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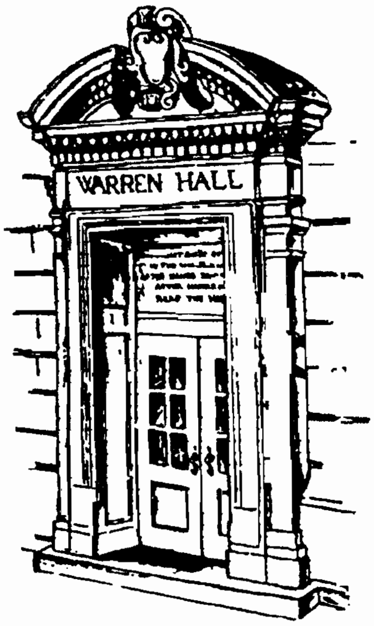

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RETHINKING CONTRACTS FOR PURCHASING POWER: THE ECONOMIC ADVANTAGES OF DISPATCHABILITY

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Abstract:

The purpose of this article is to evaluate and compare the incremental cost of purchased power from non-utility generators versus utility built generation considering a variety of contracts for energy purchases. Four types of contracts are evaluated: 1) Flat Rate Produce and Pay , 2) On-Peak/Off-Peak, 3) Basic Dispatchable, and 4) Actual Cycle Energy Dispatch. The type of contract can affect the competitiveness of electric rates through increased energy production costs as well as increased risks, in terms of financial liability, affecting the cost of debt to the purchasing utility. An analysis conducted for a representative utility calculates the effects of NUG power purchases on a utility's energy production costs and the cost of new debt issuances. Dispatchable energy contracts are shown to provide significant economic and operating advantages over Flat Rate and On-Peak/Off-Peak energy contracts. In addition, an example shows that NUG purchases based on the actual thermal cycle and fuel costs for dispatch cost less than utility-built generation financed at the utility's weighted average cost of capital. NUG's are also shown to act as external instruments that increase a utility's leverage and result in a higher cost of debt for the utility. However, this increase is less than the finance costs for an identical facility built by the utility. NUG contracts for a utility which already has significant risk exposure are shown to parallel a capital lease. Under these conditions, additional payment obligations to NUGs increase the cost of new debt issuances making an equity issuance for utility built capacity a more attractive option.

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I. INTRODUCTION

The economic and operational contract mechanisms used in long term power purchase arrangements have a direct impact on electric rates and utility credit ratings.[1] Power contracts executed in the electric utility industry today often fail to integrate the contracted resource efficiently with a utility's existing resources or address the concerns of the financial community. This is particularly true when long-run contracts are written only for delivered energy. In a 1990 *Energy Journal* article titled "The Efficient Design of Contracts To Purchase Cogenerated Power", Hall and Parsons present a contractual structure to provide non-utility generators (Nudges) with a financial incentive to perform long term plant maintenance. They solve the moral hazard of long term plant maintenance by separating the long run avoided capacity costs from the avoided energy costs, but do not extend this framework to the more important issue of dispatchability. Doucet, in a 1994 *Energy Journal* article titled "Coordination of Non-utility Generation Through Priority Contracts", addresses the issue of dispatchability through a structured series of energy prices and energy deliveries presented in a deterministic framework. Doucet's price structure provides price signals to NUGs that put some value on dispatchability, but the deterministic framework falls short of distinguishing between avoided capacity and energy costs. Thus, limits are placed on its ability to integrate NUG resources efficiently. The following analysis shows that a much larger potential for savings exists through adopting a dynamic price structure that simultaneously address both the direct savings from dispatchability as well as the indirect effects on the cost of capital for the purchasing utility.

Since its nascent stages before 1990, the competitive power market has matured significantly, presenting a whole host of new problems as the NUG becomes a major source of new capacity for many utilities.[2] This article examines four general forms of

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[1]Moulton (1993) and Abbot (1992).
[2]According to the North American Reliability Council, the New York Power Pool had 817 MW of NUG capacity in 1990 and is predicted to have 5,417 MW of NUG capacity by the decades' close. For the United States, 18,156 MW of capacity existed in 1990 with 35,352 MW predicted for the year 2000.

economic power purchase contracts 1) Flat Rate Produce and Pay , 2) On-Peak/Off-Peak, 3) Dispatchable Energy Contracts 4) Actual Cycle Dispatchable Energy Contracts. The risks and benefits associated with each contract form are examined for the utility, the power supplier, and the rate payer. To elucidate the distinctions between each contract form and further clarify the economic consequences of each contract, an analysis of both direct incremental costs for energy production and indirect financial costs are performed for a Northeast utility.[3] The analysis concerns incremental differences in variable energy production costs and does not include or depend upon optimal capacity expansion choices by the utility.[4]

Optimal integration of a new NUG resource into an existing utility power supply system can potentially maintain the economic mechanism of least cost energy production as well as shift the construction and operating risk of new power plant construction away from the utility and the rate payer. Under less optimal provisions, power contracts for non-utility generation (NUG) can have negative effects on the system. These include:

1) loss of system control,
2) required purchases of uneconomic NUG energy,
3) reduced bond rating from assumed liabilities[5], and
4) higher electric rates for customers.

In many situations, the regulatory process has forced utilities to contract with NUGs under economic and operating terms that are often far less than optimal for the utility and the electric customer.

The potential economic efficiencies of competitive power markets, such as reduced costs and lower operating and financial risks for rate payers, are paradoxically being undermined through inefficient power purchase contracts. Issues such as regulatory risks,

[3]The analysis is relevent for any utility considering capacity additions from thermal energy plants.
[4]The critical element is the optimal dispatch of NUG facilities, and the additional costs associated with having surplus capacity are not part of the analysis.
[5]"Assumed liabilities" refer to capacity payments to NUGs which effectively become liabilities as the utility has an obligation to make payments to NUGs independently of changes in capacity and energy requirements.

insurance, and the consequences of failing projects have been addressed by the use of "regulatory out" clauses and contract pre-approval, force majeure and damage provisions, takeover provisions for failing projects and performance criteria for payments.[6] The challenge is to enhance the economic efficiency and operating integrity of traditional utility power supply systems within a more competitive power market. The objective of the proposed new form of contract is to increase benefits for rate payers from efficient power contracting while controlling possible detrimental effects to utility shareholders or the owners of NUG facilities.

II. POWER CONTRACTING MECHANISMS

1. FLAT RATE PRODUCE AND PAY CONTRACTS

Flat Rate "produce and pay" contracts, often referred to as Flat Rate "take and pay" contracts, were the first form of NUG power purchase contracts and represent the preponderate share of electric power purchase agreements with NUGs.[7] The rather simplistic economic structure of this type of contract pays producers on a ¢/kWh basis for energy delivered as shown in the following formula:

$$E = \sum_{i=1}^{N} P^{*} e_i$$

where,

P^* : price of energy for hour i with the "*" indicating a price adjusted periodically according to either pre-determined escalators or an index of escalation
e_i : energy kWh delivered for i hours
N : number of hours in billing period (e.g. month)
E : electric sales bill to utility for billing period

6.Boling (1992).
7Abbot (1992). Other power purchase arrangements may claim larger capacity and energy sales.

The economic inefficiency of "Flat Rate" contracts can be attributed primarily to its failure to account for the specific and dynamic operating and economic environment of the utility. In effect, the harmonious picture of continuous cost minimization based on each plant's marginal cost of production becomes distorted. The NUG operator will maximize profits under the flat rate power purchase price structure by producing electricity whenever possible, independent of its operating costs relative to that of the utility system. This indifference to the time of day or season can result in less than optimal resource allocation whenever the utility has resources with a lower marginal cost of production. Consequently, Flat Rate power contracts can result in higher energy production costs and capacity costs than would be incurred if more efficient contract mechanisms are used. Furthermore, these contracts represent a market risk to the extent that higher than competitive market prices cause the utility to lose customers, sales, and earnings. In particular, contracts developed with energy purchase rates fixed to a forecasted rate of escalation present the risk of diverging from competitive market prices over the life of the contract.

2. *ON-PEAK/OFF-PEAK ENERGY PRICING*

On-Peak/Off-Peak energy pricing is a slightly more complex form of the flat rate contract. The utility provides a higher ¢/kWh power purchase rate for energy delivered during on-peak hours as opposed to energy delivered during off-peak hours. An example of this type of contract can be written:

$$E = \sum_{j=1}^{J} \sum_{i=1}^{6} b^* P^* e_{ij} + \sum_{j=1}^{J} \sum_{i=7}^{19} a^* P^* e_{ij} + \sum_{j=1}^{J} \sum_{i=20}^{24} b^* P^* e_{ij}$$

where,

- J : number of days in the billing period (e.g. 30 days)
- i : hours of the day
- a^* : on-peak adjustment of power price P^*
- b^* : off-peak adjustment of power price P^*

The difference in on-peak versus off-peak energy rates are commonly developed to reflect the average variable energy cost spread between on-peak and off-peak hours and, for example, may be developed from a utility's retail on-peak/off-peak rates or marginal energy and capacity costs. The * implies that the price and the differentials are predetermined.

The on-peak versus off-peak rate can potentially provide an incentive for the NUG to produce energy in accordance with the purchasing utility's needs. However, the economic criterion for real-time electric power dispatching is continuous cost minimizing which can not be accurately represented by only two different average purchase rates.[8] The loss in efficiency is a function of the variance in the actual dispatch costs. In addition, capacity payments are often included in a ¢/kWh form for energy delivered, so that the combined capacity and energy rate effectively becomes one energy rate.[9] This combined rate is invariably greater than the NUG's variable cost of production off-peak as well as on-peak. Thus, in practice, the contract resembles a flat rate "produce and pay" contract with the NUG trying to maximize energy production. The following analysis will refer to and treat Flat Rate and On-Peak/Off-Peak contracts jointly as non-dispatchable because a Flat Rate contract can be considered as a special case of an On-Peak/Off-Peak contract ($a^*=b^*$).

3. *BASIC DISPATCHABLE ENERGY CONTRACTS*

A Basic Dispatchable energy contract with a NUG can provide the same degree of economic efficiency and operational control to the utility as one of its own plants. These contracts closely resemble the economic structure of utility-owned generation with a capacity and energy component of the following form,

$$E = \sum_{i=1}^{N} \left[h^* f_i e_i + c_i k^* \right]$$

[8]Joskow (1983).
[9]A more sophisticated form of on-peak/off-peak pricing is Doucet's priority pricing structure and real time pricing which can provide consistent economic incentives that capture the variability in daily energy production costs. However, the forecasting energy production rates seriously impairs the ability to accurately capture the variablity in energy production.

where,

c_i : capacity available to produce energy for hour i
k^* : capacity price in ¢/kW
h^* : average plant heat rate in Btu/kWh
f_i : fuel price for hour i in $/Btu

The first term on the right hand side of the equation represents the fuel cost for electric energy produced and the second term represents the capacity payment for available capacity.[10] The variable energy cost is the product of the net plant heat rate (h) and the hourly fuel price (f_i) times the energy delivered. The heat rate term is often predetermined from preliminary cycle design analysis (and consequently has an *) with an additional conservative measure to insure profitable operation and satisfy the project finance criteria. The dispatchable energy price will always be equal to or greater than the average variable cost of energy production in order to insure against economic losses over the full range of energy dispatch offered as well as account for the deterioration of plant efficiency.[11]

By integrating the NUG resource with the existing utility system, a Basic Dispatchable energy contract provides significant production cost savings over a flat rate contract, as well as significant operational advantages.[12] NUG electric output levels are adjusted based on the plant's variable cost of production. Moreover, when the facility's output is less than full load, the unused capacity can be included in the utility's active 10 minute spinning reserve. In addition, coordinated plant maintenance with the utility can also reduce energy costs and required capacity reserve margins.

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[10]The capacity component should reflect the fixed costs of furnishing power and include taxes, capital payment, operations and maintenance, and depreciation. As a result, the capacity component maintains a constant value over the duration of the billing period. Portions of the capacity component are subject to periodic change, such as O&M costs, and are escalated with an appropriate index.
[11]The capacity component for the NUG is based on an availability basis. This can effectively be done by either paying the NUG on a ¢/kW basis for available capacity (whether or not the energy is dispatched) or through a $/kW-month capacity component adjusted for availability. Further mitigation against assuming risk for capacity payments can be achieved through a cut-off of capacity payments for plants falling below a certain minimum level of availability.
[12]Transaction costs for dispatchability are negligable. Dispatch instructions can be delivered electronically or by telephone.

Use of a single value for the heat rate of a NUG plant provides a reasonable mechanism to integrate a thermal power plant into a utility's power supply mix. However, this mechanism falls short of capturing the full economic value of the resource by fixing the variable cost of production to a single estimated value. In order to integrate the costs of a NUG resource efficiently, the contract must provide an economic structure that treats the NUG on the same basis as if it were owned by the utility. This is achieved in the next type of contract.

4. ACTUAL CYCLE ENERGY PRICING

Actual Cycle Energy Pricing (ACEP) is an efficient contract structure. Its form remains essentially the same as the Basic Dispatchable energy contract with a capacity component based on plant availability, but the energy component is based on the actual variable cost of production,

$$E = \sum_{i=1}^{N} [I(e_i)f_i + c_i k]$$

where,

$I(e_i)$: heat input (MBtu) required to produce e_i kWh of electricity. The heat input is determined from the actual plant heat rate curve.

These contracts are referred to as "actual cycle energy contracts" because the variable energy component is determined from the plant's actual heat rate curve.

The energy production efficiencies resulting from the use of the ACEP contract method preserve competitive electric rates and maintain maximum operating flexibility. Competitive electric rates are maintained through fully integrating the NUG resource into the utility's existing power supply mix using energy dispatch methods that are consistent with existing utility owned resources.[13] Maximum operating flexibility is achieved through contract provisions that determine the NUG's full operations as if it were a utility plant.

III. FINANCIAL IMPLICATIONS FOR UTILITIES

1. RISK AND THE COST OF DEBT

Each form of contract for purchases from a NUG represents risks and liabilities to rate payers, utilities and NUGs. Power purchases made by a utility may incur indirect costs through reduced bond ratings which in turn can undermine a utility's competitive advantage. Reduced bond ratings associated with NUG purchases are a result of the indirect liability associated with capacity payments to NUGs as well as a possible erosion of a utility's ability to serve its customers competitively with expensive NUG purchases. Bond ratings are adjusted by allocating a portion of the capacity obligations as a liability without a corresponding entry as an offsetting asset. In addition to indirect costs, NUG purchases can be viewed as an external instrument to adjust a utility's capital structure. Examination of the effect of additional indirect liabilities on a utility's overall finance costs can provide useful insight for developing a more optimal capital structure.

When setting a utility's credit status, Moody's evaluates purchases from NUGs on the basis of "financial flexibility", which reflects the operating flexibility of the power purchase contract.[14] Rigidities imposed by a contract's structure which fail to mirror the economic/operating efficiency of traditional utility owned generation reduce a company's financial flexibility. The proportion of contracted capacity payments to be made to a NUG that is characterized as balance sheet debt by credit rating firms is contingent upon the economic structure of the contract. For example, under Duff and Phelps's qualitative utility

[13]This assertion is developed from an incremental variable cost of production basis which is independent of the issues of capacity surpluses or deficiencies.
[14]Abbot (1992).

credit valuation criteria[15], the New York State standard offer for avoided energy and capacity (flat rate pricing) has the following "valuated"[16] disadvantages:

1. Little or no dispatchability so that power must be taken whenever available.
2. Limited or no ability to schedule maintenance to conform to load or company scheduled plant outages.
3. Lack of control over the facility should the seller terminate the contract.
4. Power costs under the current Public Service Commission ruling may be higher than alternatives.
5. Liability burden of ownership payments without any compensating flexibility for operations.

Standard & Poors (S&P) assesses a utility's qualitative risk factor (Q) between 0% and 100% to reflect the market, operating and regulatory risks that the utility bears. The risk factor is subject to a wide degree of variability of which the contract form is a central component. The risk factor used by S&P determines the potential debt equivalent by calculating the net present value (NPV) of future payments for capacity (K_t) adjusted by the risk factor (Q_t) discounted at 10% as shown by the following equation,

$$NPV = \sum_{t=1}^{T} \rho^t \left(Q_t / 100 \right) (K_t)$$

ρ : discount factor (.90)
Q_t : annual debt adjustment factor
K_t : annual capacity payment
T : duration of contract(s)

These adjustments are said to "enable more realistic financial comparisons between companies meeting future resources through purchased power versus companies which build their own generating plants."[17] Duff & Phelps has a slightly different methodology,

[15] Abrams (1991).
[16] A term used in credit rating industry. See Abrams (1991) or Moulton (1992).
[17] Moulton (1991).

but the principal methods of accounting for off-balance sheet liabilities are similar between the two companies.

A utility's bond rating can be maintained by either restoring the effective coverage ratio through a higher allowed rate of return or strong regulatory assurances of cost recovery for the entire contract life. It should also be noted that Duff and Phelps considers that long-term inter-utility purchases pose the same type of financial liability as purchases from NUGs.

From the utility's perspective, NUG payments are equivalent to fuel purchases from a long term contract. These payments are typically run through a utility's fuel adjustment clause or some other recoverable expense with the future payment obligations and the associated asset value omitted from the balance sheet. Credit rating agencies view the capacity portion of NUG purchases as undertaking characteristics similar to an equipment lease with a long term obligation to make payments to the NUG for delivered capacity. Because utility accounting practices do not recognize future obligations to make NUG payments associated with capacity purchases, the rating agencies perform off-balance sheet adjustments to utility balance sheets. The implicit liability of NUG purchases result from the following perceived risks: 1) the regulatory risk of continuing to allow fuel adjustment clause expensing of NUG payments, 2) the market risk of maintaining sufficient revenues to cover NUG purchase obligations, 3) maintaining the competitiveness of a utility's electric rates.

2. *EVALUATION OF RISK FACTORS FOR DIFFERENT FORMS OF CONTRACT*

FLAT RATE CONTRACTS

Flat Rate contracts, such as the New York State's legislatively mandated ¢6/kWh contract, have all the disadvantages discussed in the previous section. These contracts fall significantly short of mirroring utility built generation, and consequently, have high qualitative risk factor so that a large proportion of the capacity payments are treated as additions to balance sheet debt by rating agencies.

ON-PEAK/OFF-PEAK POWER PRICING

On-Peak/Off-Peak contracts, reflecting retail on-peak/off-peak rates or some other two tiered rate structure, effectively present the same financial risks and potential liabilities to the utility as Flat Rate contracts. In order to prevent unnecessary "dumping" of electric power, when the demand for power is low, some contracts contain provisions for curtailing NUG purchases up to an established number of hours per year.[18] This may prevent the utility from having to dump power, but it still does not succeed in capturing the full economic potential of NUG power. Standard & Poors recognize correctly that, in practice, On-Peak/Off-Peak power pricing is equivalent to a Flat Rate power pricing.

BASIC DISPATCHABLE ENERGY CONTRACTS

The economic and operational advantages of Basic Dispatchable energy contracts reduce most of the qualitative operating disadvantages of Flat Rate contracts. This form of contract goes a long way to maintaining competitive electric rates by minimizing the production costs of energy and reducing a utility's qualitative risk factor. A reduced risk factor will improve a utility's credit rating over Flat Rate contracts.[19]

ACTUAL CYCLE ENERGY PRICING

The ACEP contract's efficiency in meeting electricity demand improves a utility's bond rating over Basic Dispatchable energy contracts by additional reductions in the production costs of energy and reduced financial costs. Although the capacity payment obligations (off-balance sheet liability) remain the same as under the other pricing forms, the qualitative risk factor is lower, which reduces the impact of the contract on the utility's

[18]New York State curtailment proceedings Case 92-E-0814.
[19]Moulton (1991).

off-balance sheet liabilities.[20] The ACEP contract provides the best form of a contract for keeping electric rates low compared to the other three contracts for purchased power.

IV. FINANCIAL STRUCTURE OF CAPITAL

Credit agencies assess the risks of NUG purchases by examining a contract's capacity payments and evaluating the utility's overall fuel and power supply risks.[21] This falls short of evaluating the extent to which the capital structure of the NUG is leveraged. Although the capital structure of the NUG has little direct effect on a utility's credit rating, additional leverage may provide a comparative cost advantage in financing new construction. By design, utilities earn a relatively secure rate of return, with rates set relatively low by regulation. However, by the same design, utilities are limited in their ability to assume risk through additional debt financing.

The target capital cost structures adopted by most utilities and accepted by regulators can be characterized as "low risk" with the equity component commonly approaching the proportion of debt. The security of regulated utility investments generally results in lower interest rates for debt and equity for utilities versus NUGs. Table 1 shows an example of the comparative capital costs for a utility and a NUG. The utility has lower costs of both debt and equity compared to the NUG, and in addition, the utility has a lower weighted cost of capital before taxes. However, the same capital structures on an after-tax basis provide the opposite conclusion.[22] The after-tax weighted cost of capital is 7.94% for the NUG versus 8.41% for the utility. The nearly one half of a percent lower interest rate for of NUG capacity provides an advantage over utility capacity in a competitive power

[20]See Moulton (1993), Abrams (1991), or Abbot (1992),
[21]See Moulton (1993), Abrams (1991), or Abbot (1992),
[22]The after-tax interest rate for debt is calculated as the product of one minus the tax rate of 40% times the interest rate, and the equity rate remains unaffected by taxes.

market. However, it should be recognized that the NUG is able to achieve a highly leveraged capital structure through the utility's commitment to pay for energy deliveries.[23]

Table 1: Capital Cost Structure

	NUG					Utility				
	Percent	Interest	Pre-Tax Weighted Average	After Tax Interest	After Tax Weighted Average	Percent	Interest	Pre-Tax Weighted Average	After Tax Interest	After Tax Weighted Average
Debt	82%	9.20%	7.54%	5.52%	4.52%	52%	8.50%	4.42%	5.1%	2.65%
Equity	18%	19.0%	3.42%	19.0%	3.42%	48%	12.0%	5.76%	12.0%	5.76%
Total			**10.96%**		**7.94%**			**10.23%**		**8.41%**

V. ANALYTICAL FRAMEWORK

Electric rate payers bear the cost of inefficient long term power purchase arrangements. In order to understand the effects of contracts on rate payers under the four power purchase contracts discussed above for a representative utility (Utility A) incremental energy costs are calculated and the financial costs are determined using two alternative methods: 1) the increased cost of debt (discussed in Section III), and 2) capacity payments as capital lease obligations.[24] The results can be generalized using method I for any utility, although the size of the indirect costs of financing will depend on the importance of NUG purchases. The capital lease approach should only be considered if a utility is perceived as high risk where an increase in costs or leverage pose a problem to the company's financial viability. (Utility A was selected because it has a relatively large amount of NUG purchased power.) Both analyses evaluate the total incremental costs with each contract as the exclusive means of purchasing the NUG capacity. These costs are

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[23]In addition, debt may be retired more quickly by the NUG than the utility leading to lower total finance charges.

[24]The results are based on inputs obtained from utility A's *1991 Integrated Resource Plan (IRP) and 1980-1990 Financial and Statistical Review.*

developed using Utility A's existing and planned capacity and energy purchases from NUG resources.[25]

Both financial analyses share the same incremental costs for energy purchases which are determined from an Energy Production Cost Model (EPCM).[26] The direct costs determined by the EPCM measure the incremental costs to rate payers for inefficient energy dispatch and can consequently be classified as fuel costs.[27] For the Debt analysis, the indirect finance costs are determined from a Financial Cost Model (FCM)[28] using an incremental cost method consistent with the EPCM. The indirect costs of NUG purchases are determined from the increase in the cost of new debt attributed to these newly assumed risks and financial liabilities. The indirect costs are distinct from but comparable to the incremental cost of equivalent capacity built by Utility A and financed at its weighted average cost of capital. The same incremental cost method is used for the lease analysis. It should be remembered throughout the analysis that the physical characteristics of the new capacity are identical in all cases. In other words, the investment in capacity is the same, but the cost of financing the investment varies.

The lease analysis draws upon the "buy/borrow versus lease" model to determine finance costs. The signing of a capital lease utilizes a utility's debt capacity, reducing the lessee's ability to issue more debt in the future. Lease obligations can consequently be viewed as equivalent to capacity additions financed entirely with debt. The comparative capacity additions for Utility A are financed at the after tax cost of debt instead of the weighted average cost of capital with an adjustment for the indirect finance costs.

[25]The amount of NUG capacity and electric energy delivered to the utility was kept the same in all four scenarios and was based on the values listed in Utility A's 1991 IRP. Annual energy purchases from NUGs beyond the year 2002 were assumed to escalate at a constant rate of 1.2%.

[26]See Technical Appendix for description.

[27]Costs associated with surplus capacity resulting from mandated purchases were not calculated for Utility A, and costs of additional reserve requirements when NUGs fail to follow established utility practices for coordinated maintenance scheduling were also omitted. The justification for abstracting from these real problems is that the objective of the paper is to focus on the general implications of different forms of contract, and not to describe the idiosyncrasies of a specific regulatory environment.

[28]See Technical Appendix for details.

1. ENERGY PRODUCTION COST MODEL

The direct cost calculated by the EPCM assess the additional cost for NUG energy purchases over operating and pricing the same energy resources efficiently. The EPCM determines the incremental energy cost of purchased energy versus energy deliveries based on the most efficient dispatch mechanism for the new generating resource (i.e. utility generation). Since it is assumed that utility owned generation and the ACEP contract mechanism are operated and priced efficiently, there are no incremental energy costs. These efficient forms of energy dispatch can be compared to the less efficient Basic Dispatchable and the two non-dispatchable contracts.

The incremental energy cost for NUG purchases is determined by segmenting the week into six components consisting of four partitions for weekday hours and two partitions for weekend hours.[29] In addition to calculating the direct energy production cost differentials, the EPCM accounts for other energy production costs such as ten minute spinning reserve. An energy production simulation determines the hourly production cost differential between the contract price versus efficiently operated generation. The hourly energy cost differentials are consolidated into the six time partitions. The differentials for each time partition are assumed to escalate at a 5% per year nominal rate to reflect the characteristics of a typical contract.

Table 2 displays the incremental energy costs for a 1 MW purchase of non-dispatchable NUG energy over a typical week in 1990. The "delta" values in $/MWh represent the average estimated incremental cost of NUG energy purchases above Utility A's system lambda.[30] The "duration factor" represents the percent of operating time the delta value applies. For the off-peak hours of 11 PM to 7 AM, Partition D, non-dispatchable energy contracts cost rate payers an additional $5/MWh for 80% of the

[29]In order to simplify the analysis, the Flat Rate and On-Peak/Off-Peak contracts, as discussed above, are assumed to be operationally the same, and accordingly, were consolidated into a single contract form (non-dispatchable).

[30]System lambda refers to the incremental variable production cost for a utility.

weekday hours of the year. Over the same time period, lost ten minute spinning reserves cost $0.23/MWh, calculated as the product of percent of capacity associated with spinning reserve times the load duration factor and a $1.1/MWH spinning reserve value. The costs for each $/partition are aggregated for the week and then the year.

Table 3 displays the incremental energy production costs for non-dispatchable contracts for the years 1995, 2000, and 2005. Additional details of incremental energy costs are for shown in Appendix A. As one would expect, the dispatchable energy contracts have no cost for 10 minute spinning reserve, but the Basic Dispatchable contract has a small incremental energy cost associated with the inefficiencies of using a linear heat rate curve.

Table 2: Incremental Energy Costs for 1 MW Proxy Unit in 1990

Flat Rate and On-Peak/Off-Peak						
Weekdays	Time	Hrs/Week	Delta $/MWH	Duration Factor	% of Capacity as 10 Min. Spin	$/Partition
Partition A	'10-18	45	0	100.0%	4.0%	$1
Partition B	'8-9, 19	15	3	50.0%	20.0%	$26
Partition C	'20-22,7	20	5	65.0%	20.0%	$69
Partition D	'23-6	40	5	80.0%	20.0%	$169
Weekends						
Partition E	'12-24	24	5	60.0%	20.0%	$77
Partition F	'1-11	24	5	100.0%	20.0%	$125
Total						**$468/wk** **$24,313/yr**

Table 3: Incremental Energy Costs by Contract (nominal dollars)

	1995 $/MWH	2000 $/MWH	2005 $/MWH
Flat Rate, On-Peak/Off-Peak	3.54	4.52	5.47
Basic Dispatchable	0.30	0.38	0.46
ACEP	0.00	0.00	0.00
Utility Owned Gen. (Debt & Lease)	0.00	0.00	0.00

2. *THE FINANCIAL COST MODEL*

The Financial Cost Model (FCM), used for the debt analysis, calculates the indirect costs associated with NUG purchases which are determined from the increased cost of issuing new debt. Because the capacity additions are supplied by NUGs, these new debt issuances are for other investments such as transmission line upgrades, construction of new transmission facilities, or installation of emissions control equipment on existing plants. These indirect financial costs can be compared to the cost of building the same resource at the same level of investment with the weighted average cost of capital (shown in Table 1). The indirect costs are intended to adjust the balance sheet of Utility A, making it appropriate to use the weighted average cost of capital.

The FCM estimates Utility A's long term debt issuance's as $330 million for 1991 through 1993 and thereafter escalating at a constant nominal rate of 3% annually through 2005. A moderate escalation rate is used to reflect slower long term regional economic growth, improved efficiencies in electric equipment, and a greater dependence on NUG purchased power. The maturity of long term debt issuances are set according to the duration and proportion of past issuances. The off-balance sheet obligations and qualitative risk factors are determined according to the established criteria of credit rating companies and are used as a basis for adjusting interest rates for debt.[31] Both bond rating downgrades and denied upgrades as a result of NUG purchases are assessed in the Financial Cost Model (FCM). However, the rating adjustments are specified conservatively for large shifts in off-balance sheet obligations.

The other cases evaluated by the FCM are the Basic Dispatchable contract and the ACEP contract mechanism. In each case, the assessed contract mechanism is the exclusive means of contracting for NUG power under Utility A's projected procurement of NUG capacity and energy. Table 4 specifies the basis point premiums used to determine the indirect financial costs of NUG purchases.

[31]Moulton (1991).

Table 4: Basis Point Premiums by Contract Type

Utility Interest Premiums

Year	1991-1994	1995-1997	1998-2002	2003-2005
Flat Rate and On-Peak/Off-Peak	25	50	75	50
Basic Dispatchable	13	25	33	13
ACEP	10	20	25	10

Credit ratings for Flat Rate and On-Peak/Off-Peak contracts follow S&P's procedures which attribute 60% of the total projected payments as capacity related. A 25 basis point premium from 1991 to 1994 can be interpreted from Utility A's financial statements as a denied increase in credit rating. The large addition of new NUG resources between 1995 and 1997 results in an additional 25 basis point premium. Another 25 basis points are incurred from 1998 to 2002 because of further NUG additions to the point where the company may be forced to dump power.[32] It is assumed that Utility A will survive the large infusion of NUG power over the next decade without any significant effects on the company's overall financial success. Consequently, the financial rating institutions will become more comfortable with Utility A's proven success and reduce the qualitative risk coefficient of off-balance sheet liabilities, improving the company's credit rating by 25 basis points in 2003. Although the proportion of NUG capacity will continue to increase from the years 2003 to 2005, the company is anticipated to manage these new acquisitions effectively and adjust its balance sheet to prevent additional credit deratings.

Under the Basic Dispatchable and ACEP contracts, Utility A's credit position for planned NUG purchases follow the same pattern as the non-dispatchable contracts for the same reasons. The significant difference in basis points between the non-dispatchable and the dispatchable cases can be attributed to a reduced qualitative risk coefficient. An additional component of the FCM is to assess the higher finance cost of utility built generation versus NUG generation. To determine the additional cost of utility built

[32]Higher energy costs associated with dump power in the late 1990's for non-dispatchable contracts were assumed to be partially mitigated by an external system sale.

generation, a 47 basis point finance premium (from Table 1) is assessed on the estimated average capital expenditures for new capacity acquisitions. This cost is compared with the finance premiums associated with NUG purchases for selected years in Table 5.

Table 5: Indirect Financial Costs by Source (nominal dollars)

	1995 $/MWH	2000 $/MWH	2005 $/MWH
Flat Rate and On-Peak/Off-Peak	0.53	1.67	2.67
Basic Dispatchable	0.26	0.76	1.08
ACEP	0.21	0.61	0.86
Utility Built Gen. Debt Analysis	0.78	0.75	0.84

3. *BUY/BORROW VERSUS LEASE MODEL*

The use of the "buy/borrow versus lease" model in the lease analysis corresponds to a high risk situation where additional leverage or increase in costs poses a problem to the financial viability of the utility. Under a capital lease, the present value of the future lease liability appears as debt with the corresponding asset value also written into the books.[33] Thus, the capacity purchase obligations for Utility A become equivalent to a debt liability. With the entire capacity obligation treated as debt, there are no indirect finance costs for Utility A. However, the treatment of incremental capacity additions as debt requires Utility A to use its after tax cost of debt in comparing the finance cost of utility owned generation versus NUG purchases.[34] The 2.18 percent difference between the NUG after tax cost of capital (7.94%) and the utility after tax cost of debt (5.76%) adds a significant finance premium to NUG capacity additions.[35] Finance costs for the lease analysis are shown for selected years in Table 6.

[33]A capital lease requires the present value of the lease liability to appear on company balance sheets while an operating lease acts as off-balance sheet financing.
[34]Bierman (1986). The weighted average cost of capital or a risk adjusted rate can be used if adjustments are made for the fact that the decision involves asset financing.
[35]The nominal values of the NUG and utility cost of capital change through time, but the incremental difference remains nearly unchanged through time.

Table 6: Lease Analysis Financial Costs by Source (nominal dollars)

	1995 $/MWH	2000 $/MWH	2005 $/MWH
Flat Rate and On-Peak/Off-Peak	4.70	4.52	5.08
Basic Dispatchable	4.70	4.52	5.08
ACEP	4.70	4.52	5.08
Utility Built Gen. Debt Analysis	0.00	0.00	0.00

The lease analysis provides a direct and conservative basis for evaluating NUG purchases versus utility built generation and avoids the uncertainty associated with determining the qualitative discount factor used in the Debt analysis. However, this uniform approach to assessing finance costs indiscriminately amalgamates the finance costs for radically different power contracts without effectively distinguishing the true risk characteristics of each contract form. There are additional shortcomings to this approach which will be become manifest when the results for the lease analysis of utility A are presented and discussed.

VI. IMPLICATIONS FOR RATEPAYERS

1. DEBT ANALYSIS OF COSTS

The results presented in Figure 1 are the incremental 15 year levelized hourly production cost differentials in $/MWH for utility built generation and NUG power purchases based on contract type.[36] These costs can be compared to an "efficient" contract with no energy or finance increments corresponding to optimal efficiency of energy production and no risk to the purchasing utility. The total incremental costs of $5.21/MWH for the non-dispatchable contracts are comprised of a $1.38/MWH finance cost and a $3.83/MWh energy production cost. Both the energy and finance costs increase in real dollars over the 15 year period as NUG's comprise a larger portion of the power supply mix for Utility A.

[36] Levelized values were determined using a 10% discount rate for the annual energy costs shown in Table 4 and Appendix A..

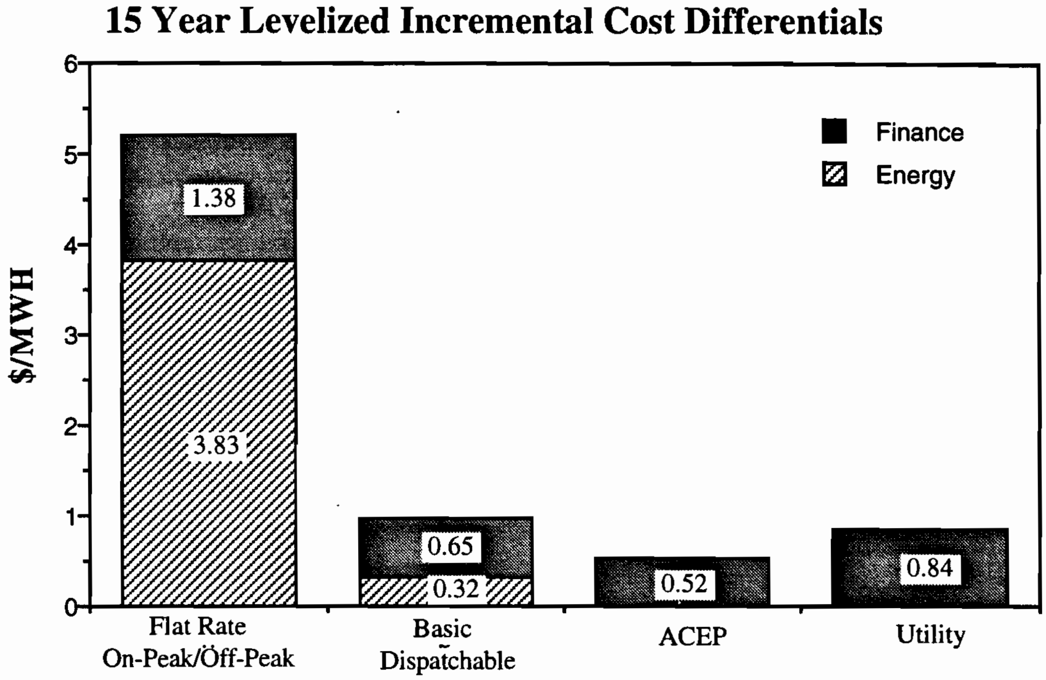

Figure 1: Debt analysis based on Utility A's financial and energy data

With a total incremental cost of $0.97/MWh, Basic Dispatchable contracts provide a substantial cost advantage in excess of $4/MWh over non-dispatchable contracts. Unlike the non-dispatchable contracts, the important incremental cost for the dispatchable contracts are attributed to finance charges, reflecting the contract's operating efficiency in meeting electric load. The ACEP contract has the lowest cost compared to other contract mechanisms with a total cost of $0.52/MWh. All the costs associated with the ACEP contract are attributable to additional finance charges, because it meets electric load as efficiently as utility owned and operated power, and consequently, there is no energy cost differential.

Using the weighted average cost of capital for Utility A (Table 1), utility built generation results in a finance cost differential of $0.84/MWh. Comparing these incremental costs with ACEP contracts, utility built generation results in roughly a two thirds higher incremental cost to rate payers. Furthermore, the NUG has the potential to achieve additional competitive advantages through improved fuel utilization efficiency (e.g. using cogeneration). In addition to these calculated costs advantages, ACEP contracts do not place the full risk of plant availability and construction cost over-runs on the rate payer. Thus, the rate payer assumes less risk with ACEP contracts at a lower cost than utility built generation.

Analysis of the finance costs can be extended to illuminate the effect of a more leveraged capital structure on the weighted average cost of capital. Although the pre-tax capital costs for each incremental capacity addition is assumed constant between NUG and utility built generation, a finance cost component results from the different levels of risks assumed by the utility under each NUG contract form, the differences between NUG and utility capital structure, and the effect of taxes. The relatively small debt component attributed to dispatchable contracts results in incremental finance costs for Basic Dispatchable and ACEP contracts respectively of \$0.65/MWh and \$0.52/MWh compared with the \$1.38/MWh for non-dispatchable contracts.

The external debt of the dispatchable contracts increases the leverage of Utility A, but also results in reduced finance costs compared to utility built generation (assuming the capital structure remains constant). In this case, the NUG becomes the agent for shifting Utility A to a more efficient capital structure. This indicates that the utility could compete more favorably against a NUG by becoming more highly leveraged. The dark solid line in Figure 2 illustrates the effect of Utility A undertaking additional leverage which shifts the weighted average cost of capital to the right along the cost of capital curve. The dispatchable contracts add the appropriate amount of leverage to bring the utility closer to the minimum. On the other hand, if the NUG forces the utility to become too highly leveraged so that the cost of capital increases, the utility should consider issuing equity to offset the higher risk premiums associated with debt.

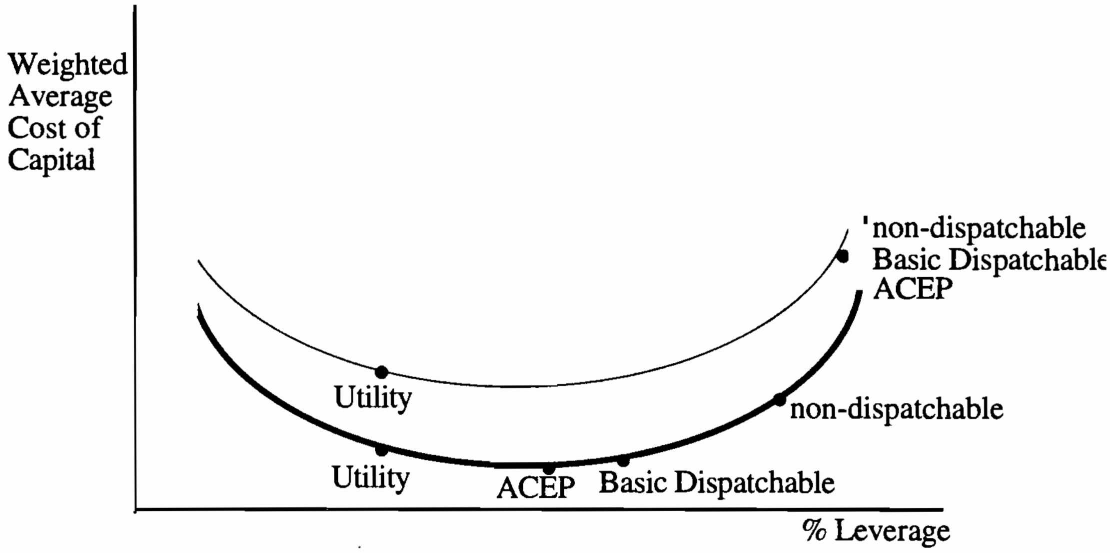

Figure 2: Effect of Leverage on the Cost of Capital

For example, the non-dispatchable contracts increase Utility A's leverage to the point where the indirect finance costs are greater than the incremental finance cost of the utility building its own generation. Utility A can minimize the potentially detrimental effects of power purchase contracts on its cost of debt by adjusting its capital structure through debt issuances to account for the new liabilities.

The cost advantages of ACEP power over utility built generation adds credence to assertions that competitive electric power markets can benefit rate payers. These results also show that regulators and utilities should evaluate the merits of NUG contracts in terms of the implications on credit rating as well as the direct energy costs. Efforts should also be made to negotiate contracts that provide rate payers with the most efficient use of NUG purchases. Otherwise, the potential cost savings of NUG power can easily be lost to contract inefficiencies. The debt analysis also serves to highlight the importance of the capital structure on electric rates and the potential advantages of increasing leverage. Finally, as competition for building new capacity intensifies,[37] utilities may be forced to move toward a more highly leveraged capital structure to remain competitive.

[37]Due to the Energy Policy Act of 1992.

2. *LEASE ANALYSIS OF COSTS*

As discussed earlier, the lease analysis employs the buy/borrow versus lease finance model to determine the cost of utility built generation versus purchased power. This corresponds to a high risk situation where an increase in electric rates could drive customers off the system. Although Utility A is not be in such a vulnerable condition, such an analysis provides insight into potential cost difficulties. These conditions represent a higher than normal existing risk for the utility where the impact of additional capacity payments to NUGs may have a disastrous effect on the viability of the utility.

The additional risk assumed for the lease analysis results in an upward shift in the weighted average cost of capital curve to the thin gray line shown in Figure 2. The simultaneous increase in finance costs for Utility A and the NUGs can be attributed to the increased risk of Utility A's ability to pay for debt and NUG contract obligations. The lease analysis provides a comprehensive method of cost comparison between NUG purchases versus utility built generation and does not require off-balance sheet adjustments. Since the incremental capacity additions cost the same between NUG and utility built generation, the difference in finance costs highlight the effects of changing the capital structure for a high risk utility. The lease analysis results presented in Figure 3 show a substantial increase in indirect finance costs for the NUG purchases from the debt analysis and an additional risk premium of $1.40/MWh common to both NUGs and Utility A. Incremental energy costs remain unchanged from the debt analysis. The incremental finance cost of $5.21/MWh for NUG capacity purchases shown in Figure 3 reflects the fifteen year levelized cost difference over utility built generation.[38]

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[38]From a financial analysts perspective, the NUG contracts have zero incremental finance costs and Utility built generation has a negative incremental cost of $5.21/MWh (energy costs remain the same).

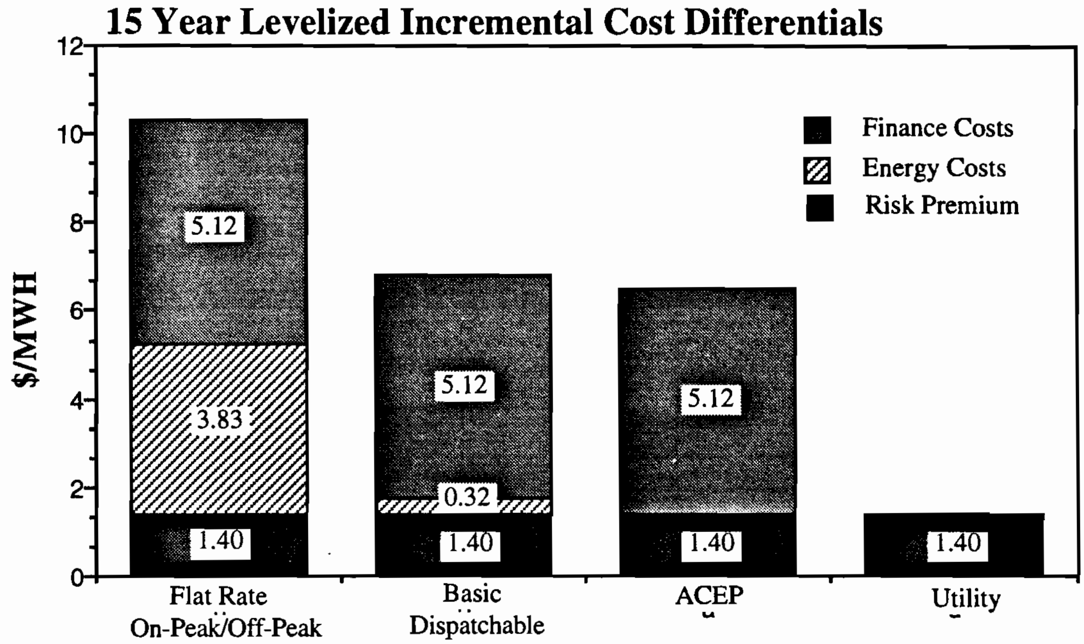

Figure 3: Lease analysis based on Utility A's financial and energy data

The significant disparities between the cost of utility built generation and NUG purchases indicate that Utility A has assumed a highly leveraged capital structure through NUG purchases. With the social cost of the incremental capacity additions identical between NUG and utility sources, the difference in finance costs illustrates the potential for the utility to adjust its capital structure to reduce costs. In order to reduce the differential in finance costs between NUG and utility built generation, the utility may consider issuing additional equity and repurchasing debt. This reduces the leverage of Utility A brought on by NUG purchases and brings the weighted average cost of capital toward the minimum of the curve shown in Figure 2. However, issuing equity for debt repurchase may dilute the value of existing shares, but it would provide a potentially more stable capital structure. An equity issuance may be preferable to a high leverage situation with a high cost of debt if equity holders receive less than the allowed rate of return in order to keep electric rates low.

Although the lease analysis provides a rigid and consistent financial structure and removes the potential subjectivity associated with adjusting off-balance sheet liabilities for

Utility A, the structure has the short coming of overlooking an important rationale of utility accounting. The treatment of NUG purchases as lease obligations effectively ignores the regulatory entitlement of Utility A to recover NUG capacity payments through its fuel adjustment clause or any other accounting mechanism. Furthermore, the lease analysis fails to account for the risks associated with the efficiency of each type of contract. It makes intuitive sense that inefficient power purchase arrangements undermine a utility's competitive position and have implications for its ability to repay debt, and consequently, should adversely affect its bond rating. Finally, the lease analysis makes utility generation appear more favorable than NUG generation when in fact the capacity resources are identical. Rate payers may be better off if the utility adjusts its capital structure and purchases power from NUGs, with an ACEP contract.

VII. OTHER IMPLICATIONS

1. UTILITY'S PERSPECTIVE

Although electric utilities share the concerns of rate payers over bond ratings and the direct costs of generation, these concerns are dominated by concerns over maintaining company earnings without incurring additional risk. The risk associated with building large base load generation is viewed by many shareholders as excessive for current allowed rates of return. Acquisition of dispatchable NUG resources provides a viable alternative for meeting electric load without incurring the risks of developing new utility plants. Furthermore, to the extent that NUG purchases provide lower cost electric power, a competitive advantage is obtained. In regions with slow electric load growth, NUG purchases can be viewed as eroding a utility's electric rate base as existing plants depreciate. As competition increases in the bulk power market, a utility's ability to provide competitive services becomes the foremost factor. An even handed analysis of the total costs of purchasing NUG power becomes the most effective means of maintaining competitiveness and preserving a customer base.

2. *NUG'S PERSPECTIVE*

The four basic economic structures for purchased power from NUGs provide different risk/reward relationship to the NUG. The Flat Rate contract and On-Peak/Off-Peak contracts encourage the NUG to maximize electric output. Additionally, these contracts often require the NUG to accept significant risk in future years as the rates of fuel escalation and plant operation and maintenance costs may diverge from the contract prices. The financial community is particularly sensitive to cost coverage risks, and weights heavily the ability to maintain a positive relationship between power sale prices and production costs in evaluating NUG projects.[39] However, these contracts are easy to understand and represent a broadly accepted and well understood risk.

On the other hand, the Basic Dispatchable and ACEP contracts provide little risk of diverging rates of escalation, but are not as well understood by the financial community. By almost any comparative standard, the economic and operational risks of dispatchable contracts are less than the other contract forms. In addition, the NUG operator is financially indifferent to the operating level. The NUG achieves profit maximization through maintaining the highest possible availability level, not maximizing production. In addition, the NUG is likely to view lower production as lower plant wear or in other words asset preservation. The economic implications of the power contract are designed to match fuel and operational costs and reduce the risk of a cash flow deficit, enhancing a project's competitiveness and "financability".

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[39]Goldsmith et. al. (1991).

VIII. CONCLUSIONS

Competitive electric rates and high credit ratings are possible for utilities with power purchase contracts if they are designed to reduce a utility's liabilities and minimizes energy costs. NUG purchases under efficient power contract mechanisms can have a lower cost than utility built generation. Traditional produce and pay contracts fail to integrate the contracted resource efficiently into the existing power supply mix or to address the concerns of the financial community. Flat Rate and On-Peak/Off-Peak contracts lack dispatchability and result in higher production costs and risk premiums that raise the cost of debt for the purchasing utility. Basic Dispatchable and Actual Cycle Energy Pricing (ACEP) contracts were shown to provide significant economic and operating advantages over non-dispatchable contracts. ACEP contracts achieved optimal resource allocation while reducing utility and rate payer risk.

Criticisms of NUG purchases can generally be traced to the form of contract used (e.g. non-dispatchable) or the associated risk premiums that result in a higher cost of debt for the purchasing utility. From an economic perspective, the analysis treated the actual investment made in new generating capacity as the same in all cases regardless of the owner or type of contract specified. In situations where the utility could achieve a lower weighted average cost of capital through increased leverage (the typical situation for regulated utilities), an ACEP contract may achieve a competitive advantage over utility built generation through utilizing a more leveraged capital structure. From the rate payers perspective, an example shows how dispatchable NUG contracts act as an external debt instrument shifting the utility to a more efficient capital structure resulting in a lower cost for the new capacity addition. With ACEP contracts being operated as efficiently as utility owned capacity, the overall conclusion is that ACEP contracts for NUG purchases can be economically efficient. However, the same example also shows that non-dispatchable contracts increase the utility's leverage beyond a cost effective level and result in a higher weighted average cost of capital than utility built generation.

For a utility that is already in an unusually risky financial position, NUG purchases may be treated as leased capacity rather than external debt. This increases the utility's leverage so much that utility built generation appears to be the option with the lower finance costs. An alternative would be for the utility to offset the increased leverage of a NUG purchase by issuing equity. However, shareholders may object because of dilution of their stock. The standard procedures used for leasing ignore the real differences in risk and operating costs of dispatchable contracts over non-dispatchable contracts. Consequently, lease analysis may attribute too much risk to NUG capacity with no risk benefits attributed to dispatchable versus nondispatchable contracts. This will be expensive for rate payers.

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Appendix

Energy Production Cost Model (EPCM)

The model calculates the incremental variable cost differential between energy production under different contract forms. The incremental costs measure the hourly differential energy production costs between the utility system lambda with and without NUG generation. The utility-generation-only case maintains the same capacity level as the NUG cases and assumes the utility operates the same type of facility as the NUGs. The evaluation of each NUG contract was done assuming that no other types of NUG contract exist contemporaneously. This provided an equal and representative analysis of the attributes and short-comings of each type of contract.

As electric load increases, the variable cost of production increases and consequently the system lambda changes. Electric demand was broken into six time blocks, four for weekdays and two for weekends. A system lambda was determined for each time block. The incremental variable costs are the differences between the system lambda for each time block summed over the entire week and then divided by the number of hours in the week. The time block method provides insight into the hours of the week a NUG contract may increase energy production costs. In addition, the analyst can evaluate the effects of 10 minute spinning reserve between the each contract type and utility built generation. The costs of 10 minute spinning reserve are incorporated into the analysis.

In summary, the EPCM acts as a least cost dispatch model. The incremental variable energy procution costs are determined for future years and then levelized to determine a 15 year energy cost.

Financial Cost Model

The Financial Cost Model (FCM) calculates the indirect costs associated with NUG purchases which are determined from the increased cost of issuing new debt. The FCM applies an annual risk premium, disucssed in Section III, to the annual debt issuances for Utility A. The product of the annual debt issuances and risk premium equals the financial penalty. This penalty is carried for the entire duration of the debt. Debt duration follows the same pattern that Utility A carried from 1980 to 1990.

The total amount of debt issued each year is held constant from 1991 through 1993, but escalates at 3% from 1994 through 2005. The risk premium only applies to debt issued after 1991. The risk premium ranges from 6 to 100 basis points. These values are determined by an annual debt adjustment factor (Q_t) which places in a smaller portion of the NUG capacity payments as off-balance sheet debt.

Table A1 — **Derivation of Incremental Energy Production Costs**

Case 1: Flat Rate and On-peak/Off-peak at ¢6/kwh with 60% committed to capacity payment
Case 2: Dispatch based on linear heat rate curve
Case 3: Actual Energy Cycle Dispatch

This analysis concerns the incremental energy costs for purchasing an additional MW of NUG electricity under each contract form.
The analysis does not include the incremental benefits or costs to ratepayers for capacity surpluses or deficiencies resulting from NUG purchases.
This is equivalent to meeting the standard system reserve requirements with no surpluses or deficiencies in capacity.

1 MW Proxy in 1990

			Flat Rate and On-peak/Off-peak				Basic Dispatchable				ACEP			
Weekdays	Time of Day	Total Hrs/Week	Delta $/MWH	% of time Delta Applies	% of Cap. as 10 Min. Spin	$/Part.	Delta $/MWH	% of time Delta Applies	% of Cap. as 10 Min. Spin	$/Part.	Delta $/MWH	% of time Delta Applies	% of Cap. as 10 Min. Spin	$/Part.
Partition A	10-19	45	0	100.0%	4.0%	$2	0	100%	0.0	$0	0	100%	0.0	$0
Partition B	8-9, 20	15	3	50.0%	20.0%	$26	0	100%	0.0	$0	0	100%	0.0	$0
Partition C	21-23, 7	20	5	65.0%	20.0%	$69	0.5	40%	0.0	$4	0	100%	0.0	$0
Partition D	23-7	40	5	80.0%	20.0%	$169	1	40%	0.0	$16	0	100%	0.0	$0
Weekends												100%		
Partition E	8-20	24	5	60.0%	20.0%	$77	1	40%	0.0	$10	0	100%	0.0	$0
Partition F	1-7, 21-24	24	5	100.0%	20.0%	$125	1	40%	0.0	$10	0	100%	0.0	$0
	Total	**168**			**Total$/wk**	**$469**			**Total$/wk**	**$39**			**Total$/wl**	**$0**
					Total$/yr	**$24,364**			**Total$/yr**	**$2,038**			**Total$/yr**	**$0**

Spin Res 1.1 $/MWH

Table A2

Debt Analysis Annual Incremental Energy Production Costs

Year	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
NUG Capacity	1027	1384	1982	2139	2355	2355	2355	2355	2355	2355	2355	2355	2383	2412	2441
NUG Energy GWH	4304	7516	10834	13457	15036	15420	15420	15420	15420	15420	15420	15420	15,605	15,792	15,982
NUG Cap Factor	0.48	0.62	0.62	0.72	0.73	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
NUG Energy Add GWH '90	0	504	3716	7034	9657	11236	11620	11620	11620	11620	11620	11620	11620	11805	11992
Energy Production Costs Differentials					($/MWH)										
Flat Rate & On-Peak/Off-Peak	2.91	3.06	3.21	3.37	3.54	3.72	3.91	4.10	4.31	4.52	4.75	4.98	5.14	5.30	5.47
Basic Dispatchable	0.24	0.26	0.27	0.28	0.30	0.31	0.33	0.34	0.36	0.38	0.40	0.42	0.43	0.44	0.46
ACEP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utility Built	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Cost differentials for Cases 1-3 above are escalated as 5% from the 1990 energy cost differential values.

Finance Cost Differentials	1991	1992	1993	1994	1995 ($/MWH)	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Flat Rate & On-Peak/Off-Peak	3.27	0.67	0.47	0.43	0.53	0.67	0.83	1.10	1.37	1.67	1.97	2.29	2.42	2.54	2.67
Basic Dispatchable	1.64	0.33	0.23	0.21	0.26	0.33	0.42	0.50	0.63	0.76	0.89	1.04	1.05	1.06	1.08
ACEP	1.31	0.27	0.19	0.17	0.21	0.27	0.33	0.42	0.51	0.61	0.71	0.82	0.83	0.84	0.86
Utility Built	1.37	0.73	0.90	0.75	0.78	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.78	0.81	0.84

The finance cost differentials in units of $/MWh are determined from the total annual fiance costs divided by additional NUG energy production since 1990.
It is assumed that there are no finance costs until 1991 because of the relatively small amount of NUG capacity.

Consequently, it becomes appropriate to evaluate the finance costs as increments from the 1990 base.

Energy & Finance Cost Differentials	1991	1992	1993	1994	1995	1996 ($/MWH)	1997	1998	1999	2000	2001	2002	2003	2004	2005
Flat Rate & On-Peak/Off-Peak	6.19	3.73	3.68	3.80	4.07	4.39	4.74	5.20	5.68	6.19	6.72	7.28	7.56	7.84	8.14
Basic Dispatchable	1.88	0.59	0.50	0.50	0.56	0.64	0.74	0.85	0.99	1.14	1.29	1.45	1.48	1.51	1.54
ACEP	1.31	0.27	0.19	0.17	0.21	0.27	0.33	0.42	0.51	0.61	0.71	0.82	0.83	0.84	0.86
Utility Built	1.37	0.73	0.90	0.75	0.78	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.78	0.81	0.84

Table A3

Lease Analysis Annual Incremental Energy Production Costs

Year	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
NUG Capacity	1027	1384	1982	2139	2355	2355	2355	2355	2355	2355	2355	2355	2383	2412	2441
NUG Energy GWH	4304	7516	10834	13457	15036	15420	15420	15420	15420	15420	15420	15420	15,605	15,792	15,982
NUG Cap Factor	0.48	0.62	0.62	0.72	0.73	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
NUG Energy Add GWH '90	0	504	3716	7034	9657	11236	11620	11620	11620	11620	11620	11620	11620	11805	11992
Energy Production Costs Differentials					($/MWH)										
Flat Rate & On-Peak/Off-Peak	2.91	3.06	3.21	3.37	3.54	3.72	3.91	4.10	4.31	4.52	4.75	4.98	5.14	5.30	5.47
Basic Dispatchable	0.24	0.26	0.27	0.28	0.30	0.31	0.33	0.34	0.36	0.38	0.40	0.42	0.43	0.44	0.46
ACEP	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Utility Built	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cost differentials for Cases 1-3 above are escalated as 5% from the 1990 energy cost differential values.															
Finance Cost Differentials					($/MWH)										
Flat Rate & On-Peak/Off-Peak	8.28	4.44	5.43	4.57	4.70	4.54	4.54	4.54	4.54	4.54	4.54	4.54	4.71	4.89	5.08
Basic Dispatchable	8.28	4.44	5.43	4.57	4.70	4.54	4.54	4.54	4.54	4.54	4.54	4.54	4.71	4.89	5.08
ACEP	8.28	4.44	5.43	4.57	4.70	4.54	4.54	4.54	4.54	4.54	4.54	4.54	4.71	4.89	5.08
Utility Built	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Riskyness Premium	2.27	1.22	1.49	1.25	1.29	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.29	1.34	1.39
Energy & Finance Cost Differentials															
Flat Rate & On-Peak/Off-Peak	13.47	8.72	10.13	9.20	9.53	9.51	9.69	9.89	10.09	10.31	10.53	10.77	11.14	11.53	11.94
Basic Dispatchable	10.80	5.91	7.18	6.11	6.28	6.10	6.11	6.13	6.15	6.17	6.18	6.20	6.43	6.67	6.93
ACEP	10.55	5.66	6.91	5.82	5.98	5.79	5.79	5.79	5.79	5.79	5.79	5.79	6.00	6.23	6.47
Utility Built	2.27	1.22	1.49	1.25	1.29	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.29	1.34	1.39

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