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

Mark Bolinger, Ryan Wiser, and William Golove
Lawrence Berkeley National Laboratory

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1. 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. Very little of this debate, however, has focused specifically on publicly owned electric utilities, and with few exceptions, renewable sources of supply have received similarly scant attention.

Contrary to historical treatment, however, the buy versus build debate is quite relevant to publicly owned 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 article looks at a publicly owned utility's decision to buy or build new renewable energy capacity – specifically wind and geothermal power – in California. To examine the economic aspects of this decision, we used a 20-year financial cash-flow model to assess the levelized cost of electricity under four supply options:

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.

We focus on wind and geothermal because both resources are abundant and, in some cases, potentially economic in California. 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 compare the levelized costs of wind and geothermal power to one another. Instead, our intent is simply to compare the costs of buying wind or geothermal power to the costs of building and operating wind or geothermal capacity under various scenarios. 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 "buy versus build" decision not reflected in the economic analysis.

This article summarizes a longer LBNL report intended to inform the actions of the Public Renewables Partnership, 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. The full report can be downloaded from http://eetd.lbl.gov/ea/EMS/reports/48831.pdf.

2. Model Description

Our cash-flow model consists of a spreadsheet containing projected cash flows for representative geothermal and wind projects from 2002 (when construction occurs) through 2022 (i.e., a twenty-year operational life). 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.

- 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 minimize the 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) 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. See the full report for a detailed discussion of these assumptions.

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 (IRR)	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
California Energy Commission (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%

3. Model Results

Because of the uncertainty surrounding both the PTC for wind and the REPI for both wind and geothermal,[1] we report results for our four supply options under different assumptions about the availability of these incentives (i.e., Cases 1 through 4). Table 2 presents the model output in terms of the nominal levelized cost of our four supply options under these different cases.

Table 2. Model Results

			Nominal Levelized Cost (¢/kWh)			
			Wind		Geothermal	
Case	**PTC?***	**REPI?**	**Buy**	**Build**	**Buy**	**Build**
1	Yes	No	4.03	4.68	5.50	5.05
2	Yes	Yes	4.03	3.42	5.50	3.74
3	No	No	5.62	4.68	5.50	5.05
4	No	Yes	5.62	3.42	5.50	3.74

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

3.1 Base Case Results (Case 1)

Because most wind 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, we view Case 1 as the most likely and relevant of the four cases presented in Table 2, and therefore adopt it as our "base case." In this case, the value of the PTC to the wind NUG (as well as accelerated depreciation and the CEC incentive) more than offsets the tax-free financing advantage of publicly owned utilities, allowing the NUG to offer a wind 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 2 but are discussed in a more qualitative fashion later.

3.2 Other Results (Cases 2-4)

Table 2 shows the "build" option becoming increasingly attractive in Cases 2 through 4 with the inclusion of the REPI (Cases 2 and 4) and as the PTC expires (Cases 3 and 4 for wind only). Although we view Cases 2 through 4 as less likely than our base case (i.e., Case 1), we present all four cases in the event that the reader holds a different probabilistic view.

[1] 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.

3.3 Sensitivity Analysis

In the full report, we also look at a scenario in which geothermal receives the PTC but loses the ITC. The result is a 1.10¢/kWh net reduction in the cost of the geothermal PPA (i.e., +0.37¢/kWh from losing the ITC and -1.47¢/kWh from gaining the PTC), which makes a PPA – at 4.40¢/kWh – cheaper than utility ownership in the case without the REPI (i.e., Case 1).

We also analyze the model's sensitivity to both equity costs (i.e., IRR) and the level of the CEC incentive. Under Case 1 assumptions, 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 any 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 briefly summarize the discussion of qualitative considerations contained in the full report.

4. Qualitative Considerations

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. Utilities in general have had little experience building and operating large-scale geothermal and wind 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 – perhaps an insufficient margin of protection should the project encounter difficulties.

The full report also contemplates a number of other qualitative considerations, including the implications of municipal bonds potentially losing their tax-exempt status, as well as how the buy/build decision may impact a utility's flexibility, system reliability, exposure to price risk, vulnerability to market power, organizational development, and ability to jointly undertake projects.

5. Conclusions

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 publicly owned 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 publicly owned 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.