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Risk Allocation in Independent Power Contracts

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Executive Summary

This paper reviews evidence on the allocation of risks in long term contracts between private power producers and utilities. The primary source of data for this analysis is a sample of actual contracts. The sample includes 20 contracts for 4570 MW from eight states and 13 utilities. There are nine IPPs and 11 QFs. Half the contracts resulted from some kind of competitive bidding process. The sample is skewed toward large projects and emphasizes contracts recently signed. Such projects are apt to indicate future directions better than a more strictly representative sample.

Private power contracts typically involve a generic allocation of risks between developers and utility ratepayers. Developers sign fixed payment contracts for capacity or investment related costs. To earn these payments, the projects are subject to performance standards. Developers also agree to a first-year variable cost which is the product of fuel cost and a fixed conversion efficiency, or "heat rate." The heat rate remains fixed, but future fuel costs are adjusted by an external index. Fuel cost indexation effectively transfers most fuel price risk to the utility ratepayer. Demand risk is also born, almost universally, by the utility and its ratepayers. Important variations on this generic risk allocation and the most significant additional contract clauses are summarized topically below. Price trends are also reviewed.

1. Performance Standards

Virtually all contracts have explicit performance standards for generation availability and penalties for failing to achieve contract targets. There are also specifications for capacity testing and frequently penalties for degradation from contract commitments. Many contracts include "minimum take" restrictions which limit the utility's operational flexibility. This is a further shift of demand risk to ratepayers.

Enforcing performance standards depends on the definition of force majeure. Liberal interpretations can excuse non-performance.

2. Fuel Supply and Price

Fuel price indexation is standard. Coal based projects typically index to GNP or the buyer's costs. Gas based projects typically use national fuel cost indices or buyer's cost. Projects using imported gas involve indices that will escalate more slowly than domestic gas costs. Only two contracts have explicit benefit sharing if actual project costs are less than the indexed price. Many contracts allow re-negotiation of the base price. This can amount to de facto acceptance of demand risk by the utility for variable costs. Variations in heat rate with project output, "heat rate curve pricing," are incorporated in only one contract. This omission is the cause of many minimum take clauses, because sellers want to limit production to the output range where variable prices cover their costs.

project may not be able to acquire financing. Future research on the risk allocation mechanisms in the private power industry should focus on the loan agreements.

Despite these limits, we can observe two trends which suggest that the private power market is functioning reasonably well in the ratepayer's interest. The first trend is the measurable movement to lower prices in this highly competitive market. Second is the growing tendency to incorporate increasingly strict terms in the contracts as utilities move away from lenient risk allocation terms that tend to be found in earlier contracts.

1.0 Introduction

This paper reviews evidence on the allocation of risks in long term contracts between private power producers and utilities. As this segment of the electricity market grows, there is increasing interest in the efficiency of these arrangements. Long term contracts can impose rigidities that make adaptation to changing circumstances costly. The task of regulation in a contracting environment is to assure that project selection is equitable and efficient, and that risks are appropriately allocated. This paper addresses the latter subject by examining how contract terms make this allocation.

The power sales contracts examined here represent only a part of the governance structure associated with private power. The other part is the financing agreements among lenders, equity investors and developers. Of these, the loan agreements are most critical. Lenders are in the business of limiting and managing risk. They can be expected to constrain the behavior of developers and operators. This paper does not analyze loan agreements; they are more difficult to obtain than power sales contracts. Therefore, the discussion of risk allocation mechanisms here will be incomplete since it is confined to analysis of only power sales contracts.

The primary source of data for this analysis is a modest sample of power sales contracts for recent, relatively large projects. Both Qualifying Facilities (QFs) under PURPA and Independent Power Producers (IPPs) are considered. Contracts are available only from the files of state utility regulatory commissions, or in the case of IPPs that must get Federal Energy Regulatory Commission (FERC) approval, the contracts are filed with that agency. There is often a set of background issues involving local regulatory policy that has influenced particular contract features. Frequently this contextual material is either not formally documented, or so dispersed and fragmentary that it is impossible to organize systematically. As a substitute for the kind of ideal documentation of economic context associated with each agreement, this paper will begin with a general discussion of the kinds of contract data that are available and will be reviewed in this study. Section 2 gives a general background on risk allocation in private power contracts. Section 3 gives an overview of the contracts that will be analyzed in detail. Section 4 discusses performance incentives. Section 5 surveys fuel supply and price issues. Section 6 discusses termination clauses. Section 7 reviews issues associated with affiliate relations. Miscellaneous provisions are discussed in Section 8. Price trends are reviewed in Section 9. Conclusions and suggestions for future research are discussed in Section 10.

2.0 Analysis of Risk Allocation

Power projects have inherent risks, regardless of who develops them. The shift of responsibility for power plant construction, operation and economics from the vertically integrated utility to private producers involves a change in the allocation of these risks. The traditional vertically integrated firm constructed new generating capacity under a specific set of regulatory procedures

Private power contracts typically involve some fuel price risk sharing between the seller and the utility customer through the indexation mechanism. Indexation does not guarantee the producer complete recovery of his costs. It only allows a general tracking of market price movements. The degree of cost recovery depends on the choice of index. Once the indexed price is determined, the utility commonly recovers from its customers the cost of its private power purchases through a fuel clause adjustment procedure. Section 5 below discusses additional features of the fuel cost clauses in the contract sample, including the question of what happens if the variable costs get completely out of a reasonable range for some reason.

The other generic price risk associated with private power contracts involves the demand for power. This is a form of price risk that involves the value of output, rather than its cost. Construction cost risk and operating cost risks are commonly measured against a standard of comparable costs for these commodities. The demand risk involves the question of whether the project's output is needed or not; that is, its value compared to the alternative of not having the output at all. The "used and useful" test associated with the rate base treatment of new capital investment amounts to imposing this risk upon the utility and its shareholders. If the projected need for power does not materialize, new utility plants may be partially or completely excluded from rate base until there is sufficient demand to make them economic. Private power contracts typically insulate the seller from this risk. Some contracts contain explicit clauses that commit the utility to payments even in the event that regulators disallow recovery of contract payments (this subject is discussed below in Sections 8.2 and 8.3). As a result of these arrangements, the financing cost for private contracts is reduced, but a risk premium is transferred to the utility (Perl and Luftig, 1990).

In the next sections we consider some of the variations on this basic allocation. We organize the discussion of risks topically and treat each issue with reference to the relevant contracts in our sample. The two issues treated at greatest depth in this paper and in the sample itself are: performance incentives and fuel supply and price provisions. Other topics discussed include termination provisions and affiliate relations.

3.0 Overview of Contract Data

Table 1 summarizes the sample of private power contracts that will be analyzed in this study. The contracts are organized by states, and each project is characterized by a small number of descriptors. These descriptors include: (1) firm capacity rating, (2) fuel type, (3) whether the project is an IPP, (4) whether the project emerged from competitive bidding, and (5) what kind of dispatch is associated with the contract.

The sample expands upon contracts previously analyzed, primarily with regard to dispatchability features (Kahn, et al., 1990). The sample is definitely skewed toward large projects; only three of the contracts represent projects of less than 100 MW. The two largest private power projects are included, Doswell and the Cogen Technologies Linden project, which are each approximately

600 MW. As a point of reference, a recent survey of contracts awarded through competitive bidding as of July, 1990 (*Current Competition*, 1990) is summarized in Table 2.

While Table 2 is instructive about competitive bidding, there are other channels through which private power contracts are concluded; principally, negotiation and standard offers. In practice, it can often be difficult to categorize the genesis of particular contracts definitively among these three alternative paths. Negotiation plays an important role even in bidding and standard offer settings. For large projects, negotiation is almost inevitable. The transactions costs of negotiating are more affordable for both sides of the arrangement when projects are large, than when they are small. The rationale for focusing on large projects in this analysis, is that they are likely to show the most sophistication and to set patterns for contract language that will then become standard for smaller projects.

Table 2. Winning Bids (Through 7/90)

Supplier Type	Projects	Total MW	Average MW
QF	137	5252	38.3
IPP	13	2075	159.6
Utility	7	1311	187.3
Total	157	8638	55.0

Table 1 does not purport to give a geographically representative sample. It shows a very substantial number of projects whose output is sold in Virginia. This is a disproportionate representation with respect to the private power market as a whole. For the competitively bid segment, the Virginia representation is more in line with its share of the market. The recent developments in competitive bidding show an evolution in contract terms and substantially more refinement in risk allocation than earlier developments. For this reason, California and Texas, the two states with the most private power capacity, are deliberately under-represented. In both states development of private power was determined by regulatory and economic conditions of the mid-1980s. In the case of Texas, most of the cogeneration projects were associated with boom conditions in the oil and petrochemical industries. A small number of these have capacity contracts. The aggregate total of firm capacity contracts in Texas is about 3200 MW (PUCT, 1990). In California, almost all of the capacity in operation reflects standard offer contracts developed in 1982-83. The one project discussed, Kern River, has a non-standard contract, and raises important issues of contract administration and affiliate relations.

Finally, Table 1 gives a summary characterization of the operational features of these projects under the column labelled "Dispatch." Different project types have different risks associated discussion of affiliate relations. Two other projects also serve multiple utility buyers, Enron and the Paulsboro/Vista projects. In these projects the priority rights questions are not treated very explicitly. Unlike TECO, these two other projects are designed for baseload operation. Both Keystone and Chambers have contracts to serve industrial facilities on a "second call" basis.

A final word needs to be said about the vintage of the sample. The selection is heavily tilted toward recent history. The older projects in the sample indicate circumstances that have largely been superseded. It is useful to have such projects for analysis, but they will seldom represent the "state of the art." The oldest project discussed is the Kern River Cogeneration project. The final agreement was signed in January, 1984. The AES Shady Point contract was signed in December, 1985. The Ocean State project also dates from December, 1985 (although the FERC application for treatment as an IPP was not filed until October, 1986). Ocean State is probably the first large IPP, but the regulatory model it presents was not widely imitated. Essentially, Ocean State is structured on a pattern similar to traditional regulation with a performance incentive system, rather than the PURPA avoided cost or competitive bidding paradigm.

The Hopewell and Doswell projects were selected by Virginia Power in its 1986 solicitation. The Hopewell contract was signed in June, 1987. Doswell went through much subsequent history, and its final amended contract was concluded in January of 1990. The four other Virginia Power contracts were winners in the 1988 solicitation. The New Jersey contracts include two projects negotiated with Atlantic City Electric and signed in 1988, Keystone and Chambers; the others resulted from the Jersey Central Power and Light 1989 RFP. Both the Dartmouth and Enron agreements were signed in 1989. The TECO contracts were signed in 1989. Cogen Technologies was signed in 1989. Wallkill was the result of Orange and Rockland's 1989 RFP. Both Indiantown and Sun Peak were signed in 1990.

4.0 Performance Incentives

Regulatory interest in generation performance incentives predates the large-scale development of the private power market. The large baseload utility generation projects which started to come on line in the 1970s stimulated regulatory attention to the development of performance standards. Utility returns are linked to the output achieved by units subject to these standards. There are typically rewards for exceeding a target performance goal and penalties for falling short. This system is intended to create incentives for good performance (Joskow and Schmalensee, 1986; Brown, Einhorn and Vogelsang, 1989).

In the private power market, where the obligation to serve is absent, performance incentives are more important than under standard rate-of-return regulation. In a contracting environment the utility is acting like a regulator with respect to the private developer, but lacks the kind of sanctions that the state agencies can impose on regulated firms. Therefore, the utility must rely on an explicit incentive structure in the contract. The performance incentives are usually tied to payments for firm capacity. It is unnecessary to give a performance incentive for energy payments under "must-take" contracts since the tariff price alone is sufficient. When

Table 3
Performance Incentives

	Threshold/Target Level	Penalty/Bonus
New Jersey		
JCP&L	Project Availability < Utility Availability unless Proj. Av. ≥ 80%	Δ Availability * PJM Cap. Deficiency Charge
Atlantic City	90% Availability	Δ Availability * PJM Cap. Deficiency Charge
New York		
Cogen	PMT = $/kWh for deliveries (=Fixed + O&M + Fuel) = Fixed + O&M during curtailment *unless* capacity not available (including transmission)	
Wallkill	80% Availability	Δ Availability * Δ (kWh Cost, Long Run Avoid. Cost)
Massachusetts		
Enron	90% availability	for every 1% below 90%, $2.40/kW-yr is deducted from fixed PMT (same rate paid if av. > 90%)
Dartmouth	85% availability	$\left[\left(\frac{EAF}{.91}\right)-1\right]$ * capacity charge; same rate paid if av. > 85%
Ocean State	80% availability	for every 1% below 80%, $3/kW-yr penalty; for every 1% above $4.35/kW-yr bonus (scaled to capital cost and rate base fraction)
Virginia		
Commonwealth Atlantic	15 days forced outage allowance	1.33% of Capacity Price per Excess F.O. Day
Turbo Power	25 days forced outage allowance	$5.17/kW-day
Beckley	30 days forced outage allowance	$3.65/kW-day
Florida		
TECO CC/CT	87.5% availability	0.2% reduction in capacity charge for every 1% below target
Indiantown	87-92% Capacity Billing Factor (CBF)	Penalty: CBF < 55%, payment 0; CBF 55-86%, 36-98% * capacity charge. Bonus: 92-97%, 105-110% * Capacity Charge.
Oklahoma	14.46% Maximum Equivalent Forced Outage Factor	1% reduction in capacity price for 1% excess outage

Finally, consider Indiantown. The monthly capacity payment formula is expressed in terms of a quantity called the "Capacity Billing Factor," which is the normal capacity factor adjusted in several ways. First, if the unit is on scheduled maintenance, those periods are excluded from the calculation. Second, if there is a force majeure event, then the Capacity Billing Factor for that period is defined to be 55%. With these definitions, the monthly capacity payment is zero if the capacity billing factor for that month is less than 55%. If it is between 55% and 87%, the capacity payment goes linearly from 36% of the standard contract payment to 98% of that standard rate. When capacity billing factor is in the range from 87% to 92%, the standard rate is paid. This amounts to a maximum forced outage allowance of 13%, or 47 days per year. The threshold for non-zero capacity payments of 55% Capacity Billing Factor amounts to 130 days/year of excess forced outage. This is calculated by first netting out an expected six weeks per year of maintenance, multiplying by 55%, and then subtracting the allowed 47 days of forced outage (365-42 = 323; 323*0.55 = 177; 177-47 = 130).

4.2 Force Majeure

This term is defined in dictionaries as an unexpected and disruptive event that may excuse parties from contractual obligations. Force majeure clauses are a necessary, but troublesome, feature of contracts. We treat this subject here because it has strong interactions with the performance incentive provisions discussed above. The distinction between a forced outage event and a force majeure event can be vague. This is frequently recognized in the contracts by clauses allowing the utility, at its discretion, to re-classify events as force majeure, that had been called forced outages. This kind of re-classification amounts to forbearance on the utility's part. It will financially benefit the seller to the degree that their payments in a given case are constrained by the performance target.

The most significant issue with respect to force majeure events is whether they trigger an interruption in capacity payments. Such interruptions are standard clauses in the Virginia contracts. In these contracts the monthly capacity payment is suspended and prorated for the duration of the force majeure period. This can be less of a financial burden to the seller than treatment of the event as a forced outage. At the opposite extreme, the New Jersey contracts (both JCP&L and Atlantic Electric) do not deem force majeure events sufficient to affect capacity payments. If such events were to last long enough, the contract would probably go into default and terminate. But sellers would probably receive capacity payments for at least 18 months in these cases. The proposed revisions of the JCP&L RFP system would modify this treatment to the standard adopted in Virginia, namely suspension of capacity payments (JCPL 1990).

There are intermediate cases. The AES Shady Point contract provides for up to three months of capacity payment during force majeure before suspension. The facility must then operate for 90 days before another force majeure event would qualify for up to three months capacity payment. The Indiantown contract also allows capacity payments during force majeure. They would be calculated under the standard performance payment formula, which would have the effect of reducing them over time until they became zero after one year.

The Ocean State contracts specify that capacity payments will be reduced only if the facility tests at lower than 90% of its originally determined capacity. These reductions would be proportional from a base of 90% of original capacity. This amounts to a free 10% capacity degradation. Both Keystone and Chambers also have a "dead band" in the contract specifications for capacity degradation. It is only 5% in these cases, compared with the 10% in Ocean State. The penalty, however, is only assessed at the rate of the PJM Capacity Deficiency Charge. This price is much less than the capacity price in the Chambers contract. It becomes comparable or even larger than the capacity charge in Keystone after the fifteenth year of that contract.

The Jersey Central Power and Light contracts invoke only "best efforts" obligations on seller's whose tests fail to meet contract capacity. The lack of explicit remedy in these contracts amounts to shifting the risk of capacity degradation completely onto the utility ratepayers.

4.4 Minimum Take Provisions

Minimum take provisions represent a performance guarantee from the buyer to the seller. In various ways the utility can assure the developer that a certain amount of output will be purchased. Under standard PURPA implementation, there is no need for such provisions. The obligation to purchase from QFs makes all their output "must take." In our contract sample, only the Kern River project represents this kind of obligation. All other contracts, which are of more recent vintage, reflect the concern with dispatchability.

The discussion of dispatch in Section 3 already identified one kind of minimum take provision, a contractually specified minimum number of operating hours. The Chambers, Keystone and Wallkill projects all have this feature. AES Shady Point exhibits a slight variation on this, a required 65% minimum annual capacity factor. This project also has a clause giving it dispatch priority over any subsequent QF with which the utility may contract.

Another form of minimum take is limited curtailment rights. This issue has been discussed and analyzed at length in Kahn, et al. (1990), so it is treated only briefly here. Essentially this situation involves projects that may be started up and shut down at the discretion of the utility, but once operating cannot be dispatched over a very wide range of output. Doswell, for example, can only be curtailed to 80% of maximum capacity. The same limit occurs in the Vista/Paulsboro contracts. The Turbo contract limits curtailment to only 85% of maximum capacity. These limits impose operational rigidities upon the utility which can be very costly. Minimum take restrictions are another way in which demand risks are allocated to ratepayers.

5.0 Fuel Supply and Price

All contracts contain provisions addressing fuel supply and price issues. The standard treatment of price issues, described briefly in Section 2, involves a base year price and an indexation mechanism. Embedded in the base year price is both a fuel cost and a conversion efficiency, or "heat rate." The seller must maintain this conversion efficiency over the term of the contract.

Table 5A. Variable Price Terms: Coal Contracts

	Energy Price Escalation	Other Variable Price Factors	Adjustment to Escalator
Shady Point	Buyer's fuel index	O&M costs indexed to GNP	
Paulsboro	GNP		
Keystone	Constant and coal used by NJ utilities	On/off peak distinction	Prespecified changes after years 8 and 15
Chambers	Constant & coal used by NJ utilities	On/off peak distinction	
Multitrade	Virginia Power's in-system coal-fired generation	O&M costs indexed to GNP	Renegotiation available every 3 years. Price discounting specifically allowed.
Beckley	GNP		
Indiantown	Seller's cost & buyer's fuel index, benefit-sharing	Heat rate curve pricing	

Table 5B shows only three contracts involving variable O&M costs. These escalate at either the consumer price index (CPI) or GNP deflator. More significantly, five contracts specifically allow renegotiation. Four of these are Virginia Power contracts, where such clauses seem standard. In the case of Enron, renegotiation amounts to the project bearing a certain amount of demand risk. The project involves significant fixed costs of gas transportation. If it is dispatched at low capacity factors, the overall cost of power will be high. Therefore the project sponsors will renegotiate the variable cost downward to achieve an 80% capacity factor if escalation has caused the project to be dispatched less. This willingness to lower price is equivalent to accepting demand risk. Other clauses in this contract also provide for price reductions in the event that total cost exceeds the buyer's average cost of power.

Only one gas-based contract, Cogen, provides for benefit sharing in the event that the project's costs are lower than the indexed price. The renegotiation provisions in the Virginia Power contracts might achieve the same goal, but that is not their ostensible purpose.

None of the contracts involve "heat rate curve pricing" of the kind in Indiantown. This is connected to the minimum take provisions noted at the end of Section 4.4 above. Because the reduced efficiency of combustion is not provided for through heat rate curve pricing, these projects offer relatively little curtailment. As noted above, this amounts to a further transfer of demand risk to ratepayers.

5.2 Fuel Supply

Although inventory is the standard hedge against fuel supply interruptions, surprisingly few contracts address this issue explicitly. Only Doswell and Hopewell have specific requirements. The security of fuel supply issue is addressed more indirectly through incentives associated with availability requirements. As in so many other cases, the key factor is force majeure definition. The Virginia Power contracts exhibit the tough line on this subject. A fuel supply interruption is only deemed to be a force majeure event if the cause of the interruption was a force majeure event in the fuel transport system. This means that economic causes are excluded. The same terms appear in Walkill, Enron, and the JCPL contracts. More lenient terms appear in Keystone, Chambers and AES Shady Point. In these contracts any fuel supply interruption, whatever the cause, is considered a force majeure event. Since these three contracts are all coal-based the probability of fuel supply interruption can be considered low. Some contracts, such as Cogen, Dartmouth, TECO and Indiantown, fail to discuss the fuel supply issue at all.

Finally, Sun Peak represents the most unique fuel supply arrangement in the sample. In this case the utility, Nevada Power, assumes all responsibility for fuel supply and price. Fuel is simply delivered to the project, which is also operated by Nevada Power personnel. The unusual arrangements in this case arise out of the special circumstances surrounding this project. Sun Peak is essentially an emergency capacity purchase made by Nevada Power due to unanticipated high demand. The arrangement was made on a third party basis due to the heavy financial pressure Nevada Power is under because of its already substantial construction program. In this

The more common practice is for the contracts to specify some proxy value for the damages associated with failure to come on line at the estimated date. Usually the seller is required to make deposits into a liquidated damages fund that are timed to a schedule of project development milestones. These milestones include events such as securing fuel and construction contracts, financial closing, construction ground-breaking and initial equipment testing. The range of variation in the contracts is along two principal dimensions: (1) the size of the liquidated damage deposits, and, (2) the period before termination is triggered.

The damage deposits range from a low of \$10/kW in the Atlantic City Electric contracts to \$30/kW in the Indiantown contract and the Virginia contracts associated with the 1988 Solicitation. More typical values are in the \$15-18/kW range. The maximum period allowed before termination is triggered is three years in the JCP&L contracts and AES Shady Point. The Virginia Power contracts from the 1988 Solicitation and Indiantown allow only one year. Others fall in the one to two year time frame. During this allowed period of non-performance, however, the utility will take proportional payments from the liquidated damages fund.

These clauses allow forbearance in certain cases. As usual, force majeure is a central locus with respect to the rigorous enforcement of these provisions. There are considerable differences among the contracts with respect to responsibility for securing governmental permits and approvals. In some cases this responsibility rests solely with the seller. This is typically the case for environmental permits. Keystone and Chambers, for example, impose partial damages for failure to secure these permits in 36 months. Dartmouth must secure them in 24 months or be liable for termination and forfeiture of all the liquidated damages deposit. If Dartmouth failed to obtain FERC approval, termination would ensue, but not forfeiture of the liquidated damages fund. Failure to secure FERC and SEC approval by one year from the signing date of the Sun Peak project triggers both termination of the contract and buyout by the purchasing utility, Nevada Power.

6.2 Operational Period

Once the project is in operation, termination can be triggered by excessive performance failures. Representative thresholds where non-performance would cause contract termination are in the range of 12 months (Wallkill) to 18 months (Vista/Paulsboro) to 27 months (Indiantown). The Virginia contracts, which are usually the most constraining on sellers, have no clause which causes termination for non-performance.

There is often a security requirement associated with the operational period. This is conceptually distinct from the liquidated damages fund associated with the project completion risk discussed above, although in the case of the Virginia contracts it has the same name. There are two distinct rationales for ongoing security deposits. The first is the planning risk facing the utility. This is not much different than the concern about project completion. The major difference is the lack of distinct milestones during the development process which track the progress of the project. Premature termination of ongoing projects will impose adjustment costs on the utility.

is an emerging case law at FERC governing affiliate relations. This addresses the affiliate issues at the stage where projects have been selected by utilities, contracts are signed and the projects are seeking waivers from FERC's cost-of-service regulations under the Federal Power Act; i.e., becoming designated as IPPs. The federal concern does not address QFs which may be 49% owned by regulated utilities. It is left to the states to deal with these issues. Second, the states have responsibility for ongoing contract administration. We will show how affiliate abuse can operate through this mechanism as well as through the project selection channel.

7.1 FERC Case Law

Private power projects that are not Qualifying Facilities under PURPA and that seek waivers from federal cost-of-service regulation must apply to the FERC. Decisions on such cases are still relatively few. In general, the FERC has granted such waivers where it was shown that the rates for power purchase did not reflect the exercise of seller market power. Market power is related to control of transmission facilities, or may arise from affiliate relations.

Two recent FERC decisions, involving projects in our sample invoked these general principles, and granted the exemptions (Doswell Limited Partnership, 1990 and Commonwealth Atlantic Limited Partnership, 1990). Other recent cases resulted in rejected applications, primarily because of improper affiliate relations. The TECO Power Services project represents a complex arrangement involving Tampa Electric, an affiliate of TECO, and Seminole Electric Co-operative. One part of the transaction involves the sale of capacity from Tampa to TECO for resale to Seminole. This arrangement in particular raised the issue of abusive self-dealing (TECO, 1990a). The FERC order rejecting the original TECO application does not prove that the abuse occurred, but simply asserts that there is no evidence to the contrary. The applicants subsequently re-filed with FERC, changing the basis of their application from an exemption on the grounds of "workable competition," to traditional cost-of-service. On this altered basis, FERC accepted the proposal (TECO, 1990b). Similarly, the Sun Peak project's application to FERC for market-based rates was rejected due to concerns over market power (NSP, 1991a). Upon re-application, FERC accepted the rates based on cost-of-service (NSP, 1991b). Finally, there is a related case where FERC rejected an arrangement based on affiliate relations. The contracts, which are not included in our sample, involved Iowa Southern Utilities and its affiliate Terra Comfort Corporation. They were rejected on the grounds that there had been no showing that abusive self-dealing had not occurred (Terra Comfort Corporation and Iowa Southern Utilities Company, 1990).

These cases all involve the concept of competition as a substitute for regulation. Where FERC has decided that the facts of the case clearly support a finding of no seller market power, it has granted exemption from traditional regulatory principles based on cost-of-service. Affiliate transactions by definition raise doubts about the workability of competition. The FERC case law appears to require that in such situations a clear demonstration must be made that no abuse occurred. Absent such a demonstration, there is a presumption that market power was operative.

KRCC was allowed unusually liberal termination provisions. It was not required to provide the standard five years advance notice of termination required of projects greater than 100 MW. Because QF capacity payments are levelized, they must refund overpayments in the event of premature termination. KRCC's contract was for twenty years, but its repayment obligation ended after twelve years. For these reasons, DRA claimed the KRCC contract was more like non-firm, or "as-available" capacity, than firm capacity. The CPUC ultimately endorsed the DRA analysis and disallowed $48 million in overpayments made by SCE (CPUC, 1990).

8.0 Miscellaneous Provisions

This discussion has not exhausted the various standard provisions of private power contracts. Neither has it completely surveyed all the risks identified by analysts of this market. In this section we identify and discuss briefly some of the more important features that have been ignored so far. As one useful point of reference, we rely on the survey of this subject by Frank (1989), which reflects the perspective of an important financial participant in the private power market. In this section we discuss, (1) interest rate risk, (2) QF risks, and, (3) "regulatory out" clauses. We do not address tax risks, because they have become a very much smaller part of project returns than was the case before the 1986 Tax Reform Act (Kahn and Goldman, 1987).

8.1 Interest Rate Risk

The possibility that interest rates will fluctuate between the time when a project is proposed and when it is permanently financed is a risk of development. This can be a relatively long time, because permanent financing is commonly put in place only after construction is completed and operation is about to begin. If interest rates increase substantially between the time when a bidder prepares his bid and when permanent financing is acquired, then project economics can deteriorate considerably. With only one exception this interest rate risk is borne by the developer in our contract sample. The exception is the Commonwealth Atlantic contract. In this contract, the capacity price is determined by a schedule in the contract that ties payment level to Treasury bond rates. The exact capacity price will be calculated by a formula that first computes the yield to maturity corresponding to a 13 year term for actively traded Treasury bonds, and then fixes the capacity payment from a table that links such rates with capacity payments. The purpose of this contract feature is to enable the developer to secure leveraged lease financing for the project.

Other projects in the contract sample probably involve greater interest rate risk than Commonwealth Atlantic, because this project has a relatively short lead time between project formulation and the time when the project is permanently financed. In general, interest rate risk is an increasing function of this time interval. For coal projects the interest rate risk is greater because this time interval is longer. This is primarily due to the need to acquire environmental permits before permanent financing can be closed. This will typically take longer for coal than for gas-fired projects.

9.0 Price Trends

It is generally believed that prices paid to private power producers have declined over time. In this section we will substantiate this claim to a limited extent, using data from the contract sample. It is difficult to compare all projects in the sample because they vary along important dimensions. For this discussion we will simplify the comparison considerably.

First, we separate projects by fuel type; gas-fired projects are compared to one another and coal-fired projects are compared to one another. Secondly, we cannot address all the projects because the product differentiation in the sample is considerable. There is no simple way to compare prices for the peaking projects with those of the baseload projects. Similarly, the imported gas projects have a cost structure that resembles baseload coal more than it resembles conventional gas. The imported gas projects (Enron, Dartmouth and Ocean State) have substantial fixed costs for gas transportation that are offset by lower cost fuel. This kind of substitution (fixed cost for variable cost) is the standard trade-off used to compare conventional gas and coal projects. The key to the gas/coal comparison is estimates of future gas price escalation. These estimates are highly uncertain, and would complicate our task.

Instead we look simply at the two earliest contracts in our sample, AES Shady Point and Kern River Cogeneration Company, and compare their costs to project of similar structure that came later in time. We focus on projects capable of serving the baseload segment, even if they have dispatchability options which would make them more flexible in operation. Even this task raises issues that complicate comparisons. Table 6 summarizes the comparison.

9.1 Baseload Gas-fired Projects

We begin with the Kern River case. This contract specifies a twenty year capacity payment of $143/kW-yr and an energy payment that is indexed to gas costs. The form of the energy payment is a heat rate times the gas price paid by the utility for its own use. The value for the heat rate is 9300 Btu/kWh. There is also a 2 mill/kWh payment for variable O&M which is fixed over the term of the contract. This contract is related to the California Interim Standard Offer No.4 (ISO4) contracts that were available in the 1983-1985 period. ISO4 contracts specified capacity payments similar to those of KRCC. The heat rate and O&M provisions were slightly different. ISO4 heat rates were lower (about 8900 Btu/kWH), but if limited curtailments were offered, they would be about the same. The variable O&M rate in ISO4 contracts was indexed to inflation changes.

The Virginia Power gas-fired combined cycle contracts dating from the 1986 and 1988 solicitations make useful contrasts to KRCC. Although these projects, (Hopewell, Doswell and Turbo Power) offer substantially more dispatchability than KRCC, or even the curtailment option under ISO4, they are considerably cheaper on both the capacity and energy dimensions. The 25 year levelized capacity payments, starting in 1990 and 1991 are $115/kW-yr for Doswell, $121/kW-yr for Hopewell, and $128/kW-yr for Turbo Power. Given the 5 to 6 year differences charges. When distillate oil is used, there can be expected to be a fuel cost premium over gas. The contract estimates this at 37% in its base year prices. The contract heat rate is 7898 Btu/kWh in both seasons. We can think of the distillate premium as the economic equivalent of the gas demand charges. Assuming that the 37% premium stays constant, we can amortize it over a year and re-express the premium in terms of the contract heat rate. In these terms, then, the use of distillate oil is equivalent to a 12% heat rate penalty, or an adjusted heat rate of 8846 Btu/kWh. Notice that this heat rate is both less than the KRCC and Hopewell heat rates, but it also applies only to gas commodity costs and not to the sum of commodity and transportation charges. Thus, Turbo Power, even with the distillate oil premium, is less expensive than KRCC. Depending upon how often it is dispatched, the lower variable costs would probably also offset its slightly higher fixed cost compared to Hopewell.

Doswell is structured so that gas demand charges are treated as fixed costs. These are in addition to the capacity payments. The contract provides no information about their magnitude. The variable costs are based on a contract heat rate of 8470 Btu/kWh times the gas commodity costs. During the summer period Turbo will be dispatched before Doswell, since its contract heat rate is lower and both are based on gas commodity costs. During the winter period, this dispatch order will be reversed, since the distillate cost premium can be expected to exceed the 7% heat rate differences.

All three Virginia Power projects offer much more flexibility than California ISO4 projects (of which KRCC is a variant) at lower prices. The other gas-fired projects in the contract sample are not easily comparable with KRCC and the VP projects. We have already discussed the problems posed by the imported gas projects. The two peaking projects, Sun Peak and Commonwealth Atlantic, are an altogether different product. Wallkill is also in a different category. Its pricing structure defines it as an intermediate load project only. The fixed capacity price is paid on a cents/kWh basis. This means that even during off-peak periods, its price will be high. Therefore, the minimum take provisions in the contract of 4760 hours are also likely to be maximum take as well.

Finally, the Cogen project appears to be the most expensive baseload gas-fired project in the sample. Its fixed payment of $0.018553/kWh is equal to $138/kW-yr at an 85% capacity factor. This is roughly comparable to KRCC. In addition, however, there is an O&M payment of $0.009/kWh (1988$) which escalates with the GNP deflator. This is more than four times greater than any other O&M payment for a gas-fired project. At an 85% capacity factor, it is equivalent to $67/kW-yr. The variable pricing in Cogen is difficult to evaluate because there is a benefit-sharing arrangement in the contract which could lead to significant economies compared to the contract price.

One way to summarize this discussion is to draw the contrast between the competitively bid projects from Virginia and the negotiated projects, KRCC and Cogen. Along this axis, the clear result emerges that competition has meant lower prices and greater value. Alternatively, if we consider Cogen an outlier, then the price decline becomes a time trend. Since the sample is so escalation rate, the levelized fuel savings are worth \$168/kW-yr. This means that Beckley's fixed costs net of these fuel savings are \$333/kW-yr. This is clearly less than the other project costs. The economic comparison depends crucially on the assumed capacity factor. At 6000 hours/yr (68.4% capacity factor), levelized fuel savings are \$144/kW-yr. At 5000 hours/yr (57% capacity factor), levelized fuel savings are \$120/kW-yr. At this point, Beckley's total cost advantage begins to fade away.

The basic conclusion from this limited review is that baseload coal project costs are declining. We have too limited a set of costs for the intermediate coal projects to make any assessment of those.

10.0 Conclusions and Future Research

This review of private power contracts gives a flavor of the range in risk allocation practices. Certain general trends are clear. Performance standards for both availability and contract capacity are nearly universal. Failure to maintain standards is almost always punished financially. Bonuses for superior performance are less common. Construction cost and interest rate risks are generally borne by developers. On the other hand, ratepayers typically bear fuel cost risks through indexation clauses.

Beyond this broad allocation, there is also some indication of a trade-off policy at the state or utility level between the accommodation of developers' needs and the desirability of imposing responsibility. These trade-offs appear at the level of contract feature bundles. Contracts show leniency on one feature and severity on others. For example, the Virginia Power contracts are tough on performance requirements and force majeure, but are the most concessionary on the "regulatory out" clause. Conversely, the JCPL contracts are lenient on performance penalties and capacity testing, but tough on the "regulatory out" issue. It is very difficult to assess risk balance at this level.

A complete assessment of risk allocation would require more quantitative economic analysis. If the prices paid in a lenient contract are low, then perhaps ratepayers are not damaged. Similarly, if contract prices are high, but terms and conditions are demanding, the ratepayer may also be well-served. The present state-of-the-art does not allow a systematic assessment of this kind. We do not have well developed methods to price out all contract features, nor are benchmark methods for measuring high and low prices well established.

Despite these limits, we can observe two trends which suggest that the private power market is functioning reasonably well in the ratepayer's interest. The first trend is the measurable movement to lower prices in this highly competitive market. Second is the growing tendency to incorporate increasingly strict terms in the contracts as utilities move away from lenient risk allocation terms that tend to be found in earlier contracts.

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