be approximately $467 million in 1990 and close to $5 billion over the 10-year, fixed-price period. The company's total QF overpayments by 1990 were projected to be $857 million, which would force PG&E to raise its retail electric rates by at least 7%. In addition, PG&E cited a 1986 report prepared by the California Energy Commission (CEC) that showed that, largely as a result of the QF purchases, the supply of generating capacity in PG&E's service area would exceed demand until the late 1990s. The state's other major investor-owned utility, San Diego Gas & Electric, raised many of the same points as SCE and PG&E in its comments critiquing SO4 and California's overall approach to setting avoided cost rates.

Long-term Contracts with Fixed Rates

Long-term estimates of avoided or marginal costs are inherently subject to error. In the preamble to its PURPA regulations, FERC argued, in supporting the provision that allowed avoided costs to be established at the time the purchase obligation was incurred, that over time, overestimates and underestimates of avoided cost would tend to cancel out. Experience with PURPA suggested that this was not likely to be the case. As noted above, mid-1980s vintage oil and natural gas price forecasts, almost without exception, significantly overstated actual oil and natural gas prices during the 1990s. Hence, mid-1980s vintage long-term PURPA contracts with fixed payments were likely to overstate a utility's actual avoided costs. Long-term contracts based on the estimated cost of a baseload coal plant also were likely to overstate a utility's avoided cost during the 1990s because, during that decade, most of the new generating capacity built was gas-fired generation, given the (then) low natural gas prices and efficiency (heat rate) improvements in gas-fired generating technologies. In 1987, many utilities argued that long-term avoided cost payments were likely to vary far from their actual avoided costs for the foreseeable future.

Some utilities, e.g., Houston Lighting & Power (HL&P), argued that there should be periodic after-the-fact adjustments of capacity and energy payments under long-term contracts to account for changes in avoided costs. HL&P asserted that, based on its 1987 projection of avoided costs, its long-term contracts with QFs were expected to result in overpayments to cogenerators of more than $500 million-$750 million over the period 1987-1995. The American Paper Institute, however, argued that such "reopening" of long-term contracts was contrary to FERC's PURPA regulations and would make it impossible to finance their projects. While many complaints were made about long-term contracts, there was no resolution as to how to better manage or mitigate the risk associated with such contracts. There is no doubt, however, that utility customers typically bore the risk of long-term contracts with prices above actual avoided cost.

A related concern with long-term contracts was the fact that these contracts tended to be front-loaded, which meant that prices in the early years of the contract were above the utility's projected avoided cost. In theory, the above-cost payments in the early years of the contract were offset by payments below projected avoided cost in the later years of the contract. QFs sought such contracts because they helped them obtain financing, and FERC's regulations specifically permitted long-term contracts with levelized rates. Some argued that there was an "inter-generational equity" issue associated with such contracts, because today's ratepayers were paying for projects that would only provide customer benefits—in terms of prices at or below full avoided cost—many years in the future. Others pointed out that since QFs did not have an obligation to serve, the QF could earn its return in the early years of the project and shut down the project before its contract expired, thus depriving utility customers of the opportunity to recoup their earlier overpayment to the QF. We did not find data on how often such situations ultimately occurred (e.g., a QF voluntarily retired prior to the end of its contract but after it had recouped its investment through a front-loaded contract), but this was a risk associated with front-loaded contracts.

General Errors in Avoided Cost Methodology

This is a catch-all category that includes a variety of problems. For example, some utilities were required to include sunk costs in their avoided cost payments, which was erroneous because sunk costs by definition cannot be avoided. Another problem was the identification of an incorrect or "phantom" proxy unit in some of the states that used this method. Another problem was the failure to consider avoidable or available firm power purchases in the calculation of avoided cost. For example, in its comments to FERC, Sierra Pacific Power stated that, in 1986, the Public Utilities Commission of Nevada (PUCN) established a long-term avoided cost rate of 6.3 cents/kWh. At the time the PUCN established this long-term avoided cost, Sierra's next planned capacity addition was a firm power purchase from a Northwest utility at a cost starting at 2.6 cents/kWh and escalating to 5.3 cents/kWh in 1992.

Paying the Same Rate to QFs, Regardless of Their Characteristics

There is both an operational and a financial element to this issue. The operational issue primarily arose from the fact that most QFs (except for resources with inherently intermittent production, like wind-powered generators) preferred to be operated as baseload, "must run" resources. These included fossil-fueled cogenerators and stand-alone small power producers that relied on biomass, coal waste, and municipal waste as their fuel input. As QF capacity became a more significant presence in utility generation portfolios, the lack of dispatchability or operating flexibility became an important operational concern for utilities, especially with respect to minimum load conditions. The growth in must-run QF supply started to force some utilities to cycle inexpensive baseload generation during low-load hours. This, of course, was directly inefficient, and it also would generally imply that estimated avoided energy costs would be overstated. For example, HL&P noted that QFs generally do not follow the utility's load pattern. As a result, HL&P asserted that in 1986 it was forced to back down its baseload coal and lignite units—the equivalent of approximately 1.37 million barrels of oil—to accept gas-fired cogeneration. Large, baseload units generally are designed to run at full or close to full output, so utilities sometimes incur a "negative" avoided cost by backing down such units; that is, the cost of cycling such units exceeds the energy costs saved by running such units at a lower level of output. Many utilities, including HL&P, urged FERC to modify its regulations to state that utilities do not have to purchase QF energy when doing so would force the utility to reduce its low-cost baseload generation.

Operational inflexibility in QFs raised concerns apart from minimum load conditions. PG&E explained that California's standard offer contracts did not afford much operational flexibility to the purchasing utility. With the exception of the requirement that scheduled maintenance be done during the non-peak season, the timing and magnitude of power deliveries from QFs under the standard offers in effect in California were outside the control of the utility. As the CEC noted, if more extensive curtailment or dispatch provisions had been included in the QF contract offers, a better match with the operational needs of the existing generation system would have occurred.

A related problem cited by many utilities was the fact that the operating characteristics of QF capacity sometimes did not meet the utility's needs. For example, must-run QF capacity generally would not be a good fit for a utility that needed intermediate or peaking capacity. Adding must-run QF capacity to a system that needed peaking capacity created the potential for the minimum run problems cited above.

In addition, on the financial side, avoided cost rates often tended to be the same regardless of the QF's operating characteristics. Thus, an inflexible QF generally received the same rate as a QF that was dispatchable or which was more willing to shut down during minimum load hours. Inflexible QFs were overpaid relative to flexible QFs since avoided cost rates often did not distinguish between technologies and did not account for the costs of cycling baseload generators.

Conclusions and Lessons Learned

While the particulars of each utility's situation differed, by the mid-1980s there was legitimate concern and much anecdotal evidence that some utilities were (1) paying too much for QF energy and capacity, and/or (2) buying too much of it. The reasons for this undesirable result varied; in some cases it was widely available standard offers with no volume limits, in other cases it was long-term avoided cost projections pegged to forecasts of oil and natural gas prices. In other cases, states forced utilities to use an expensive baseload unit as the proxy or committed unit when cheaper power purchase or other resource alternatives were available. Some states, such as New York, explicitly required above-cost QF payments as a means of spurring QF development. Of course, the factors cited above are not mutually exclusive; in some cases it was a combination of high fuel price forecasts, standard offers, and other questionable assumptions that created a "perfect storm" of excessive QF payments.

That said, we have not studied and make no claims about the magnitude or prevalence of QF overpayments across the U.S. and we are not aware of any recent studies that measure this. This is an inherently difficult task, given the vagaries of QF contracts. Moreover, measures of "excess" QF payments will fluctuate with changes in market prices and utility avoided costs and thus will be very sensitive to wholesale market prices and projections of such prices when such a study is done. The comments and figures cited above were done largely for context and to explain the concerns that utilities and others had in the mid-1980s. We cited 1987-vintage estimates of excessive avoided cost payments not because we believe that these estimates turned out to be correct—though they may well have been given the low wholesale power prices that prevailed during much of the 1990s—but because we wanted to highlight the potential financial and other impacts associated with questionable methods of setting avoided cost. These estimates show that the aggregate financial impact associated with QF contracts was not trivial.

It is hard to generalize as to what the "lessons learned" were from this collective experience with avoided cost pricing. The principle response to these problems, though it was by no means universal, was the implementation of competitive procurement. These bidding mechanisms addressed many of the problems cited above. For example, competitive solicitations usually cite the amount of capacity that the utility needs or desires to purchase. They often distinguish QFs by operating characteristics, and give QFs with operational and other characteristics desired by the utility a higher score, everything else being equal. They also establish a quasi-market process to set avoided cost and explicitly allow utilities to consider potential purchases (e.g., purchases from QFs) in the determination of avoided cost. Of course, bidding mechanisms still can yield long-term, fixed-price contracts that prove to be above "market" or "full avoided cost." Other mechanisms, such as financial risk management products, can be used to reduce the risk associated with long-term contracts. But prior to the industry disruption caused by retail competition and restructuring, competitive procurement of QF capacity was exhibiting promise as a means of correcting some of the problems associated with administrative determinations of avoided cost.

V: FERC'S MIDSTREAM EVALUATION: THE 1988 NOPRS

In response to comments received at the 1987 PURPA conferences and other developments occurring in wholesale power markets, FERC issued three related and significant Notices of Proposed Rulemaking (NOPRs) on March 16, 1988. One NOPR (RM88-6) was known as the avoided cost NOPR, and it proposed some changes to the Commission's regulations governing QFs and the calculation of avoided cost. The second NOPR (RM88-5), which was known as the bidding NOPR, stated that bidding was permitted under FERC's PURPA regulations and was a legal means of determining a utility's avoided cost. The bidding NOPR did not prescribe a specific methodology that states were required to use but did provide fairly extensive guidelines and conditions for states to follow in establishing bidding mechanisms. The third NOPR (RM88-4) proposed rules and guidelines for a new class of generators known as Independent Power Producers (IPPs). As envisioned by FERC, IPPs would be largely deregulated generators that would sell power to wholesale buyers at market-based rates. Utilities would not, however, be obligated to purchase power from IPPs. Nor would IPPs be subject to any size, ownership or technological limitations.

These NOPRs proved to be very controversial and were never implemented by FERC. Despite this, a review of the avoided cost and bidding NOPRs is useful because these NOPRs reflected FERC's thinking at the time as to what "mid-course" corrections were needed with respect to its PURPA regulations and the states' implementation of PURPA. Moreover, since some of the policies embedded within the three NOPRs were implemented by FERC on a case-by-case basis, it would be incorrect to conclude that these NOPRs had no impact on subsequent state actions and policies. The bidding NOPR, for example, gave states a clear signal that they were allowed to use bidding mechanisms if they wanted to do so.

Avoided Cost NOPR (RM88-6)

The avoided cost NOPR proposed a "fine tuning" rather than a major rewriting of the Commission's PURPA regulations. The Commission reaffirmed the avoided cost standard as the appropriate basis for determining rates for purchases from QFs and said that states should continue to have primary responsibility for implementation of the avoided cost standard. However, FERC concluded that additional guidance with respect to the determination of avoided cost was warranted. In particular, the Commission proposed the following changes or clarifications to the determination of avoided cost:

- States would have to explicitly consider the quantity and characteristics of a utility's energy or capacity needs, and the QF's ability to meet those needs, when determining an avoided cost rate. Specifically, states would have to consider three factors in determining the utility's avoided capacity costs, namely: (1) the utility's energy or capacity needs (both the quantity and characteristics of the power needed), (2) the energy or capacity offered by the QF, and (3) the compatibility between the qualitative characteristics of the utility's identified energy or capacity needs and the characteristics of the QF.

- States would be encouraged, but not required, to redetermine a utility's avoided cost whenever it became clear that the amount of capacity offered by QFs could exceed the utility's needs. Such redeterminations of a utility's avoided cost would become effective only on a prospective basis and would not affect contracts already executed.

- Capacity payments via standard offer rates would not be permitted once the purchasing utility's capacity needs were satisfied.

- In a clarification, determinations of avoided cost would have to take into account the availability of purchases from other wholesale sources.

- The effect of the QF's source of fuel on the utility's overall long-term risk would have to be considered in the determination of avoided cost.

- In a reaffirmation, QFs could receive long-term, fixed-price contracts based on projections of the utility's avoided cost that may differ from avoided costs at the time of delivery, but only if certain conditions were met. For example, the rates could not result in payments in excess of avoided costs as calculated at the time the obligation was incurred. In addition, the contract rates must take into account the time value of money, the QF's financing needs, and any inter-generational inequities that may result from the difference between the rates paid to the QF and the avoided cost at the time of delivery.

Thus FERC, while reaffirming the avoided cost standard, clearly was concerned about (1) utilities purchasing capacity that they did not need (or more capacity than they needed), (2) mismatches between a utility's energy and capacity needs and the type of energy and capacity provided by QFs, (3) rates exceeding avoided cost, and (4) the potential risks and inequities associated with long-term, fixed-price contracts based on long-term projections of avoided cost. The proposals described above were designed to address these and other concerns. At the same time, FERC was loath to tinker too extensively with its regulations, because it viewed the full avoided cost standard as fundamentally sound and consistent with economical QF development if implemented properly. In addition, the Commission probably did not want to take actions that would significantly jeopardize the development of the fledgling QF sector. For example, the Commission spent several pages discussing the potential problems with long-term, fixed-price contracts but ultimately suggested only minor changes to its regulations to address these concerns. While the Commission recognized the potential risks of long-term contracts, it also was cognizant of the QF industry's argument that such contracts were essential for project financing. Thus, the Commission chose not to restrict or prohibit such contracts.

Bidding NOPR (RM88-5)

The Commission concluded that bidding addressed many of the problems associated with administratively determined measures of avoided cost and had the potential to eliminate the debates over what alternative sources of supply are truly avoided by utility purchases from QFs. Therefore, the Commission proposed to amend its regulations to establish conditions and provide specific guidance to state regulators on the use of bidding programs to set avoided costs. The proposed rule sanctioned the use of bidding as a procedure for purchasing electricity from QFs.

FERC viewed bidding as not in conflict with the full avoided cost standard but rather as an alternative approach by which utilities could determine their full avoided cost. The Commission reasoned that bidding would enable utilities to discover the lowest price at which they could purchase alternative energy from another source and thus more accurately define their avoided or incremental cost. This, in turn, would eliminate inadvertent subsidization of QFs by electricity consumers. FERC further concluded that bidding among QFs was likely to generate savings by improving the incentives for efficient cogeneration and small power production, thereby encouraging the most efficient QFs. That is, bidding would reward QFs that could produce power more efficiently and therefore at a lower cost.

While the Commission did not mandate a specific bidding method, it did set forth several criteria and conditions that needed to be met for a bid to be acceptable under the proposed regulations. One condition was that all sources—QFs, utility self-supply, purchases from other utilities and IPPs etc.— be taken into account in the bidding process. FERC believed that this “all source” approach was needed to ensure that a QF received a price less than or equal to the utility’s avoided cost. FERC similarly concluded that a portion of the utility’s capacity needs should not be reserved for specific suppliers or otherwise exempted from QF offers. FERC also proposed that bidding mechanisms consider non-price criteria, such as fuel diversity, dispatchability and reliability. The Commission’s proposed regulations also provided guidance with respect to the bid solicitation and selection process. States would have been required to certify the bid selection as a condition for the use of bidding to price QF power.

Apart from the requirement for all-source bidding, the state bidding programs of the late 1980s appear to have been generally consistent with the Commission’s proposed criteria. Bids typically included non-price criteria, such as fuel diversity, environmental impacts, system operational features and development risk. In addition, QFs usually were permitted to bid on all of the utility’s identified capacity needs and the selection process was reviewed by state regulators.

VI: AVOIDED COST IN TODAY'S POWER MARKETS

The 2005 Modifications of PURPA and Related Market-tuning Policies

On August 8, 2005, the Energy Policy Act of 2005 (EPAct 2005) was signed into law. Section 1253(a) of EPAct 2005 adds a new Section 210(m) to PURPA that provides for termination of an electric utility's obligation to purchase energy and capacity from QFs if the Commission finds that certain conditions are met. Specifically, the obligation to purchase QF power is waived if FERC finds that a QF has non-discriminatory access to:

1. Independently administered, auction-based day-ahead and real-time wholesale markets for the sale of electric energy; and wholesale markets for long-term sales of capacity and electric energy; or

2. Transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords non-discriminatory treatment to all customers; and competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the QF is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

3. Wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable quality as markets described in the previous subsections.

On January 19, 2006, the Commission issued a NOPR to implement this provision of EPAct 2005. In the NOPR, FERC made a preliminary finding that QFs interconnected with utilities that are members of the Midwest Independent System Operator (ISO), PJM, ISO New England (ISO-NE), and the New York Independent System Operator (NYISO) have non-discriminatory access to such wholesale markets and that those markets satisfy the statutory criteria for removing the obligation of those electric utilities to enter into new contracts or obligations with QFs. For all other utilities, the Commission proposes to determine on a case-by-case basis whether a given utility meets the statutory requirements for relief from its purchase obligation. This means that the Commission will need to determine whether other U.S. wholesale power markets, including non-regional transmission organization (RTO) and non-auction-based markets, meet the statutory criteria for waiver of the purchase obligation.

It is possible that some and perhaps even a significant number of utilities will receive a waiver from the QF purchase obligation in the next few years, apart from those utilities that are members of the Midwest ISO, PJM, ISO-NE, or NYISO. However, on the assumption that some utilities will continue to be subject to the purchase obligation for the foreseeable future, the remainder of this chapter considers the calculation of avoided cost in today's power markets.

In addition to these refinements to PURPA eligibility, EPAct 2005 also introduced diversity and efficiency standards into the regulatory toolkit. Specifically:

- Diversity is encouraged in Section 1251, which directs electric utilities to develop plans to minimize dependence on a single fuel source and to ensure that the energy they sell is generated by a diverse set of fuels and technologies, including renewable technologies.

- Section 1251 also directs each electric utility to develop and implement a plan to increase the efficiency of its fossil fuel generation.

These diversity and efficiency policies are themselves broad enough to benefit from more detailed discussion. Their relevance to the current discussion is that these market-tuning mechanisms appear to be part of a cluster of policies aimed at giving state regulators more control over the capacity choices and operating policies of their utilities. This cluster includes the renewal of avoided cost pricing for net metering.

At a very general level, there are three lessons that can be gleaned from the history of PURPA in the 1980s and 1990s that apply to all of the current market-tuning goals:

1. *Recognize that the market will change, both on its own and in reaction to the policies that have been introduced.* Accordingly, static, fixed rules of regulatory constraints or incentives on capacity planning and operations are strongly at risk of becoming ineffective or even counterproductive, thanks to the "law of unintended consequences." One manifestation of this for PURPA was that realized marginal costs proved to be much lower than had been anticipated, resulting in significant, undue costs to customers.

2. *Be aware of existing or potential jurisdictional conflicts, or conflicts with other economically important practices of the industry.* This was a problem for PURPA when avoided cost pricing rules were approved that conflicted with existing practices for predicting and observing such costs over time. Looking forward, all of the EPAct 2005 ideas discussed herein have strong interactions with RTO practices, which organizations generally have dispatch procedures, marginal cost pricing practices (such as locational marginal prices [LMPs] for energy and installed capacity [ICAP] prices for capacity) as well as capacity adequacy and (partial) siting-approval responsibilities. State policies should be compatible with and informed by such rules, or they will lead to unplanned inefficiencies and perhaps financial risks.

3. *Place some kind of "governor" functions on how far and how fast new policies are pursued.* PURPA led to QF entry that sometimes vastly exceeded needs, and which undermined the marginal cost assumptions that originally justified the policies. Just as an unlimited amount of QFs is not a good thing, diversity is not per se desirable. It would be easy to pursue diversity that would cost much more than it is worth. It should be used as a risk management tool only to the extent that a specific, measurable goal for risk reduction has been defined, can be shown to be well served by diversity (as opposed to other means, such as hedging), and will be monitored to see when it is satisfied.

The balance of this report explores these principles more narrowly in the context of avoided cost pricing, net metering, and customer load reduction credits.

Major Uncertainties in Today's Wholesale Power Markets

Many of the issues surrounding avoided cost calculations have not changed significantly over the past 15 years. There still is much uncertainty in estimating long-term avoided costs, due to uncertainties regarding fuel and purchased power costs, environmental regulation and associated compliance costs, load growth, and construction costs, among other factors. If anything, there arguably is more uncertainty today than in the past because of: (1) volatility in wholesale power prices, which, generally speaking, is much greater today than it was in the 1980s; (2) evolving wholesale market designs and market rules, particularly with respect to capacity markets and market mitigation mechanisms; (3) the impact of "seams" between markets; and (4) uncertainty regarding the obligation to serve in states with fully or partially open retail markets but little actual retail shopping. For example, the pattern and magnitude of investment in new generation capacity undoubtedly will be affected by rules governing capacity markets and the mechanisms available to generators to recover the cost of their investments. Generation investment, particularly in peaking capacity, also will be significantly affected by the market mitigation rules and price caps imposed by FERC.

Other market developments, however, should help facilitate the calculation of avoided costs. Certain price benchmarks are available today that were not available in the 1980s. A primary example is the forward price quotes provided by brokers and other financial firms. Forward price quotes are available for virtually all regions in the U.S., though the trading of such products is more active in some regions (generally RTO markets) than in others. While such quotes usually go out only for two to three years, they at least provide a benchmark for relatively near-term estimates of avoided cost. Indeed, it may be appropriate to only make regulatory promises for avoided cost prices over horizons that correspond to what can be observed in the markets, as the lack of trading for more remote years is partly a reflection of risk and reluctance to rely on counterparties for long horizons. Other market benchmarks include the multiyear, firm price contracts signed in response to solicitations to serve a utility's standard offer or provider of last resort service. While such contracts factor in risks unrelated to avoided costs, such as the volume risk associated with customer shopping, they provide a reasonably good estimate of the near-term forward price associated with serving most customer load in a particular service area.

In addition, financial hedges and other risk management tools are more available today than in the past. For example, options contracts provide utilities, power traders and others a means to hedge themselves against large spikes in fuel or power prices. A utility could include the price of such hedges in its calculation of avoided cost. The price of such hedges would help bound the uncertainty associated with volatile fuel costs.

Today's market participants also are more familiar with the use of buyout/buydown clauses and other means of allowing purchasers and sellers to get out of bad deals. Such provisions started to be used more widely in the 1990s. For example, some utilities have placed such provisions in their power supply contracts with QFs or IPPs so that they can "buy out" the generator before it comes on line if market price movements make the contract unfavorable for the buyer.

The upshot is that while wholesale market prices are more volatile today than in the 1980s, various tools and products are available to help manage this risk and to place a financial bound on the cost associated with such risks. Moreover, forward-price benchmarks that did not exist in the 1980s are now available. These products should help improve the accuracy of near-term estimates of avoided cost. Long-term contracts of 10 years or more will continue to entail significant risks that will be difficult to hedge or mitigate.

VII: NET METERING

Net metering is a simplified method of metering the energy consumed and produced at a home or business that has its own onsite energy generator, such as a small wind turbine or photovoltaic (PV) or solar thermal electric device. Small onsite generators also are known as distributed generation (DG). These generators are owned and operated by retail customers and are used to meet a portion of the customers' demand or to provide backup service for customers that need highly reliable power. Other examples of DG include backup generators at hospitals and combined heat and power systems in industrial plants. The Energy Information Administration (EIA) projects that 5.5 gigawatts (GW) of DG, or slightly less than 2 percent of all new generating capacity, will be installed over the next 25 years.[11]

Under net metering, excess electricity produced by the onsite generator will spin the customer's meter "backwards" such that the customer is a net seller of electricity to the local utility at such times. Many states have implemented net metering programs to encourage the use of small, renewable energy systems. Approximately 40 states have adopted some form of net metering law for small wind and/or photovoltaic technologies whereby the customer receives a credit for excess power sold to the utility.[12] While most state net metering programs are open to all retail customers, some states restrict eligibility to particular customer classes. Customer participation in net metering programs has grown significantly. In 2004, a total of 15,286 customers was in net metering programs—a 132 percent increase from 2003. Residential customers accounted for 89 percent of all customers participating in such programs.[13]

Section 1251 of EPAct 2005 provides further encouragement for net metering by requiring states to consider whether electric utilities should make net metering service available upon the request of any customer served by the utility at any level. This suggests that almost all electric utilities may need to establish tariffs for net metering service.

Net metering offers retail customers a convenient and inexpensive way to sell excess energy in quantities that are too small or intermittent to market directly. However, net metering raises important policy issues that are similar to those raised by QF purchases. Namely, care must be taken to ensure that net metering customers are not overcompensated for their energy sales to utilities; otherwise, customers without DG facilities may end up cross-subsidizing those with onsite generators. Such cross-subsidization could have perverse distributional effects, given that low- and moderate-income consumers would be less likely to install solar panels or renewable generators than high-income customers. Moreover, overpaying net metering customers for their output likely would spur an oversupply of onsite generation, as some customers install technologies solely to take advantage of payments (credits) that exceed the market value of the energy. The remainder of the chapter will recommend policies that state regulators can adopt to help ensure that net metering is implemented in an economical and equitable manner.

[11] *Annual Energy Outlook 2006*, February 2006, DOE/EIA-0383 (2006), Table A9.
[12] See www.dsireusa.org
[13] *Green Pricing and Net Metering Programs 2004*, Energy Information Administration, March 2006.

Basis for Setting Customer Credits

From a utility perspective, net metering service is somewhat analogous to purchasing energy from a small renewable generator that sells energy on an "as available" basis.[14] Because the quantity and timing of energy provided by onsite renewable generators is uncertain, net metering probably does not allow the utility to avoid any generation capacity costs. Under PURPA, a QF that provides energy on an intermittent, as-available basis would be entitled to receive compensation equal to the utility's avoided energy costs, but it is questionable as to whether the QF would be entitled to a capacity payment (presuming the utility needed capacity).

However, some supporters of net metering argue that customers should receive the full retail rate for any excess power sold to the utility. In other words, if a customer purchases 1,000 kWh in a given month at a price of 10 cents/kWh and sells 200 kWh back to the utility, the customer would receive a bill of $80 [(1,000 - 200) * 0.10]. Many state regulators have been sympathetic to this argument. A recent survey of state net metering rules shows that most states with such rules credit excess generation at the utility's retail rate rather than at the utility's avoided cost.[15] A few states vary the credit by customer class. For example, Idaho credits excess generation provided by residential and small commercial customers at the retail rate but credits excess generation provided by large customers at the wholesale spot price for energy.

States presumably have been receptive to setting credits for excess generation equal to the utility's retail rate because this is easier for customers to understand—indeed, most small customers probably have no understanding of avoided cost—and it provides an incentive for the installation of small renewable energy systems. Such pricing also likely reflects historical metering limitations, as explained below. However, from an economic perspective, crediting excess generation at the utility's retail rate makes no sense, because retail rates include charges for transmission, distribution, and administrative and overhead costs, not to mention sunk generation costs, and *none of these costs, generally speaking, is avoided* as a result of excess generation provided by a retail customer. Simply put, the embedded, average cost of service is quite different from the time-differentiated incremental cost of generating the last kWh of electricity. Credits based on retail rates could be reasonable if the customer purchased electricity under marginal and/or time-of-use rates, but most residential customers in particular purchase electricity under non-time-differentiated rates set equal to the utility's embedded cost of service.

Paying the full retail rate for any energy provided by net metering customers could lead to significant revenue losses and earnings reductions for utilities. The direct reduction in a utility's revenue from a kWh displaced by net metering (i.e., the retail revenue from that kWh) is offset only by the utility's incremental cost of energy (i.e., the utility's avoided cost). Referring to the earlier example, if the retail rate is 10 cents/kWh, while the utility's incremental cost of energy to serve the customer is 3 cents/kWh, the utility has a net revenue loss of 7 cents/kWh on all energy purchased from the net metering customer. The utility loses 7 cents that would have gone to the recovery of its fixed costs. This lost revenue would have to be collected from other customers by raising their rates or would translate directly into lost earnings for the utility. The impact on a utility's earnings could be significant because of the potentially large gap

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14 Some net metering advocates argue that net metering customers do not "sell" power to the utility, but only "offset" power purchased from the utility. It's true that over a billing cycle a net metering customer will be a net purchaser of energy from the local utility rather than a net seller. However, during certain hours, onsite generators will be net sellers, i.e., generate more electricity than needed for their own use. Thus, net metering customers do not merely reduce their consumption of electricity; at times, they sell power back to the utility.

15 Interstate Renewable Energy Council (IREC) "Connecting to the Grid" Project, State and Utility Net-Metering Rules (Updated July 2005) at http://www.irecusa.org/connect.

between its retail rate and its short-term avoided cost, which is the total revenue available per kWh for fixed cost recovery.

The following example illustrates this phenomenon. Consider a typical mid-sized utility with the following characteristics.

Peak load	5,000 MW
Total sales revenue	$2.0 billion
Net income	$200 million
Common shares outstanding	100 million
Earnings per share	$2.00 per share

The potential impacts of two types of net metering programs are illustrated. The first case is representative of one of the more restrictive programs in the nation, while the second case is representative of one of the more liberal programs in the nation.

Case 1	
Eligible customers	Residential, family farm
Eligible technologies	PV, wind, biomass (all under 10 kVA)
Average capacity factor of generation	0.25
Program cap	0.1% of utility's peak load
Average residential (farm) retail rate	10¢ per kWh
Avg. wholesale value of displaced energy	3¢ per kWh

Under Case 1, full subscription of the program would reduce earnings by $766,500, which is equivalent to 0.38 percent of net income, or 0.77¢ per share.

Reduced Earnings

= Peak Load ∗ Program Cap ∗ Capacity Factor ∗ Annual Hours ∗ Price Spread

= 5,000,000 kW ∗ 0.001 ∗ 0.25 ∗ 8,760 Hours ∗ ($0.10 - $0.03)/kWh

= $766,500

Even though the net metering cap is only one-tenth of one percent of peak load, there is an implicit multiplier of nearly four. That is, the impact on earnings is nearly four times as large as the impact on sales.

Case 2	
Eligible customers	Residential, commercial, farm
Eligible technologies	PV, wind, biomass, fuel cell, micro-turbine
Average capacity factor of generation	0.4
Program cap	1.0% of utility's peak load
Average residential and commercial retail rate	10¢ per kWh
Avg. wholesale value of displaced energy	3¢ per kWh

Under Case 2, full subscription of the program would reduce earnings by $12.26 million, which is equivalent to 6.13% of net income, or 12.26¢ per share.

Reduced Earnings
= Peak Load ∗ Program Cap ∗ Capacity Factor ∗ Annual Hours ∗ Price Spread
= 5,000,000 kW ∗ 0.01 ∗ 0.4 ∗ 8,760 Hours ∗ ($0.10 - $0.03)/kWh
= $12,264,000

Again, even though the net metering cap is *only* one percent of peak load, the impact on earnings is more than six times as large as the impact on sales.

Some net metering advocates may argue that these examples are incomplete or misleading because they assume that the utility has sufficient generating capacity. These advocates likely would argue that once this assumption is relaxed, the cross-subsidy problem goes away because onsite generators help the utility avoid capacity costs. There are two problems with this argument. First, as explained above, the timing and quantity of energy provided by net metering customers is uncertain. Nor are such customers under any obligation to provide specified quantities of power to the local utility at specified times. Thus, even if a utility does need additional capacity, it is questionable as to whether net metering customers will enable the utility to avoid or defer the construction of new generating capacity. Simply put, the energy provided by net metering customers is not a "firm" supply source that a utility can count on to meet its capacity requirements.

Second, even if onsite generators collectively do enable the utility to avoid or defer the construction of additional generation (and/or local distribution) capacity, the cross-subsidy problem does not necessarily go away. To the extent that the retail rate that the net metering customer receives for its output exceeds the utility's avoided cost, including the incremental cost of avoided capacity, the utility continues to overpay for this power and lose a contribution to its fixed costs. This lost revenue will have to be recovered from other ratepayers or will result in reduced earnings for shareholders.

For these reasons, we recommend that credits for excess generation be tied to the utility's avoided cost, rather than its retail rates, because avoided cost is a much more accurate measure of the value of the excess generation provided by retail customers with onsite generators. Moreover, compensating net metering customers in this manner does not impair the utility's recovery of its fixed costs. Credits linked to retail rates may be acceptable where the customer purchases power under a marginal or time-of-use rate. In addition, credits for excess generation ideally should reflect the time and locational value of the energy provided by onsite generators. That is, credits for energy provided on peak should be greater than the credits received for energy provided during off-peak hours. For a utility in an RTO market operating under LMPs, reflecting such nodal prices in the avoided cost payments to the net metering customer will satisfy both time and locational cost-differentiation. Since it is unlikely that net metering will enable a utility to avoid any generating capacity, as intended by PURPA, avoided cost credits should be based solely on avoided energy costs.[16] However, if state regulators wish to provide incentives for small renewable energy systems, including a modest capacity payment in the avoided cost credits made available to onsite generators could be a reasonable incentive and more justifiable economically then setting credits equal to the utility's retail rate. Here, it may be possible to credit the net meterer with capacity value in accordance with the historical coincidence between such excess energy and the regional system peak. Alternatively, it may be appropriate to encourage RTO policies that would let onsite generators make more of their capacity available on a firm, callable basis by RTOs, and let any capacity payments be earned from those arrangements. Again, honoring the market structure in which these regulatory policies play out is important to their long-term effectiveness.

Requiring Net Metering Customers to Have Advanced Meters

Appropriate compensation for the energy provided by net metering customers will require the replacement of conventional meters with advanced "smart" meters. A conventional meter, much like a car odometer, spins forward and records energy use over a period of time. Conventional meters cannot account for the difference between high-cost peak and low-cost, off-peak electricity, nor can they account for the difference in wholesale and retail electricity costs of electricity. For example, a conventional meter only can record that over a given month an onsite generator sold a net of 100 kWh to the local utility. It will have no record of when the 100 kWh was sold. Sales at 4 pm on a hot summer weekday will have a higher value than sales at 4 am on Saturday morning. With a conventional meter, when a DG source exports power onto the grid, the meter simply spins backwards, so power injected at 4 pm registers the same as power injected at 4 am.

With conventional metering, an onsite generator likely will have to be compensated at the utility's average retail rate, which, as explained above, will not accurately reflect the value of the energy provided by the generator. Conventional meters, coupled with credits equal to the average retail rate, also allow net metering customers to "game" the system by buying power from the electric company at high-cost times and selling to the grid at times when power is inexpensive.

Advanced meters, conversely, measure power use on a time-differentiated basis and therefore can track usage by the time of day. By collecting energy data on a real-time basis, they will enable power companies to know precisely when net metering customers are selling energy into the grid and can account for the actual wholesale value of the electricity produced. A smart meter also enables electric utilities to better account for the component costs of electricity. Advanced meters cost approximately $100-$150 per meter, but this is a worthwhile investment given that they will enable much more accurate valuation of the energy provided by net metering customers (as well as facilitate other services that cannot be provided by conventional meters).

Limiting Eligibility and Total Capacity

Until advanced meters are in place, one way to limit gaming and minimize total potential overpayment to net metering customers would be to limit net metering programs to wind, solar, and other forms of intermittent renewable energy sources that are not dispatchable, because such resources cannot readily be used to game the system. Solar collectors and wind generators, for example, are non-dispatchable sources of energy that only will be available at times largely unknowable in advance. Fossil-fired DG units, however, generally will be dispatchable and could game the system in the absence of a smart meter. Since most states do, in fact,

[16] For utilities in RTOs, the spot market energy price would be the logical measure of avoided energy cost.

limit net metering eligibility to renewable technologies such as solar, wind, biomass and hydro, the potential gaming problem described here should not arise.[17]

Another way of limiting potential overpayment to net metering customers is to limit the size of units eligible for net metering and the total capacity that the utility is required to purchase through such programs. All existing net metering programs limit the size of generating units eligible to participate. These limits typically range from 10-150 kW and sometimes vary by customer class. For example, in Georgia the limit is 10 kW for residential systems and 100 kW for commercial systems whereas in Maine and many other states, there is a single size limit (100 kW in Maine) applicable to all customer classes. In some states, eligibility is limited to certain customer groups, such as residential customers, schools and government facilities. Customer restrictions, however, may be in conflict with EPAct 2005, which requires states to consider making net metering available to any customer who asks for it.

Many states also limit the total capacity that utilities are required to purchase through net metering programs. In many cases, these limits are based on a percentage of the annual utility's peak demand—typically 0.1-1.0 percent of peak demand. For example, Hawaii limits total net metering capacity to 0.5 percent of the utility's annual peak demand. These limits on total capacity, while arbitrary, are another way of limiting potential overpayments to net metering customers until advanced meters are in place and energy provided by such customers can be valued at the time-differentiated wholesale price of energy. Note, however, that capacity limits may still expose a utility to significant earnings losses, as described above.

17 See State and Utility Net Metering Rules (Updated March 2006) prepared by Interstate Renewable Energy Council (IREC) National Interconnection Project.

VIII: CUSTOMER DEMAND REDUCTIONS

Section 1252 of EPAct 2005 requires electric utilities to offer time-based rate schedules to all of their customers, and identifies the types of schedules that satisfy this requirement, with one being credits for customers with large loads who enter into pre-established peak load reduction agreements. Utilities traditionally have offered large commercial and industrial customers such credits through interruptible service tariffs. Under such tariffs, customers typically receive a credit in return for agreeing to curtail all or a significant portion of their load up to several times a year, at times when the utility has a system operating emergency or when incremental generating costs are very high. Although enrollment in these programs usually is voluntary, the participant can face significant financial penalties if it fails to reduce demand when directed to do so, such as paying the spot market price for electricity consumed during a requested interruption period. Curtailable demand provides the utility or system operator with another resource to maintain system stability when resources are tight and also can reduce a utility's installed capacity obligations.

EPAct 2005 appropriately did not direct how such credits should be determined, leaving that to utilities and their state regulators. As with avoided cost pricing for QF purchases, determining the appropriate basis for the credit raises a host of difficult conceptual and practical issues. At a high level, one first needs to determine the types of costs that a utility could avoid as a result of customer demand reductions. Peak load reductions enable a utility to avoid serving a portion of its load at times when marginal energy prices are high, so they clearly enable the utility to avoid energy costs (i.e., fuel and other variable production costs). Moreover, peak load reductions that a utility can count on in a planning sense could enable a utility to avoid building or purchasing peak generating capacity, which suggests that the credits could reflect the capacity cost of peaking units, such as combustion turbines. Interruptible customers do not enable a utility to avoid the sunk costs of any existing peaking units; they only potentially enable a utility to avoid capacity costs associated with prospective peaking units.[18] Since avoidable costs are, by definition, costs that have yet to be incurred, credits should be based on prospective capacity costs that the utility would incur "but for" the load reduction provided for by the customer with curtailable load. Thus, if a utility has ample installed capacity, and has no plans to build or purchase additional peaking capacity over the foreseeable future, then it may be appropriate to not include a capacity component in the credit provided to customers with curtailable demand. However, even if a utility does not need additional peaking capacity, credits would reflect the incremental fuel and other operating costs saved through load curtailment.

In addition, credits could in some way reflect the "option value" provided by demand response.[19] Load reduction programs, depending on their specific design, can be similar to options in that the utility or system operator has the right but the not the obligation to reduce load for a flexible-load customer. The value of the option to choose to alter demand can be established using methodologies designed for evaluating options in financial and energy markets.

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[18] The exception would be if peak demand reductions enabled a utility to retire or mothball one or more peaking units. In this case, the reduction programs would enable the utility to avoid the ongoing maintenance and other fixed costs associated with keeping such units in service, and it would be appropriate to reflect such costs in the credits provided to flexible-load customers.

[19] Osman Sezgen, Charles Goldman, P. Krishnarao, *Option Value of Electricity Demand Response*, Ernest Orlando Lawrence Berkeley National Laboratory, October 2005, LBNL-56170.

To be eligible for credits, peak load reductions need to be measurable and verifiable. Otherwise, a utility could not know if the load reduction actually displaced the need for energy and/or capacity. For utilities in RTO markets, interruptible load programs will have to meet the RTO's rules to be eligible for capacity credits (or to count as credits against the company's installed capacity requirement). Utilities outside of RTO markets will be responsible for verifying the demand savings provided by load reduction customers. Utilities also will need assurance that customers will curtail demand when requested to do so; otherwise, a curtailable customer becomes an unreliable resource that could impair system reliability. Moreover, load curtailment only enables a utility to avoid peaking capacity if the utility can count on being able to reduce the customer's load when necessary. Financial penalties in addition to charging customers spot market prices when consuming power during requested interruption periods may be necessary.