CHAPTER 5
Getting the Best Deal

The aim of the previous chapters was to provide a basic understanding of the economic and engineering principles underlying such issues as avoided costs and interconnection standards. This chapter deals only with practice and strategy. Avoiding the question of what should be, it tells what is and how qualifying facilities (QFs) can operate within the existing laws and regulations to negotiate the best contract.

Always remember, the utility is trying to get the best deal for itself. The negotiation process is to some extent an adversarial one, so be prepared. Don't sit down at the negotiations table without having done your homework, and don't negotiate by phone. Telephone conversations are fine for eliciting information, but serious bargaining can only be done face-to-face.

You must know your rights under the Public Utility Regulatory Policies Act (PURPA). You should also make sure the utility knows that the public service commission, the city council or the Federal Energy Regulatory Commission (FERC) is aware of your efforts. Do some background investigating to uncover the operating characteristics of the local utility. Find out how their PURPA tariffs were developed. Read through the existing contracts on file at the regulatory commission, the city council or the rural electric board. Know how your own technology works. Make sure you have performed a basic cash-flow calculation for your proposed investment so you know what the minimum acceptable terms are that allow you to go ahead with the project. And be prepared to bargain. Negotiations are a process of give and take.

Remember also that in the best of situations QFs are entering a field that involves risk. Negotiations may reduce the risk, but they cannot eliminate it. QFs must accept the risk that the technology may not function as expected. The wind turbine, for example, may be out of service more than expected. Or the wind regime may not be as strong as had been predicted. To that you must add the economic risk that avoided costs could drop in the future and reduce your revenue.

Finally there is the political and legal risk that court orders or legislation will dramatically change the QF's rights under PURPA.

The Regulatory Process

QFs have to bargain as individuals, but they also bargain as a class. This type of bargaining takes place in the regulatory commission chambers, city councils or state legislatures. As a previous chapter pointed out, the PURPA regulatory process is an ongoing one, and owners of QFs must participate in this evolution. To do that you should be well aware of the regulatory process for implementing PURPA. The FERC required state regulatory commissions and unregulated utilities to initiate PURPA proceedings by March 1981. Most of them missed the deadline, but they had initiated such proceedings by the end of 1981.

The first step was for commissions to appoint a hearing examiner or administrative law judge to take testimony and to hold hearings on possible rules to implement the federal law. This is not an evidentiary procedure, which means it doesn't involve witnesses presenting formal evidence. Nor does it permit intervenors to request data in support of witness testimony. The process mainly consists of comments filed by all parties. The hearing examiner then issues a decision. This process takes about six months (although it can take a great deal longer when there are intervening lawsuits, as in the case of PURPA).

The parties have a period to file exceptions and comments. The commission then issues a Proposed Decision. There is another comment period, and then the commission issues a Final Order Adopting Rules. This process usually takes about three months.

At the time the commission issues the Final Order Adopting Rules, it issues a Compliance Order to utilities under its jurisdiction to file tariffs in compliance with the Order. Within two to three months, utilities file draft tariffs. Some commissions routinely approve these. In many, these draft tariffs are vigorously contested and public hearings are held. These hearings, which can take up to a year, are evidentiary in nature. Utilities can be forced to justify their tariffs with data. Usually a hearing examiner or administrative law judge presides over these hearings. Sometimes the full commission does so. These hearings can take up to a year. Another comment period follows and then the commission issues a final order approving tariffs with certain modifications.

Thus, even in the best of circumstances, the entire process takes about 18 months. The New Hampshire Commission combined the rulemaking, ratemaking and evidentiary hearings. Spurred on by the passage of the state's own mini-PURPA law in 1979, the commission completed its task within 6 months. No other state has been as efficient.

In some states, actions by the legislature have forced commissions to start all over again. Indiana and Minnesota have reopened the implementation process. In other states, like Arkansas, the administrative law judge issued an opinion on proposed rules in August 1982. Rhode Island is reopening its process. In California so much controversy has surrounded the PURPA rules that it is in its third year of hearings. Utilities are still operating under interim tariffs. "It's driving me nuts," says one wind developer.

Many QFs are frustrated at the apparent slowness with which PURPA is being implemented. Yet the rule has been that the more rapid the implementation, the worse the buyback rates and other terms QFs receive. (New Hampshire and Vermont are exceptions to this rule.) States in which commissions routinely approve draft tariffs submitted by utilities, or that hold no hearings because there are no QF intervenors, usually provide for very low buyback rates and discriminatory standby or back-up charges. Those states that are just entering their PURPA implementation process can learn from other states. QFs who in 1979 had little knowledge of utility economics and the concept of marginal cost pricing are now much better versed in these concepts.

Sometimes utilities insert provisions in contracts that allow them to terminate the contract if pending legal suits against PURPA are successful. Thus, for example, in the preface to a contract the utility may insert the following:

> *WHEREAS, Buyer is entering into this Agreement in good faith in compliance with article 210 of the Public Utility Regulatory Policies Act of 1978 (16 U.S.C.A. 824a-3), and (applicable state statutes) and regulations promulgated thereunder, in order to lessen Buyer's dependence upon foreign supplies of fuel oil and the uncertainties inherent in such foreign supplies;* without waiving any claim it may have as to the validity of said laws and regulations.[1] *(Emphasis added by author.)*

This bail-out provision is not normally found in power contracts that are negotiated without the specific imposition of the PURPA avoided cost rate. The utility may also insert in its termination section clauses such as the following:

> *If after this Agreement becomes effective Section 210 of the Public Utility Regulatory Policies Act (or the relevant state statute implementing PURPA) is repealed or modified so that Buyer is not re-*

quired to purchase energy and capacity at avoided cost, Buyer reserves the right to terminate this agreement.[2]

The seller should very much oppose these types of clauses. Instead, the seller should try to insert an antibail-out or positive provision that says, in effect, that the agreement remains in full force and effect even if PURPA is repealed or modified.

The possible insertions of bail-out provisions make it extremely important that QFs form associations, as QFs in a dozen states have already done, to lobby the legislature and to provide expert testimony to the public service commission.

One possible outcome is a state mini-PURPA law that mirrors the federal law. In that way the state's small power producers will be largely immune from court reversals of federal regulations. Another is the direct intervention of the state legislature in establishing rates or other contract decisions. This is rare but not unprecedented. At least two state legislatures have been so frustrated by the regulatory commissions that they established high minimum buyback rates *before* the commissions issued their own final tariffs. Statewide associations of QFs facilitate the sharing of information about existing contracts, which puts QFs in a better position to negotiate the best deal. This sharing of information can also expose patterns of discrimination on the part of utilities, which could prompt regulatory commissions to hold evidentiary hearings in which QFs as intervenors in the hearing can ask for specific data from utilities.

Many QFs have found it easiest to negotiate with utilities that have independent oversight agencies. The latter can be used to cajole or coerce the utility into offering better terms. Most state regulatory bodies lack oversight authority over municipal utilities and rural electric cooperatives (RECs). But the Oregon and Minnesota legislatures expanded the jurisdiction of the public service commission to include co-ops, public utility districts and municipal utilities for the purpose of implementing PURPA Sections 201 and 210.

Where no independent oversight function exists, one must depend on the city council or the rural electric board to play that role. City councils lack the expertise and, depending on the city, may be hesitant to become involved in QF negotiations or tariff development. On the other hand, they are vulnerable to direct political pressure in a way that regulatory commissions are not. Rural electric boards must play the dual role of manager and customer. Beset by their own problems with cost overruns and changes in demand, many view QFs as an additional nuisance. On the other hand, many of their rural customers find hydroelectric and wind facilities economically attractive. These customers are also owners, and as they also become producers a political constituency can grow within the association to make its presence felt. One farmer who owns a wind turbine told about his problems with the rural electric co-op, but added, "There are another ten machines going in real soon. When that happens I expect the co-op will be a lot more generous in its dealings."

In any event, the owner of a QF should understand that his or her individual bargaining session is set against the backdrop of vast changes in the electric system. This country is in the process of deregulating and decentralizing the electric generation system. Rate structures are being revised, load profiles are changing and new technologies are coming on-line. The QF owner must learn to live with the risks involved in such a fluid situation.

The Negotiation Process

For those with sufficient courage to push on, the following story should provide a sobering example of what could happen. Consider the trials and tribulations of one pioneer, Robert Hetzler, owner of a 20-kilowatt (kw) wind system in Mandan, North Dakota. His Rural Electric Cooperative (REC) demanded that he get certified by the FERC even after he showed them the regulation that said mandatory certification is only necessary for QFs over 500 kw. Then they called a meeting with him and the state electrical safety board even though the safety board has no jurisdiction over co-ops. "At the meeting the co-op literally demanded that the electric board stop the project on safety grounds," he remembers. The electric board refused. The co-op then demanded the board send an inspector to certify the wiring. They did and the inspector found the wiring "perfectly acceptable." The co-op pays Hetzler 1.3¢ per kilowatt-hour for any power he sells and charges him 5.2¢ per kilowatt-hour for any power he buys. They billed him $700 for the hookup, including mileage for the trip out by the co-op's engineer. Then the REC insisted he carry $1 million in general liability insurance plus $500,000 in property insurance. "They came by and pulled out my meter when they decided I didn't have it [insurance]." Then they claimed his meter was defective because he couldn't be generating so much electricity, and they replaced it twice. The meter tested out perfectly. Then the REC refused to pay him $42 they owed because they first wanted a letter spelling out Hetzler's "payment policy." A beleaguered but still fighting Hetzler rhetorically asks, "Now that's discouragement, isn't it?"

Hetzler's experience isn't unique, but he's a pioneer. This book is based on the experiences of the first 200 small power facilities to come on-line under PURPA. These people have cut a path through the jungle. Those who come later will have their route marked and an easier path to follow. And those who come still later may find a wide highway with all of the bumps flattened out. In fact, even the pioneers note changes in the attitudes of utility personnel over the periods of their contracts. Initial hostility has given way to mutual respect and even warmth. A number of the pioneers express satisfaction and even gratitude for the help they received from the utility. For after all, utility people are also breaking new ground.

For almost all QFs, the negotiation process is a learning experience. For those willing to take the time to do some basic research, a little homework can make an astonishing difference in the outcome of bargaining.

Take the case of John Eckland of Great Falls, Virginia, and his local utility, Virginia Electric Power Company (VEPCO). In May 1980 VEPCO offered independent power producers a purchase price of less than a penny per kilowatt-hour. It levied an astonishing monthly charge ranging from $40 to $90 for those interconnected with its system and insisted that residential customers choosing to generate electricity switch to a highly discriminatory rate structure. Eckland tried to discuss some changes in this rate structure with VEPCO. When he received no response, he examined the FERC's regulations and then wrote to VEPCO's president, sending copies to the state utility commission and the attorney general of Virginia. The letter identified several apparent violations of federal regulations by VEPCO.

Not long afterward, VEPCO's rate department agreed to negotiate. After several meetings, Eckland won a fivefold increase in his purchase price and a tenfold reduction in the monthly service charge. He also persuaded VEPCO to eliminate its discriminatory rate schedule for independent producers. The moral of the story? "Take your time, read the regulations and don't be afraid of direct negotiation," advises Eckland. "It can work wonders."

If direct negotiations prove unworkable, the consumer can appeal directly to the state utility regulatory commission and, finally, to the FERC. The applicant may find a sympathetic ear. Court proceedings are also possible in the event of stalled negotiations. They are also available if regulatory or other commissions fail to enforce, or erroneously enforce, PURPA regulations. Most regulatory commissions are closely monitoring the way utilities respond to PURPA. When Pacific Power and Light (PP&L) appealed an order of the Montana Public Service Commission because it made complaint procedures available to QFs but not to utilities, the commission responded, "As the stronger negotiating party, the Commission expects that utilities can, and will, protect their interests. If in doing so, the utility requires terms considered onerous by the QF, or refuses to contract with the QF, the natural course of events would be a complaint to the Commission from the QF. . . . Complaint procedures contemplate actions from one aggrieved. In the context of interconnection of QFs, it is difficult to contemplate a time when a utility would be aggrieved in the negotiating process."[3]

QFs who believe the contract offered by the utility violates the final order of the state commission should complain before signing the contract. It is much more difficult for regulatory commissions to revise existing contracts than to intervene before the contract is signed.

Regulatory commissions have weapons beyond a complaint procedure. Several commissions have warned utilities that continued foot-dragging could affect future rate requests. The Montana commission reminded utilities "of their obligation to provide information to the Commission regarding their initial written response to each prospective QF. ... In addition to reporting each *contact* made, the Commission directs the Companies to submit one copy of the completed contractual agreements with each QF. The Commission welcomes additional information that will aid the Commission in analyzing the individual efforts of each utility in encouraging QF contributions to a utility's resource base."[4]

When the California Public Utility Commission decided Pacific Gas and Electric (PG&E) was not encouraging cogeneration, it levied a $7.2 million penalty in a rate case. That amount was withheld contingent on PG&E's bringing on-line specific amounts of cogeneration capacity within a certain time frame. Montana's commission warned that "utility failure to actively pursue QF contributions to their resource base . . . (will) constitute failure to provide cost effective service. To the extent the evidence in future proceedings does not demonstrate that the utilities have in fact vigorously pursued such contracts, the Commission will use such evidence in considering whether utilities are providing adequate service at just and reasonable rates."[5] Thus, if sufficiently angered, a commission can impose severe financial penalties on utilities that do not negotiate in good faith.

Know Thy Opposition

Before entering negotiations, the QF should obtain as much information as possible about the utility with which it is bargaining. PURPA Section 210 requires that utilities provide specific data with respect to avoided costs. They must provide their avoided energy costs at the time of filing and projected costs for the next five years; they must provide information on their plans for additions to and retirement from generation equipment and purchases of firm power for the next ten years and they must estimate costs of capacity to be added to the system as well as the energy costs associated with operating new generation capacity. Regulatory commissions can add to this basic list. Montana, for example, requires its utilities to provide information on estimated line losses.

By 31 May 1982 and each two years thereafter, utilities with annual sales over 500 million kilowatt-hours (kwh) must provide such data. Utilities with annual sales of under 500 million kwh need to file similar data only upon request from a QF, and utilities receiving power through an *all-requirements contract* may file data on their supplier that is adequate to determine avoided cost. Most municipal utilities and RECs are of this latter type.

Supplementary data can come from several sources. One is the annual report that each utility is required to file with the FERC. Form 1 was discussed in a previous chapter in an example about Boston Edison. Form 12 also contains considerable amounts of data on the utility's cost structure. These reports are on file at the state Public Utility Commission (PUC). Find out from PUC staff whether the utility is currently involved in a rate case or if it is seeking a Certificate of Public Convenience and Necessity (CPCN). The latter is needed any time power plants are constructed or major changes are made in physical facilities. In either event, utilities will have to have filed considerable amounts of data to support their case in a hearing. This could be useful in evaluating avoided costs.

Another part of PURPA, Section 133, requires larger utilities to file cost-of-service data. This section was created to encourage regulatory commissions to revise rate structures to reflect marginal cost pricing, such as time-of-day rates and inverted rate structures. Note that the greater the success of Section 133 in meeting its objective, the less the difference between average (or embedded) costs and marginal or avoided costs would be. Utilities were required to submit detailed cost-of-service data for each customer class. These "133 Filings" should be compared to the avoided cost data which are filed separately under PURPA Section 210. These filings will include many load curves that can help QFs analyze peak and off-peak demand for different customer classes.

Examining Existing Contracts

Although one might expect that contracts negotiated by the utility and QFs would be available for public inspection, they usually are not. The policy varies greatly. New Jersey, for example, will provide all documentation, including contracts and testimony at utility hearings, free of charge as part of their overall policy of strongly encouraging cogeneration. Most, like California, consider the contracts private. New Hampshire does also, but will divulge the names of the QFs who have signed contracts so they can be directly contacted. North Carolina and New York consider QF contracts public.

Commissions almost always charge for copying contracts or any other documentation. The usual charge is 10¢ to 15¢ per page, but this varies greatly. Virginia's commission charges 50¢ per page, and Florida's charges 75¢ to $1 per page. Given that one may need hundreds of pages of information to get a good idea of the utility's avoided costs, operating structure and other PURPA-related information, that can obviously put a large dent in the QF owner's pocketbook. You can avoid excessive copying charges by going to the regulatory commission office. Plan on spending a day or two at the regulatory commission in any case, talking to staff, using their library and examining documents.

PURPA requires all utilities to offer standard contracts to QFs with less than 100-kw capacity. This recognizes the unequal bargaining power of an owner of a 10-kw wind turbine against that of a multibillion dollar utility. The 100-kw cutoff is arbitrary. Some states have significantly raised it, which is specifically permitted by PURPA regulations. The presumption by FERC was that at $1,000 per kilowatt, the developer above that level would have sufficient money at risk that hiring expert assistance would not constitute a heavy additional burden.

The standard contract is developed by the utilities in close consultation with the regulatory commissions. Even though this contract is supposed to integrate all the attractive features of PURPA, QFs should examine it closely before signing. Some utilities have added burdensome conditions to their standard contract to encourage QF owners to negotiate one that removes these terms, while offering a lower buyback rate. After reading sample standard and negotiated contracts sent to QF owners by Southern California Edison (SCE) in 1982, the staff of the California PUC concluded, "Edison has aggressively encouraged private developers to accept a negotiated contract rather than a 'standard offer' at full avoided cost." SCE's standard contract, but not its negotiated contract, contained the following conditions: (1) Seller will reimburse Edison within 30 days for a portion of the capacity payments he has received if the project terminates before the end of the contract, (2) Edison has the right to take over the project and sell the electricity to itself at a low average rate if the original project operator abandons it and (3) Edison can renegotiate the terms of the contract at any time.

David Silverstone, a Connecticut attorney who has negotiated contracts on behalf of several QF owners, proposes some rules of thumb for prospective developers. "If you have a capacity under 200 kw, take the posted tariff," he advises, unless you absolutely need a long-term contract for financing. The long-term rate will be lower, and "you'll have to give up something to get the certainty of payment. Expect to take two to three months minimum for a signed contract for any load. Four to five months for any negotiated rate is very optimistic. It takes on average two to three months to get a letter of understanding."

As for legal services, Silverstone says that some clients want a lawyer only to look over and advise on a contract. Others want the lawyer to sit in on negotiations and cut the deal, using his or her knowledge of the utility business. The latter approach costs a great deal. Depending on the size of the project and complexity of the deal, it could take 50 to 100 hours of a lawyer's time, which could cost $75 or more an hour. Some lawyers will do the legal work on an "if come" basis, requiring payment out of the proceeds of electric sales on a monthly basis. Getting a hydro permit (discussed in a later chapter) can sometimes be done by clients on their own, without substantial attorney's time. Problems develop when there is a fight for site development rights. For 200-kw-and-under projects, "once there's a legal struggle over rights, the project loses its economic viability," says Silverstone,

Some suppliers of power plants will negotiate on behalf of their customers. Ken Hach is a dealer in Elkader, Iowa, of 10-kw Jacobs wind-power systems. He sold 10 in Iowa, 4 in Illinois and 4 in Nebraska. Sixteen of the 18 are interconnected. As part of the customer service, he handles all utility relations. His standard procedure is to notify the utility after the sale. Otherwise, utilities have been known "to try to discourage potential customers." Then he sends a letter to the chief engineer of the Iowa Commerce Commission, if the QF is in that state, and one to the FERC, notifying them of self-certification.

Standard Contract Variations

Everything in a contract is negotiable. If the QF agrees, even the provisions of the standard contract can be changed. However, once one provision is altered, the utility has the right to reconsider all other provisions. By altering one, the QF enters into an individual negotiating stance under the PURPA regulations.

QFs can choose to sell electricity on a short-term basis. They then sell it when available and receive a price based on the cost of displacing energy from the most expensive power plant operating at that time. In some states, like New Hampshire, the price the QF receives is the same no matter when it sells the electricity. In the vast majority of states, however, the price paid for electricity generated during the peak hours of the day and year is greater than that generated during off-peak hours. QFs who do not choose to install time-of-day meters are paid an average, which is either midway between the peak and off-peak rate or just the off-peak rate. If they want to be paid based on the time they generate electricity, they must sign a firm energy contract and install several registers, depending on the number of peaking periods. In California, which has three periods, peak, middle and off-peak, three registers must be installed. Each additional register costs $50 above the $50 regular cost of a watt-hour meter.

Often utilities will charge QFs for additional registers or meters. A number of commissions, such as Colorado's, have explicitly required utilities to charge the customer no more than its own cost. PURPA requires the charge to represent only the *additional* costs incurred by the utility. Thus it should be charging the customer based on its bulk purchase price, not the individual retail rate. Customers should also be permitted to purchase their own meters. In at least one case in Iowa, a customer convinced the commission to reduce the proposed metering charge simply by showing them a catalog with a very low price for such a meter. Some utilities have charged $15 to $80 a month for meters. These charges would allow it to recoup its costs within the first year or less. QFs should appeal such charges to the regulatory commission.

QFs can sign long-term contracts for energy and capacity. In those states where utilities have convinced the regulatory commission that they have an excess capacity and no construction plans for the foreseeable future, the QF is ineligible for capacity credits.

QFs willing to sign long-term contracts can usually gain a higher price for energy. In states that include a capital cost in their long-term energy cost calculations, as do North Carolina and Montana, the difference in price can be quite substantial.

Where capacity credits are given, they vary from $25 to $85 per year per kilowatt. In part, the difference is accounted for by the difference between the short-term capacity displaced, represented by the cost of an efficient combustion turbine that costs between $350 and $650 per kilowatt, and long-term capacity credits, represented by the cost of a baseload plant that costs between $1,200 and $3,000 per kilowatt. Part of the difference stems from the various methodologies used by regulatory commissions, including the various discount rates and inflation rates assumed.

About a half-dozen states give QF owners capacity payments in the form of a cents-per-kilowatt-hour rate for electricity delivered during peak periods of the year. In some states, like North Carolina, QF owners are only eligible for these "as available" rates if they sign long-term contracts. In Montana the minimum term is four years. In North Carolina it is five years. In others, like California, the QF can receive as available capacity payments even without a long-term contract. Such payments are based on the avoided cost of a combustion turbine. If the QF should want to receive the higher avoided cost based on a baseload plant, it could sign a long-term contract with the utility. Such a contract, however, would require the QF to meet certain performance criteria.

Long-term contracts usually trade off price for certainty. The QF might, for example, negotiate a fixed rate for energy and capacity credits. Since these are fixed, the QF knows what it will receive in the future. But since they are fixed, their real value decreases as inflation eats up future dollars. To alleviate this problem, the QF might negotiate a contract that has a fixed rate with a minimum floor below which the payments cannot drop or an escalator clause based on the consumer price index or the price of oil. A utility would negotiate such a contract only if it received something of value in return.

Many QF owners who are involved with outside investors or bank financing prefer to receive higher payments in the early years and lower payments in later years. Such contracts are usually called front-loaded contracts. The contract between U.S. Windpower (USW) and PG&E in 1982 illustrates such a contract.[6] A Massachusetts-based corporation, USW manufactures wind turbines and develops so-called wind farms consisting of dozens or even hundreds of wind turbines spread over a specific geographic area. The wind farms are excellent tax shelters because investors can buy into a specific wind turbine just the way they can invest in a specific oil or gas well and take advantage of attractive tax benefits associated with such investments.

USW needed a long-term contract to protect its investors. PG&E was willing to provide such a contract if it received benefits during the later years of the contract for its ratepayers.

During the early years of the 30-year contract, PG&E pays USW a constant price for each kilowatt-hour of electricity actually delivered. The price is 9¢ if the current Internal Revenue Service (IRS) provisions regarding tax credits continue in effect and 10¢ if the 10 percent investment tax credit for wind machines is eliminated. The constant price gives USW investors a guaranteed minimum (assuming the wind turbines themselves function as projected and the wind regimes are as estimated) and will probably be higher than the standard rate in the early years. PG&E keeps track of the difference between the constant price and 97 percent of the standard offer price in a separate account called a *payment tracking account* (PTA). The balance in the PTA account accrues interest at 120 percent of Bank of America's prime rate for 90-day loans to commercial borrowers. As the standard rate rises above the constant rate, the balance falls. PG&E estimates that the balance will fall to zero within 5 years. After the balance falls to zero PG&E pays USW only 95 percent of the standard offer price for energy delivered. This continues until 1 January 2002. Afterward, a 10 percent discount on the standard offer rate is in effect until the contract expires on 31 December 2011.

The contract contains no provision for capacity payments, because wind machines are not yet given any capacity credits in California. If these are added by the commission at some future time they will be included in the contract.

This contract provides USW a higher initial price for its electricity and a certainty about the price it will receive. That satisfies its investors. PG&E estimates that over the life of the agreement the net present value of ratepayer savings will be $5.8 million, representing an internal rate of return of 63 percent. In other words, the investors in the wind farm are willing to forego almost $6 million in revenue in return for the certainty of the long-term pricing arrangement and the higher prices in earlier years.

Long-term contracts benefit renewable-based technologies, like wind and solar and hydro, differently than they do technologies that use fossil fuels, like cogeneration. Renewable-based projects have high initial capital costs and low operating costs. Fuel is free. Given outside financing, the project developer not only knows the carrying cost but is paying a fixed monthly payment over 5 to 25 years. The fixed contract guarantees the QF and the bank that finances the facility a monthly payment that will meet the financing costs. (It is important to note here that no bank so far has lent a QF owner money when the only collateral was a long-term contract. The bank will require a net worth analysis of the individual's wealth and possibly other collateral as well.) As noted above, long-term contracts at fixed prices without a built-in inflation escalator clause decline in real value in later years. A dollar earned 5 years from now is likely to be worth far less than a dollar earned this year. But the developer may be willing to accept this decline in real values because the fixed monthly loan payments are also declining in real value. The loan is also being paid back in devalued dollars.

The cogenerator, on the other hand, has a low capital cost but a high operating cost. Fuel represents the primary component of that operating cost. Given uncertain oil prices and the deregulation of natural gas, the cogenerator would be unlikely to benefit from or to seek a long-term contract (unless methane were the fuel source or unless it were a bottoming-cycle cogeneration system operated by waste heat from an industrial process).

If a cogenerator signs a long-term contract to attract bank financing, it probably will still need to get insurance from another source to satisfy the bank. David Silverstone tells of one negotiation that illustrates this point. His client owned an 8-megawatt (Mw), coal-fired cogenerator sited at an abandoned mill yard. The developer is converting the mill to an industrial park and wants to sell steam to the tenants. Negotiations began in February 1981. The letter of intent from the local utility was finally sent in July for an avoided cost price of 6¢ per kilowatt-hour with a consumer price index escalator with an upper limit of the then-current price of oil in any year. The utility insisted on renegotiating the contract in the fall of 1981, partly due to the declining oil prices. It then announced it would only commit to purchase 75 percent of the output. So after a full year of negotiations, the cogenerator abandoned negotiations with this utility.

A contract was signed later with another utility. This utility refused to take the risk of rapidly rising oil prices increasing avoided costs, so the 15-year contract is tied to a percentage of avoided costs which varies inversely with the price of oil. The formula for estimating the percentage is the following: 1 divided by the square root of the current price of oil (O_c) minus the base price of oil (O_b) at the start of operation ($1 \div \sqrt{O_c - O_b}$). Thus, if the price of oil rises $2, the formula equals 1 divided by the square root of 2 ($O_c - O_b = 2$), or 1 divided by 1.4, or 0.7. Thus the QF receives 70 percent of the current avoided cost level. To protect against oil prices dropping, the bank required the QF to take out a policy with an insurance company.

Remember the time value of money when negotiating. Know the difference between *nominal* and *constant* dollars. For example, a contract may agree to pay the QF owner the present value of future avoided costs. Assume the buyback rate today is 5¢ per kilowatt-hour and it rises to 7¢ per kilowatt-hour by 1985. Assume further that the consumer price index also rises, by 10 percent a year. Over three years the buyback rate has risen 40 percent, but inflation has eaten away almost all of that increase. So in constant dollars the QF hasn't made any more money.

PURPA does not require a QF to sign a contract based on its own production costs. However, QFs can negotiate such cost-plus contracts if they wish. Such a contract has been negotiated between the University of Washington and Seattle City Light and Power, a municipally owned utility. The agreement provides for separate purchase prices depending on the type of fuel the university burns in its cogeneration plant. When coal is used to fire the boiler, City Light will, according to the contract, purchase the electricity "at a price of 32.58 mills per kilowatt-hour, based on the University's estimated cost to produce the energy as determined in the attached Production Costs of University Cogenerated Power, Plant Operational Mode I, 14 October 1981." The price increases to 42.10 mills (4.21¢) per kilowatt-hour when oil or gas is the fuel. The purchase prices are based on the production costs plus an agreed-upon rate of return.

The first option is the standard rate, where over the life of the contract the QF is paid a standard rate that varies from year to year. Assuming no real inflation in the cost components used to compute standard rates, curve B in figure 5–1 would represent this option.

The second option is where the QF is paid a fixed minimum, in this case the greater of the initial year's standard rate (curve A) and the actual standard rate. In this case the rate can never drop (in current dollars) but could rise.

The third option is where the QF receives a fixed payment consisting of the initial year standard rate plus the previous year's inflation. Curve B represents this option.

The fourth option also consists of a fixed payment. In this case the QF is paid the initial standard rate plus a negotiated level of projected inflation. Curve C represents this rate assuming the projected inflation rate were to be higher after 1995 than the actual inflation rate.

The fifth option is a levelized payment that takes into account projected inflation rates. The present value of projected inflation (curve C minus curve A) is levelized over the life of the contract and added to the initial standard rate, resulting in curve D.

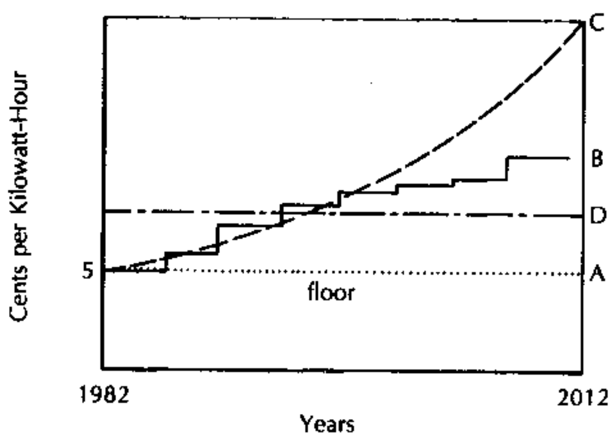

Figure 5–1: *Redrawn from* Public Service Commission of the State of Montana, Docket No. 81.2.15, *order no. 4865b, p. 16.*

Initially Montana's Public Service Commission merely recommended these as possible options. Given the reluctance of Montana utilities actually to offer these options, it held hearings in early 1983 to decide whether to make it mandatory for utilities to offer them.

Wheeling

While the QF owner cannot require the local utility to transmit electricity for sale to another utility, it might be able to make the transaction attractive enough to entice such a commitment. This is especially the case for those with municipalities or all-requirements utilities. Study the demand patterns, construction plans and avoided cost schedules of surrounding utilities.

In the case of the 8-Mw, coal-fired cogenerator previously cited, this QF ended up selling its electricity to a remote utility. The utility charged $25 per kilowatt per year for wheeling. For the 8-Mw facility, this amounted to $200,000, an attractive profit for the local utility. A 200-kw QF would be paying $5,000. The QF owner can afford to pay this amount if the price received from the next utility offsets that additional cost. Assuming a capacity factor of 80 percent for the cogeneration facility, the additional revenue comes to more than $500,000 a year for every penny increase in the buyback rate. A 200-kw QF with the same capacity factor would receive about $14,000 in additional revenue.

Some utilities have adopted a policy toward wheeling. Concord Electric Company, Exeter and Hampton Electric Company, and the New Hampshire Electric Cooperative, for example, have stated their willingness to wheel power from small generators for sale to Public Service Company of New Hampshire. In such cases, Public Service Company pays the small generator directly for the wheeled power.

The last chapter discussed the situation in Oregon with respect to wheeling. To provide higher buyback rates to QFs, Oregon has originated the idea of a base-case price. Even if a utility buys cheap electricity directly from the Bonneville Power Administration (BPA), it cannot use that price as its avoided cost. It must pay the QF either its avoided cost or the base price as calculated by the Public Service Commissioner, *whichever* is higher. The base price is high enough that it acts as an incentive for the local utility to wheel electricity to its supplier, thus giving the QF a higher price.

There is a further wrinkle to the wheeling issue in the New Hampshire Limited Electrical Energy Production Action of 1979. PURPA doesn't require utilities to wheel a QF's power to another customer, only to another utility. But the New Hampshire law allows the QF to demand that its utility wheel to as many as three customers so it can sell to them retail. As of late 1982 the law had never been tested. Many believe its provisions, which require rather than permit utilities to wheel and allow QFs to sell electricity directly to retail customers, are illegal.

Net Sales versus Simultaneous Purchase and Sale

The QF can choose one of two contractual arrangements. Under a *net purchase and sales contract,* the QF uses its power on-site and sells the excess to the utility. It buys power only when it cannot meet its own load. Sometimes in this case utilities will allow the QF to use an existing watt-hour meter. The current is reversed if the QF is selling power to the utility. Other utilities worry that reversing the meter will shorten its life and install a separate meter to measure the QF sales. In either case it is a net billing arrangement.

The QF can also choose to sell all of its generated power to the utility and simultaneously purchase all the plant's power needs from the utility. This arrangement is generally known as the buy-all, sell-all arrangement or *simultaneous purchase and sale contract*.

Electrically speaking, the situations are identical. Electricity flows to the load of least resistance. If a QF sends electricity to the grid and is in need of electricity at that moment, it will be served by its own generator. The only difference is the way the two arrangements are metered. Indeed, one regulatory handbook put out by the New Hampshire Public Service Commission calls the two arrangements different "bookkeeping methods."

However, the two types of contracts can have very different effects. Those QFs that elect net billing may be placed under a tariff distinct from those that purchase all their electricity from the utility. The difference in the revenue that the QF earns is dependent on the utility's charges and PURPA payments. QF owners should analyze utility charges and credits closely before they decide under which contractual arrangement they choose to operate.

To illustrate this, take the example of a typical residential customer who owns a 10-kw wind turbine. The residential consumption is 700 kwh a month. Two capacity factors have been chosen for the wind machine: 15 percent (case A) and 25 percent (case B). Under these capacity factors, the residential wind system generates 1,095 and 2,555 kwh per month, respectively. Seasonal variations have been omitted to simplify the illustration. The final assumption is that the QF could use no more than 50 percent of its own output internally.

Given these assumptions (a real QF owner would make more detailed calculations), the analysis of whether the QF should choose net billing or simultaneous generation and sale is purely an exercise in arithmetic. Those uncomfortable with numbers should work with someone who isn't before making decisions about contracts and approaching the utility.

The first utility used in this example is Green Mountain Power Corporation in Vermont. To evaluate the various cases, first assume the QF sells everything and buys everything. The residence consumes 700 kwh per month. Under Green Mountain's Residential Rate 01 the homeowner pays a customer charge of \$5.50 plus a monthly energy charge in peak season (five months of the year) of 300 kwh × 4.07¢ = \$12.21 plus 400 kwh × 7.90¢ = \$43.81 for a total of \$49.31 each month for five months or \$246.55 for the peak season.

Once again, to simplify the problem, assume the residence uses the same amount of energy in the off season. It pays the same customer charge of \$5.50 plus 300 × 4.07¢ = \$12.21 plus 400 × 4.40¢ = \$29.81 for a total of \$35.31 a month or \$247.17 for the off season. The yearly payment is therefore \$493.72, and the average monthly energy bill is \$41.14.

Under PURPA, Vermont utilities pay QFs 9¢ per kilowatt-hour on-peak and 6.6¢ per kilowatt-hour off-peak. The QF can choose to receive a flat annual rate of 7.8¢ per kilowatt-hour. For this problem, that flat rate is used.

Under the simultaneous purchase and sale contract, where the QF sells everything it generates to the utility under the assumptions of case A, the 10-kw wind turbine will generate income of \$85.41 a month or \$1,024.92 yearly. This is taxable income. If the taxpayer is in the 30 percent bracket, the after-tax income would be \$55.75 a month, or \$669.00 a year. Therefore, under a simultaneous purchase and sales contract, the net benefit is \$14.61 per month, or \$175.32 a year. Under case B, which assumes a higher output from the wind turbine, it earns \$199.29 a month or \$2,391.48 yearly.

Under a net purchase arrangement the QF has two sources of income: (1) direct sales to the utility and (2) displaced purchases from on-site use.

Since the QF uses 50 percent of the output on-site, it will use 50 percent of 1,095 or 547 kwh per month on-site. The other 547 kwh it generates is sold to the utility. The residence earns 547 × 0.078¢ = \$42.67 a month by selling the electricity to the utility, and displaces 400 kwh of peak energy and 147 kwh of off-peak energy a month. In the peak months, the cost of this displaced energy is \$37.50 and in the off-peak months it is worth \$23.58. The total yearly revenue from the utility is thus equal to 12 × $42.67 = $512.04. This income is taxable. Assuming a 30 percent tax bracket, this is equal to $29.87 a month or $358.44 a year in after-tax income. The QF purchases 547 kwh per month. Based on previous calculations, the QF will pay Green Mountain $34.07 per month or $408.84 per year.

Now look at the various comparisons for case A. Under simultaneous purchase and sale contracts, the QF earns a net benefit of $14.61 per month, or $175.32 per year. In other words, the QF will receive $14.61 more each month from the utility than it will pay to the utility for electricity used on-site. Under a net billing arrangement, the QF will reduce its utility bills, but over the year it will pay out $4.20 more per month or $50.40 per year than it will receive. The difference between the two arrangements to the QF is $18.81 per month. Since simultaneous purchase and sale requires an additional meter, another conclusion of this analysis is that the QF can afford to pay up to $18.81 per month for the meter and still find this type of contract preferable.

Take the same technology and the same residential load but relocate it to the service area of Montana-Dakota Utilities Company. Under its residential electric service Rate 10, the homeowner pays 300 × 5.562¢ = $16.69 + 400 × 6.900¢ = $27.60 or $44.29 per month, or $531.48 a year. There is no customer charge, nor is there seasonal pricing.

If the wind turbine owner signed a PURPA contract for short-term power purchases under their Rate STPP-92, it receives 2.16¢ per kilowatt-hour regardless of the time of year. If it chose a simultaneous purchase and sale contract, it receives 1,025 × 0.0216¢ = $22.14 a month, or $265.68 a year. Given a 30 percent tax bracket, this is equivalent in after-tax income to $15.69 a month or $188.28 a year. The QF pays $28.60 per month ($343.30 a year) more to the utility than it receives. If, on the other hand, it chose a net billing arrangement and used 50 percent of its output to replace its own consumption, it receives 547 kwh × 0.0216 = $11.82 from the utility, equivalent to $8.27 per month after taxes. The QF will purchase $33.90 of electricity each month for internal use ($406.80 per year). Under the net billing arrangement, the QF will pay the utility $25.63 more per month than it receives from the utility.

In this situation a net billing arrangement is only slightly better than the simultaneous purchase and sale contract.

What if this QF signs a long-term contract with Montana-Dakota Utilities Company under Rate LTPP-93? Under this minimum four-year contract, the energy rate more than doubles, and the QF receives a capacity credit based on its capacity factor. In other words, if the wind turbine has a capacity factor of 15 percent, it receives 0.15 ÷ 0.85 ×

$5.33 per kw or 94¢ per kilowatt. For a 10-kw wind turbine, that would equal $9.40 per month. Add to that the 1,025 × 4.38¢ per kilowatt-hour, or $44.90 per month it earns, and it receives a total of $54.30 per month. If the wind turbine capacity factor were to increase to 35 percent, not only would its capacity credit rise to $2.13 × 10 = $21.30 per month, but its energy derived revenue would increase to $117.02, for a total of $138.32 a month.

What emerges from this brief analysis is the following:

1. *If the buyback rate is significantly lower than the purchase price, displaced energy becomes valuable enough to offset the advantages of simultaneous purchases and sales*. This means a net billing arrangement would be preferable. In many states the utility buyback rate is less than half its retail rate. In fact, Ken Hach is developing a switch that automatically diverts excess electricity to a water heater storage tank for those situations where the buyback rate is very low. The electricity brings more value as stored hot water than when it's sold to the utility. Net billing works best for small systems. For systems greater than 10 kw, only a small fraction of the electricity generated could be used internally.

2. *A long-term contract may contain valuable advantages*. It should be noted, however, that the disparity between firm and nonfirm energy in Montana is the greatest in the nation. In most cases, the QF would not receive more than 1¢ to 2¢ more for long-term energy contracts, and if these contracts do not contain escalator clauses for inflation and short-term avoided costs continue to rise, the QF might be better off with an as available energy contract.

3. *The capacity factor of the technology can make a dramatic difference both in the amount of electricity produced and in the ability to qualify for capacity credits*. Once again, Montana's formula for calculating capacity credits is unusual but not unique. That formula allows the QF to receive partial credits based on the ratio of its own capacity factor to that of a baseload coal plant (85 percent). In most states the QF would have to meet a minimum capacity factor (typically 65 to 80 percent). Partial capacity payments are not available.

Remember, the utility may require a customer that selects the net billing contract to come under a different rate schedule than one that buys all its electricity from the utility. This rate schedule may include back-up or standby charges but only if such a rate already exists for that class. The utility cannot impose higher back-up rates for QFs unless it can prove that QFs impose higher system costs. The burden of proof rests with the utility. To prove its claim it must use system cost data. The FERC prohibits the utility from assuming that any outage of the QF facility occurs coincident with the system peak demand. In other words, the utility cannot assume the QF will need electricity at precisely the time the system is at its peak. If it could, it could justify a high back-up charge under the theory that it must have an additional power plant standing by for that time. But if the QF needs electricity when the system has excess capacity, back-up rates should reflect only regular energy charges.

Remember that in bargaining with the utility you are going to have to make trade-offs. In states that establish high buyback rates, you will have more room to maneuver. For example, Dan Darrow, owner of a 10-kw hydro system on a small farm in South Newfane, Vermont, sent a letter in fall of 1981 to the Public Service Board of Vermont and received a copy of the PURPA rates. PURPA rates at the time were 9¢ peak, 6¢ off-peak and 7.8¢ for a 24-hour average. He then wrote to the local co-op, Vermont Electric Co-op, asking them how much they'd give him including in the letter the specs on his machine. Vermont Electric wrote back saying it didn't agree with the PURPA rates, but would offer him 12¢ peak and 3¢ off-peak, with an average of about 5¢ per kilowatt-hour.

Darrow didn't insist on the PURPA rate. Vermont Electric acknowledged that its marginal costs would probably rise sharply, reaching an estimated 18¢ kilowatt-hour by 1986. They were willing to write such projections into a contract. At the time Darrow was interviewed, the final approval on his interconnection equipment and rate was still pending. He knows he could win in a fight over the PURPA rates but would rather wait to see what the utility will offer on interconnection equipment and future rates first.

Force Majeure and Interruption of Power

The QF on a long-term contract wants some guarantee that if its own deliveries are interrupted temporarily because of forces beyond its control it will not be penalized. The QF also wants certainty that the utility will exercise its right to refuse power purchases only at limited times and with sufficient notice.

The first provision is called Force Majeure. The following is a typical paragraph in a contract:

> *As used in this agreement, "Force Majeure" means unforeseeable causes beyond the reasonable control of and without the fault or negligence of the party claiming Force Majeure. It shall*

include failure or interruption of services due to causes beyond its control, sabotage, strikes, acts of God, drought or accidents not reasonably foreseeable, appropriation or diversion of electricity by rule or order of any governmental authority having jurisdiction thereof, and failure to deliver electricity during such time as it may be obliged to temporarily discontinue delivering the electricity on account of system operating conditions and in the case the service is so interrupted.[7]

Usually utilities require the insertion of the following sentence into a contract: "Force Majeure shall not include the nonavailability of fuel or other motive force to operate Seller's Facility." Utilities argue that without such a provision the wind turbine or hydro operator would be exempted from any capacity penalties if the wind didn't blow or the water flow dropped. The seller, on the other hand, wants some protection against low water flow or low winds and if exempted from Force Majeure status, then it should be specifically inserted into the contract. For example, the seller might not sell electricity during the summer months to a winter-peaking utility.

The QF might also propose a paragraph that allows it to shut down the facility for scheduled maintenance periods. Usually such a paragraph must specify the maximum number of days each calendar period that this can occur (e.g., 30 days). Any payments for capacity shall be conditioned upon scheduling the maintenance of the facility at a time acceptable to the buyer and to the regional power pool.

Although not directly relevant, it might be of interest to note the clause one utility inserted in a contract to a 15-kw wind developer about the utility's responsibility for reliable electric service: New York State Electric and Gas Corporation

will endeavor to provide continuous and reliable service hereunder, but if it is prevented from doing so due to circumstances beyond its reasonable control, or through the ordinary negligence of its representatives, agents, or employees, it shall not be liable therefore.[8]

PURPA allows utilities the right to interrupt power purchases when making such purchases would actually increase their costs. Utilities often try to widen their authority to exercise this right. The legislation as defined by the FERC regulations does not permit the utility to interrupt power just because it would be cheaper for it to buy from someplace else. Most regulatory commissions recognize the right of utilities to interrupt purchases under light load conditions when expensive baseload plants, especially nuclear, are operating at very low capacity. Under such circumstances, purchasing QF power might drop the load carried by the plant to such a low level that the plant has to be shut down. Starting up the plant again would cost more money than running it at this light load. Therefore the QF in this instance imposes negative avoided costs on the system.

The QF should propose a clause for the contract that requires sufficient advance notification of such purchase interruptions and limits these interruptions to a specific maximum time period. PURPA regulations do require sufficient advance notification, so it is the QF's right to have such a clause in the contract. As discussed in an earlier chapter, PG&E limits such periods of nonpurchase to not more than 7 percent of the year.

The QF could try to insert a "take or pay" provision in the contract. This provision might say that "in the event the Seller is prevented from delivering energy because Buyer is unable or unwilling to accept energy or is precluded by the regional power pool or any successor organization from doing so, Buyer shall nevertheless be obligated to make payment." These provisions are common between all-requirements utilities and their bulk suppliers. Utilities that buy a share of a proposed power plant commit themselves to purchase a portion of its electricity even if they find they do not need it at some later time.

Billing and Payment

A minor point, but one that may fulfill some QF owner's fantasy, is to insert a paragraph that requires the utility to pay for electricity within a certain time period. Late payments will be assessed a penalty and/or an interest charge at the current prime rate.

Liability Insurance

The question of how much insurance a QF should have, and what type, is not yet a settled issue. All utilities will insert an indemnity clause in the contract. The following is a typical clause in a contract between a 15-kw wind turbine QF and the New York State Electric and Gas Corporation (NYSE&G):

> *Customer agrees to indemnify and hold harmless NYSE&G, its representatives, agent and employees, from and against any costs, damages, liens, suits, claims, demands and expenses of any kind for any injury or death to any person or any damage to any property caused by or arising from any act of Customer or Customer's representatives, agents of employees in connection with the construction, installation, interconnection, operation, maintenance, disconnec-*

tion or disassembly of any part or the whole of Customer's system, including any change, modification or addition thereto.[9]

Such a clause is acceptable, but only if the seller has the same indemnity protection from the utility. *Indemnity should run from each party to the other for all harm resulting from the establishment, maintenance and operation of the respective equipment of each.*

Most investor-owned utilities do not require specific amounts of insurance coverage. For those that do, the amounts vary, for example, from general liability insurance of $100,000 by Niagara Mohawk Power Corporation in New York to PP&L's requirements in Oregon of $1 million liability (as per their contract) "which limits may be required to be increased by Pacific's giving Seller two years' notice. Such increase shall not exceed fifteen percent (15%) per year."

PP&L also requires property damage insurance, although most utilities do not. Based on the recommendation of the National Rural Electric Cooperative Association (NRECA), most rural electric cooperatives require $1 million in liability insurance. Ken Hach, the Iowa-based supplier of wind turbines who also negotiates PURPA contracts for his clients, believes the QF owner can have this requirement lowered if he or she fights it. Paul Gipe, who advises wind turbine owners in Pennsylvania, points out that NRECA's recommendation of $1 million is three times the normal $300,000 auto liability insurance required by most states. That implies that a small stationary wind generator can do three times more damage than the average driver.

Denver Roseburg, owner of a 10-kw Jacobs interconnected with the McLean Rural Electric Cooperative in Underwood, North Dakota, refused to buy $1 million in blanket liability insurance because it would have cost him $300 per month. He ended up having to swear in an affidavit that he has assets in excess of $1 million.

Co-ops argue that this kind of insurance is actually cheap, only an additional $25 to $50 per year, especially if the homeowner already has business insurance with the same company. Another slant comes from the Gundermeier family, which owns a small, 10-kw wind system in Storm Lake, Iowa, that's interconnected with the Buena Vista Cooperative. Their wind turbine vendor, Hach, told them they could successfully appeal the $1 million liability provision to the Iowa Commerce Commission, but they did not do this. Instead, they paid extra for insurance with the Farm Bureau, their original homeowner policy carrier. Later they switched to State Farm and got a lower overall premium for the entire policy, including the liability insurance. The point is that QF owners should shop around for insurance carriers.

Nonutility Status of QFs

A QF owner may want a paragraph inserted into the contract that reaffirms the nonutility nature of the seller and in most states reinforces the lack of jurisdiction of public utility commissions over the seller's facility. Investors and lenders may insist upon such a provision as protection against governmental intervention. A typical paragraph would read as follows:

> *Nothing in this Agreement shall be construed to create any duty to, any standard of care with reference to, or any liability to any person not a party to this Agreement. No undertaking by one party to the other under any provision of this Agreement shall constitute the dedication of that party's system or any portion thereof to the other party or to the public, nor affect the status of Buyer as an independent public utility corporation, or Seller as an independent individual or entity.*[10]

Resolution of Disputes

The QF can appeal to the regulatory commission before a contract is signed. Disputes that occur after the contract is in effect might best, from the QF's perspective, be submitted to binding arbitration by an independent arbitrator mutually agreed upon by the parties. The arbitrator should be empowered to make binding final awards including monetary damages and specific performance.

Binding arbitration is a relatively quick way to settle disputes. This can be important if during the dispute the utility is purchasing none of the QF's power. Such an interruption could easily bankrupt the QF if allowed to continue too long.

Contract Modification and Termination

A short-term contract usually runs for a year. Either party can give the other relatively brief notice for termination or contract modification. At least one New York State utility has offered a one-year contract to a QF that could be terminated "by either party upon 48 hours prior written notice to the other." On the other hand, long-term contracts longer than one year often contain termination or modification provisions that are very long. In some cases the QF could not modify or terminate the contract in less than two years. Thus QF owners who found that their generators operated at a higher than predicted capacity factor, or who wanted to switch to a time-of-day sales arrangement or from net billing to simultaneous purchase and sale, would find themselves stopped from doing so for a significant time period. QF owners must make the decision as to whether they want to give themselves sufficient leeway to modify the contract, knowing that the utility can do the same, or whether they feel the contract is sufficiently favorable to tie the provisions to a long advance notice provision for modification or termination.

Interconnection Requirements

The area of interconnection requirements is the thorniest of all that the QF owner will encounter. (See chapter 4 for a discussion of the technical aspects of interconnection.) The FERC gives no guidance on interconnection standards. However, it did say that "interconnection costs of a facility which is already interconnected with the utility for purposes of sales are limited to any additional expenses incurred by the utility to permit purchases."[11] The vast majority of regulatory commissions have been reluctant to become involved in this area, leaving interconnection standards to the individual utilities.

This is one question that is still very much in a legal limbo. The Federal Power Act specifically states that utilities do not have to interconnect if doing so would undermine the reliability or safety of the grid. Until PURPA was enacted anyone wanting to interconnect had to apply to the FERC. The utility could deny the application, and the decision by the FERC would be based on the individual merits of that case. In attempting to follow the spirit of PURPA, the FERC cut through the red tape process. It basically decided that QFs would not undermine the reliability or safety of the grid system and required utilities to interconnect with them. Utilities would prefer to have the option of requiring a case-by-case evaluation before the FERC. That type of evaluation would add significantly to the time and expense of interconnection and, if required of very small QFs, would simply negate the intent of PURPA.

In any event, most utilities are treating each QF on a case-by-case basis. All states require the utility actually to do the installation or to oversee it. All interconnection arrangements must meet with the approval of utilities. No QF is permitted to come on-line without the utility's inspection and approval of the interconnection equipment.

Those utilities that have developed standards often differentiate among sizes of QFs. This is as true within one state as it is between states. PG&E has interconnection requirements for QFs of up to 20 kw, for those 20 kw to 100 kw, and for those over 100 kw. Southern California Edison has interconnection requirements for those under and over 200 kw. In New York State, Central Hudson Gas and Electric

Corporation has a general interconnection standard only for wind turbines of under 15 kw. All the rest must be treated on a case-by-case basis. Niagara Mohawk Power Corporation limits its general standards to QFs of under 50 kw. NYSE&G has separate requirements for systems greater than 15 kw and less than 15 kw. Rochester Gas and Electric Corporation (RG&E) requirements apply to all systems of 80 Mw or less. Orange and Rockland Utilities, Inc., has general standards only for those under 10 kw. RG&E doesn't allow QFs with greater than 45 kilovolt-amperes (kva) to connect to its low voltage lines. Consolidated Edison (Con Ed) doesn't even allow QFs with greater than 10-kw capacity to connect to its low voltage lines.

Sometimes utilities will use the interconnection standard to discourage QFs. That may be difficult to prove, but most utility engineers admit they are extremely conservative about interconnection standards. They dream up any combination of circumstances and faults and then require redundant systems to protect against such possibilities. Pennsylvania Power and Light interconnection standards are of this type.

Ed Zimmerman, president of E-Z Manufacturing Company, installed a 125-kw gasifier induction generation system in a factory that produces charcoal as well as sawmill equipment. Pennsylvania Power and Light pays him an attractive 6¢ a kilowatt-hour buyback rate. According to Zimmerman, it took a full year after he first tried to go on-line to complete negotiations about interconnection hardware requirements. Pennsylvania Power and Light requires over/under voltage/frequency/current, plus phase unbalance and individual phase monitoring. Zimmerman had to include a mechanical relay on top of an electronic relay for each function. An electronic voltage relay costs $150, and a mechanical relay costs from $500 to $600. Plus Pennsylvania Power and Light forced him to pay $30,000 to replace the hydraulic overcurrent relays (two) then serving his step-down transformer with electronics in order to guarantee that the company's circuit breaker would not reclose in the event of fault conditions on that line that continued over a longer-than-normal time frame. This prevents the theoretical possibility that Pennsylvania Power and Light capacitors, installed for voltage compensation "at the end of the line," would allow the induction generator to continue operating, a circumstance which Zimmerman protests is "impossible, not only because line voltage would collapse but even if it happened to end up in that range of my over/under voltage relays, my frequency relays would trip the breaker and shut down." He fought bitterly against this additional cost but finally acquiesced because he was losing money by not being able to interconnect. In his case the total interconnection cost was $60,000, more than a third of the total cost of the installation.

Ted Keck, owner of a 70-kw hydro site in Pillow, Pennsylvania, says that Pennsylvania Power and Light required him to install over/under voltage relays on each of his three phases, plus over/under frequency on one phase for a total of 8 relays costing from $300 to $600 each. Pennsylvania Power and Light requires utility-grade relays, which are more expensive than industrial-grade. Keck at first thought this was excessive but now allows it is "probably for my own good" and notes that utility-grade relays last for 40 years, almost ten times longer than industrial-grade. Pennsylvania Power and Light insisted that he buy two transformers from them for $500 each, which he probably would not have used. He expects that the total, installed cost of interconnection equipment will be $4,000 to $5,000.

The easiest interconnection we've come across took place in Connecticut. Connecticut Light and Power (CL&P) connected to a 12-kw hydro site owned by a firm of solar architects and a 60-kw site owned by a factory making hi-tech plastic laminates. Bill Johnson, president of Newfound Power Company in Rhode Island (a firm that publishes *Currents,* a hydro quarterly, and develops sites) did the negotiations. At the 12-kw site he's using only a "magnetic starter," made by Alan Bradley Company. He describes the device as a "heavy-duty electromagnetic industrial relay." It appears to be a circuit breaker with a built-in overcurrent relay. No other relaying or dedicated transformer was necessary. This case also illustrates the need to discuss the electrical equipment intelligently.

CL&P originally wanted three phase with over/under voltage relays simultaneous with phase balance monitoring. However, they were persuaded to copy the requirements of Narragansett Electric, another utility with which Johnson was negotiating. It took Johnson one month to work out the interconnection arrangements with Narragansett and two months with CL&P.

One would expect that the rate of innovation in the microprocessor industry would soon bring into the marketplace "black box" devices that perform the protection functions more cheaply. That is already happening. The Beckwith Electric Company of Largo, Florida, has developed a solid-state device that handles all eight relay functions for a cost under $2,000. Pennsylvania Power and Light is testing the box and hopes to designate it utility grade for use in its program.

The advances in interconnection equipment may be coming along fast but some utilities impose standards that make it difficult to integrate these advances rapidly. For example, Long Island Lighting Company (LILCO) and Orange and Rockland Utilities require Underwriters'

Laboratories (UL) approval for all equipment. The problem with that requirement is that UL approval is based on a certain amount of operating experience. Thus equipment like Beckwith's would not gain approval for some time. UL approval as of mid-1982 restricts one's search to General Electric and Westinghouse equipment, built for utility companies or very large industrial cogenerators.

Zimmerman raises an oft-repeated complaint by QFs. Utility engineers are not used to induction generators. So they design standards for synchronous generators and refuse to change them. Induction generators, as the previous chapter discussed, can operate only when the outside line is energized, because they need to be excited by grid electricity (unless a bank of capacitors is located nearby). Moreover, they are in phase with the grid for this same reason. Synchronous generators can operate in isolation with the grid and, therefore, need a great deal of additional synchronizing equipment and relay protection.

One sticky problem is that the utility and the QF owner might agree on specific wiring diagrams but the local building inspectors might prohibit them. Some utilities require that electrical wiring adhere to national codes, others to state codes and still others leave that open. Thus the QF must work closely with the local electrical code official as well as the utility engineer and the QF's engineers.

Many utilities require QFs to supply either single or three-phase current, while others allow both. In New York State, for example, NYSE&G allows single or three-phase. RG&E allows single or three-phase if the generator capacity is less than 48 kilowatt-amperes (kva). If larger than that, it must be three-phase. Central Hudson Gas and Electric requires single-phase current. Niagara Mohawk has no specifications. LILCO requires three-phase circuits.

The vast majority of utilities provide general requirements about the quality of electricity supplied by the QF. Some are quite specific. Central Hudson Gas and Electric requires an oscillographic print showing the wave shape of the voltage or current supplied to the network systems at the interconnection output terminals. RG&E not only requires a similar print but wants two, under "light load and full load conditions." The print must include current magnitude, harmonic content, power output, and estimated or measured power factor of generator load.

Some utilities have no harmonic standards, although most do. Niagara Mohawk requires total harmonic distortion (THD) of not more than 5 percent, but adds that in certain cases a more stringent limitation may apply. Central Hudson Gas and Electric requires a THD of less than 10 percent of the fundamental voltage measured at the point of delivery. NYSE&G allows a maximum distortion of 3 percent for any single frequency or 5 percent THD.

It is unclear what recourse QFs have to onerous interconnection standards. The FERC regulations make clear that these standards should not be used to discourage QFs. Also, QFs can appeal to the regulatory commission if they feel that a double standard is being used. Thus, for example, the Potomac Electric Power Commission (PEPCO) argued before the Washington, D.C., Public Service Commission that it should not be required to interconnect QFs of greater than 300 kw to its low voltage lines because of the burden it would place on the transformer and distribution lines. The electrical engineer testifying for QFs countered that there were several customers with loads of more than 300 kw already on the line and that the existing transformer had several megawatts of capacity. The customer load forces that amount of electricity to be supplied through the line and transformer. Therefore PEPCO should not discriminate against a QF that imposed similar demands on the existing distribution system.

Similarly, utilities that have no standard for harmonic distortion for their nonproducing customers should arguably not have one for QFs. Steve Strong, of Solar Design Associates in Lincoln, Massachusetts, has designed two residential photovoltaic installations in Massachusetts and New Mexico. He comments, "If you measured the waveform on any utility distribution feeder, you'd find lots of 'hash'—bad power factor, overvoltage and harmonic distortion caused by interference by neighboring loads on the line" especially during full-load periods.

Angelo Skalafuris, vice-president of Re-Energy Systems, which sells small cogeneration systems, goes a step further. The waveform coming out of a central utility plant may be almost perfect. But even an infinitesimal imperfection is magnified when the signal passes through a transformer. The current will pass through two and possibly three transformers on the way to its final destination. Each time, the slightest out-of-phase tendency will be vastly exaggerated. Skalafuris has monitored a 100-kw gas turbine cogeneration system at a hotel in Philadelphia and found that the meter was actually running faster when using the utility's electricity. A significant reason in Skalafuris' estimation was the "dirtier" electricity coming in from outside.

If utilities already have standards for harmonics or for independent power production, it is more difficult for QFs to argue for exemption even though the existing standards were designed for the utility itself or for large industrial cogenerators. Numerous studies have been done to indicate that small QFs, especially those of under 100 kw, put no burden on overall system reliability even at high penetration levels and that small numbers of QFs with capacities of less than 20 kw need not have high-quality protective devices.

Utilities often require a dedicated or isolation transformer. Yet this is not always the case. Steve Strong notes that neither Boston Edison nor Public Service Company of New Mexico required a dedicated transformer for the 7.3-kw and 3-kw respective photovoltaic arrays.

Paying Interconnection Costs

The cost of interconnecting with the grid system can be high. Several QFs interviewed indicated payments that were up to one-third their total cost of installation. Most regulatory commissions allow utilities to finance such costs. Utilities, at their discretion, can allow the QF to repay the costs over several months or years. Several states require utilities to provide for monthly payments to amortize the interconnection costs. In such states the repayment period is often based on the term of the contract. It might be a percentage of the term of the contract, for example. Even in these states, however, the utility need not amortize the interconnection costs if the QF is not credit worthy. In cases where the utility extends the QF credit, it charges interest, usually at the prime rate.

Most utilities require full payment of interconnection costs up front, prior to the commencement of service. In some cases, the interconnection equipment is owned by the customer if paid for by the customer. In most instances, it is owned by the company even if paid for by the customer.

Some utilities, usually those that try to impose a very high meter charge (e.g., $50 per month) try to impose additional interconnection expenses. Con Ed, for example, proposed to the New York State Public Service Commission that, over and above its full cost reimbursement for interconnection costs, "the Customer shall pay an annual charge of 9 percent of the capital costs of interconnection, including the costs of distribution system reinforcements, to cover property taxes and operation and maintenance expenses." The QF can and should require the utility to justify this additional expense. Such justification would include submission of its past property tax payments as well as its *additional* operation and maintenance expenses for the QF interconnection equipment.

The field of interconnections is probably among the most rapidly evolving of all those the QF will encounter. New technologies that perform protective functions more cheaply and reliably than existing technologies will be entering the marketplace. As greater numbers of

QFs come on-line, their impact on the secondary distribution system will change. One might expect that interconnection standards would evolve for different-size technologies and for different types of grid systems (e.g., radial or network) and for different types of generators (e.g., induction or synchronous). To repeat the basic advice of this chapter: *Those who are operating or want to operate under PURPA must establish city-wide, statewide and national associations to deal with these issues.*

So far the actual types of equipment and systems available to the homeowner or small business person desiring to enter the field of small power production have yet to discussed. The following chapter covers four basic systems: wind turbines, hydroelectric plants, photovoltaic systems and cogeneration plants.