The Value of Salton Sea Geothermal Development in California's Carbon Constrained Future

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Executive Summary

The purpose of this study is to quantify the value of additional geothermal energy in helping California comply with recently enacted legislation establishing a 50% Renewable Portfolio Standard (RPS) by the year 2030 and achieving the long term goal of reducing carbon emissions by 80% below 1990 levels by 2050. The study finds that development of an additional 1,250 megawatts (MW) of geothermal resources at the Salton Sea is cost effective as part of a diverse renewable portfolio.

This analysis compares two renewable energy portfolios. The "base portfolio" represents how California might achieve a 50% RPS by continuation of current policies that emphasize development of solar with some out of state wind. The "geothermal portfolio" replaces 3,800 MW of solar generation with 1,250 MW of new geothermal generation from the Salton Sea. Total renewable energy production under the two scenarios does not change, despite differences in generation capacity, because geothermal plants have a capacity factor three times that of solar photovoltaic plants.

Relative to the base portfolio, the geothermal portfolio reduces CO2 emissions both in California and the rest of the West, and saves California $662 million per year in energy and ancillary service costs, $44 million per year in system resource adequacy costs, and $29 million per year in flexible resource adequacy costs, reducing overall utility revenue requirements by nearly 2%. Each megawatt hour (MWH) of additional geothermal production lowers California energy costs by $75 compared to the base portfolio under current operating and procurement practices.

This value difference between geothermal and solar decreases as other measures are taken to increase the flexibility of the grid. However, even after implementing all other potential mitigation measures including investing $4.5 billion in new bulk storage, at the margin, geothermal energy is still over $20/MWH more valuable than solar energy.

These savings result from multiple factors. At low penetration levels, integrating variable renewable resources like solar and wind is relatively easy and emphasis on the lowest cost renewables makes economic sense. But as renewable penetration increases, so do problems like lack of flexibility and over-generation in certain hours of the year, which raises costs, and changes the economic calculus. As California moves towards its

50% RPS, adding baseload geothermal reduces solar over-generation in the middle of light load days, causes fewer starts and stops in the gas fleet, lowers carbon emissions and the number of cap and trade allowances held by utilities, and reduces demand for the most expensive flexible resources.

This study is the first analysis to isolate the contribution that new geothermal production could make to meeting California's 50% RPS, but its finding that adding geothermal is beneficial is consistent with other analyses of how California could achieve its renewable energy and greenhouse gas emissions goals. The core renewable energy portfolios that Energy+Environmental Economics (E3) constructed to show viable pathways for meeting the state's greenhouse gas reduction targets all added at least 1,170 MW of new geothermal power.[1] Similarly, the portfolio that E3 modeled for PacifiCorp to show how regional integration could help California meet its renewable goals included over 1,000 MW of new geothermal generation.[2]

Introduction and Methodology

Most of the analytical studies of high penetration of renewables on the California grid extol the virtues of diversity in the renewable portfolio.[3] Nevertheless, solar, especially solar photovoltaics, and wind receive the most procurement attention. As important as solar and wind are to attaining California's ambitious energy and climate goals, their output depends on weather conditions, creating potentially large portfolio effects. As Mills and Wiser at Lawrence Berkeley Laboratories found, the marginal economic value of solar and wind energy decline sharply with increasing penetration levels.[4] This means that, at high penetration levels, the net value of solar and wind depends as much on what other resources are on the system and where

[1] California Pathways: GHG Scenario Results, Energy + Environmental Economics, April 6, 2015.
[2] Regional Coordination in the West: Benefits of PacifiCorp and California ISO Integration, Energy + Environmental Economics, Oct 2015.
3 See, e.g., "Investigating a Higher Renewables Portfolio Standard in California," Energy + Environmental Economics, 2015, or "Integrating High Levels of Variable Energy Resources in California," GE Energy Consulting, Schenectady, NY, 2015, or "Beyond 33% Renewables: Grid Integration Policy for a Low Carbon Future," A California Public Utilities Commission Staff White Paper, Nov 25, 2015.
[4] Strategies for Mitigating the Reduction in Economic Value of Variable Generation with Increasing Penetration Levels, Andrew Mills and Ryan Wiser, Ernest Orlando Lawrence Berkeley National Laboratory, March 2014.

the solar and wind resources are located as it does on the standard metric of cost, referred to as the "Levelized Cost of Energy" (LCOE).

As California implements SB 350 and moves towards obtaining 50% and more of its annual electric energy from renewable resources, these portfolio effects dramatically increase and must be taken seriously. Simply procuring the renewable resource that is "least cost" by the standard metric of LCOE for an individual project will not lead to a least cost system. Furthermore, "best fit" in the current "least cost/best fit" paradigm cannot be assumed to be a simple fixed generic "integration cost adder" for each specific technology or a time of delivery (TOD) multiplier based on historic load shape. What are important at high renewable penetrations is how all of the pieces fit together and complement each other, and how the remaining non-renewable resources (including demand side resources) are utilized.

In this paper, we illustrate this important finding and quantify the marginal value of adding a "baseload," non-flexible renewable resource -- specifically, geothermal energy derived from the extensive Known Geothermal Resource Areas near the Salton Sea -- to California's renewable portfolio.

We use the Low Carbon Grid Study as a platform.[5] The Low Carbon Grid Study (LCGS) is a peer-reviewed study of the California electric sector in 2030. The LCGS concludes that California can cut electric sector greenhouse gas emissions in half by 2030 using proven technology with minimal rate impact and with minimal curtailment of renewables without compromising reliability. The focus of the LCGS is on the detailed changes to procurement and operational practices required to accomplish this objective. The LCGS did not attempt to design an "optimum" renewable portfolio, only to demonstrate the value of diversity.

In this study, we focus on one element of the LCGS strategy: procurement of additional geothermal as part of a diverse renewable portfolio. To test the value of geothermal energy derived from the Salton Sea region in the renewable portfolio, we compare a "base portfolio" with a "geothermal portfolio" that replaces 10 terawatt hours per year (3,800 MW of generation capacity) of utility scale solar photovoltaics with 10 twh/yr (1,250 MW of generation capacity) of geothermal capacity from the Salton Sea. The base portfolio represents how California might achieve its Renewable Portfolio

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[5] www.lowcarbongrid2030.org.

Standard under current policies. New procurement from now to 2030 is almost all solar with a small quantity of repowered in state and out of state wind. The two portfolios generate the same quantity of renewable energy and differ only by the substitution of new geothermal generation in the geothermal portfolio for a portion of the utility scale solar PV in the base portfolio.

We run a simulation model of the Western Interconnection for a full 8,760 hours per year for both portfolios and compare their performance across the following relevant outputs:

- System variable operating costs including fuel, variable O&M, cap and trade carbon allowances, and ancillary services,
- System Resource Adequacy and Flexible Resource Adequacy costs per the current California Public Utilities Commission program,
- Annual utility revenue requirement to cover the cost of renewable Power Purchase Agreements.

The two renewable portfolios are shown in Table 1. For reference, the total California load in both scenarios is 320 twh/yr yielding a 56.3% RPS.[6]

TABLE 1

	Energy, Twh/yr		**Capacity, MW**	
	Geothermal	**Base**	**Geothermal**	**Base**
Biomass	10.6	10.6	1450	1450
CSP	5.2	5.2	2050	2050
Geothermal	**18.3**	**8.3**	**2250**	**1000**
Hydro	4.9	4.9		
Utility PV	**66.3**	**76.3**	**25900**	**29700**
Rooftop PV	23.6	23.6	15000	15000
CA Wind	39.4	39.4	12850	12850
OOS Wind	12.0	12.0	2750	2750

[6] The study assumes that Diablo Canyon Nuclear Plant retires when its NRC Operating Licenses expire in 2024 and 2025 and is replaced with renewable energy that is additional to the RPS mandate of 50% in SB 350.

The total generation portfolios, including imports of nuclear energy from the Palo Verde plant in Arizona, and "system power" from gas plants in Arizona and Nevada depicted by both enegy and capacity are shown in Figures 1-4.

Figure 1
Base Case Portfolio by Energy

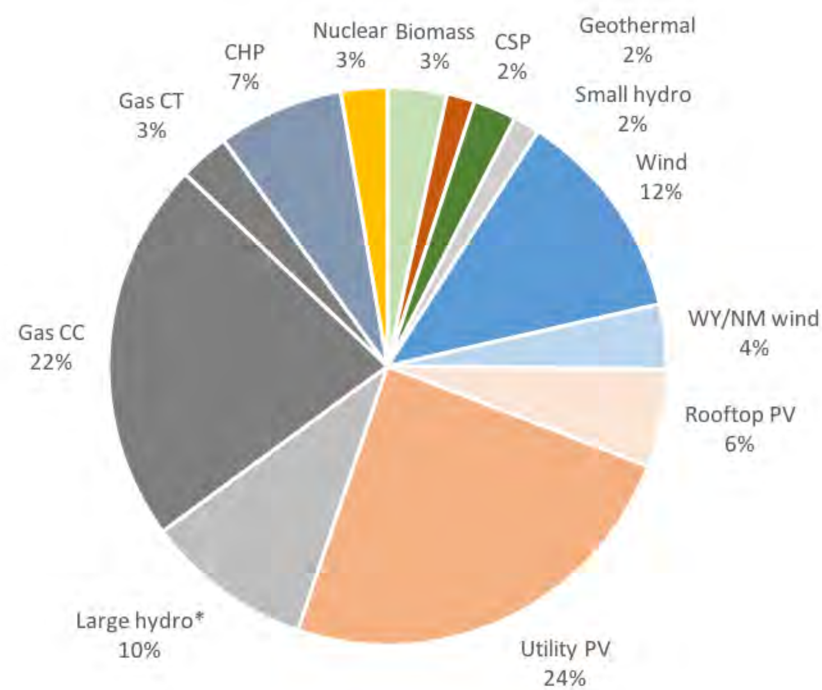


Figure 2
Geothermal Case Portfolio by Energy

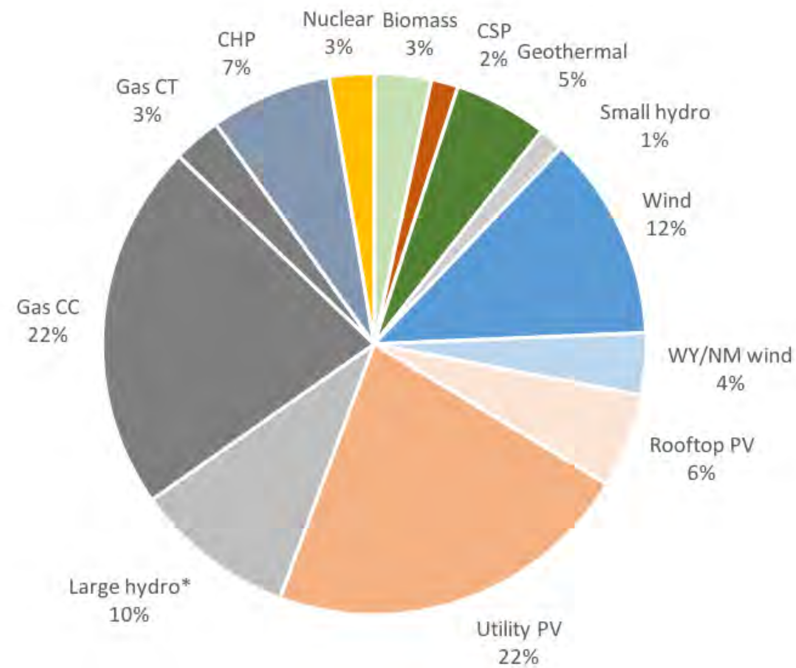


Figure 3
Base Case Portfolio by Capacity

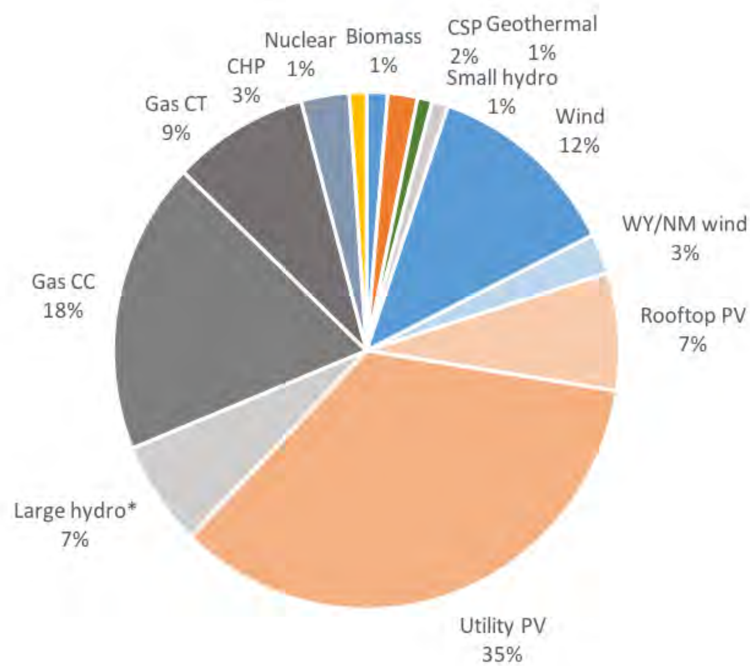
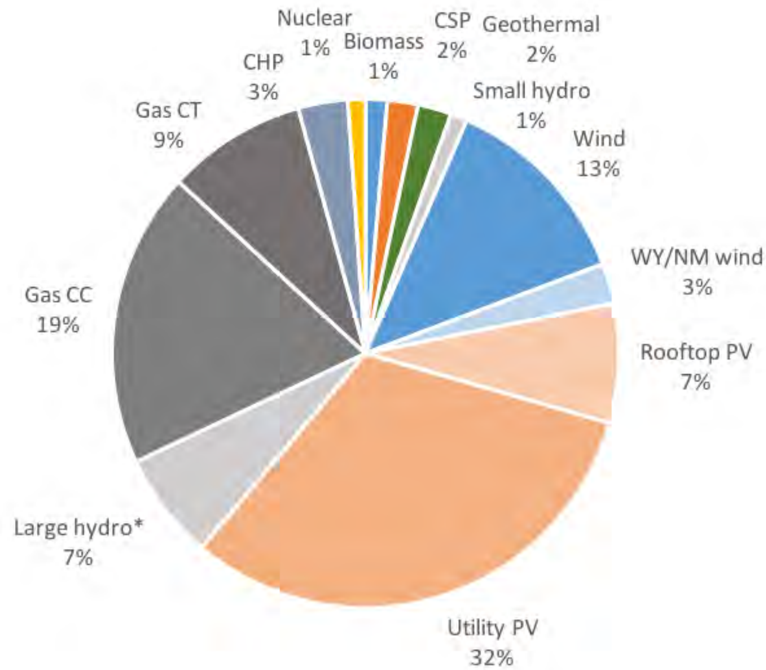


Figure 4
Geothermal Case Portfolio by Capacity



Modeling Results

Energy and Ancillary Service Costs

The two portfolios, both complying with a 50% RPS mandate in the year 2030, but one with a little more than double the amount of geothermal (2,250 MW vs.1,000 MW) and correspondingly less utility scale PV (25,900 MW vs. 29,700 MW), were run through the PLEXOS production cost simulation model by the same National Renewable Energy Laboratory (NREL) team that conducted the modeling for the Low Carbon Grid Study.

The model was configured with default settings consistent with the way the California Independent System Operator (CAISO) configures the same model for its annual long term transmission planning exercise, called the "TPP," and for the California Public Utilities Commission's long term procurement exercise, called the "LTPP." Both of these exercises model different loads and resources (neither of these planning exercises have officially modeled a 50% RPS or a doubling of energy efficiency consistent with the recently passed SB 350) and cover different years (2024 vs. 2030).

To incorporate as much as possible of the agency's approach, however, we represent the system in the same manner as the CAISO using the same model and the same default database of loads and resources.[7]

Summing the results over the entire 8,760 hours per year produces multiple benefits for California, as shown in Table 2.

Table 2
Energy and Ancillary Service Costs

	CA Production Cost, $M/yr	CA CO2, MMT/yr	WECC CO2, MMT/yr	Renewable Curtailment
Geothermal	8,642	46.8	301.5	9.7%
Base	9,304	51.0	303.9	11.8%

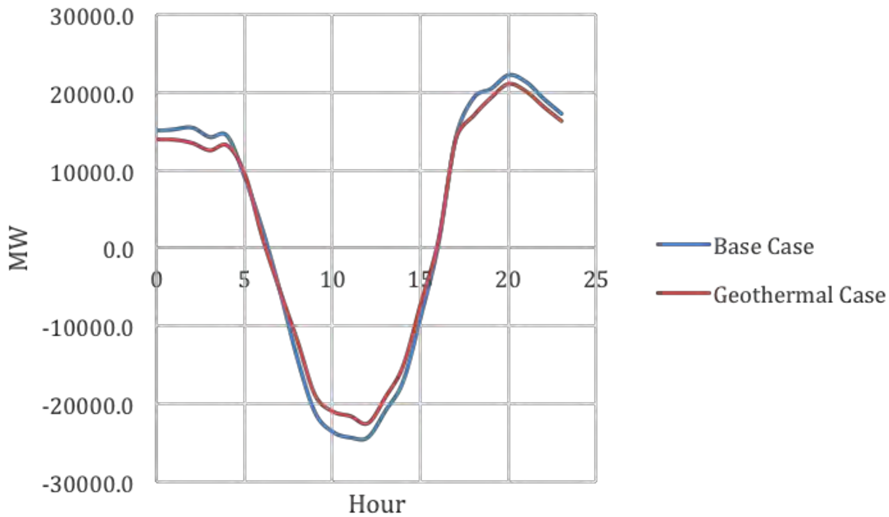
The results show that replacing 10 twh of solar PV with geothermal has several positive advantages. The addition of geothermal reduces annual costs for energy and ancillary services by $662 million per year (M/yr). It also reduces CO2 emissions by 4.2 million metric tons per year (MMT/yr) in California and 2.4 MMT/yr in the rest of the West and reduces renewable curtailment by over 20%. Stated another way, at the margin, geothermal energy is worth $66.2/MWH (6.62 cents/kwh) more than solar PV energy at a 50% RPS.

The cost savings comes from several factors: a.) Reducing curtailment means delivering more zero variable cost renewable energy to serve electric load and using less fossil energy that requires purchasing natural gas for fuel, b.) Reducing carbon emissions, which is the result of burning less natural gas and using the gas fleet more efficiently, means purchasing fewer cap and trade allowances, c.) Reducing starts and stops on the gas fleet mean less operating and maintenance expenses and higher fuel efficiency, and d.) Producing more renewable energy "on-peak" when prices are higher and reducing the hours with negative pricing due to over-generation lowers system costs. Figure 5, which depicts the "net load" curve for a light load spring day, graphically illustrates some of these effects. The addition of

[7] For a detailed description of differences between these modeling runs and those conducted by the CAISO, see www.lowcarbongrid2030/PhaseII/NRELReport.

geothermal to the portfolio fills in the "belly of the duck" when prices are low and shaves the late afternoon peak when prices are high.

Figure 5
Net Load for a Spring Day



Capacity Value

The next value difference between the geothermal portfolio and the base portfolio is in their relative capacity value. The CPUC conducts an annual proceeding called "Resource Adequacy" wherein each power plant is assigned a capacity value called "Net Qualifying Capacity" (NQC). The system peak load for the next year is then forecast and utilities are required to procure enough NQC one year in advance to ensure that enough resources are available to the CAISO to reliably serve next year's peak load.

This procurement results in "RA payments" to generators based on their NQC, and, in return for receiving these payments, the generators incur a "must offer obligation" to bid their resource into the CAISO real time energy or ancillary service markets.

These RA payments serve as reservation fees outside of the CAISO energy and ancillary service markets to ensure that enough capacity is available to the CAISO to meet peak load. For renewable resources purchased under a Power Purchase Agreement (PPA), the RA payment is included in the PPA price and no extra money changes hands. For fossil resources, the utilities conduct an annual bilateral procurement that allow the resources to bid a fee to provide their NQC to the system under the must offer obligation, and these payments must be added to the variable production cost savings calculated by the PLEXOS model to arrive at total system costs.

For geothermal resources, NQC is the generation facility's nameplate capacity. Therefore, the NQC of the additional geothermal energy in the geothermal scenario will be 1,250 MW. The capacity value in foregone RA payments to fossil producers if the geothermal were not present is included in the PPA price of the geothermal resource.

The NQC for solar PV is calculated by a methodology called "Effective Load Carrying Capability" (ELCC) which varies with the penetration level of the resource in question. This complicated and data intensive methodology is the subject of an ongoing proceeding at the CPUC and its details are beyond the scope of this paper. In the case of solar PV, the NQC declines as solar penetration increases. At low levels of solar penetration, its energy is delivered mostly "on peak" and its NQC is relatively high, but as the penetration of solar increases, the additional solar energy pushes the net load peak to later in the day. At about 33% to 40% annual average penetration of solar, the peak is likely to be pushed to near sunset and the next increment of solar will provide only very limited capacity value.

For the base scenario, we calculate a marginal NQC value for solar of 4% of nameplate capacity or 150 MW of NQC for the 3,800 MW of solar that is replaced by the 1,250 MW in the geothermal scenario.[8] Thus, utilities must procure an additional 1,100 MW of NQC (1,250 MW – 150 MW) from fossil resources to ensure a resource adequacy in the base scenario equal to the 1,250 of NQC provided by the additional geothermal in the geothermal scenario. The RA payments required to induce these fossil resources to submit to the must offer obligation provide an additional value stream in the geothermal scenario.

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[8] Mills & Wiser, op cit, calculate a similar ELCC value for PV solar. This marginal value only applies to the last increment of solar that is displaced by the added geothermal energy. The solar fleet as a whole clearly provides a capacity value well in excess of 4% of nameplate.

The RA payments to individual resources are confidential information and not publicly available. However, 18 months after the annual RA procurement, the CPUC publishes a report summarizing the aggregate prices paid. The latest such report gives a current price for RA payments of $40/kw-yr. Thus, the added capacity value for the geothermal in our scenario is $44 M/yr ($40/kw-yr x 1,100 MW) or $4.4/MWH (0.44 cents/kwh).[9]

Flexibility Value

Geothermal is often criticized for its lack of flexibility. As the argument goes, the dramatic rise of solar and wind has significantly increased the demand for flexibility on the grid, and, therefore, non-flexible resources like geothermal have much less value than flexible ones like natural gas. While it is true that Salton Sea geothermal would have a difficult time supplying "flexibility" as it is currently defined, and, if it could, the flexibility would be expensive, adding geothermal to the renewable resource mix does reduce system flexibility needs. This valuable attribute can be quantified and priced.

Today, "flexibility" is defined in the CAISO tariff, and "Flexible RA" is procured in the same CPUC Resource Adequacy proceeding as "System RA" as explained above. The demand for Flexible RA is calculated annually by forecasting next year's maximum three-hour ramp in "net load" (i.e., load minus wind and solar) by month. The utilities are then required to procure enough resources that can ramp (change their output up or down upon request by the CAISO) to meet that calculated demand. In exchange for receiving a Flexible RA payment from the CPUC procurement, the resource is required to bid into the CAISO real time energy and ancillary services markets and respond to five-minute dispatch instructions from the CAISO. This feature is known by the acronym "FRACMOO" or Flexible Resource Adequacy Must Offer Obligation. Because geothermal, especially from the Salton Sea, has very limited ability to follow these dispatch instructions, it does not qualify for FRACMOO and is essentially ineligible to receive Flexible RA payments. Like System RA, the marginal supply of FRACMOO is the natural gas fleet that receives a strong majority of FRACMOO payments.

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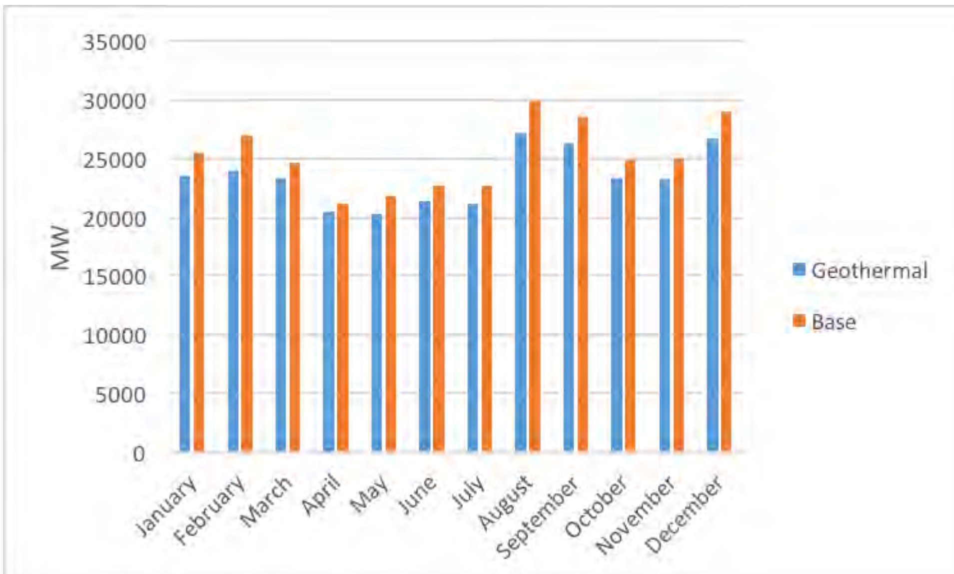
[9] The 2013-2014 Resource Adequacy Report, pp. 25-26 California Public Utilities Commission, August 2015.

We use the same PLEXOS modeling runs as before to calculate the maximum monthly three-hour ramp for the two portfolios with more or less geothermal. The results are shown in Figure 6**.**

Figure 6
Maximum 3-Hour Ramp in Net Load by Month
MW



Adding 1,250 MW of geothermal to the mix reduces the monthly demand for Flexible RA by an average of 1,825 MW. There is little or no price history on Flexible RA as it is a new program that began in earnest for the 2015 RA year. Prices are confidential, and the CPUC has yet to publish any price history. The relative supply/demand balance between System RA and Flexible RA is unclear. Flexible RA is clearly more difficult to qualify for, and the supply will be significantly lower than System RA. On the other hand, the demand for Flexible RA is about one-half of the demand for System RA. Furthermore, FRACMOO at this time remains an "interim" product subject to a complex ongoing proceeding at the CPUC that could produce significant changes to the FRACMOO protocols in the next few years.

However, the marginal Flexible RA resources are the same as the marginal System RA resources and the must offer obligation is similar. For purposes here, we assume that the price is the same as System RA at $40/kw-yr. Thus the added "flexibility value" for the geothermal in our scenario is \$73 M/yr (\$40/kw-yr x 1,825 MW) or \$7.3/MWH (0.73 cents/kwh). However, when the Flex RA is purchased, the System RA attribute is included in the price, so the net addition is only \$2.9/MWH (0.29 cents/kwh). If new resources must be constructed specifically to supply Flexible RA and satisfy the FRACMOO requirements, the price for that new product would be significantly higher than the \$40/kw-yr estimate.

Total Savings

To arrive at the total savings for adding Salton Sea geothermal to California's renewable portfolio, we add the three elements above:

- \$66.2/MWH for energy and ancillary services,
- \$4.4/MWH for system capacity value,
- \$2.9/MWH for flexible capacity value.

Thus, we estimate the total marginal value for adding 1,250 MW of geothermal to CA's 2030 renewable energy mix at \$75/MWH. The majority of these savings are related to consuming less natural gas to serve electric load. Thus the calculated savings depend on the price of that natural gas in 2030. For this paper, we, like the Low Carbon Grid Study, E3, and the other researchers cited herein, used the latest Mid-Case Energy Information Agency price forecast.[10]

To give an idea of the relative magnitude of these savings, the total statewide utility revenue requirement in 2030 has been estimated at \$38.2 billion per year.[11] Thus adding geothermal to the RPS portfolio saves almost 2% on statewide utility bills.

Relative Cost of Solar and Geothermal

There are many potential sources of projected costs for renewable resources. The Low Carbon Grid Study used ranges of capital cost for geothermal of

[10] EIA Annual Energy Outlook 2015. Natural gas prices today are roughly one-half of that forecast; gas prices eight years ago were roughly double that forecast.
[11] www.cpuc.ca.gov/documents/RPSCalculator. The latest version of the Calculator (v6.1) only estimates the revenue requirement for CPUC jurisdictional utilities. The above figure was grossed up to a statewide estimate by assuming that non-CPUC jurisdictional utilities have similar costs.

$4,000/kw to $6,800/kw and $2,150/kw to $3,400/kw for utility-scale solar PV. The current version of the RPS Calculator used by the CPUC and the CAISO for planning purposes gives a capital cost of $6,774/kw for Salton Sea geothermal and $2,470/kw for utility scale PV.[12] This does not mean that geothermal energy is two to three times more expensive than PV energy. PV is fueled by the sun that shines at full force for the equivalent of only roughly five hours per day, while geothermal produces energy at a constant rate 24 hours per day. Thus, the "capacity factor" of PV in the desert sun is about 31% while the capacity factor of geothermal is about 93%. In other words, a geothermal resource produces three times as much energy as a PV resource with the same nameplate capacity.

If these raw cost and performance numbers are run through a standard model such as the RPS Calculator to convert them into the standard metric of LCOE with all other variables held equal, the result is that geothermal is about 8% cheaper than solar PV (somewhat less than 1 cent/kwh). However, this simple calculation leaves out other relevant factors.

In the market for power, relative costs are defined by prices that a willing buyer and a willing seller agree to in a long term Power Purchase Agreement. Today, PV PPA prices are roughly $30/MWH (3 cents/kwh) cheaper than geothermal PPAs. There are two principal reasons for this disparity in what the simple performance models say and what is observed in the real world: PV receives better tax incentives[13] and commands a significantly lower cost of capital from investors. This price differential represents what developers are actually paid for their product, not their bid price. Bid prices for solar can be different than the PPA prices because bid prices are often quoted with an accompanying time of delivery (TOD) multiplier to reflect "on-peak" vs. "off-peak" prices. When solar PV was first added to the grid in large quantities a few years ago, essentially all solar energy was delivered "on-peak" when prices were high, and the TOD multiplier was as high as 1.5, meaning the developer was paid 1.5 times its bid price. As solar PV penetration increases, this multiplier is likely to drop below 1.0 to reflect the fact that, as shown in Figure 5, solar deliveries will be mostly "off-peak" when prices are low or even negative. As solar penetration increases, bid

[12] Ibid.

[13] PV is currently exempt from paying county level property taxes, geothermal is not. Recent federal legislation extending federal income tax incentives for renewable energy gives more favorable treatment to PV than geothermal.

prices may need to rise to account for the lower TOD multiplier. Geothermal TOD multipliers are at all times, by definition, 1.0 because output is the same in all hours, whether on-peak or off-peak.

Although PV is currently cheaper to buy than geothermal, the price differential ($30/MWH) is significantly less than the cost savings for California's electricity system from adding additional geothermal power modeled in this study ($75/MWH). This means that from a system standpoint, investing in additional geothermal makes economic sense.

Moreover, there are reasons to believe that the current price advantage for solar PV compared to geothermal may diminish in the future. The current differential tax treatment between PV and geothermal will shrink going forward. For example, federal tax credits for solar PV provided for under current law start to phase out in three years. In addition, the current difference in cost of capital for PV versus geothermal resources could be significantly reduced by a change in California policy. A major cause of the cost of capital differential appears to be a result of the difficulty in securing PPAs to underwrite geothermal financing before development risks have been satisfied. A change in California policy that recognized the system benefits of adding additional geothermal would create a market for new geothermal, resulting in easier access to PPAs and lower cost of capital.

Other Scenarios

This study, like the Low Carbon Grid Study, did not seek to determine an optimum portfolio of renewable resources. However, we did consider whether the value of additional geothermal would persist in a system with enhanced flexibility beyond what is available to the CAISO today. The substantial cost of over-generation with solar penetration levels required in the future is stimulating significant changes in procurement and operating practices to deal with the issue. Two of those "mitigation measures" are already well underway and are included in both the base case and the geothermal case: (1) an Energy Imbalance Market to make trading patterns with the rest of the West more efficient and capitalize on the geographic diversity of loads and resources over the broader footprint of the eleven Western states, and (2) managed charging of the rapidly growing fleet of electric vehicles to shift loads into the middle of the day and soak up a portion of the solar over-generation.

Additional flexibility could enter the grid in the future. The CAISO has formed an “Over-Generation Task Force” to conceive, design and implement across-the-board changes in its operating practices, large and small, to reduce over-generation. These and similar efforts at both the CPUC and the California Energy Commission (CEC), as well as the private sector in pursuit of profitable investments, are likely to expand system flexibility. Indeed, the notion of a “diverse portfolio” as discussed here in the specific context of adding substantial geothermal resources to the mix is but one example of these multiple assaults on over-generation.

To test the potential for this type of change to address the over-generation issue and potentially reduce the value differential between PV and geothermal, we ran the PLEXOS model using the same two portfolios but with a different set of grid operating and procurement practices to more fully utilize the inherent flexibility of the physical assets available with today’s technology. In the Low Carbon Grid Study, these measures were termed “enhanced flexibility” versus the “conventional flexibility” of today’s practices. A detailed list of these measures can be found in the LCGS NREL Report on the study website under “Phase II Results.”[14] The measures principally consist of the following:

- Lifting of current import/export restrictions to facilitate more efficient trade with the rest of the West while fully utilizing the “Bucket 2” and “Bucket 3” allocations of Product Content Categories for RPS compliance embodied in current RPS protocols.
- Utilizing the inherent physical capability of new renewable resources and underutilized existing non-fossil resources to supply ancillary services and essential reliability services through such commercially available products as “smart inverters” and “synthetic inertia” from wind farms. This avoids the use of fossil resources to provide these services, lowering costs and CO_2 emissions.
- Procurement of additional bulk storage beyond the current CPUC mandated amount. The “enhanced flexibility” scenario procured an additional 2,200 MW of 4+-hour storage, adding roughly 30% more bulk storage than the “conventional flexibility” scenario.

[14] http://www.nrel.gov/docs/fy16osti/64884-02.pdf.

The first two of these measures do not have significant capital dollar costs associated with implementation. However, they will not come quickly or easily. In general, they involve new interconnection standards and product development to deploy flexible capabilities in new renewable projects, renegotiating existing contracts, retrofitting some existing plants, and changing long-standing behavior patterns of multiple institutions. Details are beyond the scope of this paper but are discussed at some length in the Low Carbon Grid Study.

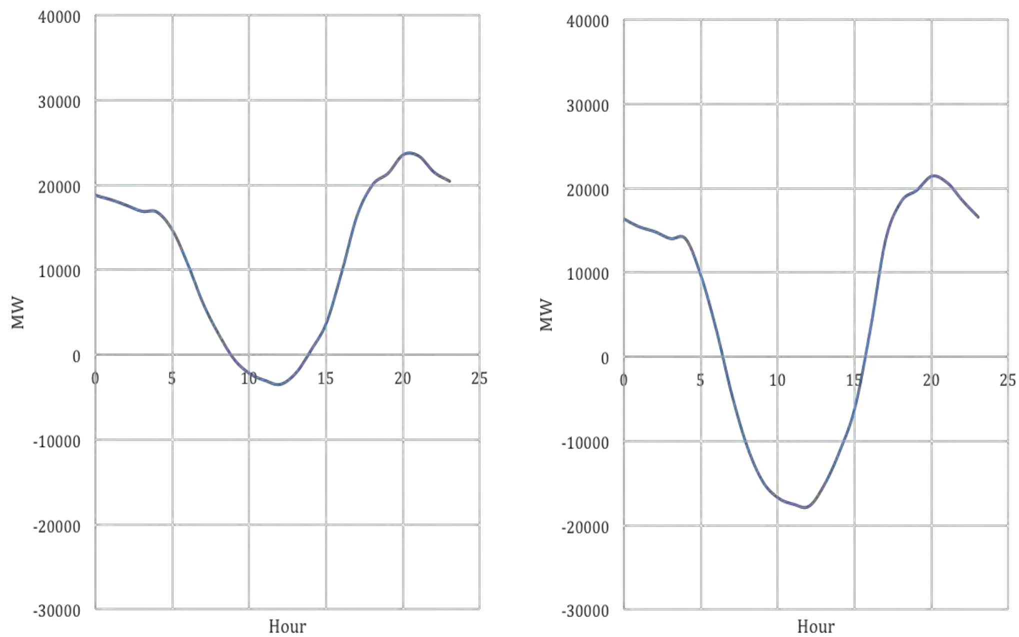
The third additional mitigation measure – procurement of additional bulk storage – is relatively expensive and raises system losses due to the fact that it is only possible to recover some 80% of the energy stored in these devices. The 2,200 MW of new four- to six-hour bulk storage in this scenario that was found to be cost-effective in the Low Carbon Grid Study is estimated to cost roughly $4.5 billion.[15]

These model runs showed there would continue to be positive benefits from additional geothermal even after all other potential mitigation measures were implemented. Specifically, the model showed that the energy and ancillary service value of adding geothermal would be $10/MWH and that the capacity value of adding geothermal would remain unchanged at $4.4/MWH as would the flexibility value of $2.9/MWH, producing a total value of a little under $20/MWH. There would also be CO2 emissions benefits, with CO2 emissions being reduced by an additional 8.5 MMT/yr in California and an additional 2.4 MMT/yr in the rest of the West as compared to the base case with conventional flexibility**.** Renewable curtailment fell to less than 1%.

To illustrate the difference these measures make, we reproduce here the "duck curve" showing over-generation in the middle of a sunny, cool, breezy spring day, when loads are light because few people are running their air conditioning systems.

[15] Low Carbon Grid Study: Comparison of 2030 Fixed Costs of Renewables, Efficiency, and Integration with Production Cost Savings, JBS Energy 2015, pp. 19-22. This report can be found at www.lowcarbongrid2030/documentsandresources.

Figure 7
Two Net Load Curves for a Light Load Spring Day



The curve on the left depicts the geothermal portfolio with the enhanced flexibility measures, while the curve on the right depicts the less diverse base portfolio with today's operating practices. The bigger, steeper hill to climb with the less diverse portfolio and today's operating practices is apparent.

These results indicate that it is possible, using current technology, to provide additional flexibility and substantially reduce system costs. If these enhanced flexibilities were adopted, the savings for adding geothermal to the resource mix would fall from roughly $75/MWH to roughly $20/MWH. However, the capital cost of acquiring the enhanced flexibility, principally the cost of the new bulk storage, would be significant. If this capital cost were converted into an equivalent dollar per megawatt hour figure, it would consume over half of the potential savings. Taking this into account, the benefit of additional geothermal to the system in a scenario with "enhanced flexibility" would be around $50/MWH – still significantly larger than the current price differential between geothermal and PV.

Conclusion

It is not a coincidence that multiple studies evaluating how California can meet its 2030 and 2050 energy goals include a major increase in geothermal generation. Over-generation becomes a significant issue at the renewable energy levels needed to meet California's 50% RPS and its greenhouse gas objectives. Adding a baseload renewable resource like geothermal is cost-effective because it ameliorates over-generation and reduces system demand for the most costly increments of flexibility.

This study is the first to quantify the economic value that adding additional geothermal resources can provide to California's electric system. It compares a base portfolio that represents how California might achieve its 2030 targets under a continuation of current policies with a geothermal portfolio that replaces 3,800 MW of solar generation with 1,250 MW of new geothermal generation from the Salton Sea. It finds that incorporating the additional geothermal generation reduces CO2 emissions compared to the base case and saves the electricity system up to $75 in operational costs for every MWH of added geothermal generation. The potential savings could be as much as 2% of total system costs by 2030.

Although this dollar figure is specific to a future system operated much like today, the general conclusion that new geothermal is cost effective is robust across a range of scenarios that contemplate other innovative solutions for dealing with high penetrations of variable renewable energy resources in a carbon constrained world.

California will need a diverse portfolio of renewable resources and system flexibilities to meet the state's renewable energy and greenhouse gas goals. This study indicates that adding new geothermal resources would be a cost effective step and one of the lowest-hanging fruit available to California as it journeys down the pathway to a low carbon future.