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The Increasing Comparative Value of Geothermal in California – Trends and Forecasts for Mid-2019

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ABSTRACT

This paper evaluates the comparative economic benefits and value of geothermal compared to other renewable resources in California from 2012 through the first half of 2019 using actual market data, as well as forecasts for the coming 10-20 years. Buyers and planners at Investor Owned Utilities (IOU), Municipalities, and Consumer Choice Aggregators (CCA) frequently compare geothermal to solar PV or solar PV with integrated storage during their planning and procurement process. They need to know, and this paper explains, how geothermal accrues greater economic benefits than solar PV in the California ISO (CAISO) wholesale energy market and in meeting resource adequacy (RA) requirements. In 2017-2018, for example, a geothermal production profile had an energy market value worth approximately \$9/MWh more than a solar PV profile. In the first half of 2019, we find that a geothermal production profile has an energy market value worth approximately \$16-\$18/MWh more than a solar PV profile. Simulations and commercial price forecasts indicate that this energy value difference will continue to grow to \$20/MWh or more in the coming years due to the continued expansion of solar energy, which decreases energy market prices during solar production hours. Correspondingly, the incremental or marginal solar PV capacity rating in California has declined dramatically with increased solar penetration. Regulators are now using a value close to zero for planning purposes, while geothermal's capacity value remains constant, in a range of 80-90% of maximum seasonal production. This disparity in energy and capacity ratings creates a difference over time between geothermal and incremental solar PV capacity values of ~ \$18.50/MWh.[2]

Additionally, as renewable penetration increases, the costs to replace high capacity factor resources such as geothermal or a natural gas combined cycle plant are much higher than replacing a low capacity factor natural gas peaker plant. The California Public Utilities Commission's (CPUC) Integrated Resource Plan tool requires 3-4 MW of PV with integrated storage to replace a single MW of geothermal. The CPUC tool finds that as renewable energy increases on the California grid, additional solar energy will require more and more energy storage to shift PV energy to the hours of the day where it is needed, exacerbating efficiency losses.

For these reasons and others, significant quantities (GW) of new geothermal are being selected through capacity expansion modeling in California's integrated resource planning (IRP) proceedings. This will require accelerated geothermal expansion across the Western U.S. and provides an analytical and policy framework for geothermal development worldwide.

1. INTRODUCTION

As the penetration of renewable resources increases in California and around the world, the comparative energy and capacity value of the primary renewable generation technologies – notably solar, wind, geothermal – is continuously changing. In California, the influx of solar energy has been drastically changing prices in the wholesale energy market, leading to lower prices during solar production hours and price spikes during the solar ramp periods. The capacity ratings or credits of additional stand-alone solar generation (also called marginal or incremental solar) measured as its contribution to meeting peak loads is also rapidly declining, essentially reaching a zero value. Wind energy in the region has an energy production profile that is more continuous throughout the day, but has a low capacity rating due to its lack of reliable performance during California's peak load hours. The addition of storage on a stand-alone basis or integrated into wind and solar plants improves their valuation, but these developments are still in early phases. Furthermore, tremendous amounts of new energy storage will be needed to address both operational and reliability needs over time. In contrast, geothermal energy obtains the average energy value across the entire year, which, while declining, is significantly higher than solar's energy value. In addition, because of its continuous operations throughout the year, geothermal obtains a robust capacity rating, no matter the level of renewable penetration. Furthermore, geothermal's performance is more reliable than solar's with integrated storage, since the latter requires solar radiation to charge the storage while geothermal has continuous operations.

These trends are significant because utilities located in regions with wholesale markets analyze both the contracted costs of new renewable resources and their future wholesale market value. This cost-benefit analysis is then used to rank alternative projects. In the western U.S., the wholesale value (\$/MWh) is what can be obtained for the energy (real power) delivered to the grid, as well as

[1] Ormat would like to acknowledge ABB Enterprise Software for approving the use of their proprietary long-term energy price forecasts for Southern California. See Section 3.3 of this report for details.

[2] This value is derived assuming the geothermal plant displaces a new combustion turbine. The value is possibly greater if new capacity resources are comprised of aggregations of solar plants with integrated energy storage.

any other wholesale services (such as ancillary services), and resource adequacy (RA) capacity obligations.[3] The difference between costs and benefits is called the "net costs" and because of this calculation, in utility procurement, a renewable resource with a higher contract cost may be selected over a lower contract cost resource if its net costs are lower.

Geothermal is the renewable resource currently experiencing the most rapid change in comparative net costs. While not the lowest cost resource on a levelized cost basis, geothermal is now by far the highest economic value renewable resource in California and the surrounding region. Even as we see the contract prices for wind, solar PV, and lithium-ion battery prices decline, their continued penetration improves geothermal's comparative economic value, thus encouraging long-term procurement on a net cost basis.

Some of these changes in comparative value were anticipated in simulation studies that preceded the recent expansion in renewable energy, such as Mills and Wiser (2012). Their forecasted changes have now been realized in California's market price and capacity valuations. In a series of recent papers, these changes have been evaluated using historical prices and capacity valuations issued by California regulators and utilities (Orenstein and Thomsen, 2017; Thomsen 2018a). Additionally, Thomsen (2018b) utilized a California Public Utility Commission (CPUC) capacity expansion model to evaluate future trends in comparative resource selection given the declining costs of solar PV and lithium-ion batteries. This paper builds on that previous work and is organized as follows: Section 1 discusses comparative energy value of solar and geothermal from 2012 to the middle of 2019, and forecasts of future value; Section 2 discusses trends in capacity value; Section 3 explains recent results on geothermal selection in integrated resource planning; and Section 4 provides conclusions and next steps for research. To maintain the focus on results, in each section, the methodology is only briefly explained, with reference to the prior papers.

2. TRENDS IN COMPARATIVE ENERGY VALUE IN SOUTHERN CALIFORNIA, 2012-2019

There have been two dominant trends in the California Independent System Operator (CAISO) energy markets over the past seven years. First, the average energy market prices have declined due to lower natural gas prices[4], increased renewable generation, and, recently, higher hydro conditions. This average energy market price, equivalent to the average price for a geothermal profile, is shown in the first row of Table 1.

Solar energy has experienced the greatest growth in recent years, and has the greatest impact on energy market prices and resource valuations. From an initial level of less than 500 MW of solar in 2010, there are now over 25 GW of solar resources on the California grid. This includes both solar PV and concentrating solar power (CSP), of which over 7 GW is behind-the-meter solar PV (CEC 2018). Solar power directly (as wholesale generation) and indirectly (by reducing load) affects CAISO energy market prices. In terms of annual energy production, in 2018, non-hydro renewable energy provided 26% of energy on the CAISO grid, with solar energy comprising 12%.[5] Additionally, in-state hydro levels have been high from 2017 through 2019, which has an impact on energy market prices in the spring months.[6]

Figure 1 shows the combined effect of solar and high hydro production on market prices from 2016 to the first half (H1) of 2019. Figure 1 plots the hourly average day-ahead energy market prices in Southern California in each year using Southern California Edison (SCE) Load Aggregation Point (LAP) prices. In 2018, the average energy price increased, but the hourly average prices show the now-consistent pattern by which solar production depresses prices during the solar production hours. During the spring months, these prices are extremely low and even become negative. When the average price level declines, all renewable resources have a lower energy value—but some resources retain greater value than others do. In particular, solar PV experiences a more rapid decline in value than geothermal because geothermal operates outside the solar PV production hours.

[3] California has a Resource Adequacy (RA) capacity requirement, but not a centralized capacity market. Hence, utility buyers provide renewable projects with a capacity credit based on a combination of short-term bilateral capacity contract costs and long-term avoided costs of new capacity. This requirement, can be monetized as capacity value (typically represented as $/kW-year and converted into $/MWh when resources are compared on an energy production basis).

[4] Natural gas prices have increased more recently.

[5] From 2012 to 2018, wind generation has fluctuated between 5-6% of annual CAISO energy production, with higher production in the latter years, geothermal generation has been between 4-5%, and the production of the remaining nuclear plant provides about 7-8%. Hydro has fluctuated between 5-15% in recent years. Natural gas production and imports make up the rest.

[6] All data in this paragraph has been from CAISO state of the market reports over 2012-2018, as found in the references.

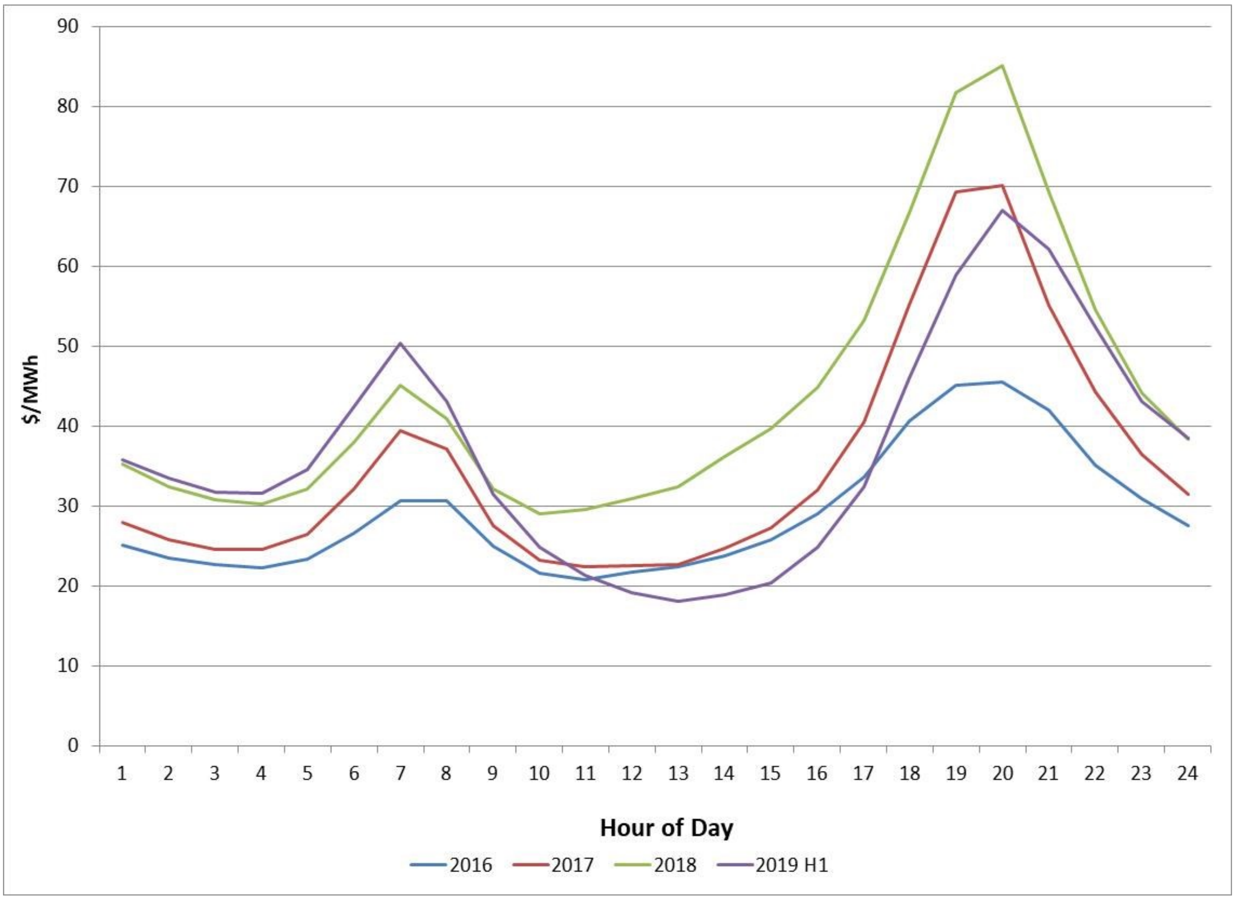

Figure 1: Average SCE Load Aggregation Point (LAP) Prices by Hour of Day, 2016-2019 H1

2.1 Trends in Annual Comparative Energy Value

To evaluate the impact of this trend on resource valuation, we used three solar PV profiles previously developed by the CAISO and the CPUC in the CPUC's long-term procurement planning process (LTPP).[7] We selected these randomly because they are at different locations and use different technologies (one uses single-axis tracking technology and the other two use fixed-tilt). The method is simple: we cross-multiplied these profiles by the CAISO day-ahead energy market prices at an aggregated locational marginal price[8] and normalized to $/MWh in market revenues. For all the results below, we use the aggregated prices at the SCE Load Aggregation Point (LAP).[9] We decided not examine real-time energy market prices as these are only used to financially settle deviations from day-ahead schedules, which rarely impacts geothermal schedules, but may affect solar generation given forecast errors.

Table 1 shows the annual results for 2012 to the middle of 2019. The first row of the table shows a geothermal energy value for a baseload profile. The next three rows shows the value of the three different solar PV profiles described above. The last three rows show the difference in value between the geothermal and solar profiles, which is simply the geothermal value minus the solar PV value. When the number is negative, it indicates that solar is worth more than geothermal. When the number is positive, it indicates that geothermal is worth more than solar and the amount of additional energy revenue that geothermal earns when compared to solar PV. Each column represents the year being evaluated.

In 2012, the solar PV energy profiles evaluated were worth $3-4/MWh more than geothermal. The higher energy value of solar was sustained into 2013, although at a lower level. In 2014, for the first time, a solar PV energy profile and a geothermal energy profile would have earned the same average energy revenues. Due to the increased solar PV production and penetration which began to depress midday prices, the geothermal value rose slightly higher than solar PV beginning in 2015 (around $2-$3/MWh greater) and continued to increase in 2016 (around $4-$5/MWh greater). In 2017, the CAISO experienced significantly lower prices in the day-ahead market during solar PV production hours, including negative prices during the spring months (see Figure 1), due to over-

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[7] The LTPP is an umbrella proceeding which has conducted simulation of future grid conditions; the LTPP is now folded into the CPUC's Integrated Resource Planning (IRP) proceeding. For more information see http://www.cpuc.ca.gov/irp/.

[8] Renewable energy contracts with California buyers differ in whether the seller is asked to settle financially at the nodal price or at one of the aggregated prices at Trading Hubs or Load Aggregation Points (LAP) (which reflect congestion from the node to aggregated location). Recent contracts we have seen asked the seller to specify whether the buyer should assume that energy is settled at the node where the generator is located or at either the trading hub or LAP.

[9] In Orenstein and Thomsen (2017), we also showed the average energy value at the South of Path 15 Trading Hub (TH), which is not repeated here; the SP15 TH and SCE LAP calculations differ only in this because of the manner in which the aggregated market price is calculated based on the underlying locational marginal prices (LMPs). We found that the SP15 TH average comparative values were consistently $1-2/MWh lower than the LAP valuations, and do not repeat them here.

generation conditions related to high hydro, low loads, and the continuing solar PV expansion. As a result, in 2017, geothermal had $8-9/MWh greater value than solar PV. In 2018, while the price pattern continued, high prices in the energy market during solar production hours in July and August shifted more value to solar generation even as solar production increased, and did not significantly change the valuation from the prior year. However, in the first half of 2019, the combination again of high hydro and even higher solar production lead to a significant increase of $16-18/MWh in value difference (although, as shown below, the value difference tends to be higher in the spring months),

Table 1: Difference in annual average energy value between geothermal baseload and three solar PV profiles ($/MWh) in Southern California, 2012-2019, using SCE Load Aggregation Point (LAP) prices

	2012	2013	2014	2015	2016	2017	2018	2019, Jan-June
Average energy value ($/MWh)								
Geothermal baseload	$30.84	$44.94	$48.04	$32.59	$29.04	$35.21	$43.99	$38.66
Solar PV-1 "Blythe 2024"	$35.00	$48.09	$48.76	$30.56	$25.27	$27.82	$37.42	$22.28
Solar PV-2 "Photovoltaic 2024"	$33.84	$47.29	$47.45	$29.64	$24.32	$26.30	$34.71	$21.87
Solar PV-3 "NV_WE"	$34.78	$47.42	$47.46	$29.55	$24.18	$25.81	$35.23	$20.25
Difference in energy value between geothermal and solar PV*($/MWh)								
Solar PV-1 "Blythe 2024"	-$4.16	-$3.16	-$0.72	$2.04	$3.76	$7.93	$6.58	$16.39
Solar PV-2 "Photovoltaic 2024"	-$2.97	-$2.35	$0.60	$2.95	$4.71	$8.92	$9.29	$16.80
Solar PV-3 "NV_WE"	-$3.94	-$2.48	$0.58	$3.04	$4.85	$9.39	$8.77	$18.42

*A negative sign indicates that solar PV is worth more than geothermal. All prices used for these calculations are downloaded from the CAISO OASIS website.

2.2 Trends in Monthly Comparative Energy Value

The annual trends in comparative energy values discussed above are not evenly distributed across the year. Historically, the highest value for solar PV energy in California has come during the summer months, when peak loads take place in the late afternoon, during sunlight hours. As shown in Figure 1, as solar penetration has increased, the impact of solar production on market energy prices has been most pronounced during spring light load conditions, exacerbated by higher hydro production. Again, we see solar PV energy values have recently been lowest in those conditions, and their value during summer months has also declined.

Figure 2 below shows the price differences which were presented annually in the last three rows of Table 1, calculated by month, for just one of the PV profiles represented in Table 1, "NV_WE".[10] In 2012 and 2013, solar PV energy values were highest in the spring and summer months and were as much as $6/MWh higher in value than a geothermal profile in those months. By 2015-2016, market price depression during solar production hours in the spring months had led to much higher average geothermal value compared to a solar value in the spring, with the maximum difference to date being $26.50/MWh in February of 2019. In the summer, higher loads lead to greater market value for both resources, and the value difference is not as great—but it then increases again in the fall months. These trends help to further clarify what is driving the changes in comparative energy value.

[10] The "NV_WE's" profile's energy value for the full year shown in Table 1 is the sum of the monthly values shown in the figure divided by twelve (12) months for the average.

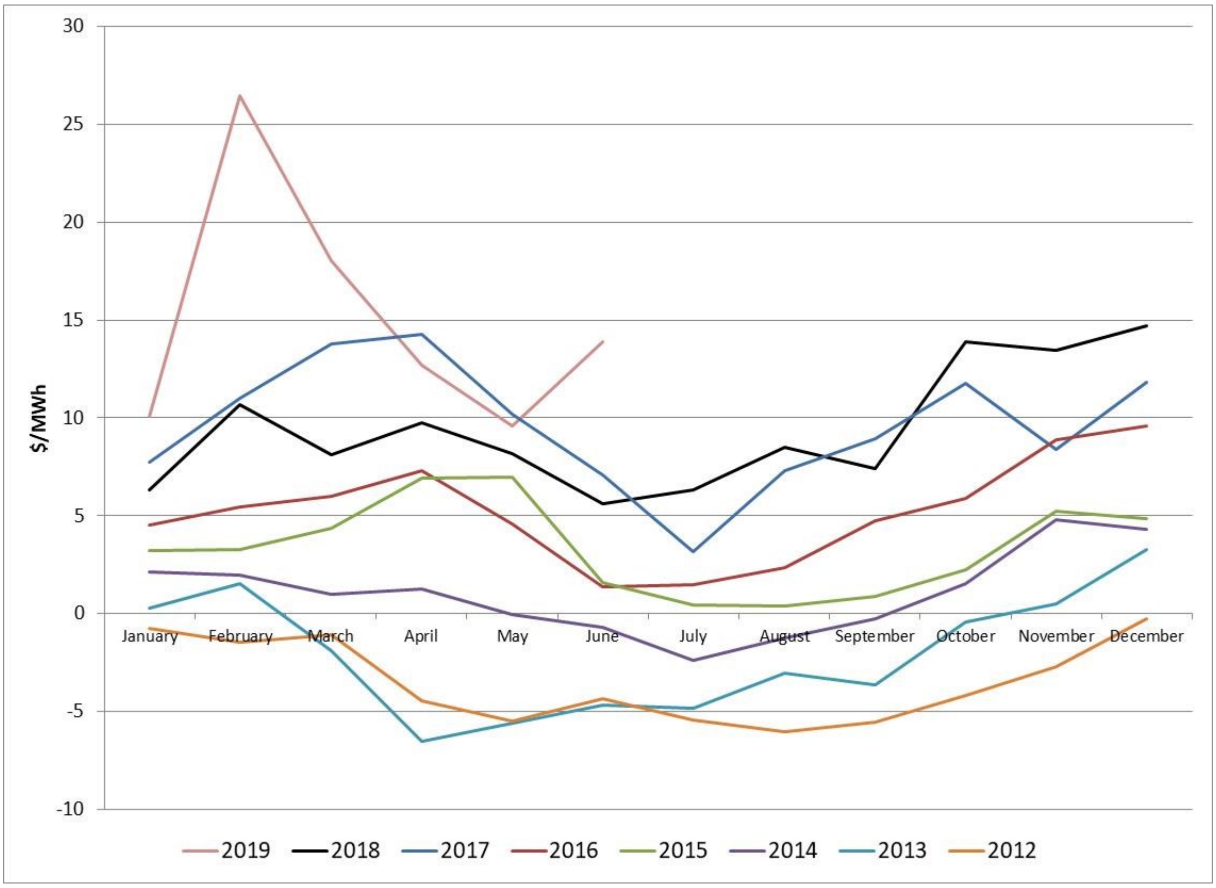

Figure 2: Difference between geothermal and solar PV energy value ($/MWh) on a monthly basis, 2012-June 2019, for a single PV profile (negative means solar PV is worth more than geothermal)

2.3 Forecasts of Energy Value

The price trends in the CAISO market are forecast to continue and to be amplified with the continued penetration of solar and other renewable resources. Ormat has evaluated several forward price curves over the coming 20 years offered by different commercial vendors. These forecasts differ with respect to the analytical methods used, as well as particular assumptions about changes to the resource mix, input costs (such as fuel prices), and bounds on market prices. While these forecasts are proprietary and will not be reviewed here in detail, we find that they predict a continuation of the trends shown in the actual wholesale markets, and that an energy value difference between geothermal and solar PV of $20/MWh—or greater— can be consistently identified over the coming 10-20 years.

As an example, Figure 3 shows the comparative valuation results utilizing one widely used set of commercial forward price curves, by ABB Enterprise Software. Through agreement with ABB Enterprise Software, these results are shown for illustrative purposes only. Other parties interested in using these forward price curves need to contact ABB Enterprise Software directly.

ABB Enterprise Software provides several scenarios for the long-term price forecast, including a “reference case” and sensitivity analyses on low and high natural gas prices and the addition of a federal carbon dioxide (CO_2) adder in the future that would supersede any state or regional CO_2 policies. Similarly to the analysis shown in Table 1, Figure 3 plots the *difference* in energy value in the SCE zone using these forecast hourly energy prices, between the same geothermal and one of the solar profiles discussed above (“NV_WE”), from 2020-2040.[11] That is, if a point on one of the lines is equal to, e.g., $10/MWh, it means that in that scenario for that year, a geothermal profile was worth $10/MWh more in energy value than a solar profile on average over the year; it does not indicate the absolute value of the renewable profile. As shown, for the ABB Reference Case forecast, the long-term energy value difference results in about $20/MWh greater geothermal value by 2040 and a simple average of the difference over the period of $14/MWh. A lower natural gas price forecast (ABB Low Gas Price) results in a lower difference in energy market value, while price forecasts with the High Gas Price and the CO2 Tax result in greater comparative value for the geothermal profile.

[11] As discussed in Section 1.1, this calculation is the hourly energy value of the geothermal profile minus the hourly energy value of the solar PV profile, averaged over each year. To simplify the figure, we calculated this number for 2020, 2025, 2030, 2035, and 2040, and connected the results with the lines in the figure.

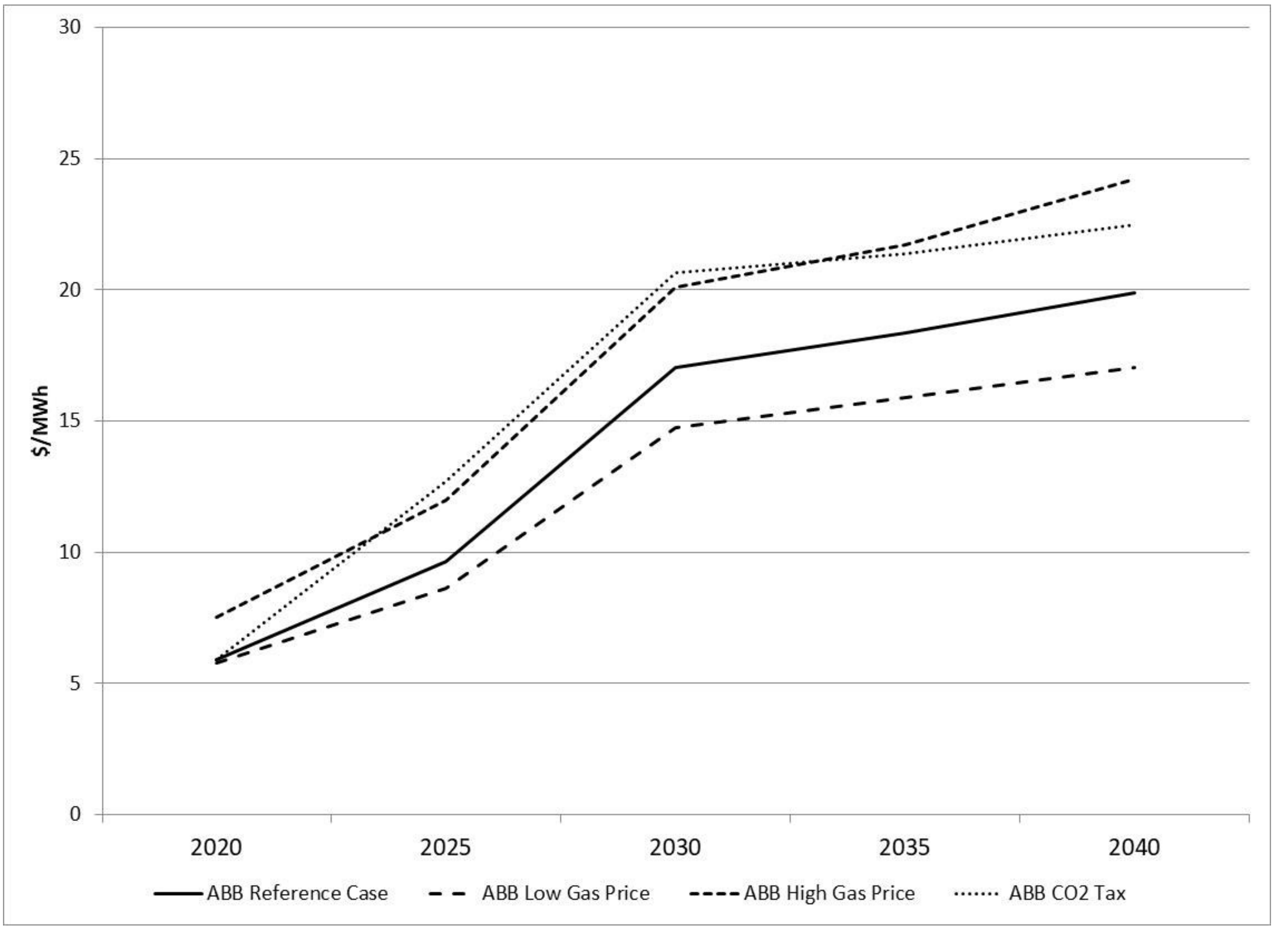

Figure 3: Difference between geothermal and solar PV forecast energy value ($/MWh) on an annual average basis, 2020-2040, for a single PV profile (measured as average geothermal energy revenue minus average solar PV energy revenue)

As another illustration of price forecasts, Orenstein and Thomsen (2017) conducted a comparative valuation using the same methods explained above with public data on simulated future southern California energy market prices from the CPUC's long-term procurement planning models of 2024, which were issued in 2014 (CAISO 2014). There were two scenarios utilized and evaluated using a production cost model: a 33% RPS scenario and a 40% RPS scenario (as described in CAISO 2014). The hourly marginal energy prices resulting from the simulations were made publicly available by the CAISO for stakeholders during this proceeding. The model was also utilized by other parties to replicate the solutions and conduct sensitivity analysis. The forecast prices were generally aligned with the proprietary commercial forecasts, but the prices included negative prices established by the renewable curtailment cost assumed in the production cost model.

In the CPUC/CAISO model results, there was significantly more renewable curtailment in the 40% RPS scenario, affecting up to 12% of hours annually, but concentrated in solar PV production hours.[12] When varying the assumed negative price during those surplus generation hours, Orenstein and Thomsen (2017) found a $15-$18/MWh higher energy value of geothermal in 2024 when no negative prices were modeled (that is, the lowest forecast price was $0/MWh). If an average negative price of -$5/MWh is forecast during surplus hours – reflecting the 2018 average negative price in the day-ahead market[13] – it does not greatly affect the comparative valuation, adding only about $1-2/MWh to the comparative geothermal value compared to the case without negative prices. However, if prices become more negative during solar production hours, as reflected in a -$50/MWh price sensitivity during surplus hours, they affect solar energy value significantly more than geothermal value. In this latter case, geothermal energy revenues were $25-$28/MWh greater than solar PV. This type of sensitivity analysis highlights that a geothermal contract provides a hedge against energy price volatility due to increasing production by wind and solar generation.

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[12] We also note that the curtailment results result even after the operations of the full 1.325 GW of new energy storage required under the California storage mandate. However, if the model is allowed to export surplus power to the rest of the west, curtailment declines.

[13] In 2018, about 1% of the day-ahead energy prices in the SCE LAP zone were negative, almost all concentrated in the spring months during solar production hours, with an average negative price of $4.87/MWh. As discussed earlier, solar energy comprised about 12% of the annual energy in 2018, with total non-hydro renewable energy being around 26% (CAISO 2019). While it is difficult to forecast trends in negative prices, the number of hours with surplus solar generation will clearly increase, and it is expected that such prices will continue to create downward pressure on all renewable energy value, but with a greater impact on solar generation revenues.

3. COMPARATIVE CAPACITY VALUE

A major economic benefit of geothermal in future renewable generation portfolios is its capacity rating. Capacity rating here is defined as the percentage (%) of a maximum operating level (MW) which can be used to satisfy the Resource Adequacy (RA) requirements established by the relevant regulatory authorities, which in California is the state energy agencies. Each year, the state agencies provide updated information on the RA requirements for the next year to the load-serving entities which must comply with the requirements. This data includes the assumed capacity ratings of all eligible resources. Geothermal's capacity rating remains stable over time on a seasonal or monthly basis. In contrast, the capacity ratings of variable energy resources like wind and solar are a function of their penetration on the power system. In particular, the capacity ratings for an additional or marginal solar plant which comes on-line during the RA compliance period is highly sensitive to the level of penetration of solar plants that came before it, as well as to the forecast levels of solar irradiation over the year.

Orenstein and Thomsen (2017) reviewed developments in the California Public Utility Commission's (CPUC) RA program's capacity ratings for different renewable resources, notably its calculation of solar PV's Effective Load Carrying Capacity (ELCC), which requires probabilistic modeling. In 2017, the CPUC calculated an average solar ELCC of 57.8% for 2018 RA compliance, and a marginal solar ELCC of 37%. In 2018, the CPUC calculated an average ELCC of 45% for solar for 2019 RA compliance, but did not publish an official marginal solar ELCC. However, also in 2018, the California Investor Owned Utilities (IOU) used their own metrics for solar capacity ratings in the coming years, and provided ranges for solar PV marginal ELCCs which were below 20% of installed capacity (MW) and very close to 0% by some measures (Astrape Consulting, et al., 2017). As shown in Table 2 below, for its 2018 Integrated Resource Planning (IRP) requirements to jurisdictional load-serving entities, the CPUC advised using 18% as the solar PV marginal ELCC in 2018, dropping to 2% in 2022 - 2030 (CPUC 2018).

This rapid decline in solar capacity ratings is a result of the rapid increase in solar production, but was not anticipated in the prior years of renewable procurement, when utilities selected high quantities of solar on a least cost basis without fully considering its net economic benefits. Stakeholders have argued that the marginal ELCC should be the basis for evaluation of new solar PV resources. This would be an important change to clarify the comparative contribution of additional geothermal capacity resources when compared to additional solar capacity resources.

In California, buyers of renewable energy credit new renewable resources with a monetary value for their RA capacity. This value is, in principle, either the prevailing bilateral capacity price in California over the near term, and/or the avoided cost of new generation if that is needed in later years over the contract term.[14] Orenstein and Thomsen (2017) estimated that this added $1.40-$18.50/MWh value for geothermal over solar PV in 2018, with the lower end of the range representing new renewable resources displacing an existing capacity resource in California, and the higher end of the range representing new renewable resources displacing a new capacity resource, which by convention is often considered to be a new combustion turbine. This range remains roughly the same given the updated CPUC solar PV capacity ratings in 2018.

Further refinements to the determination of annual renewable capacity ratings are incredibly important. In Thomsen (2018b), we found that for planning purposes, the combined impacts of the declining capacity ratings of new solar plants and the increasing potential for curtailment of solar energy may require much more than a 1 MW to 1 MW substitution of solar combined with 4-6 hours of storage to geothermal. As future capacity needs evolve and shift to the replacement of higher capacity factor conventional generation rather than gas peakers, we see a multiplier effect when comparing the capacity costs of additional geothermal to alternative capacity resources. This is examined further in Section 3.

Table 2: Solar and wind marginal ELCCs required for 2018 Integrated Resource Plans by CPUC-jurisdictional load-serving entities

ELCC Values	2018	2022	2026	2030
Marginal Solar ELCC (including BTM PV)	13%	2%	2%	2%
Marginal Wind ELCC	29%	31%	30%	30%

Source: CPUC (2018)

4. GEOTHERMAL IN RECENT CALIFORNIA RESOURCE PLANNING

The trends in comparative energy and capacity value reviewed above are components in the valuation of alternative renewable projects throughout the renewable procurement processes. However, in California, the determination of which types of resources to solicit over the next 20 years is increasingly being defined through Integrated Resource Planning (IRP) methods and processes. An IRP generally analyzes the least cost set of resources to meet peak loads or net peak loads in each year, usually over a 10-15 year planning horizon, and may also evaluate some operational needs, such as ramping and ancillary services, over the period. Thomsen (2018) provides a more detailed explanation of these methods as well as some recent results regarding geothermal selection using the CPUC's public IRP capacity expansion modeling tool.

[14] Unlike some eastern U.S. markets, California does not have a centralized capacity market which provides transparent capacity valuations. To estimate capacity monetary value, sellers use other capacity price indicators, including bilateral contract prices and costs of new generation.

The shift to IRP modeling in California has some advantages and disadvantages for the valuation of geothermal. On one hand, IRP modeling considers only the costs of alternative resources and does not consider the economic benefits of those resources, although there may be a correlation. For example, IRP modeling does not consider forecast wholesale market revenues, and the market value difference discussed above may not influence the selection of resource portfolios. On the other hand, energy market price forecasts, as discussed above, may not consider the impact on comparative resource costs of the curtailment of renewable energy taking place as a result of expanding renewable generation. In the western U.S., we see most of that curtailment focused during solar production hours that raises the levelized costs of solar energy when compared to geothermal. In the IRP capacity expansion models, additional renewable energy resources are being compared and selected on a "net" LCOE basis. The term "net" refers here to the remaining energy which can be delivered from the resource after some amount of curtailment due to surplus aggregate generation. This method advantages geothermal energy in resource selection, since it experiences a lower proportional impact of curtailment measured on a MWh basis.

To provide a preliminary assessment of these factors with publicly available data and replicable results, Thomsen (2018b) used the CPUC's IRP tool to conduct over 250 sensitivity cases on geothermal, solar PV, and battery costs, as well as the available geothermal resource potential. These cases included geothermal at costs ranging between $76.22/MWh (reflecting recent Ormat contracts) and $86.56/MWh (which is the base-case geothermal cost assumed by the CPUC).[15] It also evaluated two renewable scenarios using a 2030 electricity demand case: a ~60% renewable energy case intended to limit emissions to 42 million metric tons (MMT) of carbon equivalent (which we evaluated using CPUC 2017 and 2018 data assumptions) and a ~73% renewable energy case intended to limit emissions to 30 MMT of carbon (which was evaluated using CPUC 2017 data). Some summary conclusions are listed here:

- In the 60% renewable penetration case (2018 version), with geothermal at $76.22/MWh, the model generally selected between 1,700 MW and 2,020 MW of geothermal in all but the very lowest solar PV and battery cost forecasts. The geothermal selection of 2,020 MW is the maximum available geothermal resource potential allowed in the model.
- In the 73% renewable penetration case, with geothermal at $76.22/MWh, the model selected 1,700 MW of geothermal in the lowest solar PV and battery cost forecasts, and 2,020 MW in all other cases.
- When no restriction on regional geothermal resource potential was allowed, the model selects over 3 GW in the 73% renewable energy scenario at the lower geothermal rate.

The reasoning for this increased geothermal selection is that as renewable energy increases on the California grid, additional solar energy will require more energy storage to shift that energy to other hours of the day, which will also experience efficiency losses. As this process continues, the IRP model calculates that depending on the solar, battery, and geothermal prices, each MW of geothermal would require up to 3-4 MW of PV with integrated storage to replicate the geothermal energy profile (Thomsen 2018b). This was determined by removing geothermal from the set of candidate resources, calculating the resulting solution (which primarily substituted solar and storage), and then adding the geothermal resources back to determine what they displace on an economic basis. Figure 3 shows this result for the case of geothermal at $76.22/MWh ("Low" geothermal cost) and at $82.00/MWh ("Mid" geothermal cost) across the full range of long-term solar and battery costs tested in the model, which are labeled as "High" (H), "Mid" (M), or "Low" (L) in the IRP tool, and also in Figure 3 (see Thomsen 2018b for more information on these assumed costs). There are 9 sensitivity cases, and the displacement of PV with integrated storage (MW) by 1 MW of geothermal capacity in that scenario is shown on the lines in the figure. For example, in the scenario shown on the far left of the figure – labeled "MS, LB", which means "Mid" Solar (MS) costs and "Low" Battery (LB) costs – adding back geothermal at either the "Low" or "Mid" geothermal cost results in the displacement of about 2.8 MW of PV (the green and blue lines) and 1.4 MW of batteries (the red and purple lines), summed to 4.2 MW combined of PV with integrated storage. What is notable is that when PV and storage costs are lower, towards the left of the figure, adding geothermal actually displaces more of these resources because the model builds more of them to meet the policy targets. We did not test the even higher renewable cases in this way, but expect that the result would be that geothermal displaces even more PV and integrated storage resources; this will be examined in additional research.

The CPUC IRP model performs these calculations reasonably, and the results suggest an overwhelming opportunity for geothermal energy as renewable energy penetration increases. After some initial consideration and preliminary CPUC staff proposals seeking the addition of only 310 MW of geothermal based on ad hoc review of stakeholder submissions, the CPUC (2019) revised its position and adopted a preferred system portfolio from the proceeding which included 1.7 GW of new geothermal, consistent with the Ormat analysis. This creates a market for Geothermal not just in California but across the Western U.S. region, and should be a lesson for those states seeking deep renewable penetration around the world.

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[15] Although not shown here, Ormat also tested other geothermal costs, including lower ones, and found results consistent with the input assumptions. The solar costs modeled were as low as $20-25/MWh, depending on the location. The lowest battery cost was $345/kW in 2018, declining to $164/kW in 2030.

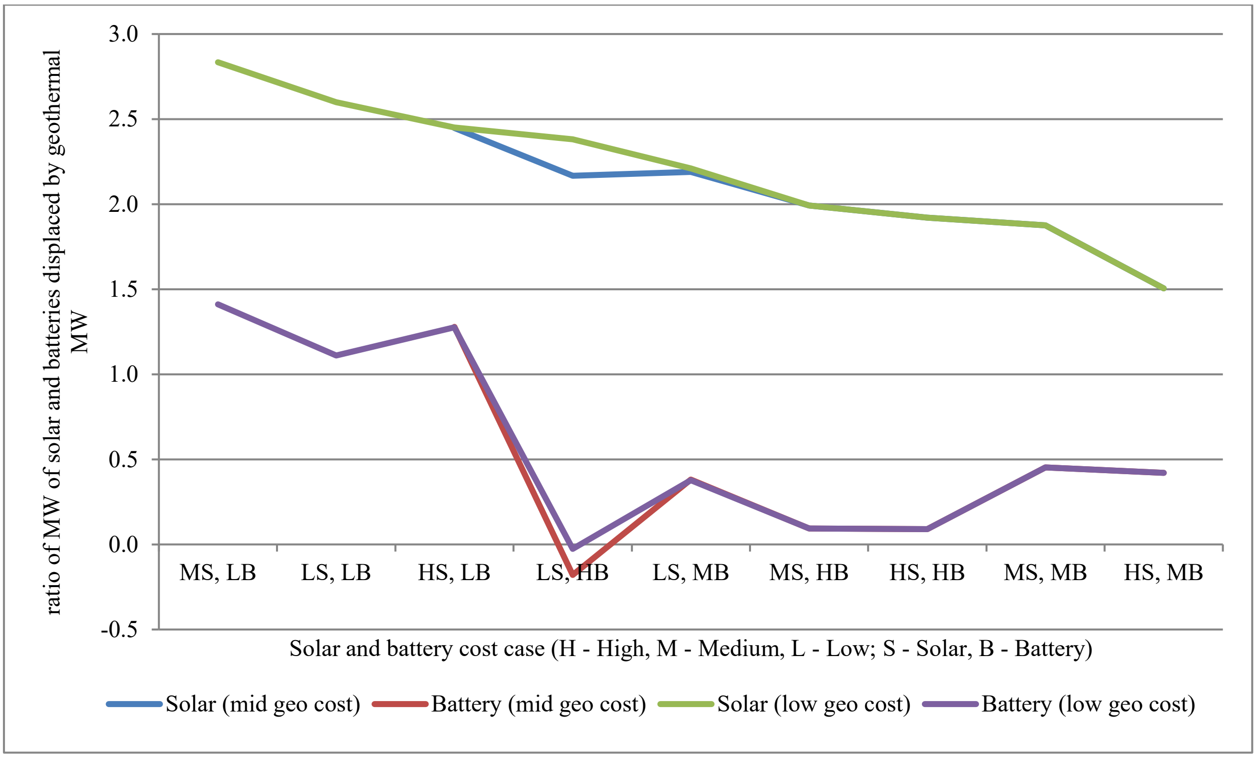

Figure 3: Displacement of solar PV and lithium-ion battery capacity (MW) by geothermal under different cost cases, 2018 42 MMT scenario

4. CONCLUSIONS

California power markets and resource procurement are changing rapidly due to the influx of new renewable energy resources, especially solar PV. As early as 2012, researchers predicted that, as solar penetration increased, the value of geothermal's energy and capacity compared to that of incremental solar PV production would increase (e.g., Mills and Wiser, 2012). Orenstein and Thomsen (2017) and Thomsen (2018a) and the expanded results in this paper used recent wholesale market price data and current calculations of RA capacity ratings to demonstrate that this trend is rapidly increasing for projects coming on-line over the next few years. Crediting a new geothermal energy project with a 20-year contract with an additional $20/MWh in energy value over a stand-alone solar project would seem to be a relatively conservative assumption. Even higher values could be justified depending on the location and expectations of future drivers of market prices, such as negative prices and additional environmental policies that increase the cost of carbon emissions. In terms of capacity value, in California, additional solar generation is already rated near zero, while geothermal's capacity is valued at its maximum rating all year. Depending on what the cost of a capacity resource to back up the additional solar power is assumed to be (combustion turbine or PV with integrated storage), it is straightforward to assume up to another $18.50/MWh or more in higher capacity value compared to new stand-alone solar. When the market values reviewed in this paper are combined with solar integration costs and increasing solar curtailment rates, which raise the net levelized cost of solar energy, we find that geothermal remains competitive in renewable procurement despite continued solar PV and battery storage cost declines (Thomsen 2018b).

These indicators from the wholesale market are also being reflected in IRP modeling tools, where we see 3-4 MW of PV with integrated storage required to replace a single MW of geothermal. As renewable energy increases on the California grid, additional solar energy will require more and more energy storage to shift PV energy to the hours of the day where it is needed, exacerbating efficiency losses. Thomsen's (2018b) analysis of geothermal selection using the CPUC's IRP tool was supported in the CPUC's (2019) most recent IRP decision, which selected significant new geothermal resources. This, in turn, will require an accelerated geothermal expansion across the Western U.S. and provide an analytical and policy framework for geothermal development worldwide.

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