

[a]--Qualifying Facilities.

[b]--Avoided Costs.

[c]--Cogeneration.

[d]--Small Power Producers.

[2]--Independent Power Producers.

[a]--Federal Power Act Pricing Approval.

[b]--Public Utility Holding Company Act.

[c]--State Public Utility Laws.


[a]--Electric Wholesale Generators.

[b]--Transmission.

§ 18.02. Contract Types and Philosophies.

[1]--Standard Offer Contracts.

[a]--What Are They?

[b]--Advantages for the Purchasing Utility.

[2]--Disadvantages.

[3]--Negotiated Contracts.

[a]--What Are They?

[b]--Advantages.
[c]--Disadvantages.

[4]--Competitive Bid (RFP Contracts).

[a]--What Are They?

[b]--Advantages.

[c]--Disadvantages.

[5]--Dispatchable Contracts.

[a]--In General.

[b]--Features.

[c]--Credit Ratings.

§ 18.03. Risk Shifting in Dispatchable Power Contracts.

[1]--What Risks Are Shifted?

[2]--How Risk Is Shifted to NUG Operator.

[a]--Cost Overruns.

[b]--Operating Costs (Other than Fuel).

[c]--Environmental Regulations.

[d]--Fuel Availability.

[e]--Demand for Energy.

[f]--Delay/Late Completion.

[g]--Failure of Project/Cancellation.

[h]--Operating Liability.

[3]--What Risks Remain With The Utility?

[a]--Demand for Capacity.

[b]--Market Price of Fuel.

[c]--Breach of Contract by Operator.

[4]--Utility Protection Where It Has Risk.

[a]--Need for Capacity.

[b]--Market Price of Fuel.

[c]--Operator Breach.

[d]--Insurance.

[1]--Capacity Payment.

[2]--Fixed Operating and Maintenance Costs.

[3]--Variable Operating and Maintenance Costs.

[4]--Energy/Fuel Costs.

[a]--Fixed Escalators.

[b]--Fuel Market Indexing.

[c]--Utility Fuel Cost Indexing.

§ 18.05. Conclusion.

6.76


In the mid-1980's, the emergence of a new energy industry component began to change the electric utility industry. That new component has been called "cogeneration," "independent power," "private power," and, more recently, "non-utility generation." None of these terms adequately describes the entirety of this new business. Because of this new business, large segments of the new capacity now being constructed to serve electric customers in this country will be neither owned nor operated by traditional regulated utilities with rates of return governed by a utility regulatory commission. That is why "non-utility generator" (NUG) is the best name for this component, despite the fact that some NUGs are considered "utilities."(1)

While this component did not become nationally significant until the mid-1980's, it was born, or at least conceived, in the late-1970's. It is one of the legacies of the Carter Administration. When James Earl Carter was elected President of the United States, the country was still feeling the effects of the Arab Oil Embargo of 1973. In response to President Carter's recommendation that Congress develop a national energy strategy, Congress passed the National Energy Conservation Policy Act of 1978.(2) This Act included something known as the Public Utility Regulatory Policies Act of 1978(3) (PURPA).

[a]--Qualifying Facilities.

PURPA created a class of power generation facilities with rights to sell power to regulated utility companies. It amended certain sections of the Federal Power Act,(4) removing, among other things, many statutory barriers to entry into the power market.

Title II of PURPA required non-regulated utilities (such as municipal utilities) and state regulatory commissions to consider several standards, including basing rates on cost of service, eliminating declining block rates, establishing time-of-day rates, considering seasonally differentiated rates, and evaluating interruptible rates and load management techniques.(5) Title II also described this new class of electric power generation facilities and the characteristics and standards for facilities to "qualify" for certain benefits. Chief among these benefits is the right to force utilities to purchase the facilities' electric output.(6)
It took several years for the number of "qualifying facilities" (QFs) to become significant. QFs have now forever changed the utility business in America.

PURPA obligates utilities to purchase electricity from these facilities, but what criteria must they meet to qualify? Under PURPA, there are two basic categories of QFs, "cogeneration" and "small power production." "Cogeneration" is a term that some say was coined by President Carter himself. It is used to describe the useful production of two forms of energy from the burning of fuel in a single plant. To qualify, at least five percent of the total energy output of any cogeneration facility must be useful thermal energy.\(^{(7)}\)

Small Power Production (SPPs) generally are fueled by waste, renewables, wind, geothermal energy, or water (hydroelectric).\(^{(8)}\) Originally SPPs were limited to 80 megawats (MW). Now the size restrictions have been removed, at least temporarily, for certain fuel types.\(^{(9)}\)

[b]--Avoided Costs.

The explosion of growth in non-utility generators can, in many ways, be traced to a phrase found in FERC's regulations implementing PURPA. That phrase is "avoided cost."\(^{(10)}\) PURPA obligates utilities to purchase from QFs at rates that do not exceed the "incremental cost" of electricity the utility can generate itself or purchase from another source.\(^{(11)}\) FERC's implementing regulations renamed this concept "avoided cost." Unlike PURPA's mandate that the rate merely not exceed the incremental costs, FERC established this ceiling as a floor as well. This became known as "full avoided costs." Electric utilities challenged this regulation, but FERC's position was upheld by the United States Supreme Court.\(^{(12)}\)

Although PURPA only addressed the purchase of "electricity," FERC obligated the purchase of both "energy" and "capacity."\(^{(13)}\) Energy is basically the kilowatt hours (HWh) delivered to the utility; capacity is the kilowatts of generating capability available to the utility. Avoided energy costs for the utility are basically the cost of fuel and variable operations and maintenance expenses that a utility would have incurred to generate the kilowatt hours delivered. Avoided capacity costs are the fixed costs the utility otherwise would have incurred to construct and maintain a facility capable of generating the amount of kilowatts available from the QF.

[c]--Cogeneration.

At first, cogeneration projects were fairly small and, frequently, were internal parts of an industrial facility. Today, there are large "third party" cogenerators who have located near industrial "host" facilities to sell these hosts steam for use in their industrial processes. Hence the phrase "steam host." A number of QFs in the early 1980's were associated with paper mills, many of whom had generated power internally for years.

In the mid-1980's developers realized that "avoided cost" could create handsome profits for a cogeneration project. Heretofore, utilities had looked on cogeneration as more of a nuisance than anything else. Now, plants of utility size were being offered to utilities at "avoided cost."

This phenomenon -- individual QFs having a capacity of several hundred megawatts -- was almost certainly not anticipated by the original authors of PURPA or the FERC regulations. FERC regulations require the filing of "Standard Rates for Purchasers" by each electric utility.\(^{(14)}\) These standard rates must be applied to all QFs with a design capacity of 100 kilowatts or less. A QF of 100 megawatts, which is fairly common now, is one thousand times as large as the maximum size for these standard rates. The regulations permit the standard rates to be applicable to larger facilities.\(^{(15)}\) In Virginia, the standard rates had been established for Virginia Power at 3 MW for the last several years. Today, Virginia Power is seeking to reduce applicability to 100 KW again. Until the advent of competitive bidding, rates for projects larger than the maximum for
standard rates were negotiated, arbitrated, or litigated.\(^{(16)}\)

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### [d]--Small Power Producers.

Small power producers were originally size limited. As QFs, utilities are obligated to purchase the SPPs' output. SPPs include municipally owned trash-to-energy facilities, landfill gas-fired, coal waste fired, hydro-electric, wind powered, peat fired, geothermal, or other non-traditional energy technologies. While the size limits have been largely eliminated, at least temporarily, the technology of a SPP often provides inherent size limits. An SPP can only be as large as its fuel source. Water sources limit the size of hydro-electric facilities; coal waste fired facilities generally are limited to locally available fuel because transportation of gob is cost prohibitive.

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### [2]--Independent Power Producers.

The size limits on SPPs and the need for a steam host for cogenerators made many large projects unworkable as QFs. Developers in the late 1980's realized that, in many instances, a large project could not be developed as a QF. A new kind of facility was proposed, the "independent power producer" (IPP).\(^{(17)}\) Utilities have no federal obligation to purchase from a non-qualifying facility. Yet, in many ways, PURPA was the indirect force behind purchases from IPPs despite the fact that they were not qualifying facilities under the Act.

Recall that PURPA obligates utilities to purchase electricity from a QF at the "incremental cost" the utility would incur either to generate that electricity itself or to purchase it from another source. If utilities are obligated to purchase from QFs, but an IPP offers to sell similar capacity for a lower price, the PURPA obligation to the QF forces the utility to "purchase the electricity from another source," i.e., the IPP.

Other PURPA benefits, such as exemption from the Public Utility Holding Company Act of 1937,\(^{(18)}\) certain provisions of the Federal Power Act, and regulation by state utility commissions are also not available to the IPP.\(^{(19)}\)

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### [a]--Federal Power Act Pricing Approval.

FERC regulates wholesale sales of electricity in interstate commerce. While there are some exceptions in Texas, it is generally true that all wholesale sales of electric power in the United States are in interstate commerce and, therefore, subject to FERC. Rates in a contract with an IPP (or a regulated traditional utility) must be approved by FERC as "just and reasonable."\(^{(20)}\) FERC has found rates resulting from competitive bidding to be "just and reasonable" on the theory that they are "market based."\(^{(21)}\) FERC has also found negotiated rates that approximated "avoided costs" similar to PURPA to be "just and reasonable."\(^{(22)}\)

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### [b]--Public Utility Holding Company Act.

The Public Utility Holding Company Act of 1935\(^{(23)}\) (PUHCA) was originally enacted to insure that multistate utilities did not abuse their multi-jurisdictional existence and create structures that prevented effective regulation by any individual jurisdiction. Obviously, an IPP was not anticipated by the drafters of PUHCA 60 years ago. However, if an IPP were formed as a subsidiary of another company, the parent was flirting with very burdensome regulations under PUHCA. The handful of IPPs constructed prior to the passage of the Energy Policy Act of 1992 went through structuring nightmares and SEC approvals to avoid regulation under PUHCA. Thankfully, such gyrations are no longer required because of the Energy Policy Act of 1992.\(^{(24)}\)
In many states, an IPP is a wholesale utility under state law, subject to degrees of regulation that vary from state to state. For example, in Virginia, regulation has focused primarily, though not exclusively, on pre-construction approval and certification. For future IPPs, the Virginia State Corporation Commission has issued a document entitled "Information Requirements in Support of Petitions for Independent Power Facilities," setting forth application procedures for approvals and certifications. These requirements are, facially, for pre-construction review only.

In the *Doswell* case, the Virginia Commission cited two state statutory provisions in support of its power to assert jurisdiction over the issuance of a certificate. Each expressly applies to pre-construction or pre-acquisition analysis by the Virginia Commission. The first provides that no public utility shall "construct, enlarge, or acquire by lease or otherwise any facility for use in public utility service" without first obtaining a certificate from the Virginia Commission. A certificate will only be issued if the public convenience and necessity so requires.

Some of the other statutory provisions in Virginia that would apply to a non-QF include the so-called "Utility Transfers Act." Under this act, there can be no disposition or acquisition of any utility assets, directly or indirectly, without the Virginia Commission's consent. In other words, if you are not a QF, you can not sell direct or indirect ownership in a generating plant without the Commission's permission. In addition, there are numerous other provisions requiring reports, operating plans and forecasts, Virginia Commission investigations, review of procurement practices, and the like that, arguably, are applicable to a wholesale utility.

In its decision granting a certificate of public convenience to Doswell Limited Partnership, the Virginia Commission set forth specific reporting requirements for an operating non-QF:

Doswell shall comply with any and all reporting requirements directed by the Commission related to the construction operation and technical aspects of the subject project, and shall not sell or transfer any of its utility assets or the certificate of public convenience and necessity without first seeking Commission approval; . . . the certificate holder together with any or all general partners or any partnership holding an interest in the certificate to the extent provided by law, their successors and assigns, shall be subject to all the regular provisions of Title 56 of the Virginia Code which are not preempted by federal law; . . . Doswell shall file with the Clerk of the Commission information reports and contracts as follows:

(a) the issuance of stock and stock certificates or other evidences of the interest or ownership, and bonds, notes, and other evidences of indebtedness, and the creation of liens on any of the certificate hold its property within Virginia as described in Virginia Code § 56-57 and the limits thereto shall be accompanied by the filing of a statement setting forth the amount, character, terms, and purposes of stocks, stock certificates, or other evidences of interest or ownership, and bonds, notes, and other evidences of indebtedness issued or assumed;

(b) copies of all contracts or arrangements and amendments thereto described in Virginia Code § 56-77;

(c) three copies of any and all future contracts or arrangements and amendments thereto executed by and between Doswell and the utility;

(d) any and all information, reports, etc. related to its operations as requested by the Commission's divisions of energy regulation, economic research and development, and accounting and finance;

(e) the foregoing following requirements shall be binding upon all successors and assigns of Doswell.

The Energy Policy Act of 1992\(^{(30)}\) was passed in October of 1992. It provided needed reform of PUHCA in development of non-utility generation. Specifically, the Energy Policy Act addresses two areas significant to the non-utility generation industry, (1) creation of the new status of "electric wholesale generators" (EWGS) and (2) transmission.

[a]-Electric Wholesale Generators.

EWGS under the Energy Policy Act will enjoy many of the exemptions available to QFs under PURPA. For example, EWGs will be exempt from Securities and Exchange Commission regulation under PUHCA. An EWG may or may not be a QF. At first, many believed that EWGs would replace IPPs but now it is generally agreed that there are benefits for a QF to also be an EWG at the same time.

[b]-Transmission.

The Energy Policy Act amends Section 211 of the Federal Power Act\(^{(31)}\) to provide that any electric utility, federal power marketing agency, or any other person generating electric energy for sale or resale may apply to FERC for an order requiring a transmitting utility to provide transmission services. This may lead to true open access to electricity transmission in this country and, ultimately, to a restructuring of the electric utility industry along the lines of the gas and telecommunications industries.

§ 18.02. Contract Types and Philosophies.

Contracting for electric power has evolved a great deal during the last 10 years. Prior to the mid-1980's, sales of electric capacity at wholesale generally were between traditional regulated utilities only. The contracts were short and frequently amounted to a gentlemen's agreement. Pricing outside of Texas was subject to FERC approval of the rates as just and reasonable under the Federal Power Act. Generally, pricing was dependent on the length of the contract. Long term capacity contracts with utilities tended to be more expensive, on an annual basis, than short term capacity.

The explosion of large QFs offering power to utilities under PURPA in the mid-1980's required a new system for organizing the purchases from these QFs. As with many trends in this country, the first large experiments began in California. When Sir Winston Churchill said "You can always count on the Americans to do the right thing . . . after they've tried everything else," he must have been thinking of Californians.

[1]-Standard Offer Contracts.

[a]-What Are They?

Standard offer contracts were established in many states in the early development under PURPA. Basically, a state regulatory commission and a utility would establish a rate for the purchase of energy and capacity from a QF over a certain time period. The utility was generally required to accept offers from all QFs that asked for the standard rate.\(^{(32)}\) In some states, the standard offer included terms and conditions of the proposed contract while in others it merely established the rates. Even today, in most states there is a "standard offer" for very small facilities. PURPA still requires a standard rate to be in place for facilities of 100 KW or less.\(^{(33)}\)

[b]-Advantages for the Purchasing Utility.
Less Work/Simple Implementation. The standard offer obviously has simplicity on its side. There is no negotiation of complex terms and conditions, there is no argument over the price, and there should be no argument over the recovery of the cost associated with purchasing this power from the utility's ratepayers. Standard offers are never created without the approval of the state regulatory commission. In effect, the state regulatory commission orders the utility to purchase power from facilities meeting the criteria at a given price. Recovery from the ratepayers should be automatic and unquestioned.

Generally Only Small Applications. Standard offers around the country are generally for small facilities. There have been exceptions, however, notably in California and New York. In New York, there are standard rates in effect for facilities up to 80 MW. Today, these facilities are the source of a great deal of controversy. Niagara Mohawk (NiMo) has too many QF megawatts available to it. The law obligates NiMo to continue to purchase power from QFs. For Niagara Mohawk, this presents a problem in that it has too much capacity available at what it describes as too high a price.\(^{34}\)

Industrial Steam Hosts Planning More Certain. To the extent that non-utility generation will be from "cogenerators," standard offers make planning by industrial facilities much more certain. Often industrial planning is done in advance of utility generation expansion planning. Without a standard offer there is no definite rate or purchaser for the power that will be produced by a cogeneration facility. This means that, when industrial facilities plan their expansions, they can not count on the revenue from electric power sales. Standard offers simplify the planning process for the industrial facilities.

[2]--Disadvantages.

Planning Is Virtually Impossible for the Utilities. While the standard offer has advantages for industrial facilities located within a utility's control area, the presence of the standard offer makes planning for the utility virtually impossible. If these rates have been high, the utility can be inundated with offers far beyond its expansion needs. The number of responses is totally unpredictable. In addition, planning is simplified when the utility plans to build a small number of large units rather than dealing with a large number of smaller facilities developed as QFs.

Megawatts Available Are Totally Unknown. The utility can never be sure what megawatts will actually be developed or how many offers it will receive pursuant to a standard offer. Yet, it has the obligation to meet the needs of its customers.

Pricing May Not Be Consistent with Avoided Costs. True avoided costs vary over time with changes in fuel prices, economic growth, load growth, consumer buying habits, and the weather. A decision as to avoided costs on a given day may be drastically inaccurate six months later, when fuel prices have changed erratically, or the country has entered a recession or a boom, or when a period of milder or more extreme weather occurs over a significant period of time. In addition, avoided costs for a small block of QF will likely not be the same as for a large block.

Standard Offer Contract May Not Be Dispatchable. Historically standard offer contracts have not been dispatchable. This is a disadvantage that could have been corrected. Non-dispatchable projects have been the source of tremendous difficulty in California, New York, and Virginia. For the most part today, large facilities being developed to sell power to utilities are fully dispatchable. Without dispatchability, a utility is required to take all power generated by the QF regardless of the utility's needs at a given time.

[3]--Negotiated Contracts.

[a]--What Are They?
Once they realized that standard offers caused significant problems for utilities, utility commission began issuing orders that limited the applicability of standard offers to a small class of facilities and required the utility to negotiate contracts with larger facilities.

[b]--Advantages.

The preparation of a formal request for proposal and evaluation of the food of bids that generally result for NUG contracts is eliminated by the negotiated contract approach. This system was initially "first come, first serve." It eventually developed into a system whereby the first party to agree would be the first one served. This gave tremendous leverage to the utility. The one who caves in first gets the prize.

This is an advantage for utilities only. Utilities frequently developed a rather free-wheeling style of negotiating with the parties that seemed most receptive to their heavy hands. QFs found themselves "knuckling under" to whatever demands the utilities could create. Eventually, this became so helter skelter that QF developers clambered for the attention of state utility commissions to bring order to the process. This played right into the hands of those utilities that favored competitive bidding.

[c]--Disadvantages.

A serious disadvantage is the frequently protracted litigation or arbitration than can occur before utility commission. There are examples across the country of litigation that has gone on for years between QF developers and utilities over whether the utility is obligated to purchase, what the price should be, and what the terms of the purchase should be.

Another disadvantage of negotiated contracts is the absence of a market test for project cost. Without any bids with which to compare the negotiated contract, the utility was at the mercy of the utility commission to second guess its contract in a subsequent rate proceeding. Unless the utility had other offers at the time or was considering the construction of similar capacity itself, there would be no contemporaneous benchmark for the utility commission to use to evaluate a negotiated price. This was risky for the utility.

Also, the resulting contracts frequently were not consistent with optimum utility generation expansion. When a utility is forced to negotiate with a QF, the length of the litigation can lead to a situation where, by the time the facility comes on-line, its pricing, capacity type, or both, may be inconsistent with the optimum generation expansion plan the utility would have used had it been left to expand the system itself. This is a function of changing circumstances, as well as of the fact that planning and assumptions used to create a forecasted avoided cost are virtually correct.

If a utility must negotiate with all comers, true integrated resource planning cannot be implemented properly because the utility loses control over the expansion of the system. The pricing in these negotiated contracts generally has been a function of utility forecasts of fuel cost, construction costs, and customer demand. Forecasts of customer demand are partially based on predictions of economic growth and weather. Frequently these projections involve 20 or 30 year time frames. Such projections can not ever be correct.

[4]--Competitive Bid (RFP Contracts).

[a]--What Are They?

Once utilities and utility commissions realized that the standard offer lead to too many proposals of excess capacity and that the "negotiations with all comers" approach did not result in optimum system expansion, utilities and utility commissions alike realized that competitive bidding on a periodic basis allowed for the best expansion system for non-utility generation. Rather than being done helter skelter on a project by project basis, competitive bidding allows the utility to lump together all expansion alternatives, including
those proposed by non-utility generators and the utility's own expansion candidates, for a simultaneous
evaluation of an optimum expansion plan, a plan that could include utility and non-utility units.

Generally, bids are evaluated by utilities based upon the lowest total system cost to operate its entire system
over a given period of time with the various expansion plans that could provide the needed capacity over
that period, including both NUGs and utility units, if applicable.

[b]--Advantages.

Competitive bidding provides a market test for project costs. This is an advantage for ratepayers, utilities,
utility commissions, and FERC. With competitive bidding, there are contemporaneous alternatives for the
supply of capacity. It should be quite easy to determine whether the utility has made a good deal or a bad
one.

Planning is done as a block. Periodic competitive bidding allows a utility to make the best choices for
expansion of its system on a block basis rather than with individual projects. This fits with integrated
resource planning very well. Because the evaluation is not on a single project basis, but rather on an overall
expansion plan basis, interaction and synergies between different expansion options can be evaluated. Their
effect on the total operation of the utility's existing system can also be considered.

The best bids of NUG projects and the utility are compared. This gives the opportunity for the utility to
determine whether expansion through construction of its own units or purchase of capacity from NUGs (or a
combination of the two) is more cost effective for the ratepayers over the given time frame.

[c]--Disadvantages.

A bid evaluation is highly labor intensive. A utility will generally spend several months preparing a request
for proposal (RFP) and the forecasts needed to evaluate bids, several months evaluating the bids, and
several more months negotiating contracts with the winning bidders. From start to finish, this effort can
occupy a significant number of people's time for the better part of a year.

Bidding may result in the displacement of utility construction. This is certainly a disadvantage for the
purchasing utility. The way utilities make money is by a return on their investment in new plants and
equipment.\(^{(35)}\) If someone else is to build an expansion unit rather than the utility, the utility loses the ability
to make a profit on that expansion.

The bids may be used as evidence to show imprudence of utility planning decisions. Again, this is a
disadvantage for the utility but a distinct advantage for the utility commission and consumers. The figures
will not lie. The alternatives to a given plan put into effect by the utility will be on display for all to see. The
opportunities to second guess utility decisions greatly increase with a head-to-head RFP.

[5]--Dispatchable Contracts.

[a]--In General.

Dispatchable contracts can be selected in any of the three methods set forth above.\(^{(36)}\) Dispatchability really
has no effect on how the contract was selected. Dispatchability could be incorporated in competitive
bidding, negotiated, or standard offer contracts. By coincidence, utility efforts to seek dispatchable contracts
occurred at about the same time that they began pushing for competitive bids. One does not necessarily lead
to the other, although their becoming common features of utility capacity acqui-sition programs did begin at
about the same time.
Operation of a NUG under contract to a utility where the NUG is fully dispatchable means that, for all intents and purposes, the NUG facility is a mirror of utility's facilities. It is generally built by the same types of entities that utilities use. It has the same equipment. It runs only when the utility wants it to run.

[b]--Features.

**Economic dispatch.** "Economic dispatch" generally means that the utility will dispatch all the units on its system (regardless of whether it or a NUG owns any facility) based on the principle of optimization of overall system economy. Obviously, there are other factors to be considered such as system stability, transmission losses, minimum run times to reach efficient levels, start-up times, and others. Optimizing system economy is more complicated than merely turning on the unit whose variable cost per kilowatt hour is lowest.

**Capacity payments.** Generally, dispatchable contracts include a payment per kilowatt hour for the electrical energy actually delivered to the utility and a "capacity payment" designed to cover the fixed cost of making the generation facility available to the utility. Again, this is a mirror of the utility's own existence. A utility obviously incurs fixed costs to construct, own, and operate a power plant. These costs are avoided by the presence of a NUG facility. As avoided costs, they should be part of the payments to NUGs. (37)

**Risks/reward for availability.** Generally, dispatchable contracts contain incentives for the non-utility generator to maximize availability. This means that the capacity payment is made to a NUG based on an assumption that the facility will meet a certain availability requirement. However, most contracts include a "look back" on a periodic basis to determine whether the NUG's actual availability warrants the capacity payments. If not, the NUG refunds all or part of the capacity payments.

[c]--Credit Ratings.

Some utilities have alleged that their credit rating will be lowered if they purchase power. This is misleading. The closer a contract is to the ideal of a fully dispatchable performance based contract, the less that contract will be treated as "debt" and more as an expenses of the utility. The closer to the other end of the spectrum, i.e., "must run," non-dispatchable, or "take-or-pay," the more the contract will be treated as debt. Of course, this exercise is more art than science. The bottom line is that the credit rating of a utility that fills future needs through dispatchable performance based contracts will not be lower than if the utility had built the capacity itself.

§ 18.03. Risk Shifting in Dispatchable Power Contracts.

An analysis of risk shifting is critical to any discussion of non-utility generation in this country for two reasons. First, the shifting of risk away from ratepayers and to the QF or IPP developer is the main reason that utility commissions across the country are interested in the development of NUG power. Second, risk avoidance is central to the thinking of utility decision makers. Regulators across the country have been preached to on innumerable occasions that NUG power relieves ratepayers of some of their traditional risks when a utility built expansion units. It is not a total shifting of risk. More accurately, it is a shifting of risks to the parties best able to control and absorb those risks. To the extent that a risk can be controlled by a party, the risk should be assigned to that party. To the extent that a risk cannot be controlled, it belongs with the ratepayers.

If you get nothing else out of this Chapter, you should understand this. Public utilities do not think the way other private businesses think. Private businesses generally make money by selling things for more than they paid for them and operating efficiently. In other words, they make money by buying low and selling high in the marketplace. This is not how public utilities make money. Public utilities have no incentive to take
gambles or risks. Utilities do not make money by buying low and selling high. Utilities earn a rate of return on their investment in new plant and equipment. The more they spend on new plant and equipment, the more money they will make (but for the fact that a utility commission is looking over their shoulder to determine that they do not spend imprudently on new plant and equipment). Some utility expenses yield no profit for the utility at all (e.g., fuel, operating expenses, and purchase power expenses). The utility basically passes through fuel, operating, and purchase power expenses to the ratepayers without mark-up (assuming that those expenses were not imprudently incurred).

Let us look at a particular fact situation. A private business is presented with the opportunity to take a chance or a gamble in purchasing something. If the gamble pays off, they make a lot of money. If the business gambles and loses, the business loses. When they win, they win; when they lose, they lose.

If a utility takes a chance by entering into a risky arrangement and the gamble pays off, the ratepayers win. If the utility loses the gamble, the utility (shareholders) loses. There is only a down-side when a utility takes a risk; there is no up-side. Understanding this is critical to negotiating a contract with a utility, whether for a NUG or anyone else. In analyzing the risks involved in utility construction and purchase of capacity from NUGs, and in comparing those risks, I believe we will find that there are risks a utility is willing to take. There are also risks a utility will insist be placed on the NUG. The more clearly a risk is borne by the ratepayer in a utility build situation, the less likely that the utility will insist on imposing that risk on the NUG. The reverse is obviously also true. Risks that are principally on the utility rather than the ratepayer are the risks that the utility most frequently demands be placed on the NUG.

Again, this is perfectly understandable because utilities are not compensated for taking risks. Utilities are compensated for making investments in new facilities. Their compensation does not vary with the amount of risk they assume. Whether they make a risky or a safe investment, their compensation is the same. It is also quite logical that a utility's compensation is not tied to risk. The vast majority of risk in the utility business is borne ultimately by the ratepayers. Therefore, why should the utility be compensated for assuming more risk, particularly when the risk involves the use of someone else's money.

Before launching into a discussion of the individual areas of risk that are shifted to the NUG developer when a utility purchases capacity. Let us summarize the risks inherent in both buying and building expansion units and identify the bearer of these risks.

Obviously, there are risks in the purchase of capacity from non-utility generators, albeit risks different from those presented by a utility's own construction program. These risks are almost certainly less than risks presented by a construction program. Both the utility's ratepayers and shareholders are relieved of some risk that is transferred to the non-utility generator. In Table 1, "N" represents large risks on the NUG, "n" small risk on the NUG; "R" large risk on ratepayers, "r" small risk on the ratepayers; "S" represents large risk on utility shareholders and "s" small risk on shareholders. My analysis assumes the contracts are dispatchable and performance based.

<table>
<thead>
<tr>
<th>RISK BUY BUILD</th>
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<tbody>
<tr>
<td>(a) fuel costs R, n R, s</td>
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<tr>
<td>(b) demand for capacity R, s R, s</td>
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<tr>
<td>(c) construction cost overruns</td>
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<tr>
<td>(including interest rate changes) N R, s</td>
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</table>
(d) operating costs (other than fuel) N, r, s R, s

(e) permitting and environmental regulation N, s R, s

(f) fuel availability N R, s

(g) demand for energy N S, r

(h) delay/late completion N S

(i) project failure/cancellation N R, s

(j) operating reliability N, s R, s

Note that the risks in items (a) and (b), fuel costs and demand for capacity respectively, are nearly the same in both the Buy and Build columns. In each case, the ratepayers bear the bulk of risk for building (subject to "prudence" exposure for shareholders) and, in the case of buying, the NUG. Generally, a NUG is only reimbursed by the utility for prudent fuel expenses, shielding both ratepayers and shareholders, even when energy payments are tied to fuel market indices. In addition, note that almost all risk is on the ratepayers if the utility builds. This is because all prudently incurred costs are passed on to the ratepayers, leaving shareholders with a small risk for imprudence. Imprudence is a risk that utility management should be able to control. For all other items, risk shifts significantly from the ratepayers and shareholders to the NUG in a "buy" situation.

Each category of risk transferred is dependent on the underlying contract provisions. For example, most contracts have fixed capacity payments that are not adjusted for construction cost overruns, though a contract could certainly be drafted to provide this adjustment. If perfectly drafted, the risk is on the NUG.

Most contracts provide for liquidated damages for late completion sufficient to purchase replacement capacity, though ratepayers and shareholders bear some small risk that replacement capacity cannot be obtained at a reasonable price. The same is true for project cancellation, though lateness and cancellation generally can be excused by force majeure, where risk remains with the utility ratepayers and shareholders.

Most contracts require the NUG developer to bear the cost of permitting and the equipment and operating costs resulting from permit requirements. Most contracts place interest rates risks and rewards on the developer.

All dispatchable contracts with fuel market based energy pricing place demand for energy risks on the NUG. If a facility makes or loses money when running, the facility is at the mercy of the utility's load demands.

[1]--What Risks Are Shifted?

Construction Cost Overruns (Including Interest Rate Changes). When a utility petitions for a certificate of public convenience and necessity to construct a new plant, the utility provides an estimate of the construction costs. The utility will not be bound by that estimate. If the estimate is high, the ratepayers will spend less money. If the estimate is low, the utility will pass on the additional cost to the ratepayers, subject of course to a finding that these additional costs were imprudent. That is why, in the "build" situation I have described the risk as being principally on rate-payers, with a small risk to shareholders. If the utility is
acting reasonably but still experiences an overrun, those costs will be passed through to the ratepayers. A properly drafted power purchase agreement will transfer this overrun risk to the developer. In some states, this estimate is used as the benchmark against which offers from NUGs are compared.

Operating Costs (Generally other than Fuel). When a utility builds a unit, all costs are passed through to the ratepayers subject, of course, to the finding of imprudence. With fixed capacity payments, any future improvements that are required to maintain efficient operation of the facility at a NUG unit will be paid for by the NUG. When a utility builds a unit, future improvements necessary to maintain the operation of the facility will be paid for by the ratepayers, again subject to a finding of imprudence. If you have worked for a utility, you know that during the 30 to 40 year life of a utility facility several large improvement projects will be undertaken. These are placed in the rate base on which the utility earns a rate of return. It may be a new control room, new computers, new precipitators, new water-making facilities, new fuel handling facilities, boiler water-wall retubing, turbine rewinding, or the like. A properly drafted power purchase agreement will impose these costs on the NUG.

Permitting and Environmental Regulation/Compliance. Generally, when a utility builds, the regulatory compliance risk is on the ratepayers. This risk is transferred to the NUG with a power purchase agreement. The NUG is responsible for procuring all necessary equipment required for environmental permitting. If regulations change, compliance costs are on the NUG. If permitting requires studies that had not been anticipated, the NUG absorbs the cost. Over the life of the facility, environmental compliance and the costs resulting therefrom are borne by the NUG. In the utility build situation, these costs are really borne by the ratepayers, subject, as always, to a finding of imprudence. (38)

This is an area where the shifting of risk is detrimental to NUGs in the evaluation of bids in a head-to-head competition between NUGs and utility owned units. Generally, when the utility provides a cost estimate, it assumes certain environmental laws will be in place. If it turns out that the utility will have to incur additional expense as a result of unanticipated environmental regulations, those costs are passed through to the ratepayer, subject to a finding of imprudence. The NUG does not have this luxury. The NUG's price is fixed; the utility's is not. At equal prices, the NUG delivers more for the ratepayers' money; therefore, the NUG should win over the utility alternative.

Fuel Availability. This item does not appear on some lists of risks transferred to the NUG. Let me give you an example of fuel availability risk. If a utility builds a gas-fired unit, the utility will have to have a back-up supply of oil available. If, for some reason, gas is not available to the utility on the day that it needs to run the unit, the utility has the option to run the unit on oil. Fuel costs, gas or oil, are passed through to the ratepayers, subject once again to a finding of imprudence. If a nonutility generator owns and operates a gas unit and the utility dispatches power from the unit, but gas is not available, the NUG will have to burn oil while being paid only for gas.

There are some rare exceptions to this in NUG contracting. Exceptions in this area, in fact, seem reasonable. If a NUG is acting responsibly and prudently but still cannot get gas, the ratepayers are certainly no worse off if the utility reimburses the NUG for the cost of oil. (39)

Energy Demand. Demand for energy is not the same as demand for generating capacity. By demand for energy, I mean demand for generation from the NUG or utility facility. I do not mean system peak demand. Once again, this is an item that does not appear on some commentators' lists of risks, however, it is real. Operators of trash-to-energy projects, waste coal projects, or any project with "free" fuel know this. If a project is dispatchable, but the project makes money on its fuel costs, the project has an incentive to insure that it runs as much as possible. However, the utility's dispatch of the unit will depend, in large part, on the weather from day to day and on the availability of other units on the utility's system that may be ahead of this particular project in the dispatching queue. Why have I identified this as being a risk principally on the
shareholders when a utility builds a unit? The reason is simple. Utilities build units for different types of capacity. If the utility anticipated large amounts of energy to be sold from the facility, it will build a base load unit, i.e., one with high capacity and low energy costs. If the demand for that energy does not materialize, the utility has constructed a unit with a high base load capacity payment when an inexpensive peaking unit would have been sufficient. This begs for a finding of imprudence, with a corresponding reduction in its rate base.

Projects with low cost fuel and a dispatchable contract must insure that the dispatch cost is low enough to maximize run time. The pricing must strike a balance between maximizing run time and maximizing energy revenue.

**Delay/Late Completion.** Most NUG contracts contain severe liquidated damages for delay or late completion of the NUG facility. Note, however, that not all risk is shifted away from the ratepayers and the shareholders. The utility will, in all likelihood, have to replace the expected NUG capacity, at least temporarily. However, it is generally true today that, on an annual basis, short-term capacity is less expensive than long-term capacity. The liquidated damages imposed in most NUG contracts approximates the cost of purchasing short-term capacity.

This actually provides a windfall to the ratepayers and shareholders, assuming that short-term capacity can be found. If the liquidated damages are calculated to purchase replacement capacity, and the replacement capacity is cheaper for a short-term than the capacity would have been under the long-term contract had the facility come on-line on time, the utility's costs go down for that short-term capacity. The utility actually benefits from the NUG's delay.

**Failure of Project/Cancellation.** When a utility builds a new unit, cancellation costs are generally shared between the ratepayers and the shareholders, with the bulk of the cost of cancellation falling on the ratepayers. Most NUG contracts include large liquidated damage payments for the NUG's failure to proceed with its contract. This does leave some risk for the utility's shareholder. The shareholder may bear the cost of purchasing replacement capacity to the extent the liquidated damages do not cover that amount. If the utility has a contract with a NUG but did not anticipate the cancellation of the project by the NUG and provide for substitute capacity, the utility commission may indeed find this behavior imprudent.

**Operating Reliability.** When a utility builds a unit, the costs necessary to maintain the reliability of the unit are generally borne by the ratepayer. Once again, there is the small risk to the shareholders of a finding of imprudence but, generally, the costs are absorbed by the ratepayers. With regard to NUGs generally, the NUG's capacity payments are fixed and the expenses necessary to maintain the operating reliability of the unit are borne by the NUG.

This is another area where the playing field between NUG's and utilities is not level. In a head-to-head comparison of a NUG bid and a utility estimate, the NUG's number includes long term expenses and improvements to enhance the facility's reliability; the utility's estimate does not. Equal prices mean the NUG's bid delivers more value and should be the winner over utility alternatives.

[2]--How Risk Is Shifted to NUG Operator.

[a]--Cost Overruns.

**Firm Capacity Payments.** Generally, capacity payments are designed to reimburse the NUG for the fixed cost of operation. Usually, the NUG has actually bid this number to the utility. The prices in the contract will remain fixed. If the utility payments to the NUG turn out to be insufficient to cover the NUG's costs, the NUG is not entitled to more money from the utility. In that event, the project could go "belly-up." The bank would foreclose. The project would be sold, in many cases to the utility itself at a fire sale price. Of
course, the utility always has the option to volunteer to pay more money to the NUG developer if it so chooses.

Posting of Security. Generally, utilities require the NUG developer to post large amounts of security with the utility in the form of a letter of credit. Some utilities have required as much as $65.00 per KW of capacity. As the NUG's internal estimates of the costs of construction and operation escalate during the development phase and project margins get tighter, the developer must weight the forfeiture of this several million dollar security deposit in the decision to cancel the unit because of projected cost overruns.

Utility Monitoring of Construction. In general, utilities monitor the construction of the NUG units under contract to them. Most NUG contracts provide clauses that obligate the NUG to show design documents to the utility, as well as reports of engineers hired by the banks to oversee design, construction, and operation.

Indexing for Interest Rates. The interest rate risk can cut both ways. Interest rates are generally beyond anyone's control. This makes them a good candidate to be a ratepayer borne risk. Some contracts with NUGs index part of the capacity payment to interest rates. If the NUG is not obligated to bear that risk, presumably it will bid a lower price. At a min-imum, I would suggest that bidders and utilities give strong consideration to option bidding a price indexed to interest rates. The savings in the bid proposals may justify allowing that risk to remain with the ratepayers.

[b]-Operating Costs (Other than Fuel).

Firm Contract. The NUG contract should contain provisions spelling out the base price for variable operating and maintenance (O&M) costs and their escalation. Once again, the utility always has the option to pay more, though it is unlikely that any utility would ever do so.

Reserve Accounts. Some utilities obligate NUGs to set up reserve accounts to ensure the funding of future maintenance. Other contracts are silent, relying on the fact that lenders generally require reserve accounts. Skipping maintenance, however, should be the last thing any NUG would do. Properly drafted NUG contracts give all the incentive to a NUG to maintain the unit at its maximum operating efficiency. If the unit is not available to perform at its maximum efficiency and in accordance with utility direction, the facility will forfeit its capacity payment. In most projects, all profit is in the capacity payment. Failure to run means forfeiture of the capacity payment. Forfeiture of the capacity payment means that the project will not make money. Performance-based capacity payments are the best insurance that the unit will be properly maintained.

[c]-Environmental Regulations.

Utility Review of Permitting Plans. Most utilities will make a strong effort to look over the shoulder of the NUG developer in the permitting process. In addition, most utilities will continue to review environmental compliance periodically during the performance of the NUG contract. Utilities are generally highly experienced at licensing and permitting power plants. If they want the power from a NUG, they can and should provide significant assistance in the permitting process.

Force Majeure Limitations. Most all NUG contracts of any significant size contain a force majeure clause. The combination of fixed capacity payments and proper limitations in a force majeure clause will provide additional impetus to the NUG to complete the permitting process and ensure that the risk in this process is on the NUG developer. For example, the clause should not relieve the NUG from performance obligations merely because it had difficulty in obtaining needed environmental permits. In my mind, the proper clause should tie the definition of force majeure to circumstances beyond the reasonable control of the party experiencing the force majeure. In other words, there should not be economic force majeure. If the
permitting agency tells the NUG project that to get an air permit the project must do X, Y and Z, and X, Y
and Z are achievable, but expensive, the NUG should not be able to say that it has experienced a force
majeure. The NUG can get an air permit; it chooses not to because it does not want to incur the necessary
cost.

[d]-Fuel Availability.

Lack of Fuel as a Force Outage. A properly drafted NUG contract will cause the NUG to forfeit capacity
payments if forced outages exceed a reasonable rate. Lack of fuel to run the facility should be a forced
outage or, at least, should trigger the same liabilities as a forced outage.

Utility Review of Fuel Supply Plans. Most utilities require that fuel supply arrangements be submitted to the
utility for review. In addition, most utilities require that they be kept informed of significant changes in the
fuel supply arrangements. Contracts also generally contain certain covenants to maintain an adequate fuel
supply with minimum fuel requirements. In my experience, lenders expect even longer term, more highly
locked in fuel arrangements than do the utilities.

Alternate Fuel Supplies. Generally, NUG contracts also require that alternate back-up fuel arrangements be
in place. This is particularly critical for a gas unit that does not have the ability to store large amounts of
fuel at the site, as is the case with coal and oil fired units.

[e]-Demand for Energy.

Dispatchability by Utility (Economic Dispatch). In this day and age, 1993, it is almost inconceivable that
any utility would be signing contracts with NUGs that are not dispatchable. Only rare exceptions are
warranted. Most facilities' "need to run" can be accommodated within economic dispatch. Through
appropriate pricing manipulation and design, a portion of a facility can be base loaded to ensure adequate
steam supplies for the host if the facility is a co-generator, for example. Proper design of the price for a
trash-to-energy facility can ensure that it is base loaded. Some utilities are hesitant to guarantee that the
NUG will be economically dispatched on the utility's system. These utilities are afraid of anyone second
guessing their "economic dispatch" decisions. There are, however, some legitimate reasons why utilities will
deviate from pure economic dispatch.

No "Minimum Takes." Again, with dispatchability, the utility will have no "minimum takes." If a unit must
run a minimum amount of time, then that portion of its facility should be priced at level that will cause that
portion to be dispatched accordingly. A garbage burner, for example, cannot afford to be dispatched off-
line. The garbage burner must propose its project to the utility in such a way that its energy price is low
enough that it will run at a level sufficient to burn the requisite amount of garbage on a daily basis.

Design Limits/Heat Rate Curve. Proper design of the contract provisions setting forth the design limits of
the facility and the heat rate curve for dispatchability are important, both to the utility and to the NUG. The
utility should make every effort to ensure that the design limits are appropriate in light of the need to
balance its flexibility needs with the efficient operational needs of the NUG. If the heat rate curve does not
accurately reflect the cost to the NUG, the NUG may be hurt on short-term dispatches of the unit. In the
long run, this will not be good for either party. At the same time, the design limits must provide the utility
with the flexibility it needs to follow its load on a daily basis.

[f]-Delay/Late Completion.

Timing of Payments. The greatest incentive to the NUG to ensure that its facility comes on-line on time is
very simple. The NUG does not begin to get paid until the facility comes on-line. Delaying the kind of cash
flow that these projects command is significant.

**Liquioted Damages.** If the inability to receive the capacity payment is not incentive enough, most utilities include significant liquidated damages payments for any delay in the on-line date of the facility. These liquidated damages are frequently at a level that provides a windfall to the utility because a season or two of short-term capacity probably costs the utility less than a season or two's worth of capacity payments under a long-term contract. Arguably, the utility actually benefits from the project being slightly late. This is particularly true if the lateness of the project does not change the capacity payments. Most utilities do not adjust the price for capacity in the event of a delay, regardless of whether the delay is caused by force majeure or the negligence of the developer. This is consistent with the concept of force majeure as it appears in most agreements; it should relieve either party from any liability to the other party associated with a delay.

**Posting of Security.** Security is generally posted to ensure the funding of the liquidated damages.

**Ultimate Termination of the Contract.** Most NUG contracts include a provision whereby a delay of more than a given amount of time (generally a year) will give the utility the ability to terminate the contract. This ultimate penalty can have a dramatic effect on the developer's will. Many utilities also take comfort from the fact that they have a co-conspirator in tormenting the developer and encouraging the development of the project in time to ensure that the contract is not terminated. That co-conspirator is the project lender.

**[g]--Failure of Project/Cancellation.**

**Termination of Project Contract.** If the project fails and the developer will not proceed, the utility generally can terminate the contract. Prior to the time the facility is built, this may be a hollow victory for the utility. However, after the project is built, the ability to terminate the contract becomes a very strong incentive to the further operation of the facility. A bank will foreclose before it will allow the utility to exercise its right to terminate the contract. The power contract is the only source of revenue available to repay the lender. Its preservation becomes paramount.

**Forfeiture of Security/Liquioted Damages.** Once again, the failure of the project can be extremely costly to the developer because most contracts provide for the forfeiture of all security which, in some cases, is as high as $65 per KW of capacity.

**[h]--Operating Liability.**

**Liquioted Damages for Poor Availability.** Most utilities include provisions in their NUG contracts for some sort of liquidated damages to the utility if the NUG has poor availability. These can take many forms. Some contracts include provisions with seasonal testing. If the facility tests low, then the capacity payments for that season will be set at a lower level. With capacity payments made on a per KW basis, a poor test will reduce revenue. In addition, if the tests are below a certain number, many utilities require liquidated damages to provide funds to purchase replacement capacity to the extent the test is below what had been anticipated. Some projects use North American Electric Reliability Council guidelines and formulas to develop an equivalent availability on a periodic basis and adjust payments to the NUG according to its equivalent availability. Some contracts use formulas for liquidated damages each time the facility experiences a forced outage (either whole or partial). Some use a combination of these approaches.

**Reduction in Rated Capacity.** Poor availability will eventually translate into lower capacity ratings. These lower capacity ratings will result in lower capacity payments to the NUG in most contracts.

**[3]--What Risks Remain with the Utility?**
Demand for Capacity. Demand for capacity is certainly beyond the control of the NUG. It is a planning risk. The utility is the planner (some-times with the "help" of the utility commission). The purchasing utility must be responsible for determining how much capacity its system will require. The risk in either a utility-build or a power purchase situation principally remains with the ratepayers. The utility's shareholders will always be exposed to some risk from a finding of imprudence if the utility purchases too much capacity or builds too many units but, short of imprudence, the ratepayer pays.

Market Price of Fuel. Again, this risk is principally on the ratepayers when the utility builds; it remains principally on the ratepayers when the utility buys capacity under a fuel market indexed contract as is most common today. There is one slight difference. When a utility builds, there is the small risk that a finding of imprudence will expose the shareholders to liability. In the NUG situation, the market price of fuel does present some small risk to the NUG operator. However, with this risk does come reward. The NUG has the ability to take some chances and attempt to beat the market for fuel. If the NUG is successful, it makes money; if it is unsuccessful, it loses money. If the utility takes chances in fuel procurement, benefits flow only to the ratepayer and losses may flow to the shareholders.

Breach of Contract by NUG Operator. The utility definitely runs the risk that the NUG operator will breach the contract. This exposure is somewhat passed through to ratepayers. The utility, however, should have alternate plans, reserve margins, and sufficient liquidated damages to protect itself in this event.

[4]--Utility Protection Where It Has Risk.

[a]--Need for Capacity.

Buy Out/Termination Clause. Most utilities include clauses allowing them to terminate the contract if certain events occur. This can be a way out for the utility when it has oversubscribed for capacity. Many utilities also include a provision giving them the ability to "buy out" the contract before the end of its term. The price is generally high but, presumably, it gives the utility an option not otherwise available.

Right of First Refusal. Most utilities include a clause granting the utility the right to purchase the facility in the event that the facility is ever sold. In many cases, this takes the form of a right of first refusal where the utility has the right to match any offer from third parties that the developer is prepared to accept. This is generally also paired with strong efforts to link the power purchase agreement to the facility. The utility attempts to require that any owner of the facility must be bound by the contract with the utility. One of the ways frequently employed to accomplish this is a waiver of the right of refusal to the extent the bank forecloses, takes over, and operates the facility according to the agreement or sells it to a third party willing to operate pursuant to the terms of the agreement. Generally these are the only circumstances under which the utility will waive its right of first refusal. Otherwise, if a purchaser will not be bound by the power purchase agreement, the utility will exercise its right of refusal and purchase the facility itself.

"Regulatory Out" Clause. Many contracts with NUGs today include a clause know as the "regulatory out" clause. This clause provides for some sort of transfer of risk from the utility to the NUG in the event that payments to the NUG cannot be passed through to the ratepayers. I believe that this clause is actually a violation of PURPA if the NUG is a QF. PURPA provides that a QF is entitled to avoided cost calculated either (1) at the time the QF enters into the obligation with the utility or (2) at the time the electricity is delivered. The choice is for the developer. A "regulatory out" clause has no benefit to the ratepayers. It protects the shareholders. It actually provides disincentives for the utility to insure that its planning is done the best possible way. This clause will allow the results of the utility's planning errors to be born by the NUG rather than the utility, i.e., the party making the plans. There are some fairer clauses that create a sharing arrangement between the utility and the NUG developer. Some clauses defer the disallowed amounts to a period after the initial financing has been paid off. Others split the effect of the disallowance.
[b]--Market Price of Fuel.

Dispatchability is one of the best protections a utility can employ to minimize the ratepayers's risk associated with a NUG contract tied to the market price of fuel. This is particularly true for a utility with a broad mixture of fuel sources. The utility will only run the units that are most cost effective to run.

Index Energy Payments (and Dispatch Costs) to Energy Market Prices. To insure that dispatchability will provide some hedge against fuel price escalation, all fuels must be indexed to market prices. In the past, several types of fuel tended to move together in escalation. As oil went up in price, so did natural gas, and, even, coal. Today all three of these fuels move independently. In the past, the price of natural gas would be tied to oil prices. This is not the case today. Signing a contract that is not market indexed generally involves paying for fuel at a premium price. Fixed escalators put the risk on the gas supplier. The gas supplier will charge a premium for accepting this risk. These premiums are avoided by signing contracts tied to market indices and having a diverse fuel mix that allows the utility to dispatch the most cost effective units and shut down those whose fuel has become expensive.

[c]--Operator Breach.

Forfeiture of Security Deposit. The most significant protections against operator breach are the forfeiture of a multimillion dollar security deposit and the threat of terminating the power purchase contract. If a developer believes that it is more cost effective to breach the contract and have the utility terminate so that the developer can make a deal with a new purchaser, the utility can protect itself through other means. The utility can sue for damages to the extent that replacement power costs are higher than those from the original developer. If original developer has gone out of business, presumably they have defaulted on their financing; the bank will foreclose; and the unit will be put up for sale. If the unit is put up for sale, the utility should have its right of refusal in place.

Right of First Refusal. The right of first refusal can provide significant protection to the utility, especially when coupled with a limited waiver allowing transfers to other entities only to the extent that the transferee has agreed to be bound by the terms of the power purchase and operating agreement.

[d]--Insurance.

Cost power purchase agreements require the operator to purchase millions of dollars worth of liability insurance coverage. Generally, the utility insists on being named as additional insured on these liability policies.


[1]--Capacity Payment.

Capacity payments are generally made on a per KW basis. The capacity payment is paid on a monthly basis according to the size of the facility. Basically, it covers the fixed costs of developing the facility.

The capacity payment must cover debt service. Generally non-utility generation projects are "project financed." The lender looks solely to the proceeds from this project to cover debt service. If the capacity payment will not cover debt service, the loan will not be made. This has lead to some capacity payments being "front-end" loaded to some extent.

The capacity payment generally includes the following.

(1) construction,
(2) transaction costs,

(3) interconnection costs,

(4) taxes,

(5) future improvement projects (planned and a contingency for unplanned),

(6) major overhauls,

(7) start-up costs,

(8) development costs, and

(9) interest during construction.

[2]--Fixed Operating and Maintenance Costs.

Fixed operating and maintenance costs are sometimes subsumed into the capacity payment. A more accurate way of providing for fixed O&M, however, is to have it as a separate item because it will escalate. Construction costs do not change once the facility is built. The capacity payment covers principally sunken overnight costs. The fixed O&M generally has both labor and material components. The labor and the materials are generally indexed separately.

[3]--Variable Operating and Maintenance Costs.

Variable O&M expenses vary with the generation of the facility. Both labor and material components are usually indexed as well. Variable O&M costs can also include lime, ash disposal, or other items that will vary with the level of generation.

[4]--Energy/Fuel costs.

[a]--Fixed Escalators.

There are NUG contracts with fixed or other escalators not tied to fuel market prices (such as the gross domestic product implicit price deflator). Eventually, this causes problems. Dispatch is based on variable cost. Variable cost is almost entirely fuel related. If the escalation is not tied to market prices for the fuel, eventually the dispatch cost for the NUG will be out of synch with fuel costs. Then either the NUG or the utility will be significantly hurt. No one benefits from this. No fuel forecast can be accurate, particularly over a three to five year period. Three or four years of running at a loss will bankrupt a project. If the fixed escalators make energy from the project much more expensive than the actual fuel cost would suggest, the facility will not be dispatched and its capacity payment may be found imprudent.

The safest thing for the utility to do is to follow fuel markets. This will rarely, if ever, be found imprudent. Remember, avoiding risk is paramount to utilities.

[b]--Fuel Market Indexing.

The trend is definitely toward fuel market indexing. For example, Baltimore Gas & Electric (BG&E) currently has an RFP index under review by the Maryland Public Service Commission. The RFP expresses a preference for indexing to market conditions. BG&E is open to other escalation methods if their
credibility can be demonstrated. Georgia Power's February 15, 1993 Solicitation also permits alternatives, but shows a clear preference for existing market indices. Virginia Power's solicitations also express preferences for market indices.

[c]-Utility Fuel Cost Indexing.

There are situations where utility costs are used. Some utilities have used proxy plants to escalate "avoided energy costs."

§ 18.05. Conclusion.

NUG developers and fuel suppliers must realize that shifting risks to the NUG from the utility and its ratepayers is the NUG's raison d'etre. Understanding of the risks, how they are transferred, and when they should or should not be transferred is critical to negotiating a NUG contract.


8. 8. 18 C.F.R. §§ 292-203(a), 292.204(a), (b), 292.206.1

9. 9. 18 C.F.R. § 292.204.

10. 10. 18 C.F.R. § 292.304(b).

11. 11. 16 U.S.C. § 824a-3; 18 C.F.R. § 292.304(a)


15. 15. 18 C.F.R. § 292.304(c).

16. 16. See text, infra, at § 18.02[4].

17. 17. Hereafter IPP refers to non-qualifying facilities.

19. At least some of these benefits are now available to non-QFs under the Energy Policy Act of 1992 discussed in the text, infra, at § 18.01[3].


24. See text, infra, at § 18.01[3].


29. Doswell.


32. It can be argued that the creation of the standard rate was a unilateral offer similar to a reward or bounty for performing some act. Under this analysis, the utility is the offeror. A contract is created when the QF performs the act needed to accept.

33. Until recently, for example, in Virginia there was a standard offer rate for facilities up to 3 megawatts. The Virginia State Corporation Commission, at least temporarily, ordered Virginia Power, at Virginia Power's request, to lower the maximum size to 100 KW. See Application of Virginia Elec. & Power Co. For a Review of Schedule 19 1992/1993 Charges and Payments to Cogenerators and Small Power Producers, Va. State Corp. Comm'n Case No. PUE920060 (Opinion and Final Order, Feb. 17, 1993). A petition is currently pending before the Commission to reduce the maximum size for the standard offer tariff permanently to the PURPA minimum standard of 100 KW. See Testimony and Exhibits of Virginia Power, Schedule 19-1993/95, Power Purchases from Cogeneration and Small Power Production Qualifying Facilities, Va. State. Corp. Comm'n Case No. PUE93____ (filed March 31, 1993).

34. See Petition by Niagara Mohawk Power Corporation for ruling pursuant to 16 N.Y.C.R.R. pt. 8 declaring entitlement to monitor and enforce qualifying facility contractual obligations, N.Y. Pub. Serv. Comm'n, Case No. 92-E-0814. This is sometimes known as the New York "Curtailment Proceeding."

35. See text, infra, at § 18.03.

36. Standard offer contracts, negotiated contracts, and competitive bidding (RFP) contracts.


38. I have seen some rare exceptions where there is a sharing of risk with the utility and the NUG.

39. This should be consistent with the guiding principle of PURPA, i.e., ratepayer neutrality. However, increasingly, state
regulators seem to be asking for ratepayer *benefit* from NUGs rather than mere neutrality.

40. 3. *E.g.*, energy below the utility's average base load unit but with high capacity prices.

41. 4. They include system stability, voltage, VARs, start-up times, minimum runs once started, testing, and aging of oil supplies.

42. 5. See text, *supra*, at § 18.03.


44. 1. Maryland Pub. Serv. Comm'n Case No. 8241, Phase II.

45. 2. For gas, Louisiana Spot Gas from *Inside FERC*, for oil, *Platt's Oilgram*, and for coal, Georgia Power's coal costs as reported on FERC Form 423.

46. 3. For example, the Georgia Power coal index.