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Revisiting the "Buy versus Build" Decision for Publicly Owned Utilities in California Considering Wind and Geothermal Resources

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List of Acronyms

CEC	California Energy Commission
DSCR	Debt Service Coverage Ratio
IRR	Internal Rate of Return on Equity
ITC	Investment Tax Credit
JPA	Joint Powers Authority
LCOE	Levelized Cost of Electricity
MACRS	Modified Accelerated Cost Recovery System
NUG	Non-Utility Generator
PPA	Power Purchase Agreement
PPREAT	Public Power Renewable Energy Action Team
PTC	Federal Production Tax Credit
REPI	Federal Renewable Energy Production Incentive

Table of Contents

List of Tables

List of Figures

Introduction

The last two decades have seen a dramatic increase in the market share of independent, non-utility generators (NUGs) relative to traditional, utility-owned generation assets. Accordingly, the "buy versus build" decision facing utilities – i.e., whether a utility should sign a power purchase agreement (PPA) with a NUG, or develop and own the generation capacity itself – has gained prominence in the industry. Specific debates have revolved around the relative advantages of, the types of risk created by, and the regulatory incentives favoring each approach.[1] Very little of this discussion has focused specifically on publicly owned electric utilities, however, perhaps due to the belief that public power's tax-free financing status leaves little space in which NUGs can compete. With few exceptions (Wiser and Kahn 1996), renewable sources of supply have received similarly scant attention in the buy versus build debate.

In this report, we revive the "buy versus build" debate and apply it to the two sectors of the industry traditionally underrepresented in the discussion: publicly owned utilities and renewable energy. Contrary to historical treatment, this debate is quite relevant to public utilities and renewables because publicly owned utilities are able to take advantage of some renewable energy incentives only in a "buy" situation, while others accrue only in a "build" situation. In particular, possible economic advantages of public utility ownership include: (1) the tax-free status of publicly owned utilities and the availability of low-cost debt, and (2) the renewable energy production incentive (REPI) available only to publicly owned utilities. Possible economic advantages to entering into a PPA with a NUG include: (1) the availability of federal tax credits and accelerated depreciation schedules for certain forms of NUG-owned renewable energy, and (2) the California state production incentives available to NUGs but not utilities.

This report looks at a publicly owned utility's decision to buy or build new renewable energy capacity – specifically wind or geothermal power – in California. To examine the economic aspects of this decision, we modified and updated a 20-year financial cash-flow model[2] to assess the levelized cost of electricity under four supply options:[3]

1. public utility ownership of new geothermal capacity,
2. public utility ownership of new wind capacity,
3. a PPA for new geothermal capacity, and
4. a PPA for new wind capacity.

Within these four options, we consider multiple sensitivity scenarios intended to inform our analysis. We focus on geothermal and wind because both resources are abundant and, in some cases, potentially economic in California.[4] Our analysis is not intended to provide precise estimates of the levelized cost of electricity from wind projects and geothermal plants; nor is our intent to

[1] The August/September 1993 issue of The Electricity Journal (Volume 6, Number 7) was almost entirely devoted to the "buy versus build" debate.
[2] First described in Wiser and Kahn (1996).
[3] The California Consumer Power and Conservation Financing Authority has recently adopted a hybrid buy/build approach for wind, in which the Authority plans to purchase power from privately owned wind plants for the first 10 years (in order to capture the federal production tax credit), with an option to buy the plant in year 11 (once the tax benefit is exhausted). We have not modeled this approach due to the difficulties in determining the plant's fair market value in year 11.
[4] With modest effort, this analysis could be extended to biomass, photovoltaic, and solar-thermal electric resources.

compare the levelized costs of wind and geothermal power to one another.[5] Instead, our intent is simply to compare the possible costs of buying wind or geothermal power to the costs of building and operating wind or geothermal capacity under various scenarios.[6] Of course, the ultimate decision to buy or build cannot and should not rest solely on a comparison of the levelized cost of electricity. Thus, in addition to quantitative analysis, we also include a qualitative discussion of several important features of the "build vs. buy" decision not reflected in the economic analysis.

The motivation for this report comes in part from the needs of the Public Power Renewable Energy Action Team (PPREAT), an organization currently comprised of representatives from publicly owned utilities in California whose purpose is to facilitate the development of large amounts of renewable generation to serve public power loads. This report is meant to inform PPREAT's course of action as it works towards its goals. As such, much of our analysis is California-specific (e.g., we include a California Energy Commission production incentive in our quantitative analysis).[7]

The remainder of this report proceeds as follows. First we provide a brief description of the financial cash flow model used for our economic analysis and highlight our modeling assumptions. Next we present the results of our modeling exercise, including several variations on our four supply options designed to gauge the sensitivity of our results to variations in equity returns, incentive levels, and other variables. We then couch our quantitative results in terms of a qualitative discussion of several factors not apparent in the economic analysis but that can and should affect a utility's decision to buy or build renewable generation capacity. After brief concluding remarks, Appendix A presents detailed output from four model runs.

Model Description

Our cash-flow model consists of a spreadsheet containing projected cash flows for representative wind and geothermal projects from 2002 (when construction occurs) through 2022 (i.e., a twenty-year operational life).[8] Projected cash flows are based on input assumptions that are derived from industry standards and through discussions with wind and geothermal developers. Because we are concerned solely with ownership comparisons rather than technology or resource comparisons, in some cases we have standardized or simplified our input assumptions in order to facilitate comparison.

Our models of NUG ownership and public utility ownership are intended to crudely replicate the tools actually used by the respective industries. Because our interest is in comparing the costs of renewable energy across ownership options, a simplified representation of the actual models used by industry should be sufficient.

[5] Direct comparisons of the cost of wind and geothermal cannot be made without also quantifying the value of baseload power (in the case of geothermal) relative to intermittent power (in the case of wind), the correlation between wind generation and load, and the additional nameplate wind capacity required to provide the same amount of electricity as a geothermal plant over the course of a year due to differences in capacity factors.

[6] Note that our "build" case allows for publicly owned utilities to contract with private companies for development, construction, and operations and maintenance services.

[7] Again, with modest effort, this analysis could be extended to other states and situations.

[8] While some wind and geothermal projects may be designed for a 30-year (or longer) life, we limited our analysis to a 20-year project life to reflect our belief that most utilities will not be willing to sign a PPA longer than 20 years.

- For NUG ownership and sale (i.e., the "buy" options), the model uses an iterative process to optimize the capital structure (i.e., debt/equity ratios) and price of electricity in order to meet minimum debt service coverage ratio (DSCR) and internal rate of return on equity (IRR) constraints. The model outputs are the fixed price of energy (escalating at 1%/year[9]) that a NUG would be willing to offer a utility through a long-term (20-year) PPA, as well as the optimized capital structure. For ease of comparison, we convert this price stream into a nominal levelized cost of electricity using the utility's 5.0% cost of debt as the discount rate.

- Under public utility ownership (i.e., the "build" options), the model simply adjusts the price of electricity to where projected revenues equal operating expenses and debt payments on a yearly basis (i.e., to where the DSCR equals one). Model output represents the nominal levelized cost of energy from the facility over a 20-year period, assuming a utility discount rate of 5.0%.

Table 1 lists the input assumptions for each of the four supply options, many of which are briefly described below.

- **Project Structure, Size, Capacity Factor, and Capital Costs:** We assume that all projects are fully integrated (e.g., the geothermal developer does not purchase steam from a third party, but rather develops the steam field as well) and sited on leased land. The wind and geothermal projects are assumed to be sizable, at 50 MW of nameplate capacity.[10] Assumed capacity factors[11] and capital costs[12] are intended to be representative of recent projects.[13] Capital costs could be much higher if the project is sited far from existing transmission lines and the project is responsible for the cost of interconnection.

[9] While conventional wisdom holds that power purchase agreements typically escalate at the rate of inflation (or perhaps slightly less), recent wind and geothermal contracts signed by the California Department of Water Resources contain no escalation factor. Likewise, wind project proposals before the California Consumer Power and Conservation Financing Authority also contain no escalation factor. Because in both of these cases the contract term is only 10 to 12 years, and because the risk of inflation is obviously greater over 20 years than over 10 years, we have included an escalation factor in our model, but have purposely kept it low, at 1% per year.
[10] While individual utilities might seek smaller projects, joint purchases could easily exceed 50 MW. All else equal, smaller projects will have higher per-MW costs.
[11] Although both projects are 50 MW in nameplate capacity, the difference in capacity factors between geothermal and wind mean that a 50 MW geothermal plant will generate roughly 3 times more electricity each year than will a 50 MW wind plant.
[12] Assumed capital costs are distilled from a variety of sources, including DOE/EPRI (1997), Wiser and Kahn (1996), conversations with geothermal and wind developers, project proposals before the California Consumer Power and Conservation Financing Authority, and McKay (2001).
[13] Our model is not detailed enough to break out construction financing costs or financing and legal fees. Although our model does not allow for a separable evaluation of the impacts of these construction-related costs on total project costs, we are de facto assuming that the effect on the buy vs. build decision is a wash – e.g., publicly owned utilities may incur lower construction financing costs than a NUG, but at the same time cannot depreciate those costs (while a NUG can).

Table 1. Model Assumptions

	Wind		Geothermal	
Variable	**Buy**	**Build**	**Buy**	**Build**
Capacity	50 MW	50 MW	50 MW	50 MW
Capacity Factor	30%	30%	95%	95%
Installed Capital Cost ($2002)	$1000/kW	$1000/kW	$2500/kW	$2500/kW
Variable Costs ($2003)	1.0¢/kWh, escalates with inflation	1.0¢/kWh, escalates with inflation	1.75¢/kWh, escalates with inflation	1.75¢/kWh, escalates with inflation
Royalties	Land royalties incl. in variable costs	Land royalties incl. in variable costs	4% of annual power sales revenue	4% of annual power sales revenue
Property Tax	1.1% of book value	1.1% of book value	1.1% of book value	1.1% of book value
Capital Structure	Flexible, optimized to minimize cost	100% Debt	Flexible, optimized to minimize cost	100% Debt
Debt Interest Rate	Long-term = 7.5% Short-term = 7.5%	5.00%	Long-term = 7.5% Short-term = 7.5%	5.00%
Debt Amortization Period	Long-term = 15 yrs Short-term = 5 yrs	20 yrs	Long-term = 15 yrs Short-term = 5 yrs	20 yrs
Debt Amortization Schedule	Mortgage-style repayment	Mortgage-style repayment	Mortgage-style repayment	Mortgage-style repayment
Debt Service Coverage Ratio	Minimum of 1.5	No project-specific requirement	Minimum of 1.5	No project-specific requirement
Equity Cost	15%	N/A	18%	N/A
Inflation Rate (EIA)	2.3%/yr	2.3%/yr	2.3%/yr	2.3%/yr
Tax Depreciation: *5-yr MACRS*	 *100% of total cost*	N/A	 *70.3% of total cost*	N/A
Depletion: *Cost Method* *Percentage Method*	N/A	N/A	8% of total cost: *(Depletable Base)/20* *15%*(35%-4%)*rev.*	N/A
First Year Expensing	N/A	N/A	18% of total cost	N/A
Effective Income Tax Rate	40.7%	N/A	40.7%	N/A
Federal Production Tax Credit (PTC, $2003)	1.8¢/kWh, escalates at inflation for 10 yrs	N/A	N/A	N/A
Federal Renewable Energy Production Incentive (REPI, $2003)	N/A	1.8¢/kWh, escalates at inflation for 10 yrs, subject to annual allocation	N/A	1.8¢/kWh, escalates at inflation for 10 yrs, subject to annual allocation
Federal Investment Tax Credit (ITC)	N/A	N/A	10% of installed cost in year zero	N/A
CEC Production Incentive ($2003)	0.75¢/kWh for 5 years, no escalation	N/A	0.75¢/kWh for 5 years, no escalation	N/A
Discount Rate	5.0%	5.0%	5.0%	5.0%

- **Variable Costs, Royalties, and Property Taxes:** Rather than treating ongoing operations and maintenance (O&M) expenses, land leases, insurance, and administration and management fees individually, we rolled many of these costs into a composite ¢/kWh number.[14] In addition, we assume that geothermal projects pay royalties equal to 4% of power sales revenue to the landowner, while the 2%-3% royalties commonly paid by wind projects are captured in the 1.0¢/kWh composite variable cost.[15] We further assume that property taxes are equal to 1.1% of installed costs for all four supply options.[16] It is important to note that our assumption of O&M input cost equivalence across ownership types is a simplification, and may not be correct. For example, to the extent that risk is transferred between the parties differently in the build versus buy options, these risks may be priced accordingly. Similarly, property taxes may in some cases be lower for public utilities than for NUGs. We address some of these issues in a more qualitative fashion later.

- **Debt Amortization Periods and Interest Rates:** In both "buy" options, we assume that a NUG would utilize both short- (5-year) and long-term (15-year) debt in order to better take advantage of what would otherwise be excess debt service coverage in the early years created by the 5-year California Energy Commission (CEC) production incentive. The model optimizes both the overall debt/equity ratio as well as the proportion of short- and long-term debt in order to minimize costs. For purposes of debt service coverage ratios, we assume that the short- and long-term debt is concurrent, rather than one being senior and the other subordinated.[17] We do not allow debt service coverage ratios to fall below 1.5 in any year.[18] In both "build" options, we simply assume that the public utility finances the project entirely through 20-year debt at a typical tax-free debt interest rate of 5.0% and with no DSCR.[19] We assume mortgage-style debt repayment in all four supply options.

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[14] Assumed variable costs are derived from DOE/EPRI (1997), Wiser and Kahn (1996), and conversations with geothermal and wind developers.

[15] It is more important to break out royalties for geothermal than it is for wind, because royalties shift some of the value of depletion allowances from the lessee (i.e., the NUG or public utility) to the lessor (i.e., the landowner).

[16] The implication of this assumption is that the effective rate of project depreciation for property tax purposes is equivalent to the inflation rate.

[17] This assumption results in interest rates being slightly higher than otherwise, as collateral is effectively shared between the two loans. For simplicity's sake, we have assumed that both the short- and long-term debt carry an interest rate of 7.5%, which admittedly is inconsistent with the term structure of interest rates under a positively sloped yield curve.

[18] While conversations with developers suggest that required minimum debt service coverage ratios (DSCR) may range from as low as 1.25 for wind to as high as 2.0 for some geothermal projects, we hold both wind and geothermal to the same standard – a minimum DSCR of 1.5 – for the sake of simplicity. Though not reflected in our model, lenders may also subject the DSCR to various stress tests, and may require a minimum average DSCR over the life of the debt. In other words, our treatment of DSCR is a simplification of both the flexibility and requirements seen in the financing of actual projects. We did look at several model runs requiring a minimum average DSCR of 1.75 (in addition to the minimum annual requirement of 1.5), and the effect on the levelized cost of electricity was negligible.

[19] These assumptions are consistent with the approach used by many municipal utilities, but perhaps not rural cooperatives. We did not consider the case where one or more public utilities creates a joint powers authority (JPA) to develop the project. While public utilities have used JPAs in the past as a means of isolating their other assets from the risk of the project under development, it is not clear that setting up such an arms-length relationship poses any significant financial differences from the case in which the public utility simply develops the project "internally" (i.e., the case considered here). One potential difference could be if the JPA is financed only by revenue bonds linked specifically to the project's future revenue stream, in which case the structure becomes more analogous to project finance in the private sector, which typically carries a higher cost of capital.

- **Equity Cost:** Equity costs can vary significantly across projects: recent wind projects, for example, have seen equity costs that range from 12% to 22%. Except when explicitly testing sensitivity to IRR, we assume that geothermal developers require a 3% higher IRR than wind developers (i.e., 18% instead of 15%) based on conversations with both types of developers. The higher rate of return required by geothermal developers may be warranted due to greater risks in production, including the risk that the steam field will decline in productivity prior to the amortized life of the project.

- **Tax Depreciation, Depletion, and Expensing:** NUG-owned wind and geothermal projects are eligible to use the 5-year Modified Accelerated Cost Recovery System (MACRS) for depreciating capital assets. While it is unclear whether all elements of a project (e.g., access roads) qualify for 5-year MACRS, we make the simplifying assumption that 100% of a project's depreciable base can take advantage of this schedule. Thus, we depreciate 100% of a wind project's installed cost using 5-year MACRS. Geothermal assets are typically classified as depreciable, depletable, or expensable. Table 2 shows our assumptions for what portion of a project falls into each category.[20] Only the costs associated with the power plant and the tangible aspects of well drilling (e.g., well casings) are depreciable; these cover 74% of the total project costs, and this is also the portion to which the 10% investment tax credit (ITC, discussed below) applies. Applying the ITC, however, further reduces the portion of the project that can be depreciated by 5% (i.e., half of the 10% ITC) of 74%, or 3.7%, thereby leaving the depreciable base at 70.3%. As with wind, we make the simplifying assumption that the entire depreciable base uses 5-year MACRS. Land costs related to wells are considered depletable, using either the cost or percentage methods, whichever is more advantageous. For cost depletion, we assume that our 8% depletable base will be depleted evenly over 20 years (i.e., the assumed life of the project), while the percentage method allows the project to deduct 15% from 35%[21] of power sales revenues less any royalties paid (in this case, 4%), capped at 50% of taxable income prior to figuring depletion. In general, projects use cost depletion in early years when operating at a taxable loss, and switch to percentage depletion once they have sufficient taxable income. Finally, the intangible portion of well costs, which we assume to be 18% of total project costs, is expensed in the first year of operation.

Table 2. Tax Assumptions for NUG Geothermal Project

	Depreciable	**Depletable**	**Expensable**
Power Plant	62%	-	-
Steam Field – Wells	12%	-	18%
Steam Field – Land	-	8%	-
Total	**74%** *(70.3%)*	**8%**	**18%**

- **Federal Tax Credits and REPI:** Authorized by EPAct, both the federal production tax credit (PTC) and its public power counterpart, the REPI, stood at 1.7¢/kWh in 2000. At the Energy Information Administration's assumed 2.3% rate of inflation, both will increase to 1.8¢/kWh in 2003, the first full year of production in our model. The PTC can be used by NUG wind

[20] These assumptions either follow or are very close to the default values in FATE2-P (NREL 1996), and are consistent with indications from geothermal developers.
[21] 35% represents the portion of revenue attributed to the steam – the depletable resource.

projects, but not geothermal projects; NUG-owned geothermal projects are eligible for a 10% investment tax credit (ITC), as mentioned above. The REPI, meanwhile, is applicable to both publicly owned wind and geothermal facilities. Of course, there is some risk that the PTC and REPI, which are slated to expire at the end of December 2001 and September 2003, respectively, may not be extended. Furthermore, unlike the PTC, the REPI is subject to annual congressional appropriations that can change the value of the incentive from year to year, effectively rendering it un-bankable to most utilities (Wiser and Pickle 1997). Because of these uncertainties, we conduct sensitivity runs both with and without the PTC, and at various REPI levels.

- **CEC Production Incentive:** Going forward, the CEC plans to hold biennial auctions of 5-year production incentives from its New Renewable Resources Account. In the past, these auctions have been capped at 1.5¢/kWh, with accepted bids in the first three auctions ranging from 0.26¢/kWh to 1.49¢/kWh, with an overall weighted average of 0.74¢/kWh. In our two "buy" options, we assume that a NUG will be able to secure a 0.75¢/kWh production incentive for 5 years – close to the weighted average incentive awarded to date. We also vary the level of the CEC incentive in a sensitivity analysis. This incentive is not available to publicly owned renewable facilities.

- **Discount Rate:** Since we evaluate all supply options from the perspective of the public utility, we use our assumed cost of capital for public utilities – 5.0% – as the discount rate for all supply options. In other words, 5.0% is the rate that we use to convert the PPA contract price (which escalates at 1% per year) in the "buy" options and the utility's stream of costs in the "build" options into a nominal levelized cost of electricity.

Model Results

Given the assumptions in Tables 1 and 2, Table 3 presents the model output in terms of the nominal levelized cost of our four supply options under six different cases. Because of the uncertainty surrounding both the PTC and the REPI, we report results for our four supply options under different assumptions about the availability of these incentives. In particular, Cases 1 through 3 vary the level of the REPI while assuming that the PTC for wind is extended in full, while Cases 4 through 6 again vary the level of the REPI, while assuming that the PTC expires.[22]

[22] Assuming that the congressional appropriation for year 2001 REPI payments comes in at $4 million (the maximum amount ever appropriated to REPI) and that all Tier 1 projects (i.e., solar, wind, geothermal, and closed-loop biomass) that received REPI funding for year 2000 production apply for the same amount to cover year 2001 production, the REPI can support roughly 55 MW of incremental wind capacity with a 30% capacity factor before payments to all Tier 1 facilities begin to decline on a pro rata basis. Tier 1 payments are cut in half when 150 MW of wind capacity comes on line, fall to 0.1¢/kWh once 1000 MW are added, and approach zero once 3000 MW are added. The equivalent incremental amounts of geothermal capacity with a 95% capacity factor are 18 MW, 45 MW, 330 MW, and 970 MW. Thus, assuming a $4 million appropriation, the addition of our 50 MW hypothetical project would already begin to cut into Tier 1 payments, especially for geothermal, potentially rendering the "Full REPI" cases unlikely.

Table 3. Model Results

			Nominal Levelized Cost (¢/kWh)			
			Wind		Geothermal	
Case	PTC?*	REPI?	Buy	Build	Buy	Build
1	Yes	None	4.03	4.68	5.50	5.05
2	Yes	Half	4.03	4.05	5.50	4.39
3	Yes	Full	4.03	3.42	5.50	3.74
4	No	None	5.62	4.68	5.50	5.05
5	No	Half	5.62	4.05	5.50	4.39
6	No	Full	5.62	3.42	5.50	3.74

**The PTC currently applies to wind only; geothermal is ineligible.*

Base Case Results

Because most industry participants are confident that the PTC will be extended, and because publicly owned utilities often do not count on receiving the REPI given the uncertain appropriations process (Wiser and Pickle 1997), we view Case 1 (i.e., full PTC/no REPI) as the most likely and relevant of the six cases presented in Table 3, and therefore adopt it as our "base case." In this case, a PPA for wind power is superior to wind ownership, while geothermal ownership is superior to a PPA for geothermal power. Specifically, in the case of wind, the value of the PTC to the NUG (as well as accelerated depreciation and the CEC incentive) more than offsets the tax-free financing advantage of publicly owned utilities in this case, allowing the NUG to offer a PPA that is 0.65¢/kWh cheaper than the public utility could do on its own. Since NUG-owned geothermal currently receives the less-valuable ITC instead of the PTC, however, the lack of the REPI does not quite make a geothermal PPA cheaper than building and owning a facility, though the difference in Case 1 is only 0.45¢/kWh – a margin that could easily be overwhelmed by a number of factors (e.g., construction and operating risk) that are not reflected in Table 3 but are discussed in a more qualitative fashion in the next section.

As shown in Appendix A, where we present model runs detailing the four supply options for Case 1, the NUG wind project minimizes costs with a capital structure of 58.5% equity, 4.8% 5-year debt, and 36.6% 15-year debt. The relatively high equity portion is attributable to the PTC, which provides no debt service coverage and reduces required power sales revenues (through a lower price), thereby limiting the amount of debt that can be taken on without violating the minimum DSCR requirement of 1.5.[23] The geothermal NUG, which receives the ITC instead of the PTC, minimizes costs with 38.2% equity, 6.4% 5-year debt, and 55.4% 15-year debt. Again, utility-owned projects are assumed to be 100% debt financed.

Other Results

Table 3 shows the "build" option becoming increasingly attractive in Cases 2-6 as the level of the REPI increases (Cases 2 and 3) and as the PTC expires (Cases 4-6 for wind only). Although we view Cases 2-6 as less likely than our base case (i.e., Case 1), we present all six cases in the event that the reader holds a different probabilistic view. A wind PPA, which was 0.65¢/kWh cheaper than public ownership in our base case, can be up to 2.19¢/kWh more expensive than public ownership in the case where there is no PTC but a full REPI (i.e., Case 6). A geothermal PPA,

[23] The 58.5% equity component is higher than the roughly 50% equity portion we expected, and may reflect the fact that we are using a simplified model to compare ownership structures.

meanwhile, ranges from 0.45¢/kWh more expensive than public ownership in our base case to 1.76¢/kWh more expensive when the full REPI is considered (i.e., Cases 3 and 6). The more extreme swings in the relative value of a wind PPA versus public ownership reflect the large value of the PTC.

Base Case Sensitivity to IRR Requirements

In this section, we perform sensitivity analysis on our base case (i.e., Case 1) assumptions.[24] Figure 1 shows the sensitivity of our four supply options (in Case 1 or full PTC/no REPI mode) to changes in equity IRR requirements over a range of 10% to 24% (with base-case assumptions of 15% for wind and 18% for geothermal denoted by circles). Note that the "build" options are unaffected by changes to IRR, since they are fully debt-financed.

Under base case assumptions, utility ownership of wind capacity only begins to look comparably attractive to a PPA as IRR requirements approach the upper end of our range. Conversely, geothermal NUGs would have to accept an unusually low IRR of 10% in order to match the economics of a publicly owned facility. Note that changes in IRR requirements affect wind more than geothermal due to wind having a higher fixed-to-variable cost ratio than geothermal, meaning that changes to key financing assumptions have a larger impact on the levelized cost of wind.

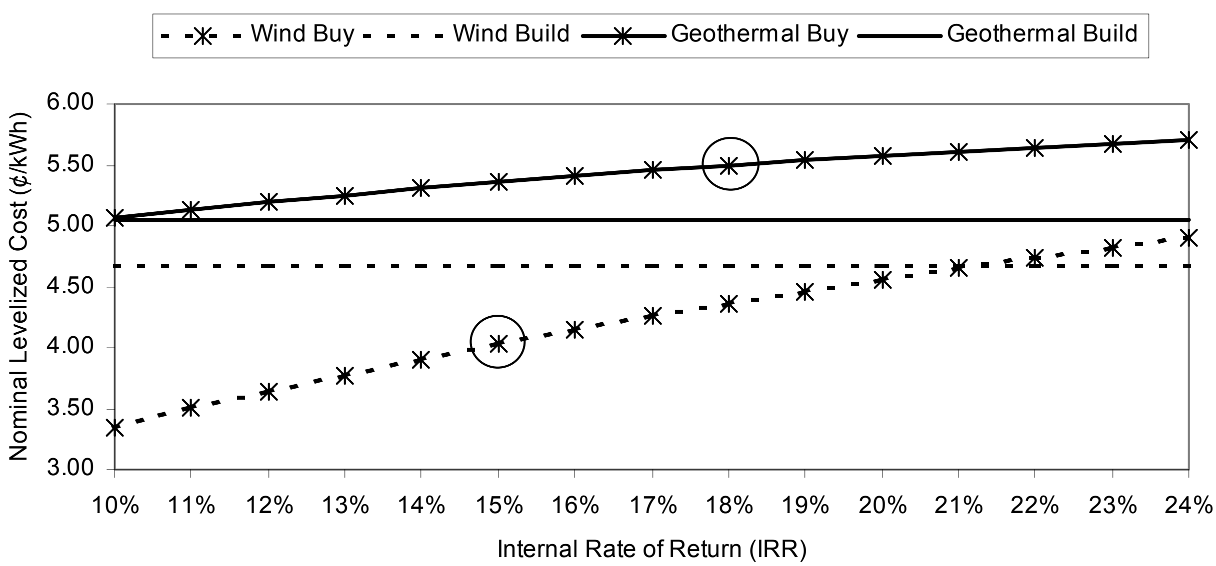

Figure 1. Sensitivity of Case 1 (Full PTC/No REPI) to IRR Requirements

Base Case Sensitivity to CEC Production Incentive Level

The CEC's 5-year production incentive for NUG projects provides a comparative advantage to the "buy" options. Though our six scenarios presented earlier assume that a 0.75¢/kWh incentive is available to NUGs, the level of available incentive could easily range from 0¢/kWh to 1.5 ¢/kWh. Figure 2 shows the effect of varying the CEC production incentive level within base case

[24] Space limitations prevent us from presenting sensitivity analysis on all six cases shown in Table 3. Instead, we have chosen what we feel to be the most likely scenario going forward – a full extension of the PTC, and a REPI that cannot be banked with any confidence – as our base case from which to conduct sensitivity analysis.

assumptions (i.e., full PTC/no REPI, Case 1 IRR assumptions). Again, the base case assumption of 0.75¢/kWh is denoted by circles.

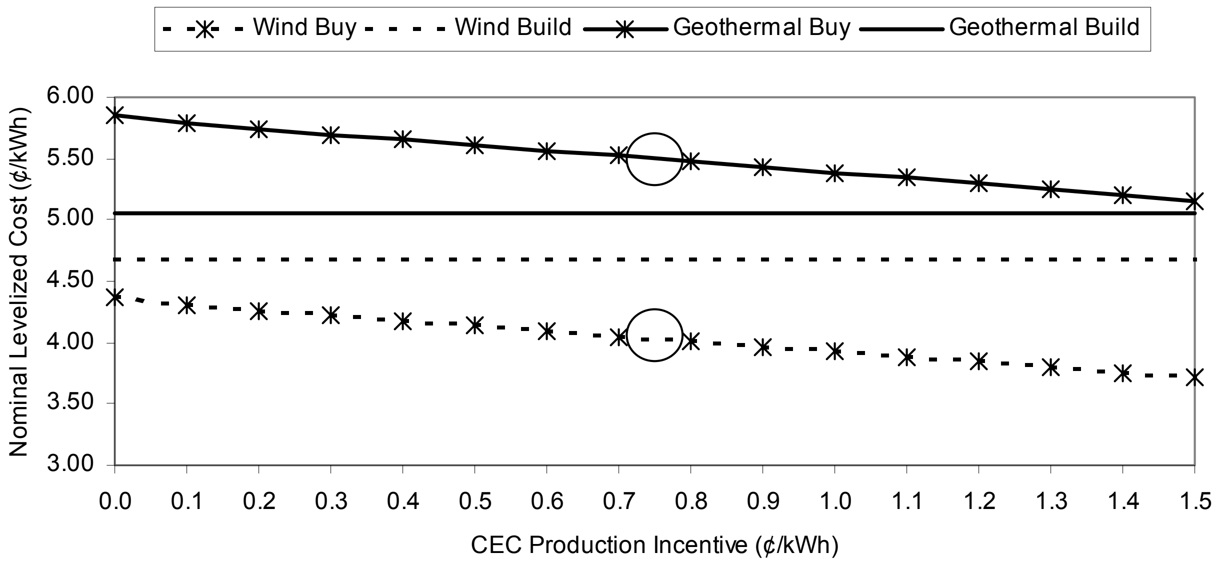

Figure 2. Sensitivity of Case 1 (Full PTC/No REPI) to CEC Production Incentive Level

Even in the event that a NUG fails to capture any CEC incentive, buying wind power is still roughly 0.3¢/kWh cheaper than building it, per Figure 2. In addition, a geothermal NUG receiving the full 1.5¢/kWh CEC incentive can match the economics of a publicly owned facility, even without access to the PTC.

Summary

To summarize, under what is perhaps the most likely case (i.e., Case 1), where the PTC is extended and the REPI continues to be sufficiently uncertain that utilities do not count on its availability, it is always cheaper for a public utility to buy wind capacity rather than to build it, except perhaps in situations where the NUG offering the PPA requires an IRR in excess of today's industry standards (i.e., >18%) *and* is unable to secure a production incentive from the CEC.

Geothermal presents a different picture: our model suggests that it is almost always cheaper for a publicly owned utility to build geothermal capacity than to buy it, except in circumstances where the NUG offering the PPA is satisfied with an IRR that is well below industry standards (i.e., <11%) and/or is able to secure the full 1.5¢/kWh CEC production incentive.

These quantitative results, however, neither tell the whole story nor present an exhaustive examination of plausible scenarios. To provide a more complete picture, we now turn to a discussion of qualitative considerations.

Qualitative Considerations

Construction and Operations Risk

The risks that a power project will not be available on schedule, will be over budget, and will perform worse than expected are perhaps the largest factors not reflected in our quantitative analysis. Construction and operations risks are typically borne by the utility in a "build" situation and the NUG in a "buy" situation, though the NUG may commonly shift many of these risks to contractors through turnkey construction and O&M contracts. Thus, while a PPA might be priced at a premium due to the cost certainty it provides (we note that our model does not account for this), the alternative – taking on construction and operations risk – is precarious, particularly given the technologies involved.

Utilities in general have had little experience building and operating large-scale wind and geothermal plants. This lack of experience – particularly with respect to geothermal facilities, which tend to be less standardized than wind farms – could lead to considerable cost overruns that could more than erase the financing advantage enjoyed by public utilities "going it alone." Recall that in the Case 1 geothermal comparison, this financing advantage (also taking into account the value of the ITC, MACRS, and CEC incentives to the geothermal NUG) amounted to only 0.45¢/kWh (see Table 3) – perhaps an insufficient margin of protection should the project encounter difficulties.

Of course, turnkey construction contracts and fixed-price O&M arrangements are just as available to utilities as they are to NUGs and can limit much of this risk, but only at a price. Utilities, which have historically focused on cost minimization rather than cost certainty, have generally been slow to make use of such contracts (Luftig 1993), though their use may be more prevalent for renewable energy projects than for non-renewable ones.

Geothermal and the PTC

NUG-owned geothermal projects currently receive the ITC (a first-year tax credit equal to 10% of installed costs) instead of the PTC (a 10-year production tax credit that stood at 1.7¢/kWh in 2000 and escalates at the rate of inflation). While the ITC may be less politically vulnerable than the PTC, it is also worth considerably less. Spreading the value of each incentive over a twenty-year project life reveals that the ITC is worth 0.37¢/kWh to a geothermal project operating under our assumptions in Tables 1 and 2, while the PTC would be worth 1.47¢/kWh.

Within broader efforts to extend the PTC beyond 2001 there is also a movement to add geothermal to the list of eligible technologies. We therefore ran a scenario in which geothermal receives the PTC but not the ITC. The result is a net reduction in the cost of the geothermal PPA of 1.10¢/kWh (i.e., +0.37¢/kWh from losing the ITC and -1.47¢/kWh from gaining the PTC). Table 4 recaps our results from Table 3, substituting into the "Geothermal Buy" column a scenario in which geothermal is eligible for the PTC but not the ITC (all other columns contain the same numbers as Table 3).

Table 4. Geothermal Becomes Eligible for the PTC (but not the ITC)

			Nominal Levelized Cost (¢/kWh)			
			Wind		Geothermal	
Case	PTC?*	REPI?	Buy	Build	Buy	Build
1	Yes	None	4.03	4.68	**4.40**	5.05
2	Yes	Half	4.03	4.05	**4.40**	4.39
3	Yes	Full	4.03	3.42	**4.40**	3.74
4	No	None	5.62	4.68	**4.40**	5.05
5	No	Half	5.62	4.05	**4.40**	4.39
6	No	Full	5.62	3.42	**4.40**	3.74

**In this scenario, the PTC applies to both wind and geothermal.*

Under this scenario, the cost difference between geothermal ownership and a PPA narrows, with a PPA looking relatively more attractive. For example, a PPA for geothermal is cheaper than utility ownership in the case without the REPI (i.e., Cases 1 and 4), and essentially matches ownership in the case involving half of the normal REPI incentive level (i.e., Cases 2 and 5).

Tax-Exempt Status

Publicly owned utilities' tax exempt status provides a financing advantage over NUGs, yet also precludes the use of tax-based renewable energy incentives. There is some indication, however, that the tax advantage of utility ownership may degrade in the future. In response to concerns from investor-owned utilities (IOUs) that public utilities enjoy an unfair advantage in competitive wholesale markets, the American Public Power Association and the Large Public Power Council (both representing public utilities) reached an agreement with the Edison Electric Institute (representing IOUs) in the summer of 2000. This agreement would protect the tax-exempt status of outstanding public power bonds and allow future tax-exempt issuances to finance distribution and transmission facilities, but not power plants (Bond Buyer 2000). In 2001, this agreement was reflected in a bill before Congress that died in committee.[25]

To examine the most extreme outcome of ongoing legislative and regulatory proceedings regarding public power's tax-exempt status, we looked at a scenario where bonds issued to finance public utility power plants completely lose their tax-exempt status. To reflect this scenario, we increased the 20-year bond yield from 5.00% to 7.25% (i.e., the taxable equivalent of a tax-free 5.0% yield, assuming a 40.7% effective income tax rate and adjusting for the fact that municipal bonds typically trade at higher yields than those implied by the tax-free equivalent of like-rated corporate bonds). Since publicly owned utilities' cost of debt also serves as the discount rate for all supply options (i.e., buy and build), Table 5 presents an entirely new set of results: the "build" columns reflect both a cost of debt and a discount rate of 7.25%, while the "buy" columns reflect a discount rate of 7.25%.

[25] Even if this industry agreement fails to become law, public utilities still must negotiate Internal Revenue Service (IRS) rules governing "private use" of publicly owned facilities (e.g., the sale of power from a tax-free power plant into the competitive wholesale market) or risk losing some or all of their tax-exempt status. Temporary rules governing such activity were updated in January 2001, and will remain in effect for only three years or until the IRS issues final regulations (or until Congress passes legislation codifying the agreement described in this paragraph). The uncertainties caused by a lack of permanent rules governing private use of public power plants may be another factor favoring "buy" over "build".

Table 5. Power Plant Bonds Become Taxable

			Nominal Levelized Cost (¢/kWh)			
			Wind		Geothermal	
Case	PTC?*	REPI?	Buy	Build	Buy	Build
1	Yes	None	**4.00**	**5.27**	**5.46**	**5.51**
2	Yes	Half	**4.00**	**4.59**	**5.46**	**4.81**
3	Yes	Full	**4.00**	**3.92**	**5.46**	**4.11**
4	No	None	**5.58**	**5.27**	**5.46**	**5.51**
5	No	Half	**5.58**	**4.59**	**5.46**	**4.81**
6	No	Full	**5.58**	**3.92**	**5.46**	**4.11**

**The PTC currently applies to wind only; geothermal is ineligible.*

As shown, the results of this scenario are somewhat different from those presented in Table 3: it is cheaper to buy than build wind in Cases 1 and 2, while for geothermal, buy edges out build in Cases 1 and 4 (i.e., the "no REPI" cases). Although in this scenario their bonds are no longer tax-exempt, public utilities retain a financing advantage over NUGs in that publicly owned plants are still 100% debt financed, with the cost of debt capital being about half the cost of equity capital.

Property Taxes

In general, publicly owned utilities pay property taxes only on the unimproved value of the land (i.e., not including capital improvements), whereas private developers must pay based on the full *improved* value of the land (i.e., including the value of the project). This distinction is not always clear-cut, however. Once a publicly owned utility ventures outside of its own municipality, it will be taxed like a NUG – i.e., based on the improved value of the site. And in a situation where a publicly owned utility leases a site from a private landowner, the landowner will presumably negotiate to make herself whole in terms of the additional property taxes she will face resulting from capital improvements. These are important considerations given that most of the known wind and geothermal resources are not located on municipally owned land.

Furthermore, in the case of a publicly owned project, towns or counties frequently find creative ways to extract from the utility the value of the foregone taxes on capital improvements. Similarly, NUGs may offer to fund local infrastructure projects or make special payments – in addition to their tax liability – to towns or counties in the hopes of gaining support for proposed projects. The terms of such side agreements (made by both NUGs and publicly owned utilities) vary widely from one municipality to the next, and must be examined on a case-by-case basis to determine whether publicly owned utilities do in fact enjoy a property tax advantage over NUGs.

Because of the uncertainties involved, we did not treat property taxes any differently in the buy and build model runs presented earlier in Table 3. Based on one estimate of the difference in property taxes between public and private wind projects (Wiser and Kahn 1996), however, we are able to at least look at this issue for wind. Table 6 shows the effect of this change; both the "Buy" and the first "Build" column recap results from Table 3 and are based on property taxes of 1.1% of book value, whereas the final "Build" column assumes a first-year property tax payment of $35,000, which escalates with inflation (Wiser and Kahn 1996). The reduction in the cost of the "Build" options is roughly 0.39¢/kWh, increasing the attractiveness of public utility ownership in instances where this property tax advantage can be exploited. As already mentioned, however, most publicly owned wind and geothermal projects are unlikely to be able to take advantage of this possible benefit.

Table 6. Public Utilities Take Advantage of Lower Property Taxes

			Nominal Levelized Cost (¢/kWh) Wind		
Case	PTC?*	REPI?	Buy	Build	Build (reduced taxes)
1	Yes	None	4.03	4.68	**4.29**
2	Yes	Half	4.03	4.05	**3.66**
3	Yes	Full	4.03	3.42	**3.04**
4	No	None	5.62	4.68	**4.29**
5	No	Half	5.62	4.05	**3.66**
6	No	Full	5.62	3.42	**3.04**

**The PTC currently applies to wind only; geothermal is ineligible.*

Other Considerations

Much of the previous discussion has revolved around tradeoffs either inherent to the "buy versus build" decision or else related to assumptions surrounding our analysis of that decision. There are a number of other considerations that also involve tradeoffs that are less easily quantified. Here we provide a brief description of some of the more important ones:

- *Flexibility:* PPAs may add flexibility by preserving the utility's reserve capital. Short-term PPAs in particular leave open many options (including the undesirable possibility of paying higher prices in the future once the PPA expires). In other ways, however, PPAs may detract from flexibility, since NUGs finance their projects based on up-front contractual agreements that are difficult to change or cancel once initiated (Luftig 1993). New renewable projects, in particular, may need 10 years of revenue certainty to obtain reasonably priced financing.

- *Reliability:* Because take-and-pay provisions only compensate NUGs when their plant is available, NUGs generally have a strong incentive to provide highly reliable power (Sant 1993). In this sense, PPAs may enhance reliability. At the same time, however, contractual agreements have been broken, resulting in messy contract disputes that the legal system is ill-prepared to handle in a timely manner (Fessler 1993). Thus, while PPAs may enhance operational reliability, they can also increase the risk of major reliability events if a contract is breached. This risk must be weighed against the construction and operations risk described earlier and commonly associated with utility ownership.

- *Price Risk:* Long-term fixed-price renewable PPAs, such as those assumed in our model, can serve as an effective price hedge against rising fuel or wholesale power costs. Once again, however, breach of contract in the event of extreme price movements is a risk that may favor building and owning renewable capacity rather than contracting for it.

- *Market Power:* The use of market power can impact both the "buy" and "build" options. On the "buy" side, the exercise of market power in spot markets can also drive up the price of long-term contracts, as has occurred in California. On the "build" side, owners of potential sites may be able to extract excessive rents from public utilities or NUGs seeking to develop the site. This concern is particularly relevant to renewable technologies such as wind and geothermal, whose economics are highly site-dependent. In California, developers and NUGs already have rights to many of the promising geothermal and wind sites, perhaps making it difficult for a public utility to access such sites economically.

- *Educational Value:* A publicly owned utility may place some value on gaining experience with building and operating renewable technologies, in which case it may be willing to either accept construction and operation risk or be willing to pay a premium for turnkey contracts that minimize such risk. Alternatively, a publicly owned utility may be more comfortable developing a long-term relationship with a NUG, therefore favoring a PPA situation.

- *Joint Versus Individual Action:* While the buy and build options may be equally viable for an individual utility, a group of utilities considering a joint project may find negotiating a power purchase agreement to be less burdensome than trying to reach consensus on the many logistical issues involved in financing and building new capacity, although there are precedents for both approaches.

Conclusions

The "buy versus build" debate has often hinged on premises that are difficult to prove and even harder to quantify. Once one brings renewable energy and publicly owned utilities into the fray, however, there are very real and quantifiable differences between buy and build that relate mostly to the tax-free status of public utilities and their inability to take advantage of tax-based and California state incentives for renewable energy.

In this report, we have analyzed the possible effect of various incentives available to public utilities and/or private NUGs on the economics of the buy versus build decision. Our analysis shows that under what is perhaps the most likely case for the availability of incentives going forward – i.e., Congress extends the PTC for wind power, geothermal remains eligible for the ITC but not the PTC, and the REPI either expires, is severely diluted by new capacity, or simply remains unbankable – a public utility is better off economically by purchasing wind power rather than building and owning new capacity. In this same case, public utility ownership of geothermal capacity enjoys a small advantage over a PPA arrangement. These margins are not always large, however, and one could easily reach opposite conclusions by altering a few of our assumptions.

Going beyond the numbers, there are several qualitative considerations that favor purchased power. Perhaps the largest is the relative inexperience of public utilities in developing and operating large wind and geothermal plants, and the substantial construction and operating risks that could easily erode public power's financing advantage. Additionally, and more specific to both California and the two technologies we considered – most of the best wind and geothermal sites in California are already tied up in easements or lease/option arrangements, perhaps making it difficult for a public utility not currently in control of a site to gain low-cost development access.

Appendix A

NUG: WIND PROJECT PRO-FORMA (CASE 1)

ASSUMPTIONS:	Value	Notes:
Capacity (MW)	50	Assumed
Capacity Factor	0.3	Assumed
Installed Capital Cost ($/kW)	1000	($2002)
Property Tax (% book value)	1.1%	Assumed
Total First Year Operating Cost ($/kWh)	0.010	($2003) Calculated
Effective Income Tax Rate	40.7%	Federal =35%, State=8.84% (deductable)
Production Tax Credit ($/kWh)	0.018	($2003) Increases with inflation
CEC Production Incentive ($/kWh)	0.0075	Assumed
Inflation Rate (%/yr)	2.3%	Assumed (EIA)
5 Year Equipment (Depreciation)	100.0%	Assumed
Discount Rate (nominal)	5.0%	Assumed
Real Discount Rate	2.6%	Calculated
Energy Price Escalation Rate	1.0%	Assumed

RESULTS:	Value
Average Debt Service Coverage	1.53
Minimum Debt Service Coverage	1.50
After-Tax IRR on Equity	15.00%
Real Levelized Price ($2003/kWh)	0.0330
Nominal Levelized Price ($2003/kWh	0.0403
First Year Electricity Price	0.0372

Financing Assumptions	Fraction	Term	Rates	Notes
Equity Fraction	58.5%	NA	15.00%	Minimum equity return
ST Debt Fraction	4.8%	5	7.50%	Assumed
LT Debt Fraction	36.6%	15	7.50%	Assumed

PRO-FORMA CASH FLOW:

Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Electric Output (MWh)		131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400
Electricity Sales Price ($/kWh)		0.0372	0.0376	0.0379	0.0383	0.0387	0.0391	0.0395	0.0399	0.0403	0.0407	0.0411	0.0415	0.0419	0.0423	0.0427	0.0432	0.0436	0.0440	0.0445	0.0449
Operating Revenues ($000)																					
Revenues		4,886	4,935	4,984	5,034	5,084	5,135	5,186	5,238	5,291	5,343	5,397	5,451	5,505	5,560	5,616	5,672	5,729	5,786	5,844	5,902
CEC Production Incentive		986	986	986	986	986															
Total Operating Revenues		5,871	5,920	5,969	6,019	6,070	5,135	5,186	5,238	5,291	5,343	5,397	5,451	5,505	5,560	5,616	5,672	5,729	5,786	5,844	5,902
Operating Expenses ($ 000)																					
Aggregate O&M		1,314	1,344	1,375	1,407	1,439	1,472	1,506	1,541	1,576	1,612	1,649	1,687	1,726	1,766	1,807	1,848	1,891	1,934	1,979	2,024
Property Taxes		550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550
Total Operating Expenses		1,864	1,894	1,925	1,957	1,989	2,022	2,056	2,091	2,126	2,162	2,199	2,237	2,276	2,316	2,357	2,398	2,441	2,484	2,529	2,574
Operating Income ($000)		4,007	4,026	4,044	4,062	4,080	3,113	3,130	3,147	3,164	3,181	3,197	3,213	3,229	3,244	3,259	3,274	3,288	3,302	3,315	3,328
Financing($000)																					
Short-Term Debt Funds (5 years)	2,413																				
Long-Term Debt Funds	18,317																				
Equity Funds	29,270																				
Total Capital Investment	50,000																				
Cash Available Before Debt		4,007	4,026	4,044	4,062	4,080	3,113	3,130	3,147	3,164	3,181	3,197	3,213	3,229	3,244	3,259	3,274	3,288	3,302	3,315	3,328
ST Debt Interest Payment		181	150	116	80	42															
ST Debt Repayment		415	447	480	516	555															
LT Debt Interest Payment		1,374	1,321	1,265	1,204	1,139	1,068	993	912	824	731	630	521	405	279	145					
LT Debt Repayment		701	754	810	871	937	1,007	1,082	1,164	1,251	1,345	1,445	1,554	1,670	1,796	1,930					
Total Debt Payment		2,671	2,671	2,671	2,671	2,671	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	2,075	0	0	0	0	0
Tax Effect on Equity ($000)																					
Operating Income		4,007	4,026	4,044	4,062	4,080	3,113	3,130	3,147	3,164	3,181	3,197	3,213	3,229	3,244	3,259	3,274	3,288	3,302	3,315	3,328
Depreciation (5 yr MACRS)		10,000	16,000	9,600	5,760	5,760	2,880														
Interest Payment		1,555	1,471	1,381	1,284	1,180	1,068	993	912	824	731	630	521	405	279	145					
Taxable Income		-7,548	-13,445	-6,937	-2,982	-2,860	-836	2,137	2,236	2,340	2,450	2,568	2,692	2,824	2,965	3,115	3,274	3,288	3,302	3,315	3,328
Income Taxes		-3,075	-5,478	-2,826	-1,215	-1,165	-340	871	911	953	998	1,046	1,097	1,151	1,208	1,269	1,334	1,340	1,345	1,351	1,356
Production Tax Credit		2,420	2,475	2,532	2,590	2,650	2,711	2,773	2,837	2,902	2,969										
Tax Savings (Liability)		5,495	7,954	5,359	3,805	3,815	3,051	1,902	1,926	1,949	1,971	-1,046	-1,097	-1,151	-1,208	-1,269	-1,334	-1,340	-1,345	-1,351	-1,356
After Tax Net Equity Cash Flow ($000)	-29,270	6,831	9,308	6,731	5,196	5,224	4,089	2,957	2,998	3,038	3,076	76	41	3	-39	-85	1,940	1,948	1,957	1,965	1,972
Pre-tax Debt Coverage Ratio		1.50	1.51	1.51	1.52	1.53	1.50	1.51	1.52	1.52	1.53	1.54	1.55	1.56	1.56	1.57					

PUBLIC UTILITY: WIND PROJECT PRO-FORMA (CASE 1)

ASSUMPTIONS:	Value	Notes:
Capacity (MW)	50	Assumed
Capacity Factor	0.3	Assumed
Installed Capital Cost ($/kW)	1000	($2002)
Property Tax ($000s)	1.1%	Assumed
Total First Year Operating Cost ($/kWh	0.010	($2003)
REPI ($/kWh)	0	($2003) Increases with inflation
Inflation Rate (%/yr)	2.3%	Assumed (EIA)
Discount Rate (nominal)	5.0%	Assumed
Real Discount Rate	2.6%	Calculated

RESULTS:	Value
Average Debt Service Coverage	1.00
Minimum Debt Service Coverage	1.00
Real Levelized Price ($2003/kWh)	0.0379
Nominal Levelized Price ($2003/kWh)	0.0468
First Year Electricity Price	0.0447

FINANCING ASSUMPIONS:	Fraction	Term	Rate	Notes
Debt Fraction	100.0%	20	5.00%	Assumed Average Tax-Exempt Rate

PRO-FORMA CASH FLOW:																					
Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Electric Output (MWh)		131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400	131,400
Electricity Sales Price ($/kWh)		0.0447	0.0449	0.0452	0.0454	0.0457	0.0459	0.0462	0.0464	0.0467	0.0470	0.0473	0.0476	0.0479	0.0482	0.0485	0.0488	0.0491	0.0494	0.0498	0.0501
Operating Revenues ($000)																					
Power Sales Revenues		5,876	5,906	5,937	5,969	6,001	6,034	6,068	6,103	6,138	6,175	6,212	6,250	6,288	6,328	6,369	6,410	6,453	6,496	6,541	6,586
Production Credit		0	0	0	0	0	0	0	0	0	0										
Total Revenue		5,876	5,906	5,937	5,969	6,001	6,034	6,068	6,103	6,138	6,175	6,212	6,250	6,288	6,328	6,369	6,410	6,453	6,496	6,541	6,586
Operating Expenses ($ 000)																					
General O & M Expense		1,314	1,344	1,375	1,407	1,439	1,472	1,506	1,541	1,576	1,612	1,649	1,687	1,726	1,766	1,807	1,848	1,891	1,934	1,979	2,024
Property Taxes		550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550	550
Total Operating Expenses		1,864	1,894	1,925	1,957	1,989	2,022	2,056	2,091	2,126	2,162	2,199	2,237	2,276	2,316	2,357	2,398	2,441	2,484	2,529	2,574
Operating Income ($000)		4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012
Financing($000)																					
Debt Funds	50,000																				
Total Capital Investment	50,000																				
Debt Interest Payment		2,500	2,424	2,345	2,262	2,174	2,082	1,986	1,884	1,778	1,666	1,549	1,426	1,297	1,161	1,018	869	711	546	373	191
Debt Principal Repayment		1,512	1,588	1,667	1,750	1,838	1,930	2,026	2,128	2,234	2,346	2,463	2,586	2,716	2,851	2,994	3,144	3,301	3,466	3,639	3,821
Total Debt Payment		4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012	4,012
Debt Coverage Ratio		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

NUG: GEOTHERMAL PROJECT PRO-FORMA (CASE 1)

ASSUMPTIONS:	Value	Notes
Capacity (MW)	50	Assumed
Capacity Factor	0.95	Assumed
Installed Capital Cost ($/kW)	2500	($2002)
Property Tax (% book value)	1.1%	Assumed
Total First Year Operating Cost ($/kWh)	0.0175	($2003)
Royalties	4.0%	of Revenues
Effective Income Tax Rate	40.7%	Federal =35%, State=8.84% (deductable)
Production Tax Credit ($/kWh)	0	($2003) Increases with inflation
CEC Production Incentive ($/kWh)	0.0075	Assumed
Investment Tax Credit (%)	10%	of depreciable base
Inflation Rate (%/yr)	2.3%	Assumed (EIA)
5 Year Equipment (Depreciation)	70.3%	Assumed
Discount Rate (nominal)	5.0%	Assumed
Real Discount Rate	2.6%	Calculated
Energy Price Escalation Rate	1.0%	Assumed

RESULTS:	Value
Average Debt Service Coverage	1.51
Minimum Debt Service Coverage	1.50
After-Tax IRR on Equity	18.00%
Real Levelized Price ($2003/kWh)	0.0450
Nominal Levelized Price ($2003/kWh)	0.0550
First Year Electricity Price	0.0507

	Depreciable	Depletable	Expensable
Power Plant	62%	-	-
Steam Field – Wells	12%	-	18%
Steam Field – Land	-	8%	-

Financing Assumptions	Fraction	Term	Rates	Notes
Equity Fraction	38.2%	NA	18.00%	Minimum equity return
ST Debt Fraction	6.4%	5	7.50%	Assumed
LT Debt Fraction	55.4%	15	7.50%	Assumed

PRO-FORMA CASH FLOW:																					
Year	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Electric Output (MWh)		416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100
Electricity Sales Price ($/kWh)		0.0507	0.0512	0.0518	0.0523	0.0528	0.0533	0.0539	0.0544	0.0549	0.0555	0.0560	0.0566	0.0572	0.0577	0.0583	0.0589	0.0595	0.0601	0.0607	0.0613
Operating Revenues ($000)																					
Revenues		21,111	21,322	21,536	21,751	21,969	22,188	22,410	22,634	22,861	23,089	23,320	23,553	23,789	24,027	24,267	24,510	24,755	25,002	25,252	25,505
CEC Production Incentive		3,121	3,121	3,121	3,121	3,121															
Total Operating Revenues		24,232	24,443	24,656	24,872	25,089	22,188	22,410	22,634	22,861	23,089	23,320	23,553	23,789	24,027	24,267	24,510	24,755	25,002	25,252	25,505
Operating Expenses ($ 000)																					
Aggregate O&M		7,282	7,449	7,621	7,796	7,975	8,159	8,346	8,538	8,735	8,935	9,141	9,351	9,566	9,786	10,011	10,242	10,477	10,718	10,965	11,217
Royalties		844	853	861	870	879	888	896	905	914	924	933	942	952	961	971	980	990	1,000	1,010	1,020
Property Taxes		1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375
Total Operating Expenses		9,501	9,677	9,857	10,041	10,229	10,421	10,618	10,819	11,024	11,234	11,449	11,668	11,893	12,122	12,357	12,597	12,842	13,093	13,350	13,612
Operating Income ($000)		14,731	14,766	14,799	14,831	14,860	11,767	11,792	11,816	11,837	11,855	11,871	11,885	11,896	11,904	11,910	11,913	11,912	11,909	11,902	11,893
Financing($000)																					
Short-Term Debt Funds (5 years)	7,994																				
Long-Term Debt Funds	69,247																				
Equity Funds	47,759																				
Total Capital Investment	125,000																				
Cash Available Before Debt		14,731	14,766	14,799	14,831	14,860	11,767	11,792	11,816	11,837	11,855	11,871	11,885	11,896	11,904	11,910	11,913	11,912	11,909	11,902	11,893
ST Debt Interest Payment		600	496	385	266	138															
ST Debt Repayment		1,376	1,480	1,590	1,710	1,838															
LT Debt Interest Payment		5,193	4,995	4,781	4,551	4,304	4,039	3,753	3,446	3,116	2,762	2,380	1,971	1,530	1,056	547					
LT Debt Repayment		2,651	2,850	3,064	3,294	3,541	3,806	4,092	4,399	4,728	5,083	5,464	5,874	6,315	6,788	7,297					
Total Debt Payment		9,821	9,821	9,821	9,821	9,821	7,845	7,845	7,845	7,845	7,845	7,845	7,845	7,845	7,845	7,845	0	0	0	0	0
Tax Effect on Equity ($000)																					
Operating Income		14,731	14,766	14,799	14,831	14,860	11,767	11,792	11,816	11,837	11,855	11,871	11,885	11,896	11,904	11,910	11,913	11,912	11,909	11,902	11,893
Depreciation (5 yr MACRS)		17,575	28,120	16,872	10,123	10,123	5,062														
Interest Payment		5,793	5,491	5,166	4,817	4,442	4,039	3,753	3,446	3,116	2,762	2,380	1,971	1,530	1,056	547					
Expensing of Intangibles		22,500																			
Taxable Income (pre-depletion)		-31,137	-18,845	-7,239	-109	295	2,667	8,039	8,369	8,720	9,093	9,491	9,914	10,366	10,848	11,363	11,913	11,912	11,909	11,902	11,893
Depletion		500	500	500	500	500	1,032	1,042	1,052	1,063	1,074	1,084	1,095	1,106	1,117	1,128	1,140	1,151	1,163	1,174	1,186
Taxable Income (post-depletion)		-31,637	-19,345	-7,739	-609	-205	1,635	6,997	7,317	7,657	8,020	8,406	8,819	9,260	9,731	10,234	10,773	10,761	10,746	10,728	10,707
Income Taxes	-9,250	-12,891	-7,882	-3,153	-248	-83	666	2,851	2,981	3,120	3,268	3,425	3,593	3,773	3,965	4,170	4,390	4,385	4,379	4,371	4,363
Production Tax Credit		0	0	0	0	0	0	0	0	0	0										
Tax Savings (Liability)	9,250	12,891	7,882	3,153	248	83	-666	-2,851	-2,981	-3,120	-3,268	-3,425	-3,593	-3,773	-3,965	-4,170	-4,390	-4,385	-4,379	-4,371	-4,363
After Tax Net Equity Cash Flow ($000)	-38,509	17,801	12,828	8,132	5,259	5,123	3,256	1,097	990	872	743	601	447	278	95	-105	7,523	7,528	7,530	7,531	7,530
Pre-tax Debt Coverage Ratio		1.50	1.50	1.51	1.51	1.51	1.50	1.50	1.51	1.51	1.51	1.51	1.52	1.52	1.52	1.52					

PUBLIC UTILITY: GEOTHERMAL PROJECT PRO-FORMA (CASE 1)

ASSUMPTIONS:	Value	Notes:
Capacity (MW)	50	Assumed
Capacity Factor	0.95	Assumed
Installed Capital Cost ($/kW)	2500	($2002)
Property Tax ($000s)	1.1%	Assumed
Total First Year Operating Cost ($/kWh)	0.0175	($2003)
Royalties	4.0%	of Revenues
REPI ($/kWh)	0	($2003) Increases with inflation
Inflation Rate (%/yr)	2.3%	Assumed (EIA)
Discount Rate (nominal)	5.0%	Assumed
Real Discount Rate	2.6%	Calculated

RESULTS:	Value
Average Debt Service Coverage	1.00
Minimum Debt Service Coverage	1.00
Real Levelized Price ($2003/kWh)	0.0409
Nominal Levelized Price ($2003/kWh	0.0505
First Year Electricity Price	0.0467

FINANCING ASSUMPIONS:	Fraction	Term	Rate	Notes
Debt Fraction	100.0%	20	5.00%	Assumed Average Tax-Exempt Rate

PRO-FORMA CASH FLOW:																					
Year	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Electric Output (MWh)		416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100	416,100
Electricity Sales Price ($/kWh)		0.0467	0.0471	0.0476	0.0480	0.0484	0.0489	0.0494	0.0498	0.0503	0.0508	0.0514	0.0519	0.0524	0.0530	0.0535	0.0541	0.0547	0.0553	0.0559	0.0565
Operating Revenues ($000)																					
Power Sales Revenues		19,435	19,609	19,787	19,969	20,156	20,346	20,542	20,741	20,945	21,154	21,368	21,587	21,810	22,039	22,273	22,513	22,758	23,008	23,265	23,527
Production Credit		0	0	0	0	0	0	0	0	0	0										
Total Revenue		19,435	19,609	19,787	19,969	20,156	20,346	20,542	20,741	20,945	21,154	21,368	21,587	21,810	22,039	22,273	22,513	22,758	23,008	23,265	23,527
Operating Expenses ($ 000)																					
General O & M Expense		7,282	7,449	7,621	7,796	7,975	8,159	8,346	8,538	8,735	8,935	9,141	9,351	9,566	9,786	10,011	10,242	10,477	10,718	10,965	11,217
Royalties		747	754	761	768	775	783	790	798	806	814	822	830	839	848	857	866	875	885	895	905
Property Taxes		1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375	1,375
Total Operating Expenses		9,404	9,578	9,757	9,939	10,125	10,316	10,511	10,711	10,915	11,124	11,338	11,556	11,780	12,009	12,243	12,483	12,728	12,978	13,235	13,497
Operating Income ($000)		10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030
Financing($000)																					
Debt Funds	125,000																				
Total Capital Investment	125,000																				
Debt Interest Payment		6,250	6,061	5,863	5,654	5,435	5,206	4,964	4,711	4,445	4,166	3,873	3,565	3,241	2,902	2,546	2,171	1,778	1,366	933	478
Debt Principal Repayment		3,780	3,969	4,168	4,376	4,595	4,825	5,066	5,319	5,585	5,865	6,158	6,466	6,789	7,128	7,485	7,859	8,252	8,665	9,098	9,553
Total Debt Payment		10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030	10,030
Debt Coverage Ratio		1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

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