California Energy Commission

STAFF REPORT

Estimated Cost of New Utility-Scale Generation in California: 2018 Update

California Energy Commission

Gavin Newsom., Governor

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ABSTRACT

This report summarizes cost trends for utility-scale power plants that may be built in California over the next decade, including solar, wind, geothermal, biomass, and natural gas-fired technologies. As California decarbonizes its electricity system, the costs of technologies will be an important consideration in the choice of new generation resources. The primary focus of the report is levelized cost, the most commonly used metric when comparing costs of the different generation technologies. Levelized cost reflects the cost of building and operating a plant over the lifetime of the facility. The report updates cost trends and assumptions including technology, financing, fuel, emissions, and others.

Keywords: Electricity, generation technologies, power plants, levelized cost, instant cost, installed cost, solar photovoltaic, PV, solar thermal, wind, geothermal, biomass, natural gas, combined-cycle, combustion turbine, gas-fired generation, capital costs, cost of debt, cost of equity, heat rate, capacity factor, tax credits.

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EXECUTIVE SUMMARY

This report provides estimates of current and future costs for a developer to build and operate new utility-scale power plants in California over the next decade. California's electricity system in undergoing major changes as the state pursues ambitious reductions in greenhouse gas (GHG) emissions. Over the next decade, the primary emphasis will remain on developing renewable and zero-emission generating resources. However, the electricity system needs some amount of strategically located, fast-ramping natural gas generation to accommodate the variability of solar and wind energy resources until the state develops low-carbon integration solutions. In addition to policies driving GHG reductions and increasing levels of renewables, cost will be an important factor in deciding which technologies to pursue in the next 10 years and beyond.

Levelized cost of electricity is a cost metric commonly used to compare different electricity generation technologies. The levelized cost estimates presented in this report reflect the average cost per megawatt-hour for an independent developer to build and operate a power plant over the lifetime of the facility. Key inputs to calculating levelized costs include capital costs, fuel costs, fixed and variable operation and maintenance costs, financing costs, assumed utilization rates (or capacity factors), and various other cost components for each generation type. The importance of these factors varies among the different technologies.

The cost estimates presented in this report reflect an update of the staff report *Estimated Cost of New Renewable and Fossil Generation in California*, published in 2015, including revised technology, financing, and general assumptions. The California Energy Commission develops generation cost estimates to use in modeling and to ensure a common set of assumptions. These estimated generation costs are also used by other state agencies, including the California Public Utilities Commission, the California Air Resources Board, the Board of Equalization, and the California Independent System Operator, as well as numerous energy consultants, researchers, and academics.

In addition to levelized cost estimates, which are the primary focus of this report, staff developed instant costs, which are the costs to build a plant as if it were built overnight, and installed costs, which are the instant costs plus the costs of construction loans and development fees. Staff also developed cost estimates for utility-owned generation. These additional cost estimates are presented in the appendices.

Renewable and Natural Gas Generation Technologies

For this update, staff narrowed and adjusted the list of technologies from previous reports to account for technology advancement and the feasibility of building new power plants in the state. The technologies studied include:

- Solar photovoltaic (PV) technology, which converts sunlight directly into electricity, and solar thermal power plants, which rely on concentrated solar energy to heat a working fluid that, in turn, is used to generate steam to power conventional steam turbines.
- Wind generation facilities, which transform the kinetic energy of the wind into electricity, located onshore or offshore.
- Geothermal binary technology, which uses hot liquid (or *brine*), drawn from beneath the earth's surface by wells and cycled through a heat exchanger to cause another fluid to boil, with the steam used to drive turbines, and geothermal flash technology, which converts the hot brine directly to steam to power a turbine by reducing the pressure on the liquid (called *flashing)*.
- Biomass technology, which uses biological resources, such as forestry waste or farming by-products, to produce electricity either through thermal processes (burning biomass fuel to run a turbine) or chemical processes (producing alcohol fuels from anaerobic digestion).
- Natural gas-fired generation, including combustion turbines (or *simple-cycle*) power plants and combined-cycle plants, which use both a conventional steam turbine with one or more combustion turbines to generate electricity.

California has a promising offshore wind resource that will require floating platforms because of the deep continental shelf off California's coast. Fixed-bottom offshore wind has been developed on the East Coast of the United States, and floating offshore wind technology has been demonstrated in the North Sea (off the coast of Scotland). However, while the report discusses the status of floating offshore wind, with no commercial projects in the state, the levelized costs for offshore wind have not been developed for this report.

Levelized Cost Components

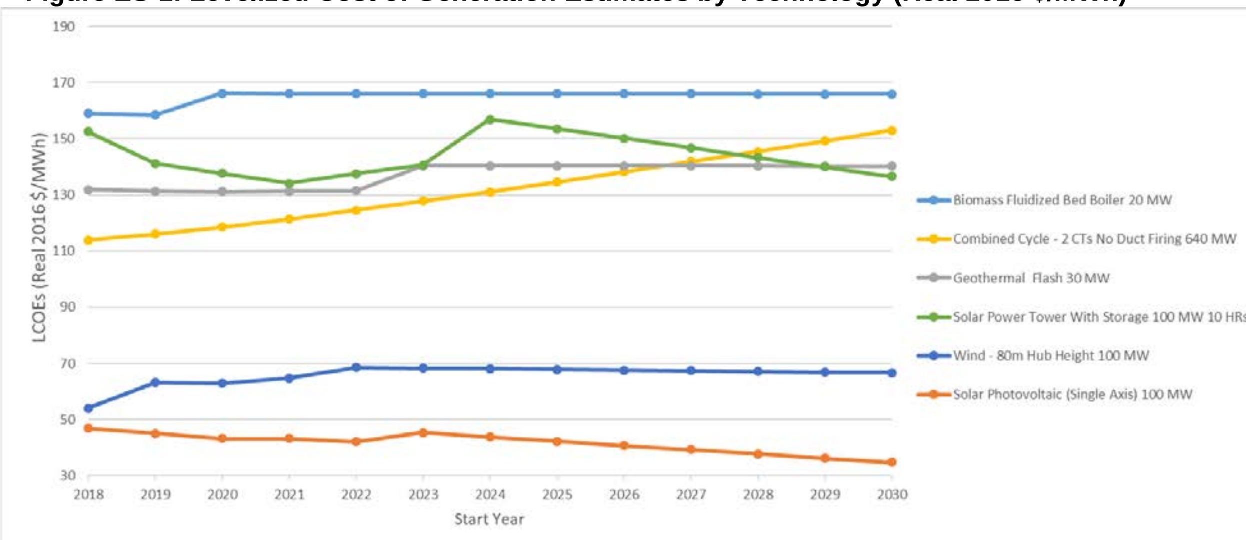
Staff developed levelized cost estimates using the Cost of Generation Model. The model includes various technology specific inputs that drive costs, such as the costs of solar PV panels (or *modules*), the quality of wind resource, well drilling costs and success rates for geothermal resources, and capacity factors for natural gas-fired power plants. In addition, several inputs are common to all technologies including the costs of financing a project, such as the capital cost structure, equity and debt rates, and taxes. Other underlying factors are independent of technology type, including emission mitigation costs, fuel prices, as well as transmission interconnection costs and line losses (the loss of electric energy due to heating of line wires by the current).

The importance of the different input assumptions differs by technology. For example, solar and wind generation have no fuel or greenhouse gas compliance costs, while fuel and greenhouse gas compliance costs are a large part of the costs for natural gas-fired power plants. In addition, the availability of incentives such as federal tax credits can also affect the cost of a particular technology and lower project financing costs.

Levelized Cost of Generation Estimates

Figure ES-1 shows the mid case levelized cost estimates for a selection of technologies studies in this report: biomass, combined cycle, geothermal flash, solar tower, wind, and solar PV (single axis). The mid case is as assessment of the cost that is most likely to occur. It is bounded by a high case and a low case, which use simultaneous highest cost and lowest cost factors.

Figure ES-1: Levelized Cost of Generation Estimates by Technology (Real 2016 $/MWh)



Source: California Energy Commission

Levelized cost estimates are lowest for solar PV, with the lowest of those being the 100 MW single axis type using crystal silicon technology, at $49 per MWh in 2018. Wind technology is most competitive before the expiration of the production tax credit, with an estimated levelized cost in 2018 of $54 per MWh. A traditional combined-cycle plant is estimated to have a levelized cost of $114 per MWh, while geothermal flash technology is $132 per MWh, solar power tower is $153 per MWh, and biomass is $159 per MWh.

Levelized Cost Trends and Implications

Solar PV has experienced dramatic price declines in recent years, exceeding previous estimates. While declining module costs have exhibited the largest cost decrease, inverters, other hardware, labor, overhead, and financing costs have all contributed to the cost decline. Tax credits were important in making solar PV more costs competitive and were a significant driver of development. The phaseout of this credit is expected to have only a temporary cost increase on solar PV projects as their levelized cost is anticipated to continue to decline. Solar PV is the least costly and most likely technology to be developed in California. The generation profile of solar resources poses challenges for electricity system operators who must manage the ramp-up of solar generation as it peaks midday and then ramps down rapidly at sunset while electricity demand remains high. California is pursuing options to integrate solar output, including developing energy storage, deploying demand response, and taking advantage of regional diversity and zero-carbon imports from the western region.

Solar power tower costs are not expected to decline as much as previously estimated. While there are still significant declines in levelized cost, the decrease of the investment tax credit counteracts much of the near-term cost declines. Lower costs are driving investments in solar PV in California, leaving the future of solar thermal in California uncertain. Future cost declines will largely depend on the success of projects installed elsewhere in the United States and internationally.

While wind turbine costs will continue to decrease and performance to improve, these changes are not expected to occur fast enough to offset the expiration of the production tax credit. However, the financing assumptions do not change over the forecast period, and developers may seek more cost-effective financing options that result in lower levelized costs as incentives expire. The production tax credit has been instrumental in spurring wind development in California. However, this credit declines over the next two years, and wind developers are well aware of the expiration date. Future economic competitiveness will depend on technology costs, performance, and the financial willingness of investors.

Geothermal technology is mature, and significant changes to the cost of these technologies are not expected. The expiration of tax credits increases the geothermal cost slightly. Developers may be able to lower the cost by finding investors who are willing to assume greater risk and a slightly lower return. While the cost of geothermal is significantly higher than PV and wind, it can provide electricity during the hours when these technologies are not generating. There is potential for significant development of geothermal power generation and lithium extraction in the Salton Sea area with the right mix of private sector interests and government support.

Biomass technology is mature, and the associated cost is estimated to be constant over the forecast period, with the exception of the effect caused by the expiration of the production tax credit at the end of 2019. This report is limited to the cost to developers and does not include external costs and benefits, such as making productive use of forest waste to generate electricity. There is legislative and executive support for using forest waste to generate electricity at biomass plants, but little development has been seen to date.

The number of biomass plants in California has decreased significantly since the 1980s due to expiring long-term contracts. In near term, they are hindered by high operation and feedstock transportation costs, which can result in insufficient revenue to cover operation and maintenance expenses. With the increasing intensity of forest fires in California and the unprecedented tree die-off from drought providing a large source of forest waste, the state is exploring opportunities for biomass electricity generation, depending on whether burning forest waster creates a net-carbon benefit.

The underlying combustion technologies for natural gas-fired power plants are mature and the prices stable. The primary drivers of cost escalation are fuel and greenhouse gas compliance costs. With the increase in renewable energy, gas-fired plants have been tasked with accommodating this new generation, providing ramping, flexibility, and reliability to the grid. While California has policy preferences for renewable and zero-emissions generation resources such as solar, wind, and hydro imports, strategically located natural gas plants play an important role in supporting the growing portfolio of renewable resources on the grid in the near term. However, with the withdrawal of the permit application for the Puente Power Project and the suspension of review for the Mission Rock Energy Center, no utility-scale gas-fired plants are under siting review at the Energy Commission. The future of new gas-fired generation is uncertain as the state looks to zero-emission generation resources, energy storage, and demand-side management strategies, such as demand response, to meet California’s energy needs.

CHAPTER 1: Introduction

This chapter discusses and defines key terms used in the report and the technology types addressed. It provides an overview of methods and updated trends and assumptions used to develop cost estimates presented in the report. This chapter also outlines the contents of the remaining chapters and appendices.

Scope

This report presents estimates of the current and future cost of five electric generation technology types: solar, wind, geothermal, biomass, and natural gas. Staff estimates instant and installed costs of generation in developing levelized cost estimates, which are the primary focus of this report. Staff uses the following definitions of these costs in the report:

- *Instant cost* is the cost to build a power plant if it could be built overnight, sometimes characterized as overnight cost. It includes cost of all equipment, permitting, and construction, with the exception of the costs for financing the construction.
- *Installed cost* is the instant costs plus the construction loan including development fees.
- *Levelized cost* reflects the lifetime cost of operations and maintenance, combined with the installed cost, expressed as a constant stream of costs per unit of value over the lifetime of the plant. It is most commonly measured in dollars per megawatt-hour ($/MWh) but sometimes reported as dollars per kilowatt-year ($/kW-Year).

Independent developers, or *merchant* developers, rather than utilities build most of the power plants in California, even though a utility may contract for the output of a power plant. Levelized cost estimates for power plants developed by merchant owners are in the body of the report. Instant costs, installed costs for merchant plants, and installed and levelized costs for investor-owned and publicly owned utility generation are in the appendices.[1]

Agencies use these estimates in a variety of studies, including for system dispatch studies and utility rate forecasting at the Energy Commission, procurement planning

1 Publicly owned utilities in the state develop their own power plants. However, with the exception of hydroelectric, nuclear generation, and two IOU-owned gas plants (Palomar Energy Center Mountainview Power Company), all other power plants are merchant facilities. Investor-owned utilities must purchase electricity from long-term contracts either with merchant power plant owners or from markets run by the California Independent System Operator.

and resource adequacy at the California Public Utilities Commission, transmission and reliability planning at the California Independent System Operator, and analysis performed by the California Air Resources Board. The California Board of Equalization uses estimated costs of generation for property assessments. In addition, a variety of consulting, research, and academic studies rely on these cost estimates.

Method of Calculating Costs

Staff used the Cost of Generation Model to calculate levelized, instant, and installed costs of the different generation types. The instant and installed costs are developed as part of the logic in the model that computes levelized cost. A description of the Cost of Generation Model is in the previous cost of generation report, with additional documentation provided online.[2] Staff constructed a mid-cost case using the most likely current cost estimates applicable across the state for all factors used in estimating the future costs of new generation. Staff built a high-cost case and a low-cost case around that mid-cost case, using the simultaneous highest cost and lowest cost factors. To establish a narrower, more likely range of cost values, staff used the Monte Carlo method to generate probabilistic levelized cost ranges.[3] The Monte Carlo tool is built into the Energy Commission's Cost of Generation Model.

The levelized cost of a resource represents a constant cost ratio, computed to compare the generation costs of one unit with other types of generating resources over similar periods. The Cost of Generation Model generates levelized cost using operational, cost, financial, and tax assumptions. The model calculates the costs for a technology on an annual basis, finds a *present value* of those annual costs,[4] and then calculates a levelized cost. The most common presentation of levelized cost is in dollars per megawatt-hour ($/MWh) or cents per kilowatt-hour (¢/kWh). **Appendix A** details the components of levelized costs.

Updates From Previous Cost of Generation Estimates

This report updates information presented in the 2015 report, *Estimated Costs of New Renewable and Fossil Generation in California*, including technology, financing, and general assumptions. Staff narrowed and adjusted the list of technologies based on technology advancement, as well as economic and regulatory feasibility of building new utility-scale power plants in California. Staff developed estimated levelized costs for following technologies:

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2 Rhyne, Ivin, Joel Klein, and Bryan Neff. 2015. *Estimated Cost of New Renewable and Fossil Generation in California*. California Energy Commission. CEC-200-2014-003-SF. https://www.energy.ca.gov/almanac/electricity_data/cost_of_generation_report.html.

3 The Monte Carlo method uses a large number of randomized samples to generate a probability distribution.

4 The *present value* of a future year dollar cost is defined as the amount of present day dollars that, when paid a fixed interest rate (typically referred to as the *discount rate*) over the intervening years, would produce the same number of nominal dollars in that future year.

- Four solar photovoltaic (PV) options, including a 20 MW and a 100 MW thin-film plant, a 20 MW and 100 MW single axis plant, and one 100 MW concentrating solar thermal power tower plant with storage.
- An 80 MW onshore wind plant.
- A 50 MW biomass fluidized bed boiler.
- A 30 MW geothermal binary plant and a 30 MW geothermal flash plant.
- Five gas turbine configurations, including a 49.9 MW and a 100 MW conventional combustion turbine, a 200 MW advanced combustion turbine, a 640 MW combined-cycle plant with two combustion turbines (no duct firing), and a 700 MW combined-cycle plant with two combustion turbines (duct firing).

In addition to changing the technology options, this report focuses primarily on updating the technology cost data, general assumptions, and bringing the base year to 2016. Background assumptions are brought up to date, such as labor rates, London Interbank Offered Rate,[5] fuel costs, and inflator series.

The report also updates the financial assumptions. A key change is that merchant financing for renewable technologies is now separate, allowing for more accurate characterizations of risk and market conditions. Previous reports used the same financing assumptions for all renewable technologies.

The electric grid is a large and dynamic system, and estimating how adding a resource at one location alters the operation of the surrounding grid is complex and beyond the scope of this report. Further, estimating the value of a power plant to a utility or the state would require capturing benefits such as environmental, economic or job, and grid reliability that are beyond the scope of this report.

Report Overview

Chapter 2 discusses the role financing and debt costs have on the total cost of the project. The chapter details the capital cost structure, equity and debt rates, taxes, and tax benefits. It also discusses the trends and assumptions for three underlying parameters that are independent of technology type: emission costs, fuel prices, and transmission interconnection costs and line losses.

Chapter 3 is devoted to each technology type. The chapter provides a brief overview of the technology, discusses recent trends and analysis, summarizes key assumptions, and provides the mid case levelized cost estimate for a merchant developer to build and operate each technology option.

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5 London Interbank Overnight Rate is a daily rate that sets the borrowing costs for financing institutions; it is the benchmark for short-term interest rates across the financial system.

Chapter 4 summarizes and compares the levelized cost estimates for the different technologies, discusses the implications of the levelized cost estimates, and provides final thoughts.

Appendix A provides additional explanation of levelized cost and related components.

Appendix B provides additional model assumptions, operations and maintenance costs, instant costs, installed costs, and high and low case levelized costs for each technology type.

Appendix C provides additional details about the probabilistic analysis, the Monte Carlo method, and associated results.

Appendix D compares levelized cost by developer type (merchant, investor-owned, and publicly owned utilities), providing a component cost breakdown for each developer case in $/MWh and $/kW-year.

Appendix E provides tornado diagrams for all the technologies—a diagram that shows the relative effect of key assumptions on levelized cost.

CHAPTER 2: Technology-Independent Cost Assumptions

While each project and generation technology brings a unique set of costs and underlying trends, several cost components are semi-independent of the technology type. These components include financing and taxes, environmental mitigation costs (including emissions) and fuel costs, and costs for transmission interconnection.

Financial Assumptions

The cost of financing a project is a major component of constructing and owning a power plant. This report focuses on private, or *merchant*, developer costs, rather than utility-owned power project costs, as private owners are by far the dominant developers in the market. Private developers typically finance projects based on *debt* and *equity*.[6] Financing costs include the capital cost structure, equity and debt rates, taxes, and benefits. This report varies the financing structure and costs based on the risk and market financing trends for each technology type, rather than using a set of financing assumptions across all technologies. This method more accurately models the real-world effects financing has on levelized and installed costs.

The specific financial assumptions used to calculate the levelized cost of a power plant project depend on the terms available to the borrower. The different ownership structures require different assumptions to estimate the cost of a new project. Financial assumptions include capital structure (amount of debt versus equity), debt term, and economic/book life and taxes.[7]

Financial structures and base parameters for merchant plant developers come from the California Board of Equalization, with adjustments to match December 2017 financial market conditions.[8] The Energy Commission received detailed financing assumptions for merchant plants from outside consultants.[9] Renewable technology financing was previously modeled with uniform capital financing assumptions. For example, solar PV and geothermal would use the same equity and debt costs. This report incorporates equity and debt assumptions for each of the renewable technologies to more accurately

6 The cost of money for power plant developers is typically a melding of two sources: equity such as ownership shares and debt such as corporate bonds or loans from large banks.

7 *Debt financing* is borrowing money by issuing a fixed payment product, such as bonds. *Equity financing* is raising capital though the sale of an ownership stake, typically shares.

8 Thompson, John K., *2016 Capitalization Rate Study*. 2017. Board of Equalization. https://www.boe.ca.gov/proptaxes/pdf/2017capratestudy.pdf.

9 Aspen Environmental Group and subcontractor MRW & Associates provided these estimates.

characterize investment risk, the ratio of debt to equity, and the costs of equity and debt.

Table B-1 in **Appendix B** summarizes the detailed capital cost structure assumptions used in the Cost of Generation Model to produce levelized costs outlined in **Chapter 3**. **Table B-2** in **Appendix B** summarizes technology-specific parameters for merchant renewable plants.

Tax Treatment

Federal tax credits for certain renewable generation facilities can substantially reduce the cost of these projects. The production tax credit (PTC) for new wind, geothermal, and biomass plants was extended in December 2015. Most technology incentives expired at the end of 2017, with the exception of wind, which has a declining incentive for projects commencing construction between 2017 and 2019.[10] The investment tax credit for new solar PV and thermal plants was likewise extended in December 2015. This incentive decreases between 2020 and 2022 but remains at 10 percent for future years. The investment tax credit also applies to geothermal electric technologies; however, the incentive is already at 10 percent and remains at this level for future years.

As the incentives decline or expire, project-financing structures are expected to change to minimize the cost of capital and optimize the use of remaining incentives and debt financing. As the renewable energy market matures, the financial structure of utility-scale renewable projects may look more similar to conventional generation assets. However, these potential changes to capital structures are not included in the model. The analysis revealed that some of the capital structures preferred by the market did not result in the cheapest financing cost.[11]

New solar projects receive a lifetime exemption from ad valorem costs until the exemption expires at the end of 2030.[12] All-solar components of the plants receive a 100 percent exemption, dual-purpose components a 75 percent exemption, and nonsolar components, such as transmission and support buildings, no exemption.

The Tax Cut and Jobs Act, passed on December 20, 2017, lowered the federal tax rate to 21 percent from 35 percent. Corporate state taxes are still deductible, resulting in a total tax rate lower than the sum. The federal tax rate is 21 percent, the California tax rate is 8.84 percent, and the total tax rate is 27.98 percent. The report does not include local taxes, as the report focus is statewide.

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10 *Consolidated Appropriations Act of 2016* (H.R. 2029), Representative Charles W. Dent. https://www.congress.gov/bill/114th-congress/house-bill/2029/text.

11 These anomalies can be attributed to the risk and ownership preferences of equity and debt providers.

12 *Ad valorem costs* are annual property taxes paid as a percentage of the assessed value and are usually transferred to local governments.

Environmental Mitigation Costs

Environmental mitigation costs, such as emissions credits, do not affect all technologies equally and depend on the emissions profile of the technology. For natural gas-fired generators, the largest compliance cost component usually is criteria pollutant emission reduction credits (ERCs) and Cap-and-Trade Program allowances. For renewable generators, compliance costs involve habitat mitigation and land acquisition. Environmental mitigation generally is incorporated directly into the plant construction cost estimates reported here, as most sources do not separately distinguish those costs. The exception is the environmental mitigation costs for natural gas-fired plants. Other compliance costs include the regulatory permit application, processing, and monitoring costs.

Emission Reduction Credits

CARB has tracked reported ERC prices since 1993.[13] These markets have few transactions and few participants, so price data can vary widely. Since these data record actual trades, some years may not contain data for particular pollutants and districts. In previous model iterations, costs appeared to increase over time, but data show little or no trend in recent years.

Given the lack of a trend in emissions costs, staff assumed no escalation of emission reduction credit costs. The model uses five-year historical averages (2012 to 2016) for the pollutants that are most tightly regulated: oxides of nitrogen (NO_x), volatile organic compounds (VOC), oxides of sulfur (SO_x), and particulate matter (PM). Emission reduction credits range from roughly $7,500 per ton to as high as about $40,000 per ton. **Table B-3** in **Appendix B** shows the weighted average price for these emission reduction credits, excluding South Coast.[14]

Greenhouse Gas Allowance Prices

The prices used in this version of the COG Model come from the Revised *2017 Integrated Energy Policy Report (IEPR)* carbon price projections. The low case estimate assumes prices escalate from the most recent historical value at the rate of the auction reserve price,[15] while the high case estimate assumes prices will reach the allowance price containment reserve price in 2030. The mid case estimate assumes a price roughly midway between the high and low. **Figure B-1 in Appendix B** shows the Cap-and-Trade Allowance Price estimates.

13 Emissions data compiled from annual reports of the New Source Review programs: *Emissions Reduction Offsets Transaction Cost Summary Reports*. Last updated May 25, 2016. Available at http://www.arb.ca.gov/nsr/erco/erco.htm.

14 South Coast Air Quality Management District regulates the cost of ERCs for new facilities (keeping them low), while ERCs traded on the market are significantly higher. For gas facilities built in the South Coast, staff used the regional prices rather than a statewide average.

15 The auction reserve price is the minimum price set annually for allowances.

Fuel Costs

The cost of fuels such as natural gas or biomass for power plants are a significant component for these technologies. Natural gas fuel cost estimates are calculated using a weighted average of estimated natural gas prices at power plants and amount of fuel used, or *fuel burn*. The natural gas price estimates come from the Burner Tip Price Model,[16] which relies on the North American Market Gas-Trade Model used in the Energy Commission's *Natural Gas Outlook* report for the *2017 IEPR*.[17] The estimated fuel uses the results of system dispatch modeling done by staff with PLEXOS®, a production cost model that simulates electric system dispatch, also used by the Energy Commission for the *2017 IEPR*. Staff compiled a weighted average of projected natural gas prices and fuel burn, adjusted for transportation costs, to create the three statewide average cost scenarios.

Gas prices range from $2.21 for the low case to 5.22 for the high case, with $3.53 being the mid case in 2018. These prices escalate over the forecast period, ranging from a low of $3.48 to a high of $8.71, with a mid case of $5.71 in 2030. **Figure B-2** in **Appendix B** summarizes the natural gas prices through 2030 used in the Cost of Generation Model. Detailed natural gas prices assumptions are provided for three cost cases, and all prices are nominal dollars in **Table B-4** in Appendix B.

Biomass fuel prices are from the previous Cost of Generation Model and are adjusted for inflation because no new price information was available. Biomass prices are driven primarily by transport and handling costs or the costs to get the fuel to the generator. Even though the recent drought increased fuel feedstock as dead trees are removed from forests, low electricity prices shrink the effective economic radius of feedstock from the plant location, which limits the impact of increased fuel feedstock. Detailed biomass fuel prices are shown in **Figure B-3** in **Appendix B.**

Transmission Interconnection

The cost of connecting a new generation project to the electric grid typically falls to the developer. The costs to build a new utility-scale power plant, of any technology, includes the cost of building electric transmission lines from the generating station to the point of interconnection with the electricity grid, usually at a substation. In addition, the cost of adding hardware at the interconnection point to allow the plant to tie into the grid is included.

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16 A *burner tip price* is the full price of gas paid by a power plant owner that includes the commodity price, as well as the price to transport it to the plant for consumption.

17 Brathwaite, Leon D, Jason Orta, Peter Puglia, Anthony Dixon, and Robert Gulliksen. 2017. *2017 Natural Gas Market Trends and Outlook*. California Energy Commission. Publication Number: CEC-200-2017-009-SF. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-04/TN222400_20180131T074538_STAFF_FINAL_REPORT_2017_Natural_Gas_Market_Trends_and_Outlook.pdf.

Interconnection Voltage and Costs

All estimates of costs and electrical losses depend on two factors—voltage and distance. There is an inverse relationship between voltage and the electrical losses in a transmission line, meaning that as voltage increases, the losses decrease. Staff used information collected by an outside consultant to construct a matrix estimating the voltage at which each technology would interconnect.[18] Generally, the higher the nameplate capacity of the power plant, the higher the associated voltage.

Staff used low-cost case substation interconnection costs from Southern California Edison filings with the California Public Utilities Commission (CPUC), showing the cost to interconnect to a substation at each voltage level if there were no upgrades needed.[19] To estimate the mid case and high case values, staff escalated the low case values by factors of 1.5 and 3, respectively.

Staff derived the transmission line costs per mile from the Western Electricity Coordinating Council report on transmission costs estimators for each voltage level.[20] The values presented in the Western Electricity Coordinating Council report formed the basis for the mid-cost case.[21] Detailed transmission interconnection voltages and costs are in **Table B-5** in **Appendix B**.

Interconnection Transmission Lengths and Losses

Transmission losses occur between the *busbar* or generator and the point of first interconnection to the transmission grid,[22] usually a local substation that then feeds into the high-voltage transmission network. *Tie-lines* are the transmission lines that connect the generation resource to the electrical substation. Losses increase with distance; therefore, plants farther from the interconnection point will deliver less energy to the grid than an identical plant located closer. Historically, conventional resources are able to locate near load centers and along existing transmission corridors because the fuel can be delivered to the power plant, while renewable resources tended to be farther away from transmission resources. However, in recent years new transmission has been built specifically to serve more remote renewable resources, changing this trend.

The lengths of the transmission interconnection lines vary widely by project. Therefore, this report uses three standard lengths (0.5 miles, 1.5 miles, and 5 miles) for all technologies to estimate the low, mid, and high cases, respectively. **Table B-6** in

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18 Aspen Environmental Group provided these estimates.

19 To estimate the mid case and high case values for interconnection costs, staff escalated the low case values by factors of 1.5 and 3, respectively.

20 Black & Veatch. February 2014. *Capital Costs for Transmission and Substations.* Prepared for Western Electricity Coordinating Council.

21 Staff derived the low-cost case by taking three-fourths of the mid-cost values, and the high-cost case by multiplying the mid-cost case by 1.5.

22 A *busbar* is the physical point of connection where the transmission lines connect to the generator.

Appendix B shows the distances and estimated losses for various sizes of interconnections.

Commodity Goods Tariffs

Various technologies rely on the some of the same raw materials, such as concrete and steel, but use these materials in different quantities and from different suppliers. Examining the raw materials used in various technologies would be beneficial to understanding how commodity markets influence technology costs. This study did not consider tariffs on commodity goods. Doing so may provide worthwhile insights but would require in-depth analysis that was not within the scope of this report.

CHAPTER 3:
Levelized Cost by Generation Type

This chapter discusses cost trends and assumptions and presents estimated levelized costs for solar PV, solar thermal, wind, geothermal, biomass, and natural gas generation technologies. Levelized cost estimates presented in this chapter are for merchant developers. A comparison of levelized cost estimates for investor-owned utility- and publicly owned utility-financed projects is in **Appendix D**.

Solar PV

The two prominent forms of solar PV technology are crystalline silicon cells and thin-film solar cells. The main components of a PV system include solar panels or modules (composed of solar cells), inverters, and the remaining hardware referred to as *balance of system*. While either can be fixed or variable axis, crystalline silicon is more commonly used for tracking applications, and the thin-film is generally used with fixed-axis. The two sizes considered for both types were 20 megawatt (MW) and 100 MW.

Utility-scale solar PV increased from 2 megawatts (MW) in 2001 to more than 9,600 MW in 2017. During this time, PV system costs have decrease with all components of the PV system contributing to the price decline. At the same time, module and inverter efficiency has increased, as shown in **Figure B-4** in Appendix B.

Solar PV has experienced dramatic price declines in recent years as production costs have declined sharply. Ample cost and pricing information exists in literature to support this finding.[23] Staff expects costs to continue to decline with further innovation in the coming years. Both polycrystalline and thin-film technologies are anticipated to decrease at similar rates, partially due to the interrelated research and production infrastructure associated with PV components.

PV Module Cost Trends

Historically, PV system costs have been driven largely by module prices that have constituted the majority of system costs. In recent years, there have been dramatic reductions in these costs as manufacturers became more efficient and economies of scale increased. Manufacturer efficiency improvements can be approximated by learning curves, which are based on the general principle that as more modules are manufactured, the process will be refined, and costs will decline.[24] **Figure B-5** in **Appendix B** shows the learning curves of various PV cell technologies for the global PV

23 Includes installed cost data for 506 projects: Bolinger, Mark, Joachim Seel, and Kristina Hamachi LaCommare. 2017. *Utility Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States.* Lawrence Berkeley National Laboratory.

24 Bollinger, Bryan and Kenneth Gillingham. December 2014. "Learn-by-Doing in Solar Photovoltaic Installations." http://environment.yale.edu/gillingham/BollingerGillingham_SolarLBD.pdf.

market. Over the long term, the learning curve for polycrystalline technologies was found to be 20 percent, with more dramatic reductions in recent years.[25] Thin-film costs have also fallen over time. Cadmium telluride costs have a roughly 20 percent learning curve, while copper indium gallium selenide modules have shown reductions of about 9 percent.[26]

Part of this decline is also due to the large investment China has made in the industry by developing its solar module manufacturing capabilities to capture economies of scale. This growth put pressure on U.S. solar manufacturing, with 25 U.S. companies closing since 2012.[27] In October 2017, the U.S. International Trade Commission, in response to petition for relief from serious injury to the domestic solar industry,[28] recommended a solar module import tariff rate on solar modules above a specified quota. In January 2018, the Trump Administration approved the recommendations, albeit with a slightly higher quota of the first 2.5 gigawatts of production excluded from the tariff. Tariffs start at 30 percent in the first year and decline by 5 percent per year until they reach 15 percent in the fourth year, after which the tariff expires. This tariff applies only to crystal silicon solar cells and modules; thin-film technologies are not affected. Since the tariff is a rate, it will decline as module prices continue to decline.

In the period leading up to the tariffs taking effect, many solar developers stocked up on modules. These stockpiles acted as a cost buffer, delaying much of the effects of the tariff on installed prices until the latter half of the first year after stockpiles depleted. However, China's National Energy Administration announced on June 1, 2018, that it would add only 30 gigawatts (GW) of capacity in 2018, down from 53 GW in 2017. This action resulted in PV modules flooding the international market, causing the price to decline by up to 34 percent in 2018.[29] This price decline essentially negated the cost increase of the solar tariff within a year.

Inverter and Balance of System Cost Trends

Inverter costs have also followed the learning curve principle. Cost reduction curves for inverters from 1990 through 2013 display a learning curve of 18.9 percent, as shown in **Figure B-6** in **Appendix B**. This learning curve corresponds to inverter cost reductions

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25 Theologitis, I. T. and Gaetan Masson. 2015. *Potential for Cost Reduction of PV Technology – Impact of Cheetah Research Innovations*. European Photovoltaic Industry Association. Available at http://becquerelinstitute.org/wp-content/uploads/2015/10/7DV.4.23-Potential-for-Cost-Reduction-of-PV-Technology.pdf.

26 Ibid.

27 https://www.greentechmedia.com/articles/read/breaking-trump-admin-issues-a-30-solar-tariff.

28 The U.S. International Trade Commission is responsible for investigations under the Trade Act of 1974 to determine if an article is being imported into the United States "in such increased quantities as to be a substantial cause of serious injury or threat of serious injury" and recommends to the president relief to remedy the injury. https://www.usitc.gov/trade_remedy.htm.

29 https://www.pv-magazine.com/2018/06/05/bnef-expects-34-fall-in-pv-module-prices-in-2018/.

of between 20 percent and 27.5 percent by 2020 and between 42 percent and 52.5 percent by 2030.

The balance of system costs, composed of all the remaining costs associated with installing a PV system, can be expected to decline over time as well. These are categorized as hard, relating to material costs, and soft, such as labor and overhead. Hard cost reductions will likely result from improving supply chains and reducing the footprint of installations as panel efficiency improves. Soft cost reductions will decline through "learning by doing" effects, reducing labor, yet these are more limited in utility-scale systems, where labor is a smaller portion of the instant cost. Most soft costs may be further reduced by cutting overhead, project development costs, and net profit.[30]

Other Solar PV Assumptions

Solar PV capacity factors trend higher in California than much of the rest of the country. Tracking increases the capacity factor significantly, adding to capital and operation and maintenance (O&M) costs. However, the higher electricity output decreases the levelized cost. In addition, developers have increased the inverter load ratio of their projects.[31] Capacity factors for solar PV are in **Table B-7** in **Appendix B**.

Photovoltaic plants do not usually require extensive maintenance. The most common task is cleaning the panels regularly to minimize losses due to soiling and to cut or trim any vegetation in or around the array to eliminate shading. In addition, inverters have an expected life of about 10 to 15 years and typically need to be replaced at least once over the life of a system. Tracking plants will have greater maintenance costs than fixed-mount systems due to motors and moving parts required for tracking the sun's arc. O&M costs for solar PV are in **Table B-8** in **Appendix B**. This report relies on a Lawrence Berkeley National Laboratory (LBNL) survey of publicly available data,[32] as well as the most recent U.S. Department of Energy SunShot report.[33]

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30 Fu et al, NREL. September 2016.

31 The *inverter load ratio* is the ratio of the size of the PV module to the size of the inverter. By increasing this ratio, a project will operate at or closer to the associated peak alternating current (AC) power output for a longer period, increasing the capacity factor. This will decrease the capacity factor in direct current (DC) output. Source: Bolinger, Mark, Joachim Seel, and Kristina Hamachi LaCommare. 2017. *Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States.* Lawrence Berkeley National Laboratory.

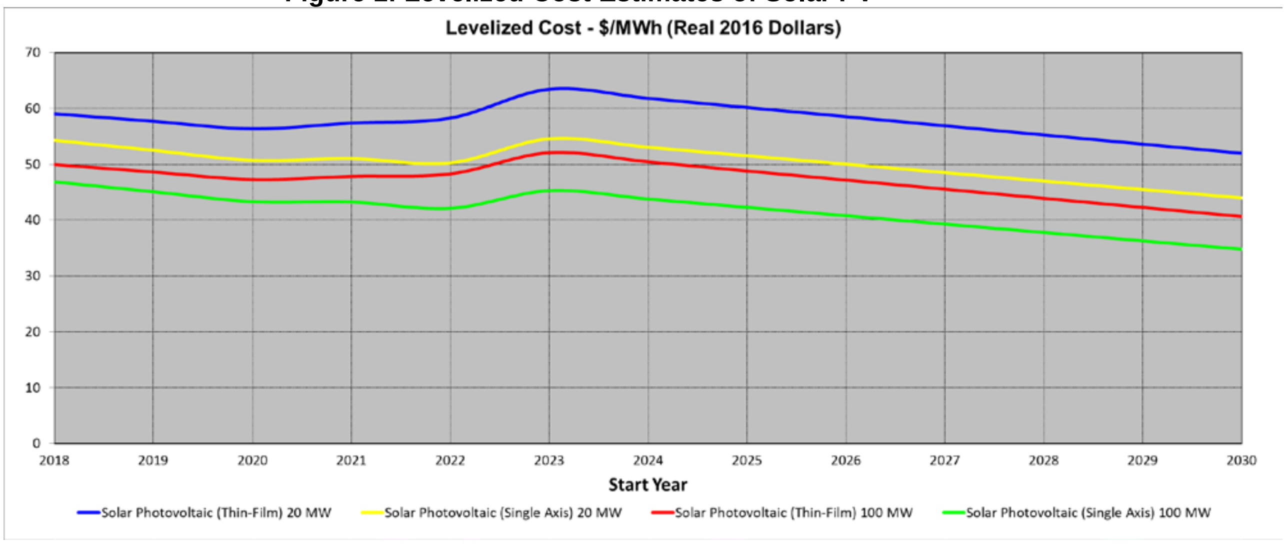
32 Bolinger, Mark and Joachim Seel. 2017. Utility Scale Solar 2016: *An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States.* Lawrence Berkeley National Laboratory. https://cloudfront.escholarship.org/dist/prd/content/qt7wd7r8cm/qt7wd7r8cm.pdf.

33 Woodhouse, Michael, Rebecca Jones-Albertus, David Feldman, Ran Fu, Kelsey Horowitz, Donald Chung, Dirk Jordan, and Sarah Kurtz. 2016. *On the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-65872. http://www.nrel.gov/docs/fy16osti/65872.pdf.

Solar PV Levelized Cost Estimates

Solar PV costs have declined more than previously estimated and are expected to continue to decline as costs decrease for all components of the PV system. **Figure 1** shows levelized costs for solar PV. The observed cost difference between 100 MW and 20 MW solar PV plants has substantially decreased. The remaining cost difference between the two plant sizes is driven by the cost distribution of less variable costs, particularly interconnection costs, over a larger capacity.

Figure 1: Levelized Cost Estimates of Solar PV



Source: California Energy Commission

The ITC was important in making solar PV more cost-competitive and a significant driver of investment in solar PV. The ITC decrease will temporarily increase solar PV costs. However, economies of scale and industry efficiencies will continue to lower the costs beyond what was achieved during the period when tax incentives were in place.

Summaries of mid, high, and low case levelized, instant, and installed costs for solar PV are in **Table B-9** in **Appendix B**.

Solar Thermal

There are two predominant commercial embodiments of solar thermal plants—parabolic troughs and solar towers—both of which collect sunlight over large *solar fields*. In total, 16 solar thermal plants have been installed in the United States. Of those, only two use tower technology, Ivanpah Solar Electric Generating System and Crescent Dunes Solar Energy Project, and only the latter makes use of storage. Thermal technologies with storage allow the plant operator to participate in the electricity marketplace in the evening hours after solar photovoltaic plants are no longer generating. Staff limited solar thermal technology to a 100 MW power tower with 10 hours of molten salt storage. This configuration is similar to the Crescent Dunes Solar Energy Project, as well as projects being developed internationally and proposed for development in western Nevada. Despite the environmental concerns surrounding the technology, such as water use, effect on wildlife, and visual characteristics, it is still the most likely solar thermal technology to be built.

Solar Thermal Technology Cost Trends

The largest cost components of tower plants are the power block, heliostats (mirrored towers that direct the sun's rays at the primary tower), and the molten salt storage system. The power block is mature technology that is not expected to decrease in price. Cost declines in the heliostats has been the primary driver for recent cost declines. Improved designs for the tower and storage system to prevent leaks, withstand temperatures, and refine the use of molten salt that can reach up to 600 degrees Celsius are necessary for lowering maintenance costs and avoiding plant outages. For example, Crescent Dunes uses a single HTF in a two tank direct storage design, where the molten salt is stored directly in the tanks, one for hot and one for cold. Additional cost savings and efficiencies may be achieved by moving to a single tank design.

Although U.S. Department of Energy's SunShot projected dramatic cost reductions for solar thermal technology by 2020, the lack of new projects in the United States since 2015 raises questions about whether those cost reductions will be achieved.[34] Cost declines for this technology depend highly on continued development and deployment of tower technology. The outcome of international developments, particularly in northern Africa and the Middle East, will determine the next iteration of the technology and related cost.

Other Solar Thermal Assumptions

Solar thermal plants have a wide range of capacity factors, and avoiding outages, which have been experienced at the Crescent Dunes facility in Nevada, will be essential in future performance and cost control. Staff assumed capacity factors to range from a low

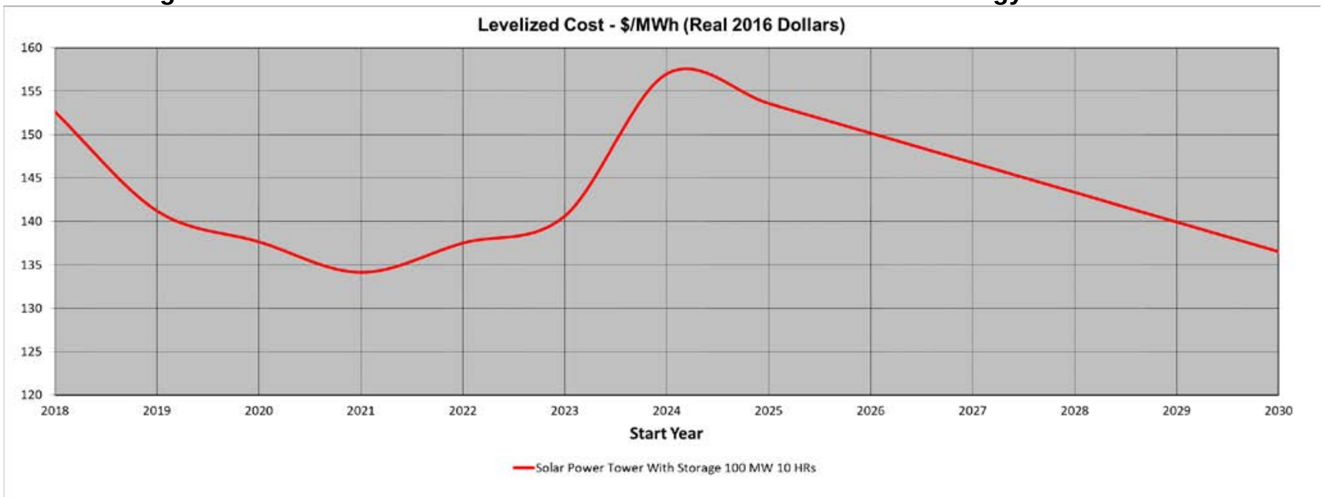
34 Mehos, Mark, Craig Turchi, Jennie Jorgenson, Paul Denholm, Clifford Ho, and Kenneth Armijo. 2016. *On the Path to SunShot: Advancing Concentrating Solar Power Technology, Performance, and Dispatchability*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5500-65688. http://www.nrel.gov/docs/fy16osti/65688.pdf.

of 40 percent to a high of 60 percent, with a mid case value of 50 percent. With only a few plants in operation, relatively little information is available on O&M costs for solar power towers. However, estimates of declining O&M costs, which are based on consensus estimates,[35] are in **Table B-10** in **Appendix B**

Solar Thermal Levelized Cost Estimates

Figure 2 shows levelized costs for solar power tower technology.

Figure 2: Levelized Cost Estimates for Solar Power Tower Technology



Source: California Energy Commission

Solar thermal costs are not expected to decline as much as previously estimated, especially SunShot projections, which showed dramatic cost reductions.[36] While there are still significant declines in levelized cost, the decrease of the ITC counteracts much of the near-term cost declines.

Summaries of mid, high, and low case levelized, instant, and installed costs for solar thermal technology are in **Table B-11** in **Appendix B.**

Onshore Wind

Wind generators are mature technologies, although they are likely to experience incremental technology improvements and slight cost reductions. The primary components of wind technologies include a rotor (or blades), a nacelle (or enclosure) containing a drivetrain with a gearbox and generator, a tower that supports the nacelle, and electronic equipment such as control, electrical cables, and ground support and

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35 Kolb, Gregory. 2011. *An Evaluation of Possible Next-Generation High-Temperature Molten-Salt Power Towers.* Sandia National Laboratories. SAND2011-9320. https://prod.sandia.gov/techlib-noauth/access-control.cgi/2011/119320.pdf.

36 Mehos, Mark, Craig Turchi, Jennie Jorgenson, Paul Denholm, Clifford Ho, and Kenneth Armijo. 2016. *On the Path to SunShot: Advancing Concentrating Solar Power Technology, Performance, and Dispatchability.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-5500-65688. http://www.nrel.gov/docs/fy16osti/65688.pdf.

interconnection equipment. Typical wind units consist primarily of 1.5 to 3.5 MW turbines atop 80-meter towers, with wind farms ranging in size from 1 MW to 265 MW.[37] In previous cost estimates, wind technology was classified by wind speed, but with changes to wind technology, that classification is no longer appropriate. Incremental changes, such as increased blade length and higher hub heights, have made use of lower wind speed areas, increasing capacity factors while maintaining nameplate capacity. This report estimates the costs for a 100 MW wind turbine facility.

Wind costs depend highly on the quality of the wind resource. The vast majority of wind turbines in California are in six regions: Tehachapi, Solano, San Gorgonio, Altamont, East San Diego County, and Pacheco. **Table B-12** in **Appendix B** shows a detailed breakdown of wind turbine development by wind resource area.

Between 2001 and 2013, installed wind capacity increased from roughly 1,534 to 5,763 MW. Since 2016, there has been almost no new wind generation added in California, and some older wind generators have retired. In 2017, roughly 5,632 MW of wind capacity was on-line. This gap in projects coming on-line may be partially explained by the 11-month lapse before the PTC was extended in 2015. The PTC has been instrumental in spurring wind development, and projects needed to start construction before the end of 2016 to receive the full benefit of the credit before it declines.

Onshore Wind Turbine Trends

Wind technologies are making incremental improvements by focusing on contract price competitiveness. To do this, turbines have increased in nameplate capacity and capacity factor. **Figure B-7** in **Appendix B** shows the increasing trend in turbine nameplate capacity over time across the United States.

Wind turbine capacity has increased by increasing rotor diameters as well as hub heights, although to a smaller degree. The increased equipment costs of taller hubs and longer blade length are offset by the increased energy production. **Figure B-8** in **Appendix B** shows the historical trend of increases in hub height and rotor diameter.

The change in rotor diameter has altered turbine *specific power* – the amount of power produced divided by the area swept by the turbine blades (in watts/square meter). Lower specific power ratings are generally associated with lower wind speed sites, intended to make the most of moderate wind speeds and raise project capacity factors. **Figure B-9** in **Appendix B** shows how the specific power has decreased over time, while **Figure B-10** in **Appendix B** shows how the expected capacity factor has increased with these changes in design.

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37 Hingtgen, John, Mathew Prindle, and Paul Deaver. 2017. *Wind Energy in California: 2014 Description, Analysis, and Context.* California Energy Commission. CEC-200-2017-001. https://www.energy.ca.gov/2017publications/CEC-200-2017-001/CEC-200-2017-001.pdf.

Other Onshore Wind Assumptions

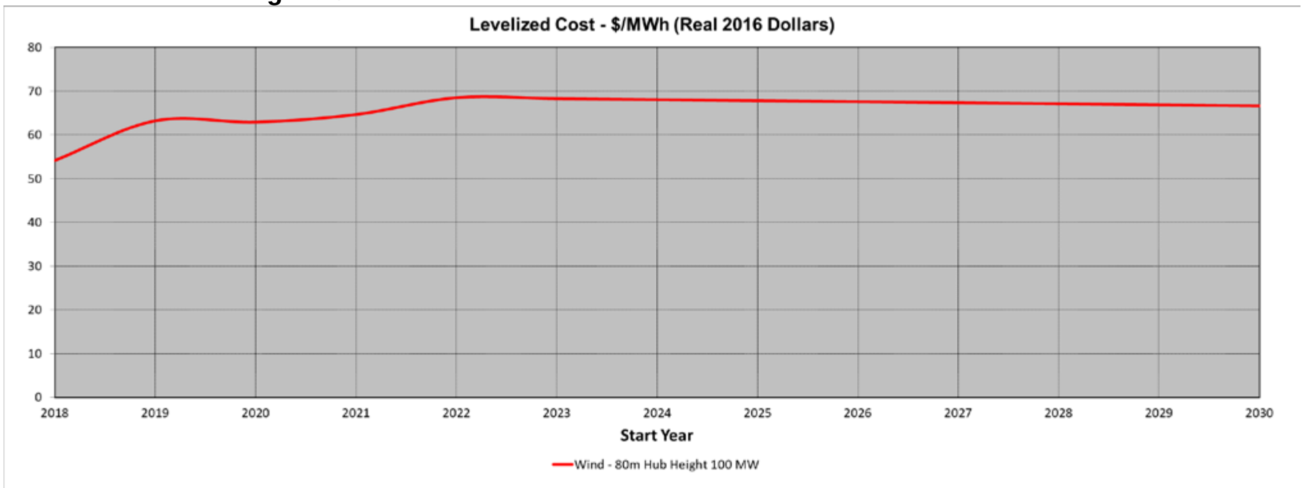
California has lower wind capacity factors, with the mid case assumption being 35 percent, than the Midwest, where a capacity factor of 40 percent or more is typical. A 5 percent change in capacity factor can alter levelized costs by more than 15 percent.

O&M costs can vary significantly across projects but are trending lower and having less variation, as shown in **Figure B-11** in **Appendix B.** Wind O&M has only a fixed cost component and is independent of production or year-to-year resource variation. **Table** B-13 in **Appendix B** shows the assumed O&M costs for wind technology, which are held constant in real terms over the forecast period.

Onshore Wind Levelized Cost Estimates

Figure 3 shows levelized costs for onshore wind.

Figure 3: Levelized Cost Estimates for Onshore Wind



Source: California Energy Commission

While wind turbine costs will continue to decrease and performance to improve, these changes are not expected to occur fast enough to offset the expiration of the PTC. However, the financing assumptions do not change over the forecast period; therefore, developers may pivot to more cost-effective financing options that result in lower levelized costs as incentives expire.

Summaries of mid, high, and low case levelized, instant, and installed costs for wind are in **Table B-14** in **Appendix B.**

Offshore Wind

Offshore wind is a generation technology that has not yet been introduced in California. The Block Island Wind Farm off the Rhode Island coast is America's first fixed-bottom offshore wind farm. The five-turbine 30 MW plant began commercial operations in 2016.[38] While fixed-bottom offshore wind exists on the East Coast of the United States, California's rapidly declining continental shelf means that most of California's offshore wind resources exists in waters more than 150 feet deep, too deep for fixed-bottom platforms. To harness this resource, developers are adapting fixed-bottom wind turbines for use on floating platforms based on oil and gas platforms. Current turbines have a capacity of 6 to 8 MW, but some as large as 10 MW are being designed. Floating offshore wind technology has been demonstrated only in the North Sea, off the coast of Scotland.

Since there are no commercial projects in California, levelized cost analysis is not included in this report. Preliminary cost estimates developed by National Renewable Energy Laboratory (NREL) are presented below.

Offshore Wind Trends

The only operational floating wind farm is Hywind Scotland, a 30 MW farm composed of five 6 MW turbines. Offshore wind holds promise in that the resource is more consistent than onshore wind, with the potential for capacity factors between 45 to 60 percent. Hywind Scotland outperformed this for a three-month period, generating an average of 65 percent.[39]

The predominant areas of interest in California, due to quality of the wind resource, are off the North Coast, west of Humboldt Bay, and off the Central Coast.[40] The project proposed for the California coast that is furthest along in the planning process is a consortium selected by Redwood Coast Energy Authority to develop a floating offshore wind farm off the coast of Humboldt County as part of a public-private partnership. The proposed project is for roughly 120 MW, with 10 to 15 turbines at 8 MW capacity or more, more than 20 miles off the coast.[41]

Developer interest in Central California is driven to some extent by access to existing transmission made available by the retirement of coastal power plants, including Morro

38 http://dwwind.com/project/block-island-wind-farm/.

39 https://cleantechnica.com/2018/02/16/hywind-scotland-worlds-first-floating-wind-farm-performing-better-expected/.

40 Musial, Walter, et al. December 2016. *Potential Offshore Wind Energy Areas in California: An Assessment of Locations, Technology and Costs*. NREL, BOEM. https://www.boem.gov/2016-074/.

41 Redwood Coast Energy Authority press release, April 2, 2018. "The Consortium, Composed of Principle Power, EDPR Offshore North America LLC, Aker Solutions Inc., H. T. Harvey & Associates, and Herrera Environmental Consultants Inc., Was One of Six Respondents, Demonstrating Interest in Pursuing Offshore Wind Development Opportunities." https://redwoodenergy.org/offshore-wind-energy/.

Bay Power Plant and Diablo Canyon Nuclear Power Plant, along with harbor infrastructure that could support turbine assembly and maintenance.[42]

Developers must consult with numerous federal state and local agencies that have jurisdiction during the permitting process. The U.S. Navy has excluded wide swaths of the ocean off California's Central Coast and set site-specific stipulations off the North Coast. The Department of Defense also release a map that excluded most of the waters off the California coast for development.[43] These actions present additional challenges to developers but do not rule out development.

The Bureau of Ocean Energy Management (BOEM) California Intergovernmental Renewable Energy Task Force (California Task Force) was established as a partnership of state, local, federally recognized tribal governments, and federal agencies to plan for potential offshore renewable energy development in federal waters offshore California. The task force is not a decision-making body and instead provides a forum to discuss ocean uses, issues, concerns, and priorities; exchange data and information; and encourage early and continual dialogue and collaboration opportunities. Using information gathered from federal and state agencies and during outreach, a California Offshore Wind Energy Gateway was developed.[44] More than 600 datasets on the gateway are informing the planning process and will be used to identify potential offshore wind energy development areas that the task force members, tribes, and stakeholders can discuss and refine.

Preliminary Cost Estimates for Offshore Wind

The offshore wind development community in the United States has observed positive trends in Europe for cost reductions in overcoming siting and operational challenges that have spurred interest in offshore development. NREL found that initial offshore wind costs presently span an estimated range from $130/MWh to $450/MWh (2015 U.S. dollars). This wide range in costs reflects the variation in geospatial characteristics among U.S. offshore wind site conditions. The NREL study indicates that several drivers that could lower costs for offshore wind.[45] NREL's cost-reduction pathway modeling and analysis of future conditions show that cost ranges could be reduced by 2022 to a range from $95/MWh to $300/MWh, and they are further reduced by 2027 to a range from $80 MWh to $220/MWh among U.S. coastal sites. Further, it notes that innovation to

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42 Both Morro Bay Power Plant and Diablo Canyon Nuclear Power Plant use once-through cooling and are subject to State Water Resources Control Board regulations on the phase out of this technology. https://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf

43 https://www.scribd.com/document/377922998/DON-CA-Offshore-Wind-Assessment-19-June-2017-003.

44 https://caoffshorewind.databasin.org/.

45 Beiter, Phillip, Walter Musai, Aaron Smith, Levi Kilcher, Rick Damiani, Michael Maness, Senu Sirnivas, Tyler Stehly, Vahan Gevorgian, Meghan Mooney, and George Scott. September 2016. *A Spatial-Economic Cost-Reduction Pathway Analysis of U.S. Offshore Wind Energy Development from 2015–2030.* NREL/TP-6A20-66579. https://www.nrel.gov/docs/fy16osti/66579.pdf.

reduce costs was found to benefit fixed-bottom and floating offshore wind systems, with the costs of the two technologies converging over the forecast period.

Demonstration projects will allow the best and cheapest technology options to succeed and bring down costs. In addition, most of the current supply chain depends on resources from distant places. Significant cost savings can be achieved by optimizing the supply chain, but that will require a steady stream of projects to encourage the industry to reorient itself. While there are many hurdles to overcome, the prospect of a large and underused renewable resource holds promise to become a significant part of California's generation resource mix and help meet California's long-term renewable energy goals.

Geothermal

California has a relative abundance of geothermal in several known resource areas around the state, with the technology type dictated by the type of resource.[46] The two most likely technologies to be developed are binary and flash, with the latter being used in the Salton Sea resource area due to the high resource temperature in that area. This report estimates the cost for a 30 MW facility of both types.

Binary Cost Trends and Assumptions

Binary geothermal is a mature technology with plants operating in California since the mid-1980s. Binary units range in size from less than 1 MW to more than 10 MW, typically with multiple units installed at a single plant site. Current California binary geothermal installations total 258 MW.[47] An additional 208 MW of potential development could use binary technology.[48]

Capital costs can vary widely due to several factors, the most important of which are well-drilling costs and success rates. Well costs can be more than half of the capital costs of a geothermal project.

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46 Most geothermal resources fall into one of the following categories: vapor-dominated, liquid-dominated, geopressure, hot dry rock, and magma. Of these resources, only vapor- and liquid-dominated resources have been developed commercially for utility-scale power generation. Vapor-dominated technology power plants, in which only steam is extracted from the geothermal well instead of brine, are applicable to only one resource in the western United States, the Geysers in Northern California. Liquid-dominated resources are characterized by reservoir temperatures ranging from 77 degrees Fahrenheit to more than 599 degrees Fahrenheit, with binary technology generally used at temperatures below 349 degrees Fahrenheit and flash technology above.

47 California Energy Commission. *Quarterly Fuel & Energy Report* (*QFER*) https://www.energy.ca.gov/almanac/electricity_data/web_qfer/.

48 Sison-Lebrilla, Elaine, and Valentino Tiangco. 2005. *Geothermal Strategic Value Analysis.* California Energy Commission. CEC-500-2005-105-SD. https://www.energy.ca.gov/2005publications/CEC-500-2005-105/CEC-500-2005-105-SD.PDF. New development was subtracted from the estimates in this report.

The fixed O&M costs reflect the total O&M costs because the power plants are operated as baseload, so variable O&M is assumed to be zero.[49] **Table B-15** in **Appendix B** shows the estimated operation and maintenance costs for geothermal binary.

Staff found the capacity factors for this technology to range from 77 percent to 95 percent, with 85 percent being the mid case value.[50] These capacity factors are consistent with operational plants. Capacity can degrade up to 2 percent per year, and thermal degradation can be as high as 5 percent per year.[51]

Most estimates of emissions show no greenhouse gas (GHG) emissions for binary geothermal plants, but one study estimated emissions at 120 pounds per MWh. Staff used the range of zero to 120 pounds per MWh to establish a range of GHG emissions estimates for the three cases. However, geothermal is exempt from cap-and-trade carbon dioxide (CO_2) costs, so this does not affect the financials of binary systems.

Flash Cost Trends and Assumptions

Flash geothermal plants are also mature technology, being the most common type of geothermal plant in the world today. Most California plants use one generator, but some use two or three generators. Total plant capacities range from 10 MW to 120 MW. Current California flash geothermal installations total 867 MW.[52] The additional potential development of flash technology is 2,165 MW.[53]

As with the binary plants, these capital costs can vary widely due to several factors, the most important of which are well-drilling costs and success rates. Well costs account for more than half of the capital costs of geothermal flash plants.

O&M costs are given solely in terms of fixed O&M because the plants run as base load resources and, therefore, have the same O&M costs each year.[54] **Table B-15** in **Appendix B** shows the operations and maintenance costs for geothermal flash.

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49 The mix of fixed and variable O&M costs and differing capacity factors makes direct comparisons of the cost ranges among studies difficult without digesting each to a single parameter.

50 Tidball, Rick, Joel Bluestein, Nick Rodriguez, and Stu Knoke. November 2010. *Cost and Performance Assumptions for Modeling Electricity Generation Technologies.* ICF International. NREL/SR-6A20-48595. https://www.nrel.gov/docs/fy11osti/48595.pdf.

51 Gifford, Jason S. and Robert C. Grace. 2011. *CREST: Cost of Renewable Energy Spreadsheet Tool: A Model for Developing Cost-BASED Incentives in the United States, User Manual, Version 1.* NREL/SR-6A20-50374. Contract No. DE-AC36-08GO28308. https://financere.nrel.gov/finance/content/crest-cost-renewable-energy-spreadsheet-tool-model-developing-cost-based-incentives-united-s.

52 California Energy Commission. *QFER.* https://www.energy.ca.gov/almanac/electricity_data/web_qfer/.

53 Sison-Lebrilla, Elaine, and Valentino Tiangco. 2005. *Geothermal Strategic Value Analysis.* California Energy Commission. CEC-500-2005-105-SD. https://www.energy.ca.gov/2005publications/CEC-500-2005-105/CEC-500-2005-105-SD.PDF. New development was subtracted from the estimates in this report.

54 The mix of fixed and variable O&M costs and differing capacity factors makes direct comparisons of the cost ranges among studies difficult without digesting each to a single parameter.

Capacity factors range from 72 percent to 95 percent,[55] with 85 percent being the mid case value.[56] These capacity factors are consistent with operational plants in commercial service. Capacity can degrade up to 2 percent per year, and thermal output can decline up to 5 percent a year.[57]

GHG emissions range from 99 pounds per MWh to 397 pounds per MWh,[58, 59] with a mid case value of 264 pounds per MWh.[60] Limited data are available on criteria pollutants, which are provided as single factors instead of ranges.[61] As stated above, geothermal is exempt from cap-and-trade CO_2 costs, so this does not affect the financials of binary systems.

Geothermal Levelized Cost Estimates

Geothermal technology is mature, and staff does not expect any significant change to the cost of these technologies. **Figure 4** shows the levelized costs for geothermal binary and flash technologies.

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55 *GETEM – Geothermal Electricity Technology Evaluation Model.* August 2012 Beta Version. U.S. Department of Energy, Office of Efficiency & Renewable Energy. https://www.energy.gov/eere/geothermal/downloads/getem-geothermal-electricity-technology-evaluation-model-0.

56 Tidball, Rick, Joel Bluestein, Nick Rodriguez, and Stu Knoke. November 2010. *Cost and Performance Assumptions for Modeling Electricity Generation Technologies.* ICF International. NREL/SR-6A20-48595. https://www.nrel.gov/docs/fy11osti/48595.pdf.

57 Gifford, Jason S. and Robert C. Grace. *CREST: Cost of Renewable Energy Spreadsheet Tool: A Model for Developing Cost-Based Incentives in the United States, User Manual, Version 1.* 2011. NREL/SR-6A20-50374. Contract No. DE-AC36-08GO28308. https://financere.nrel.gov/finance/content/crest-cost-renewable-energy-spreadsheet-tool-model-developing-cost-based-incentives-united-s.

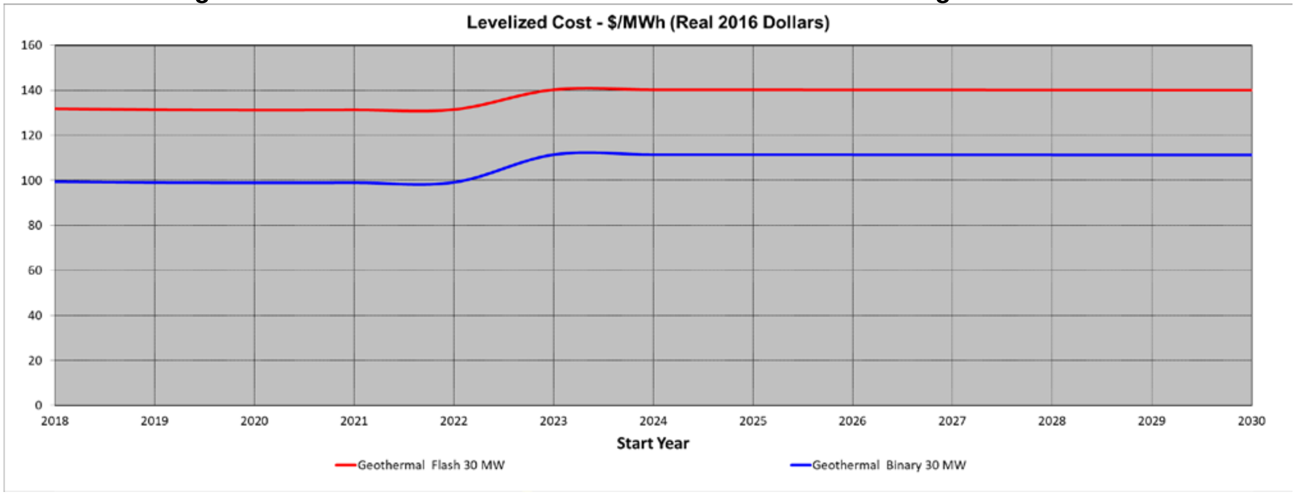
58 Holm, Alison, Dan Jennejohn, and Leslie Blodgett. 2012. *Geothermal Energy and Greenhouse Gas Emissions.* Geothermal Energy Association. http://geo-energy.org/reports/GeothermalGreenhouseEmissionsNov2012GEA_web.pdf.

59 *GETEM – Geothermal Electricity Technology Evaluation Model.* August 2012 Beta Version. U.S. Department of Energy, Office of Efficiency & Renewable Energy. https://www.energy.gov/eere/geothermal/downloads/getem-geothermal-electricity-technology-evaluation-model-0.

60 Walters, Will. "Simple single flash has rate of 0.12 MTCO2/MWh = 264.6 #/MWH," e-mail message, November 19, 2013.

61 Sison-Lebrilla, Elaine, and Valentino Tiangco. 2005. *Geothermal Strategic Value Analysis.* California Energy Commission. CEC-500-2005-105-SD. https://www.energy.ca.gov/2005publications/CEC-500-2005-105/CEC-500-2005-105-SD.PDF. New development was subtracted from the estimates in this report.

Figure 4: Levelized Cost Estimates for Geothermal Technologies



Source: California Energy Commission staff, Energy Assessments Division

Geothermal can make use of either the PTC or ITC, but while the PTC expires, the ITC does not, prompting a switch in the incentive used for new projects.

Summaries of mid, high, and low case levelized, instant, and installed costs for geothermal binary and flash technologies are shown in **Table B-16** in **Appendix B.**

Biomass

Biomass is plant-based material, agricultural vegetation, or agricultural and forestry waste used as fuel to generate electricity. Fluidized bed combustion is the current technology expected to be developed for biomass power generation applications. A traditional-style boiler burns the solid fuel in a stationary bed, and a fluidized bed boiler mixes the fuel and keeps it suspended in a column of hot gases that increases the quality of combustion.[62] Modern fluidized bed boilers also use a nonburning combustion medium to help retain heat and improve combustion. The fuel versatility of fluidized bed systems allows the burning of many biomass resource types, including those feedstocks with significant moisture variations.[63]

Plant capacities for biomass fluidized bed boilers are in the range of 15 MW to 70 MW, set primarily by the effective biomass fuel supply range, along with the most common sizes of biomass fluidized bed combustion boiler designs today. While the previous cost of generation report used a 50 MW plant, this report considers a 20 MW fluidized bed combustion boiler as the biomass technology most likely to be installed in California.

62 Overend, R. P. 2002. *Biomass Conversion Technologies.* NREL, Golden, Colorado. https://www.feagri.unicamp.br/energia/energia2002/jdownloads/pdf/papers/paper_Overend_Biomass.pdf.

63 Moisture variations can produce wide swings in energy output in conventional boiler technologies. Because drying biological material adds cost and reduces the range of available fuels, boiler designs that are capable of dealing with these variations are typically preferred.

Fueling biomass facilities with forest waste may reduce GHGs and short-lived climate pollutants and lessen the impacts of wildfires, which are the largest source of black carbon emissions in the state (roughly 67.5 percent).[64] The debate whether fuels reduction treatments combined with bioenergy production have a net emissions benefit was the focus of a forest and ecology management study. The analysis had mixed conclusions depending on the duration between fire rotation and period considered.[65] Forest managers will need to evaluate fuels treatments on a case-by-case or regional basis to determine net GHG outcomes, although it may be difficult to estimate properly.

Biomass Cost Trends and Assumptions

California has about 1,300 MW of installed biomass capacity. Some of California's biomass plants that originally came on-line in the 1980s and 1990s either shut down or were idled starting around 2010 as supply contracts ran out. California's forestry waste has increased as drought and tree die-off have provided large amounts of fuel for forest fires. This situation has highlighted the need for additional biomass plants to use forest waste productively. As a result, some idled biomass generation has come back into operation, not necessarily at full capacity, and new projects are being developed. Unlike biomass plants that had large fuel streams from local farms, these new and repowered facilities rely on forest waste, which is less concentrated and produces less waste within the same fuel supply distance. The challenges of securing sufficient fuel supply for new and repowered biomass plants will play a large role in determining the future of this technology in the state.

When planning for and developing biomass projects, considerations that affect the potential viability and costs include fuel type and uniformity, fuel transport and handling costs, boiler island cost, long-term fuel supply contracts, plant scale, emissions control costs, greenfield versus retrofit site, and long-term O&M contract capitalization.[66, 67] Capital costs for land and permitting can vary widely due to several factors, including fuel or fuel mix burned, size and scale of the plant, and the amount of postcombustion pollution controls, as well as whether the site is a brownfield redevelopment or a greenfield site.

The Cost of Generation model splits O&M costs into fixed and variable components. Besides normal inflation, O&M costs are assumed to have a real escalation rate of 0.5 percent per year. **Table B-17** in **Appendix B** shows the O&M cost assumptions for biomass.

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64 California Air Resources Board. "Short-Lived Climate Pollutant Inventory." June 2017. https://www.arb.ca.gov/cc/inventory/slcp/slcp.htm.

65 Winford, E. M., and J. C. Gaither Jr. (2012). "Carbon Outcomes From Fuels Treatment and Bioenergy Production in a Sierra Nevada Forest." *Forest Ecology and Management*. 282: 1–9.

66 Greenfield is a previously undeveloped site; retrofit is modifying an existing site.

67 These considerations are not quantified here as that is beyond the scope of this report.

Capacity factors range from 78 percent to 85 percent, with 81 percent being the mid case value. These capacity factors are consistent with operational fluidized bed boilers in commercial service.

Estimated heat rates average about 14,500 British thermal units per kilowatt-hour (Btu/kWh), with a lower bound of 13,500 Btu/kWh.[68] Heat rates can vary for biomass fluidized bed systems due to fuel moisture content and heating value.

No significant experience curve effects or learning effects are considered in the analysis, as fluidized bed technology is a mature technology. Cost drivers should not affect the long-term levelized costs significantly, absent a disruptive shift in the current technology and approach to biomass fluidized bed combustion.

The Cap-and-Trade Program exempts biogenic CO_2 from compliance obligations, so no GHG allowance costs were included in levelized cost estimates for biomass.[69]

Biomass Levelized Cost Estimates

Fluidized bed combustion boilers are a mature technology, and the associated costs are estimated to be constant over the forecast period, with the exception of the effect caused by the expiration of the PTC that is observed in the near term**. Figure 5** shows levelized cost estimates for biomass fluidized bed technology.

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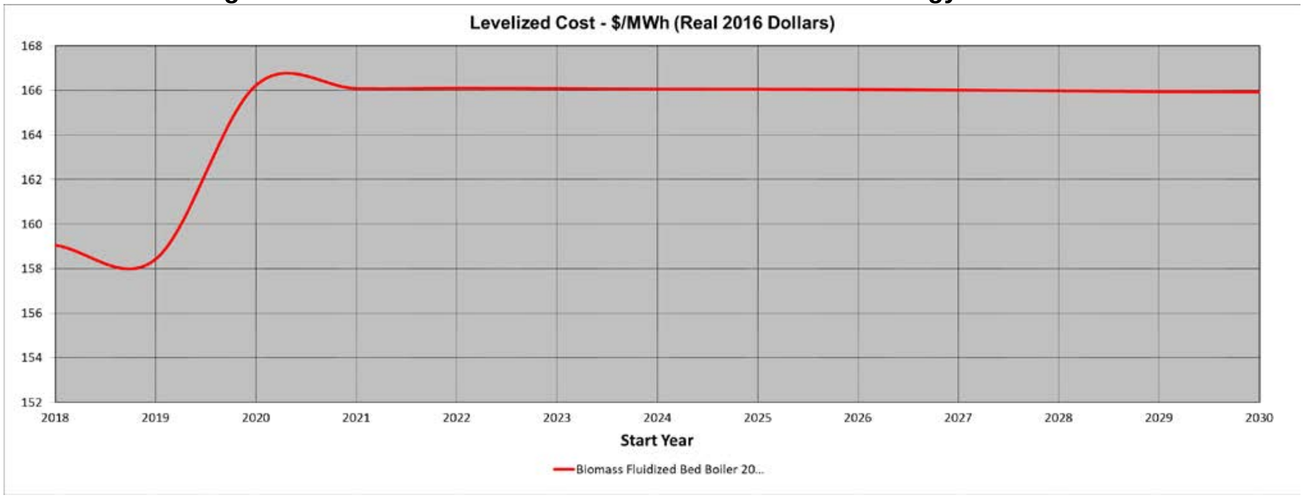
68 In contrast, new natural gas plants have heat rates of about 7,000 Btu/kWh.

69 Biogenic CO2, meaning CO2 emitted from electricity generators that use biogenic fuels, such as biomass, and fugitive emissions from geothermal generators, is exempted from Cap-and-Trade Program compliance obligations. Source: "Frequently Asked Questions," IPCC Task Force on National Greenhouse Gas Inventories, http://www.ipccnggip.iges.or.jp/faq/faq.html.

Figure 5: Levelized Cost Estimates for Biomass Technology



Source: California Energy Commission

Summaries of mid, high, and low case levelized, instant, and installed costs for biomass technologies are shown in **Table B-18** in **Appendix B.**

Natural Gas-Fired Generation

Natural gas-fired generation made up roughly a third of California's electricity generation in 2017. From 2001 to 2017, the thermal efficiency of the fleet of gas-fired power plants in the state improved 22 percent.[70] Although California's GHG reduction goals are driving a shift to zero-emission electricity resources,[71] in the near term, there is still be a need for strategically located, fast-ramping natural gas-fired plants to help manage increasing amounts of renewable resources on the grid. In the longer run, noncarbon resources, including energy storage, demand response, increased regionalization of the market, and imports of zero-emission resources from the Pacific Northwest, are being developed to meet renewable integration needs. There are two types of natural gas-fired power plants in the state: combustion turbines (or simple-cycle plants) and combined-cycle plants.

Combustions turbines come in two primary types. A *frame* design uses a turbine and combustion arrangements that resemble a steam turbine and a more advanced *aeorderivative* design that closely resembles a commercial jet engine, which provides faster ramping and operational flexibility to grid operators. The combustion turbine installations included in this report are a 49.9 MW combustion turbine, a 100 MW

70 Nyberg, Michael. 2018. *Thermal Efficiency of Natural Gas-Fired Generation in California: 2018 Update*. California Energy Commission. CEC-200-2018-011. https://www.energy.ca.gov/almanac/electricity_data/Thermal_Efficiency_reports.html.

71 Senate Bill 100 (De León, Chapter 312, Statutes of 2018) increases the Renewables Portfolio Standard from 50 to 60 percent by 2030 and establishes a state policy to meet 100 percent of retail sales with eligible renewable resources and zero-carbon resources.

combustion turbine (that consists of two of the smaller turbines located in a single site), and an advanced design 200 MW combustion turbine.[72]

Combined-cycle technology uses a conventional steam turbine with one or more combustion turbine units for higher efficiency than possible with a turbine alone. The tradeoff in this case is that the operational flexibility of the plant is reduced, and start-up and shutdown are more lengthy and costly. The typical combined-cycle power plant built in California is based on the F-class gas combustion turbine and typically consists of two combustion turbines and one steam turbine.[73] Combined-cycle systems can integrate duct burners, which add heat to the exhaust gas stream to increase power production, but that reduces efficiency. The two combined-cycle installations included in this report are a 640 MW combined-cycle and a 700 MW combined-cycle with duct firing.

Natural Gas-Fired Generation Cost Trends and Assumptions

The underlying combustion technologies for natural gas-fired power plants are mature and the prices stable. However, there is increased uncertainty in plant capacity factors. Most combined-cycle power plants built as *baseload* facilities meant to operate 80 percent of the time or more have actually operated well below this level. Instead of baseload, these plants have operated as *load following*, meaning they ramp up and down through the day tracking the overall trend in electricity demand as consumers respond to cooling, heating, and lighting needs. New gas-fired plants under construction and proposed are adapting by focusing on fast-ramping capabilities.

Staff determined the capacity factors for the existing California conventional LM6000 combustion turbine power plants and F-class combined-cycle power plants based on the historical monthly data from 30 combustion turbine and 22 combined-cycle facilities.[74] Capacity factor assumptions for gas-fired power plants are shown in **Table** B-19 in **Appendix B.**

The heat rate of a natural gas power plant is a measure of how efficiently it burns natural gas.[75] **Table B-20** in **Appendix B** shows heat rates for the different gas technologies.

72 The report uses the General Electric LM6000 gas turbine, which is the most prevalent conventional combustion turbine in California, for the two smaller combustion turbine designs, and the General Electric LMS100 aeroderivative gas turbine for the advanced combustion turbine design

73 Gas turbines are categorized by letter. F-class has been the standard for power generation in North America since its introduction in 1990, although it has been more recently losing market share to H-, G-, and J-class turbines. https://www.power-eng.com/articles/print/volume-119/issue-8/features/the-fall-of-the-f-class-turbine.html.

74 Capacity factors were derived from QFER data from 2007-2016 using the following simple equation: *QFER net generation (MWh) /(facility generation capacity(MW) x hrs./year) = capacity factor.*

75 The heat rates were derived using the following simple equation: QFER heat input (MMBTU)/QFER net generation (kWh) = heat rate (Btu/kWh).

Staff based the criteria pollutant emission factors using permitted, rather than actual emissions, which are based on the *best available control technology* requirements within California.[76] As a result, these emission factors do not vary by high, mid, and low values, as shown in **Table B-21** in **Appendix B**.

Staff estimated CO_2 emission factors based on the efficiency of each technology using an emission factor of 117.0 pounds CO_2 per million British thermal units (MMBtu).[77] **Table B-22** in **Appendix B** provides the CO_2 emission factors for each technology case based on the heat rates shown in **Table B-20**.

Combined-cycle power plants were modeled with separate fixed and variable O&M costs, as well as fuel costs. Total O&M costs for combined-cycle plants are shown in **Table B-23** in **Appendix B.**[78] Fixed O&M costs include staffing plus nonstaffing costs such as equipment, regulatory filings, and other direct costs. Variable O&M costs for combined cycles include the different types of maintenance, such as annual maintenance and maintenance for parts that are designed to wear out during normal operations, and water supply costs.

The operating costs for combustion turbines are similar to combined cycles, except combustion turbines are not modeled with a separate variable O&M component. Combustion turbines do not exhibit a relationship between variable O&M costs and capacity factor, so the associated O&M costs are included as fixed O&M costs for modeling. **Table B-24** in **Appendix B** shows the operations and maintenance costs for combustions turbine technology cases.

Natural Gas Levelized Cost Estimates

Combustion technologies are mature and do not exhibit price declines over the forecast period. All combustion technologies increase in cost coinciding with the increase in fuel and cap-and-trade compliance costs. **Figure 6** shows levelized cost estimates for natural gas-fired generation technologies.

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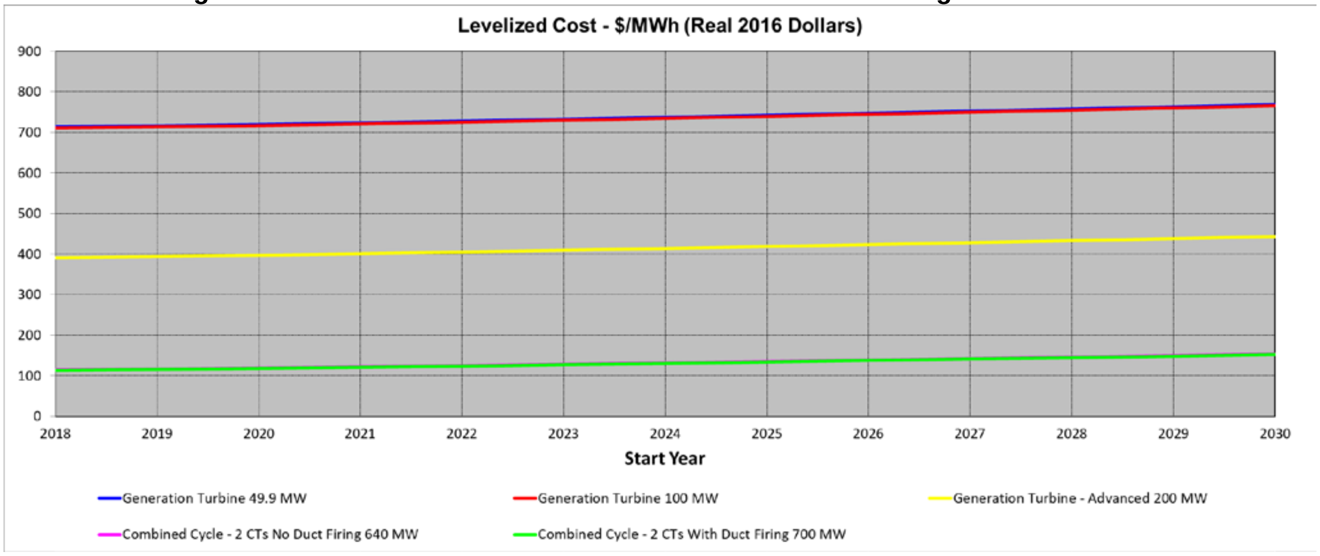
76 *Best available control technology* is defined by U.S. Environmental Protection Administration as the application of the most advanced methods, systems, and techniques for eliminating or minimizing discharges or emissions of are pollutants.

77 https://www.eia.gov/tools/faqs/faq.php?id=73&t=11.

78 O&M costs are assumed to have a real escalation of 0.5 percent per year, primarily reflecting increasing personnel salaries.

Figure 6: Levelized Cost Estimates for Natural Gas Technologies



Source: California Energy Commission

Only small differences in levelized cost are exhibited between the 49.9 MW and 100 MW combustion turbine configurations, as well as between the combined-cycle configurations with and without duct firing. Capacity factor is a major driver of levelized cost, shown between the advanced combustion turbine design that is modeled with a 7 percent capacity factor and the conventional combustion turbines that are modeled with a 4 percent capacity factor.

Summaries of mid, high, and low case levelized, instant, and installed costs for natural gas technologies are shown in **Table B-25** in **Appendix B. Table B-26** shows the percentage increase in LCOE for gas-fired technologies that is attributable to cost increases in fuel and cap-and-trade compliance costs from 2018 to 2030.

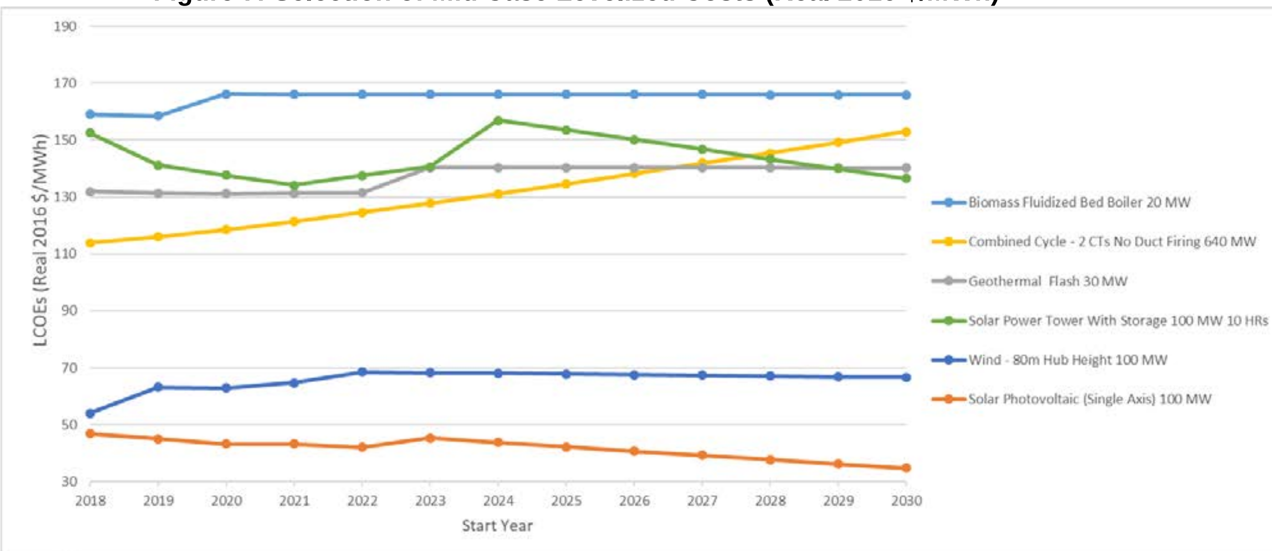
CHAPTER 4: Comparison of Levelized Cost Estimates and Findings

This chapter presents a comparison of the levelized cost of the technologies and discusses the associated implications.

Comparative Levelized Cost Estimates

Figure 7 shows the mid case levelized cost estimates for a selection of technologies: biomass, combined cycle, geothermal flash, solar tower, wind, and solar PV (single axis).

Figure 7: Selection of Mid Case Levelized Costs (Real 2016 $/MWh)



Source: California Energy Commission

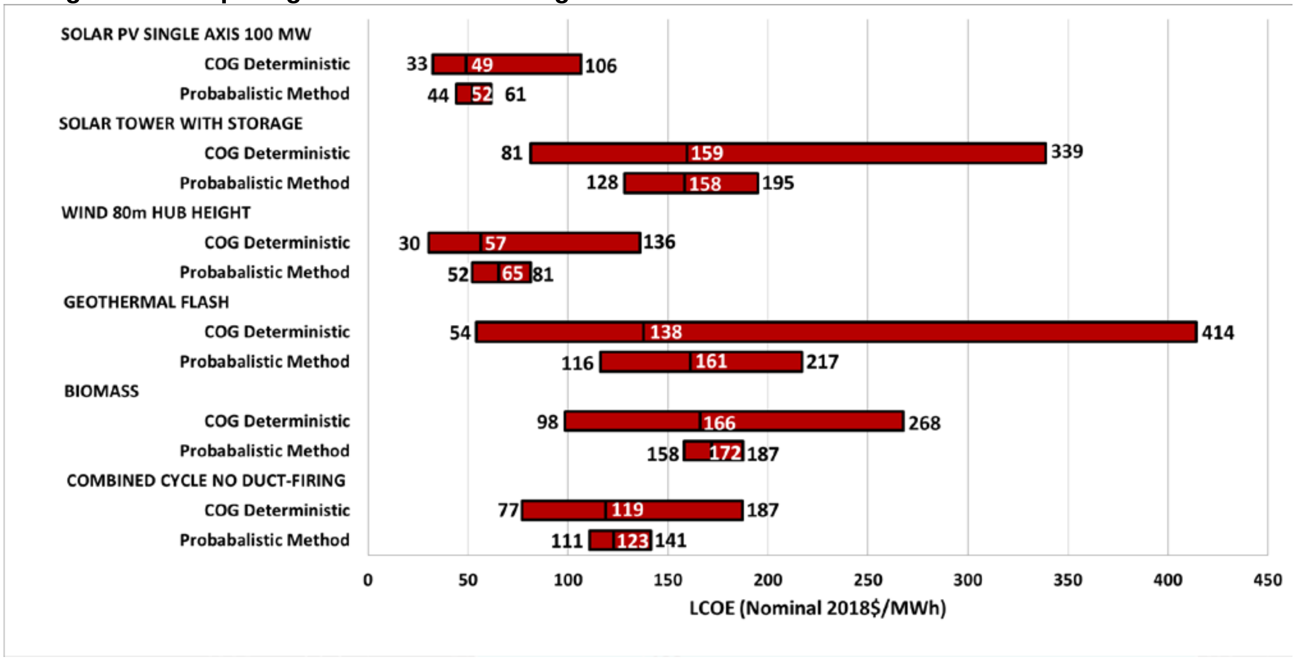
The expiration of tax credit incentives takes place at different times for each technology based on the length of time between a project breaking ground and coming on-line.[79] Solar PV is the least impacted by the expiration of the tax incentives, as the technology is expected to continue to decrease in cost throughout the forecast period.

The mid case levelized costs are the values most commonly quoted and used in cost studies, which are somewhat misleading, since they do not reflect the uncertainty inherent in the various input assumptions. Levelized costs are expected to vary across a range of possible values depending on multiple factors and should reflect the range of possibilities. However, the likelihood of all high-cost components occurring coincidentally or all the low-cost components occurring coincidentally is highly unlikely.

79 Tax incentives may be claimed if a project breaks ground before a certain date and commences operation before a later date, which differs by technology type.

Rather than select all high or all low factors simultaneously, staff used the Monte Carlo method to create probabilistic distributions that were bound by the individual high and low assumptions. Additional details about the probabilistic analysis are in **Appendix C**. **Figure 8** illustrates the dramatic difference in the range of costs and compares the probabilistic levelized costs to the deterministic levelized costs for selected technologies, including biomass, combined cycle, geothermal flash, solar tower, wind, and solar PV (single axis).[80]

Figure 8: Comparing Levelized Cost Ranges for 2018—Deterministic vs. Probabilistic



Source: California Energy Commission

Many of the technology costs overlap; for example, PV and wind technologies are in the same range and distinctly different from the cost of natural gas-fired generation. Also, for geothermal, since the largest costs are exploration, well drilling, and proving a well, the costs may be closer to the low end if a resource area has been proven, as with certain areas around the Salton Sea area.

80 The probabilistic medians differ from the deterministic mid case solutions, and exhibit skewness, which is the degree that the mean differs from the median. These are caused by the high case and low case input values not being equal measure from the mid case.

Findings and Conclusions

The large drop in PV costs has made solar thermal a less attractive solar option. Solar power tower is expected to decline in cost but is substantially more expensive than solar PV technology. There were several solar thermal plants that sought licenses to construct in California, but most have been converted to solar PV projects. The only operating solar power tower in California is the Ivanpah Solar Electric Generating system in the Southern California desert.[81] As previously mentioned, there are no new solar thermal facilities in the development pipeline in California.

Power electronics are being tested with solar PV to provide reliability services typically provided by thermal generation.[82] A subsequent study investigated the economic value of using solar as a flexible resource, having a plant operate as less than full output to allow for some flexible operation.[83] These studies demonstrate that alternative operation of solar PV resources has the potential to reduce the need for gas-fired generation to provide these services.

While no new utility-scale wind projects came on-line in 2016, there is significant wind capacity planned to take advantage of the PTC before it expires. Future economic competitiveness of wind will depend on technology cost and performance improvements, and changes to project financing. In addition, competition from lower cost solar PV and out-of-state wind have contributed to a lull in onshore wind development. The California Wind Energy Association estimates that only 2,000 MW of new wind projects may be developed in California due to the boundaries set in the *Desert Renewable Energy Conservation Plan* that industry representatives say limit their access to high quality wind resource areas.[84, 85] Instead, developers may favor repowering of older, less efficient turbines, although those projects face their own set of hurdles. Outside California, wind developers have been having more success in developing projects, and that growth should improve wind technology as a whole, improving the economics of the technology in California. It also means stiff competition with other wind resources in the West, some of which have higher capacity factors.[86]

81 Based on work done by Navigant for the Energy Commission. Solar Energy Generating Systems are nine solar trough plants built in California between 1984 and 1990.

82 Loutan, Morjaria, Gevorgian, et al. March 2017. *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant.* National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy17osti/67799.pdf.

83 Energy + Environmental Economics. October 2018. *Investigating the Economic Value of Flexible Solar Power Plant Operation.* https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf.

84 *Desert Renewable Energy Conservation Plan*: https://www.drecp.org/

85 Rader, Nancy. 2016. *Repowering 1980s-Vintage Turbines: Benefits & Barriers.* California Wind Energy Association. https://www.calwea.org/public-filing/presentation-benefits-barriers-wind-repowering.

86 Wiser, Ryan and Mark Bollinger. 2016. *2016 Wind Technologies Market Report.* Office of Energy Efficiency & Renewable Energy.

Recent geothermal development has been limited. A 49.9 MW plant built by Energy Source in the Salton Sea area, which came on-line in 2012, is the first in more than 20 years. Despite this lack of development, there is interest in this resource and currently one project going through the Energy Commission's siting process, the Hell's Kitchen Geothermal Project at the Salton Sea.[87] Estimated geothermal potential in the Salton Sea area is 2,220 MW.[88] For some flash plants, a corrosive geothermal fluid may require resistant pipes and cement. Adding a titanium liner to protect the casing may significantly increase the cost of the well.

While the cost of geothermal power is significantly higher than PV, it can provide electricity during the hours when PV is not generating. However, the lithium content of the brine could provide additional benefits to developing the resource, as evidenced by discussions among government and private sector representatives on lithium recovery at a November 15, 2018, workshop held by the Energy Commission.[89] The key barrier to development is financing and finding the appropriate investor willing to bear the significant risk and the need for production scaling. There is potential for significant development of geothermal power generation and lithium extraction in the Salton Sea area with the right mix of private sector interests and government support. Barring any changes to the status quo, little geothermal development is expected in the near term.

Biomass has the highest estimated levelized cost over the forecast period. Because the report focuses on the cost to developers, it does not include external costs and benefits, such as making productive use of forest waste to generate electricity. Notable policy support includes Senate Bill 1122 (Rubio, Chapter 612, Statutes of 2012), Senate Bill 859 (Committee on Budget and Fiscal Review, Chapter 368, Statutes of 2016), and Executive Order B-52-18. Senate Bill 1122 directed the CPUC to establish a bioenergy feed-in tariff program for small bioenergy renewable generators less than 3 MW.[90] SB 859 included the direction for utilities to enter into five-year contracts with biomass plants for at least 125 MW of power that generate a portion of their electricity through the use of forest materials removed from specific high fire hazard zones.[91] Governor Brown's Executive Order B-52-18 in May 2018 requested the CPUC to review and update its procurement programs for small bioenergy renewable generators to ensure long-term programmatic certainty.[92] Even with government support, many biomass generators remain idle, limited by the expensive cost of logging and removing dead trees.[93] Building

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87 https://www.cthermal.com/the-project/.

88 Sison-Lebrilla, Elaine, and Valentino Tiangco. 2005. *Geothermal Strategic Value Analysis.* California Energy Commission. 2005. CEC-500-2005-105-SD.

89 https://www.energy.ca.gov/geothermal/grda_workshops/.

90 http://www.cpuc.ca.gov/SB_1122/.

91 http://biomassmagazine.com/articles/13685/california-governor-signs-bill-benefiting-biomass-power.

92 https://www.gov.ca.gov/2018/05/10/governor-brown-issues-executive-order-to-protect-communities-from-wildfire-climate-impacts/.

93 https://www.powermag.com/u-s-biomass-power-dampened-by-market-forces-fights-to-stay-ablaze/?printmode=1.

new transmission lines to decrease the transportation cost is itself cost-prohibitive and would mean more transmission lines in fire prone areas. Federal funds to support the removal of dead trees and support transportation to currently idled facilities would be less expensive and risky than building new biomass facilities at this time.

While natural gas-fired technologies are the lowest-cost flexible technology, there are no new projects greater than 50 MW under siting review at the Energy Commission. The most recent project permitted was in November 2018, the Stanton Energy Reliability Center. This project is a hybrid system composed of two 49 MW combustion turbines and a 10 MW battery energy storage system. The future of gas-fired generation in California is uncertain as the state transitions to zero-emission generation resources, energy storage, and alternative grid management strategies.

Glossary

Term	Definition
Ad Valorem Costs	Annual property taxes paid as a percentage of the assessed value and are usually transferred to local governments.
Baseload Generation	Power plants that are designed to operate at an annualized capacity factor of at least 60 percent.
Biomass Plant	A plant that uses biological resources, such as forestry waste or farming by-products, to produce electricity through thermal and chemical processes.
Book Life	The period over which costs are incurred and revenues generated.
Cap-and-Trade Program	A market based regulation, managed by the California Air Resources Board, designed to reduce greenhouse gases from multiple sources by pricing carbon emissions.
Capacity Factor	A measure of the actual output of a power plant over a specific period compared to the total potential output a power plant could have provided by operating at its nameplate capacity over the same period.
Capital Structure	The financial terms used to finance a project. See: Weighted Average Cost of Capital.
Combined-Cycle Plant	A power plant has a generation block consisting of at least one combustion turbine, a heat recovery steam generator, and a steam turbine.
Combustion Turbine	An electricity generating unit that is fueled by the burning of natural gas.
Debt	Money borrowed, typically under the terms of a loan at a specified interest rate.
Discount Rate	The rate used to estimate the present value of a project by accounting for the time value of money. It may be equivalent to the total financing cost, see Weighted Cost of Capital.
Emission Reduction Credits	Permits required for the emission of criteria pollutants common to gas-fired combustion technologies, such as sulfur oxides, nitrous oxides, and particulate matter, which are obtained from local air quality management districts.

Equity	Money acquired through the raising of capital, typically through the sale of shares or ownership stake.
Geothermal Plant	A generation station that uses brine, liquid heated by the earth, to generate electricity. Typical configurations are flash, having the brine turn to steam to power a turbine, and binary, using a thermal interchange to heat water which is then turned to steam to power a turbine.
Greenhouse Gas	Any gas that absorbs infrared radiation in the atmosphere. Common examples of greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), halogenated fluorocarbons (HCFCs), ozone (O_3), perfluorinated carbons (PFCs), and hydrofluorocarbons (HFCs).
Heat Rate	Expresses how much fuel is necessary (measured in British thermal units [Btu]) to produce one unit of electric energy (measured in kilowatt-hours [kWh]).
Installed Cost	The instant costs plus the construction loan including development fees.
Instant Cost	The cost to build a power plant if it could be built overnight, sometimes characterized as overnight cost.
Interest Rate	The portion of a loan that is charged as interest to the borrower.
Investor-Owned Utility	A private company that provides a utility, such as water, natural gas, or electricity, to a specific service area. Investor-owned utilities that operate in California are regulated by the California Public Utilities Commission.
Kilowatt-Year	A unit of electrical capacity equivalent to 1 kilowatt of power used for 8,760 hours.
Levelized Cost	The lifetime cost of operations and maintenance, combined with the installed cost, expressed as a constant stream of costs per unit of value over the lifetime of the plant.
Line Losses	The loss of electric energy due to heating of line wires by the current.
Load Following	The ability to dispatch a power plant to meet changing system load requirements.

Megawatt-Hour	A unit of energy representing one thousand kilowatt-hours or, equivalently, the amount of energy produced by applying one megawatt of power for one hour.
Merchant Developer	An independent developer contracted by the utility to build and/or operate a power plant.
Monte Carlo Method	A statistical approximation that uses a large number of randomized samples to generate a probability distribution.
Present Value	The value of an expected income stream determined as of the date of valuation.
Publicly Owned Utility	An organization that maintains the infrastructure for a public service and is subject to forms of public control and regulation.
Power Plant	A power plant is defined as a station composed of one or more electric generating units.
Ramping/Cycling	Power plants altering output levels, including shutdowns and restarts, in response to changes in system load and the availability of renewable generation on the electrical grid. Includes the ancillary services of regulation up and regulation down.
Solar Photovoltaic	A technology that converts sunlight into direct current electricity by using semiconductors.
Tax Credit	An amount of money that can be subtract from taxes owed.
Tornado Diagram	A diagram that shows the relative effect of key assumptions on levelized cost.
Weighted Average Cost of Capital	The weighted average of the cost of debt and equity financing.
Wind Generator	A device that converts the wind’s kinetic energy into electrical energy.

Acronyms and Abbreviations

ACRONYM	DEFINITION
$/MWh	Dollars per megawatt hour
/kW-year	Per kilowatt year
Btu/kWh	British thermal units per kilowatt hour
California Energy Commission	Energy Commission
CF	Capacity factor
CPUC	California Public Utilities Commission
DC	Direct current
ERC	Emission Reduction Credit
GHG	Greenhouse gas emission
IOU	Investor-owned utility
ITC	Investment tax credit
LBNL	Lawrence Berkeley National Laboratory
Lbs/MWh	Pounds per megawatt hour
LCOE	Levelized cost of energy
MW	Megawatt
MWh	Megawatt hour
NO_x	Oxides of nitrogen
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
PM	Particulate matter
POU	Publicly owned utility
PTC	Production tax credit
PV	Photovoltaic
QFER	*Quarterly Fuels and Energy Report*
SO_X	Oxides of sulfur
U.S. EIA	United States Energy Information Administration
VOC	Volatile organic compound
WACC	Weighted average cost of capital

APPENDIX A:
Components of Levelized Cost

The levelized cost of a resource represents a constant cost per unit of generation computed to compare generation costs of one unit with other types of generating resources over similar periods. This comparison is necessary because both the costs and generation capabilities differ dramatically from year to year among generation technologies, making spot comparisons using any year problematic.

The levelized cost formula used in the Cost of Generation Model first estimates the annual costs over the lifetime of the power plant then uses a “discount rate” to express all the costs in terms of a single year’s dollar value, also referred to as the *net present value*. The model then sums the net present value of the cost components and computes the annual payment with interest required to pay off that present value over some specified period, usually the life of the plant.

The Cost of Generation Model presents levelized cost results as a cost per unit of energy over the period under investigation. This computation is done by dividing the total costs of the generating unit by the sum of all the expected generation output from that unit over the time horizon being analyzed. The most common presentation of levelized costs is in $/MWh or cents per kilowatt-hour (¢/kWh). A common alternative presentation is in dollars per kilowatt year ($/kW-yr.)

The Cost of Generation Model generates levelized cost using operational, cost, financial, and tax assumptions described earlier in this report. The model calculates the costs for a technology on an annual basis, finds a present value of those annual costs, and then calculates a levelized cost.

The levelized costs are constructed from the point of view of the developer. They do not reflect any electricity system effects, such as the effect the technology may have on other generation resources or the operational profile of the system. For example, for a natural gas-fired combined-cycle unit, a capacity factor has been estimated from historical data, but whether a particular unit at any point in time will realize that capacity factor is uncertain. At the same time, there is uncertainty about the effect the entry of this unit into the system may have on the capacity factors of the existing combined-cycle units—or for that matter, the operation of any existing technology in the system. Levelized cost estimates presented in this report assume *ceteris paribus*, or, all other things held constant, for the different cost cases.

Components of Levelized Cost

Levelized costs consist of fixed and variable cost components, as shown in **Table A-1**. All these costs vary depending on whether the project is a merchant facility or owned by an investor-owned utility (IOU) or a publicly owned utility (POU). In addition, the costs can vary with location because of differing costs of land, fuel, construction, operations, and environmental licensing. This appendix summarizes component LCOE cost definitions defined in **Table A-1** for 2015 and 2026.

Table A-1: Definition of LCOE Components

Fixed Costs
Capital and Financing—The total cost of all equipment and construction costs, including financing the plant
Insurance—The cost of insuring the power plant
Ad Valorem—Property taxes
Fixed O&M—Staffing and other costs independent of operating hours
Corporate Taxes—State and federal taxes
Variable Costs
Fuel Cost—The cost of the fuel used
GHG Cost—Cap-and-trade allowance costs
Variable O&M—Operation and maintenance costs that are a function of operating hours
Total Costs
Total Cost = Fixed plus variable costs at the point of interconnection with the existing transmission system

Source: California Energy Commission

APPENDIX B: Additional Model Assumptions

Financial Assumptions

Table B-1 summarizes the capital cost structure assumptions used in the Cost of Generation Model to produce levelized costs outlined in **Chapter 3.**

Table B-1: Capital Cost Structure

Mid Case				
Owner	**Equity Share**	**Cost of Equity**	**Cost of Debt**	**WACC**
Merchant Fossil	45.00%	11.50%	4.75%	7.06%
Merchant Alternative	Variable*	Variable*	Variable*	Variable*
IOU	50.20%	10.38%	4.72%	6.60%
POU	N/A	N/A	3.00%	3.00%
High Case				
Owner	**Equity Share**	**Cost of Equity**	**Cost of Debt**	**WACC**
Merchant Fossil	50.00%	13.00%	6.18%	8.72%
Merchant Alternative	Variable*	Variable*	Variable*	Variable*
IOU	70.00%	10.45%	5.11%	8.42%
POU	N/A	N/A	4.74%	4.74%
Low Case				
Owner	**Equity Share**	**Cost of Equity**	**Cost of Debt**	**WACC**
Merchant Fossil	40.00%	10.00%	4.46%	5.93%
Merchant Alternative	Variable*	Variable*	Variable*	Variable*
IOU	48.00%	10.30%	4.12%	6.49%
POU	N/A	N/A	2.84%	2.84%

Variable* financial structures are shown in **Table A-1.**

Source: California Energy Commission

Table B-2 summarizes debt, equity, and weighted average cost of capital (WACC) for merchant renewable projects.

Table B-2: Financial Parameters for Merchant-Owned Renewables

Mid Case						
Technology	**Equity**			**Debt**		**WACC**
	Developer's Cost	Equity Investor's Cost	Weighted Cost of Equity	Percent Debt	Cost of Debt	
Biomass	16.18%	11.57%	13.40%	55.00%	6.70%	8.69%
Geothermal	16.18%	11.57%	13.40%	40.00%	6.20%	9.83%
Solar Thermal	14.48%	9.23%	10.28%	40.00%	6.20%	7.95%
Solar PV	9.38%	4.13%	5.18%	40.00%	5.45%	4.68%
Wind	8.59%	3.34%	5.17%	0.00%	N/A	5.17%
High Case						
Technology	**Cost of Equity**			**Debt**		**WACC**
	Developer's Cost	Equity Investor's Cost	Weighted Cost of Equity	Percent Debt	Cost of Debt	
Biomass	18.82%	15.57%	16.70%	50.00%	8.61%	11.45%
Geothermal	18.82%	15.57%	16.70%	30.00%	8.11%	13.44%
Solar Thermal	15.64%	12.39%	13.04%	30.00%	8.11%	10.88%
Solar PV	10.54%	7.29%	7.94%	30.00%	7.11%	7.09%
Wind	9.42%	6.17%	6.82%	0.00%	N/A	6.82%
Low Case						
Technology	**Cost of Equity**			**Debt**		**WACC**
	Developer's Cost	Equity Investor's Cost	Weighted Cost of Equity	Percent Debt	Cost of Debt	
Biomass	15.45%	9.20%	11.39%	65.00%	5.91%	7.11%
Geothermal	15.45%	9.20%	11.39%	50.00%	5.41%	7.64%
Solar Thermal	13.32%	7.07%	8.32%	50.00%	5.41%	6.11%
Solar PV	8.22%	1.97%	3.22%	50.00%	4.91%	3.38%
Wind	7.82%	1.57%	3.76%	0.00%	N/A	3.76%

Variable* financial structures are shown in **Table A-1.**
Source: California Energy Commission

California Cap-and-Trade Allowance Price Assumptions

Table B-3 shows weighted average emission reduction credit costs price for these emission reduction credits, excluding South Coast.[94]

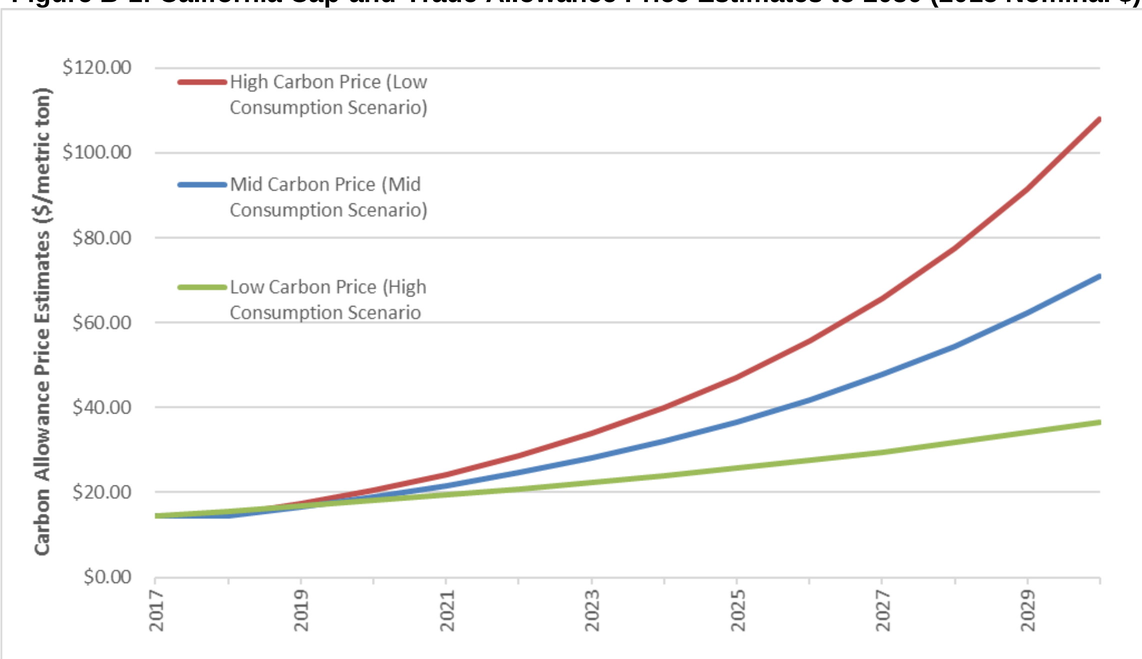
Table B-3: Weighted Average Emission Reduction Credits Cost

Emission Reduction Credit	Weighted Price ($/ton)
NOx	$ 39,997.55
VOC	$ 7,457.53
CO	$ 3,956.65
SOx	$ 21,271.20
PM10	$ 11,894.86

Source: California Energy Commission

California cap-and-trade allowance price assumptions are shown in **Figure B-1**.

Figure B-1: California Cap-and-Trade Allowance Price Estimates to 2030 (2015 Nominal $)



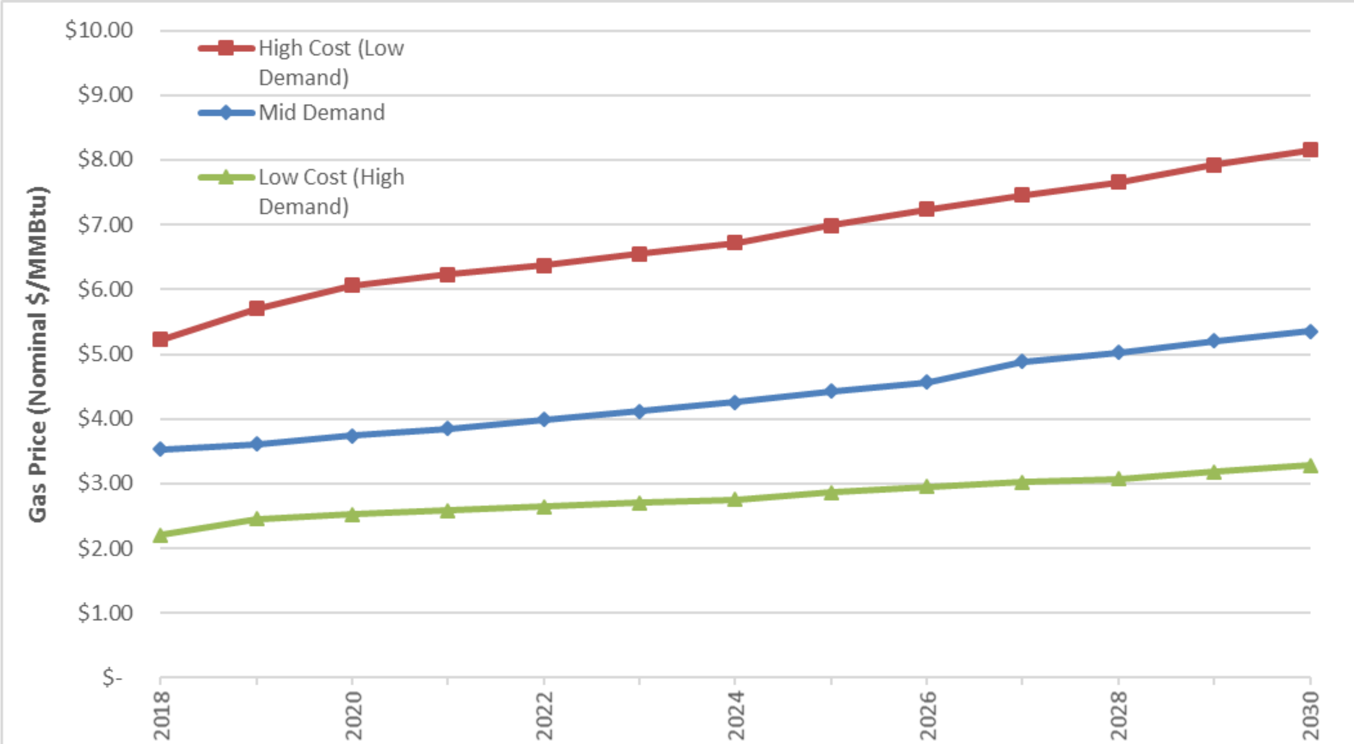
Source: California Energy Commission

94 The South Coast Air Quality Management District regulates the cost of ERCs for new facilities (keeping them low), while ERCs traded on the market are significantly higher. Including these costs distorts statewide trends and should be considered separately. Gas facilities built in the South Coast region should make use of the regional prices rather than a statewide average.

Fuel Price Assumptions

Figure B-2 shows natural gas price assumptions in nominal dollars**.**

Figure B-2: California Natural Gas Price Projections



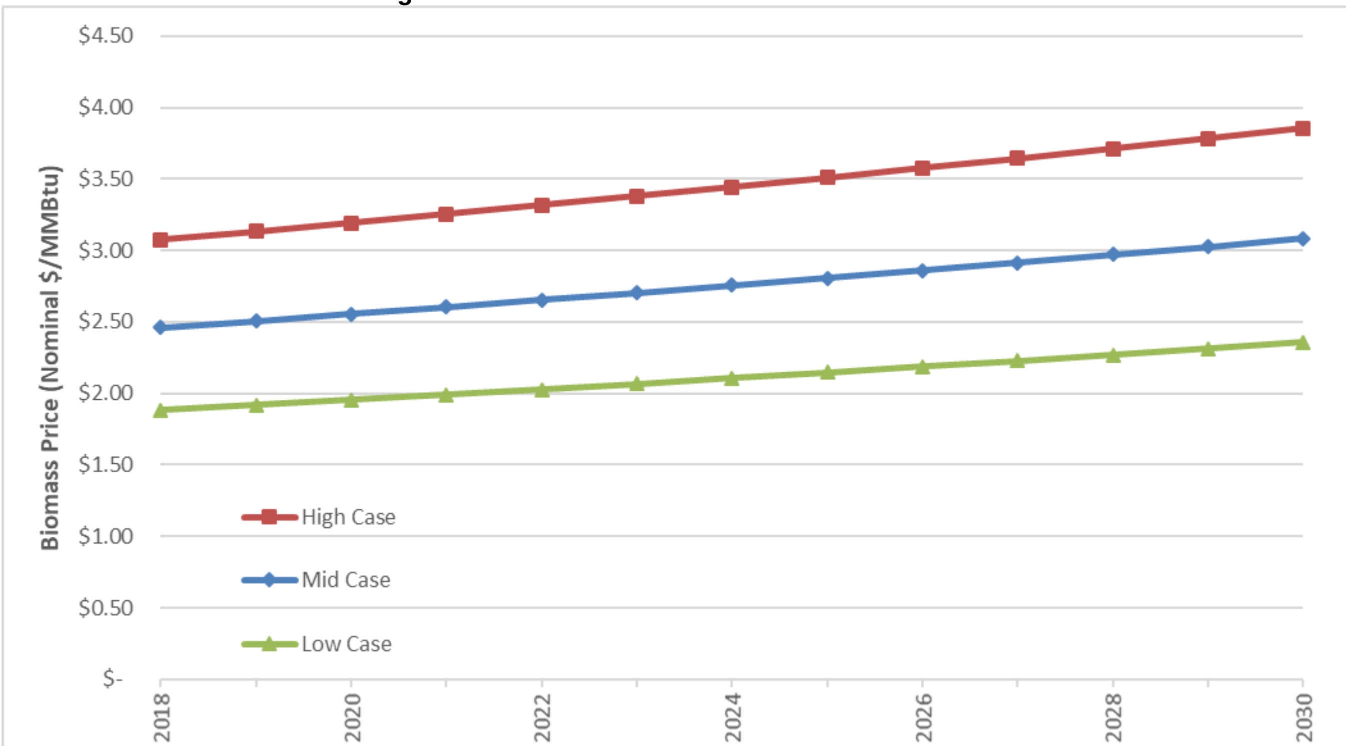
Source: California Energy Commission

Table B-4: California Average Natural Gas Price Assumptions (Nominal $)

Year	Mid Cost ($/MMBtu)	High Cost ($/MMBtu)	Low Cost ($/MMBtu)
2018	3.53	5.22	2.21
2019	3.61	5.70	2.46
2020	3.74	6.06	2.53
2021	3.85	6.23	2.59
2022	3.98	6.37	2.64
2023	4.12	6.55	2.70
2024	4.25	6.72	2.75
2025	4.43	6.99	2.86
2026	4.57	7.23	2.95
2027	4.89	7.45	3.02
2028	5.03	7.65	3.08
2029	5.20	7.92	3.18
2030	5.36	8.16	3.28
2031	5.53	8.43	3.38
2032	5.71	8.71	3.48
2033	5.91	9.00	3.57
2034	6.13	9.31	3.67
2035	6.40	9.62	3.77
2036	6.66	9.93	3.87
2037	7.12	10.29	3.97
2038	7.50	10.68	4.08
2039	7.82	11.26	4.21
2040	8.10	11.71	4.34
2041	8.43	12.20	4.47
2042	8.74	12.65	4.59
2043	9.05	13.12	4.71
2044	9.22	13.50	4.83
2045	9.55	14.00	4.95
2046	9.99	14.44	5.08
2047	10.28	14.91	5.19
2048	10.72	15.20	5.33
2049	11.36	15.81	5.39
2050	11.45	16.16	5.62

Source: California Energy Commission

Figure B-3: Biomass Fuel Prices



Source: California Energy Commission (KEMA, Inc. Renewables Energy Study)

Transmission Interconnection Assumptions

Table B-5 shows transmission interconnection voltages and costs**.**

Table B-5: Transmission Interconnection Voltages and Costs

Length of Interconnection ($/kW)	Interconnection Voltage	Mid Case	High Case	Low Case
Generation Turbine 49.9 MW	69kV	160	407	95
Generation Turbine 100 MW	115kV	84	212	50
Generation Turbine − Advanced 200 MW	230kV	145	325	92
Combined-Cycle − 2 CTs No Duct Firing 640 MW	500kV	89	191	57
Combined-Cycle − 2 CTs With Duct Firing 700 MW	500kV	81	175	52
Biomass Fluidized Bed Boiler 50 MW	69kV	160	406	95
Geothermal Binary 30 MW	69kV	266	677	158
Geothermal Flash 30 MW	69kV	266	677	158
Solar Power Tower With Storage 100 MW 10 HRs	115kV	84	212	50
Solar Photovoltaic (Thin-Film) 100 MW	115kV	84	212	50
Solar Photovoltaic (Single Axis) 100 MW	115kV	84	3183	50
Solar Photovoltaic (Thin-Film) 20 MW	69kV	400	1,015	236
Solar Photovoltaic (Single Axis) 20 MW	69kV	400	1,015	236
Wind – 80m Hub Height 100 MW	115kV	84	212	50
Battery Energy Storage System – Li-Ion 20 MW	69kV	400	1,015	236

Source: California Energy Commission

Table B-6 shows the distances and estimated losses for various sizes of interconnections.

Table B-6: Assumed Interconnection Transmission Lengths and Losses

Length of Interconnection	Mid Case	High Case	Low Case
Transmission Losses (%)	**1.5 mi**	**5 mi**	**0.5 mi**
Generation Turbine 49.9 MW	0.65%	2.18%	0.22%
Generation Turbine 100 MW	0.97%	3.23%	0.32%
Generation Turbine − Advanced 200 MW	0.22%	0.72%	0.07%
Combined-Cycle − 2 CTs No Duct Firing 640 MW	0.09%	0.31%	0.03%
Combined-Cycle − 2 CTs With Duct Firing 700 MW	0.09%	0.31%	0.03%
Biomass Fluidized Bed Boiler 50 MW	0.47%	1.57%	0.16%
Geothermal Binary 30 MW	0.94%	3.14%	0.31%
Geothermal Flash 30 MW	0.94%	3.14%	0.31%
Solar Power Tower With Storage 100 MW 10 HRs	0.97%	3.23%	0.32%
Solar Photovoltaic (Thin-Film) 100 MW	0.97%	3.23%	0.32%
Solar Photovoltaic (Single Axis) 100 MW	0.97%	3.23%	0.32%
Solar Photovoltaic (Thin-Film) 20 MW	1.37%	4.56%	0.46%
Solar Photovoltaic (Single Axis) 20 MW	1.37%	4.56%	0.46%
Wind – 80m Hub Height 100 MW	0.97%	3.23%	0.32%
Battery Energy Storage System – Li-Ion 20 MW	1.37%	4.56%	0.46%

Source: California Energy Commission

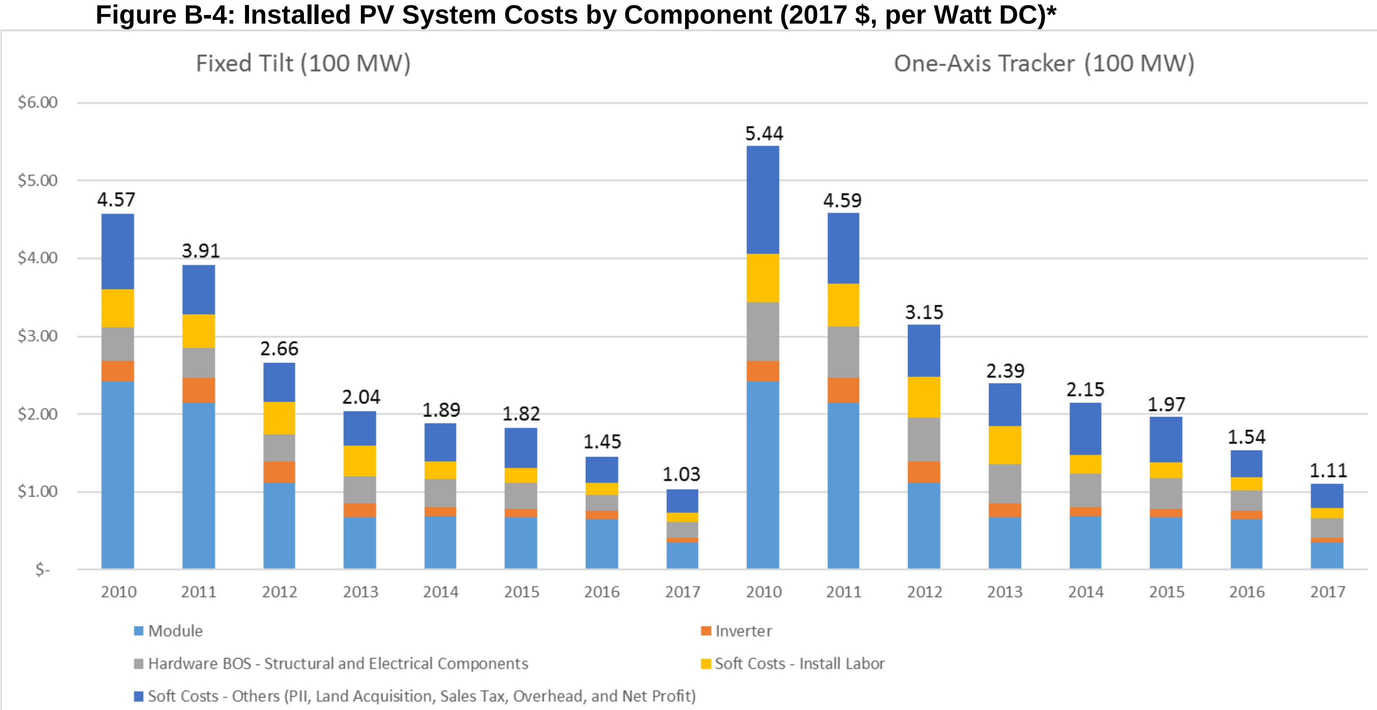
Solar PV Cost Assumptions

Staff analyzed publicly available reports and studies to evaluate the recent costs and trends of solar PV projects:

- *Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends*, Bolinger, et al., LBNL, 2017
- *On the Path to SunShot: The Role of Advancements in Solar Photovoltaic Efficiency, Reliability, and Costs*, Woodhouse, et al., NREL, 2016
- *U.S. Solar Photovoltaic System Cost Benchmark: Q1 2017*, Fu, et al., NREL, 2017
- *Current and Future Cost of Photovoltaics*, Mayer, Agora Energiewende, 2015
- *Potential for Cost Reduction of PV Technology*, Theologitis and Masson, CHEETAH Research Innovations, 2015
- *Sunshot Vision Study*, U.S. DOE, 2012

Figure B-4 shows installed PV system costs by component.

Figure B-4: Installed PV System Costs by Component (2017 $, per Watt DC)*

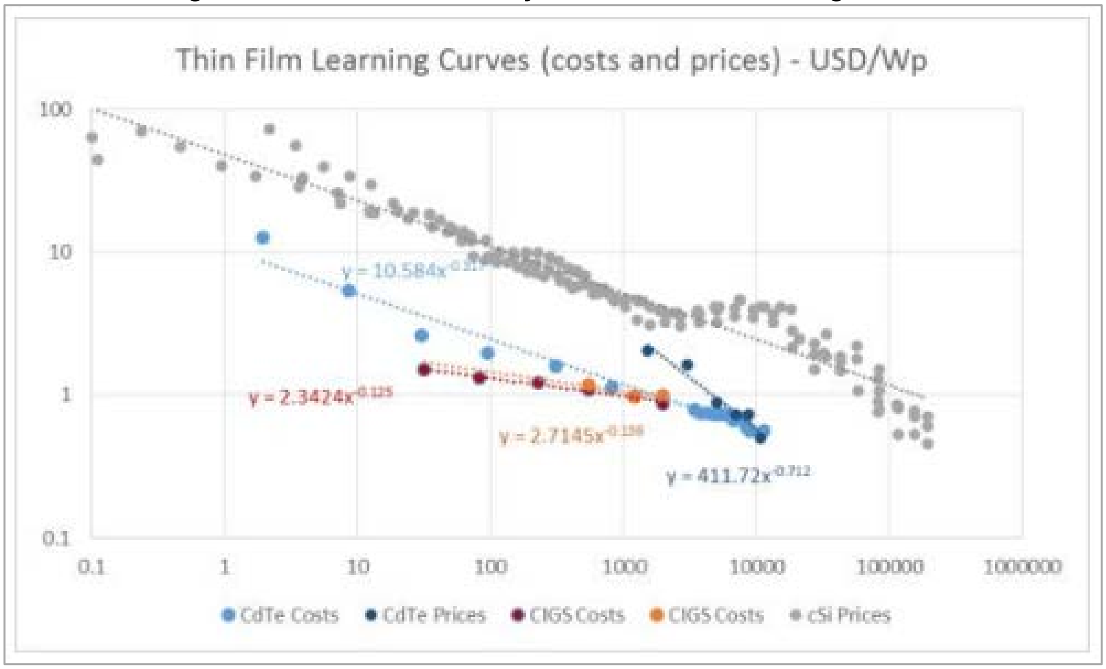


*COG costs are modeled in AC. NREL uses a ratio of 1.3 to convert DC-to-AC for utility-scale projects.

Source: National Renewable Energy Laboratory

Figure B-5 shows PV module costs trends**.**

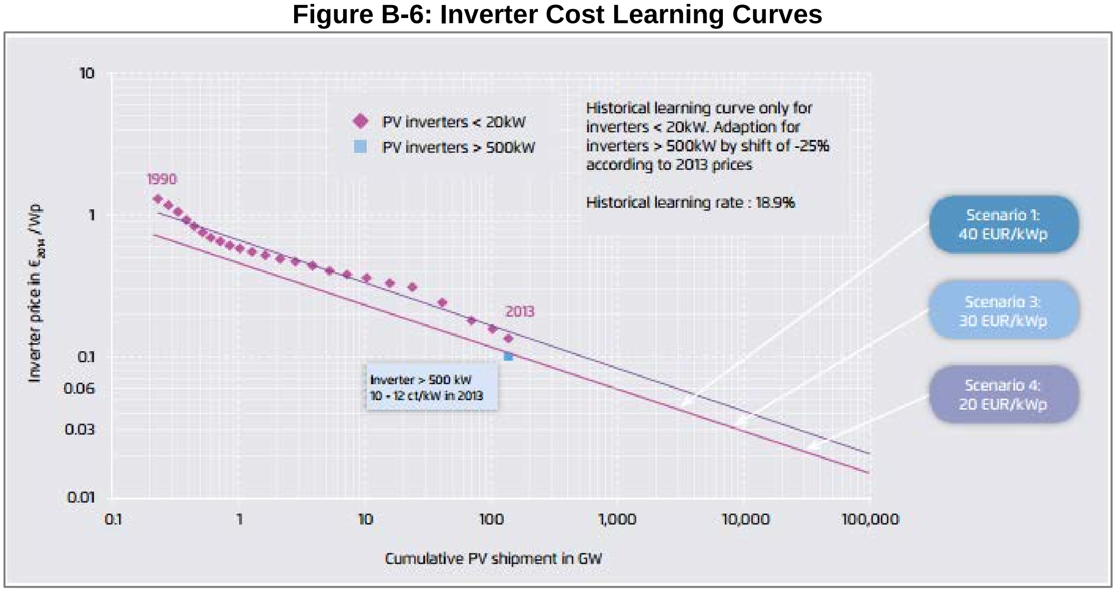
Figure B-5: Thin-Film and Crystalline Silicon Learning Curves



Source: Theologitis and Masson, CEETAH Research Innovations, Becquerel Institute, 2015

Figure B-6 shows inverter cost learning curves.[95]

Figure B-6: Inverter Cost Learning Curves



Source: Agora Energiewende

95 *Current and Future Cost of Photovoltaics. Long Term Scenarios for Market Development, System Prices and LCOE of Utility-Scale PV Systems.* 2015.

Table B-7 shows capacity factors for solar PV systems.

Table B-7: Solar PV Capacity Factors

System Type	Mid	High	Low
Fixed-Tilt	26%	21%	31%
Tracking	31%	26%	36%

Source: California Energy Commission

Table B-8 shows O&M costs for solar PV.

Table B-8: Solar Photovoltaic Operating and Maintenance Costs

Technology (Nominal 2018 $)	Mid Case	High Case	Low Case
C-Si, Tracking (100 MW and 20 MW)			
Fixed O&M ($/kW-year)	$22.05	$21.85	$20.84
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$8.12	$8.05	$7.67
Thin-Film, Fixed Axis (100 MW and 20 MW)			
Fixed O&M ($/kW-year)	$20.08	$18.94	$20.03
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$8.82	$8.31	$8.80

Source: California Energy Commission

Table B-9 summarizes instant, installed, and levelized costs for solar PV technologies, including crystalline silicon (C-Si) and thin-film, for 2018 (in 2016 dollars).

Table B-9: Summary of 2018 Solar Photovoltaic Costs for Merchant Developer

Technology Case (Nominal 2018 $)	Mid Case	High Case	Low Case
C-Si, Tracking 100 MW			
Instant Cost ($/kW)	$1,742	$2,016	$1,636
Ancillary Costs (Interconnection, Land, and Licensing)	$157	$400	$76
Instant Cost Without Ancillary Costs	$1,585	$1,616	$1,560
Installed Cost for Merchant Developer ($/kW)	$1,861	$2,313	$1,693
Levelized Cost of Electricity ($/kW-year)	$119	$204	$96
Levelized Cost of Electricity ($/MWh)	$49	$96	$33
C-Si, Tracking 20 MW			
Instant Cost ($/kW)	$2,071	$2,884	$1,830
Ancillary Costs (Interconnection, Land, and Licensing)	$486	$1,269	$270
Instant Cost Without Ancillary Costs	$1,585	$1,615	$1,560
Installed Cost for Merchant Developer ($/kW)	$2,213	$3,309	$1,894
Levelized Cost of Electricity ($/kW-year)	$137	$283	$105
Levelized Cost of Electricity ($/MWh)	$57	$151	$36
Thin-Film, Fixed Axis 100 MW			
Instant Cost ($/kW)	$1,503	$1,802	$1,402
Ancillary Costs (Interconnection, Land, and Licensing)	$157	$430	$76
Instant Cost Without Ancillary Costs	$1,346	$1,372	$1,326
Installed Cost for Merchant Developer ($/kW)	$1,606	$2,067	$1,451
Levelized Cost of Electricity ($/kW-year)	$103	$182	$85
Levelized Cost of Electricity ($/MWh)	$52	$119	$33
Thin-Film, Fixed Axis 20 MW			
Instant Cost ($/kW)	$1,832	$2,640	$1,596
Ancillary Costs (Interconnection, Land, and Licensing)	$486	$1,269	$270
Instant Cost Without Ancillary Costs	$1,346	$1,371	$1,326
Installed Cost for Merchant Developer ($/kW)	$1,957	$3,029	$1,652
Levelized Cost of Electricity ($/kW-year)	$122	$258	$94
Levelized Cost of Electricity ($/MWh)	$62	$171	$36

Source: California Energy Commission

Solar Thermal Technology Assumptions

Staff analyzed publicly available reports and studies to evaluate the recent costs and trends of solar thermal tower technology:

- *Utility-Scale Solar 2016: An Empirical Analysis of Project Cost, Performance, and Pricing Trends*, Bolinger, et al., LBNL, 2017
- *On the Path to Sunshot: Advancing Concentrating Solar Power Technology, Performance, and Dispatchability*, Mehos, et al., NREL, 2016
- *Molten Salt Power Tower Cost Model for the System Advisor Model*, Turchi and Heath, NREL, 2013
- *An Evaluation of Possible Next-Generation High-Temperature Molten-Salt Power Towers*, Kolb, Sandia, 2011
- *Power Tower Technology Roadmap and Cost Reduction Plan,* Kolb, Ho, Mancini, and Gary, Sandia, 2011
- *Solar Thermocline Storage Systems*, Libby, EPRI, 2010

Table B-10 presents estimated O&M costs for solar power tower technology.

Table B-10: Solar Power Tower Operating and Maintenance Costs

Technology (Nominal 2018 $)	Mid Case	High Case	Low Case
Concentrating Solar Power - Tower with 10 HR Storage 100 MW			
Fixed O&M ($/kW-year)	$71.95	$83.25	$51.57
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$16.43	$19.01	$11.77

Source: California Energy Commission

Table B-11 summarizes the instant, installed, and levelized costs for concentrating solar power tower with 10-hour storage technology in 2018 in nominal (2016) dollars.

Table B-11: Summary of 2018 Solar Thermal Costs for Merchant Developers

Technology Case (Nominal 2018 $)	Mid Case	High Case	Low Case
Concentrating Solar Power - Tower with 10 HR Storage 100 MW			
Instant Cost ($/kW)	$6,285	$6,740	$5,445
Ancillary Costs (Interconnection, Land, and Licensing)	$157	$430	$76
Instant Cost Without Ancillary Costs	$6,128	$6,310	$5,369
Installed Cost for Merchant Developer ($/kW)	$7,028	$7,966	$5,724
Levelized Cost of Electricity ($/kW-year)	$575	$913	$372
Levelized Cost of Electricity ($/MWh)	$159	$339	$81

Source: California Energy Commission

Wind Technology Cost Trends and Assumptions

Staff analyzed publicly available reports and studies to evaluate the recent costs and trends of wind turbines:

- *2016 Wind Technologies Market Report*, Wiser and Bolinger, DOE, 2017
- *2016 Cost of Wind Energy Review*, Stehly, et al., NREL, 2017
- *Forecasting Wind Energy Costs and Cost Drivers*, Wiser, et al., LBNL, 2016
- *Wind Energy in California: 2014 Description, Analysis, and Context*, Hingtgen, et al., California Energy Commission, 2017
- *Repowering 1980s-Vintage Turbines: Benefits & Barriers*, Rader, CalWEA, 2016
- *Recent Developments in the Levelized Cost of Energy (*LCOE*) From U.S. Wind Power Projects*, Wiser et al., LBNL, February 2012

Table B-12 shows wind resource area parameters including capacity, energy, project numbers, turbine numbers, and average capacities by project and turbine.

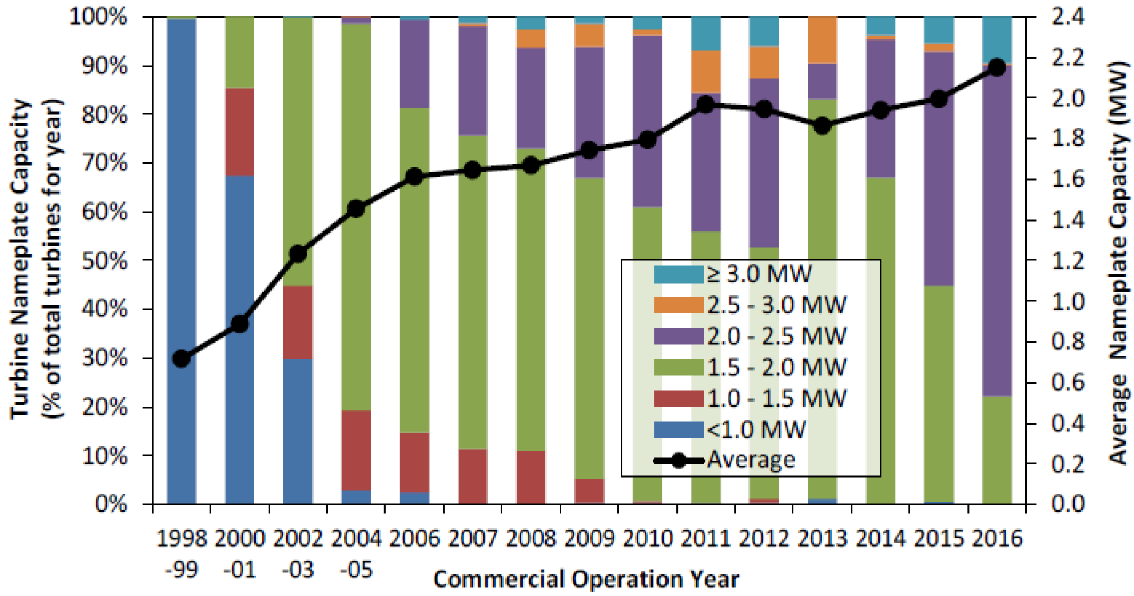
Table B-12 : Comparison of Wind Resource Area Parameters

Wind Resource Area	Capacity (MW)	Energy (GWh)	Number of Projects	Number of Turbines	Average Capacity per Project (MW)	Average Capacity per Turbine (MW)
Tehachapi	3,193	6,976	52	4,288	61	0.7
Solano	1,032	2,559	13	602	79	1.7
San Gorgonio	712	1,657	33	2,482	22	0.3
Altamont	500	843	19	3,771	26	0.1
East San Diego County	316	708	3	138	105	2.3
Other Resource Area	111	306	7	52	16	2.1
Pacheco	19	24	1	165	19	0.1
Outside of Existing WRA	3	2	2	2	1	1.2
All Areas	5,887	13,074	130	11,500	45	0.5

Source: California Energy Commission

Figure B-7 shows the increasing trend in turbine nameplate capacity over time across the United States.

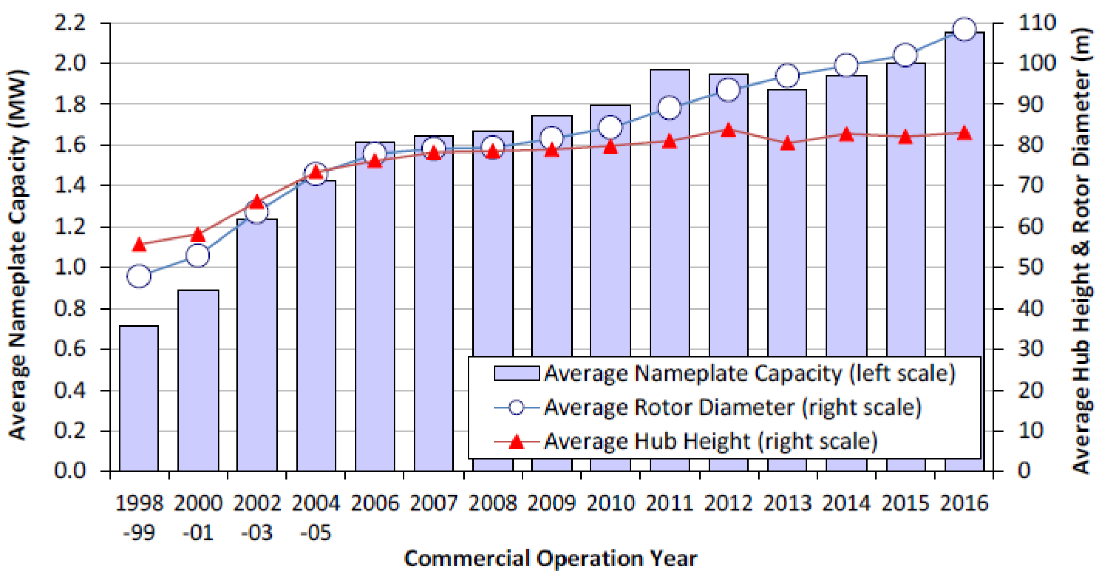
Figure B-7: Trends in Wind Turbine Nameplate Capacity



Source: U.S. Department of Energy

Figure B-8 shows the historical trends in hub height and rotor diameter.

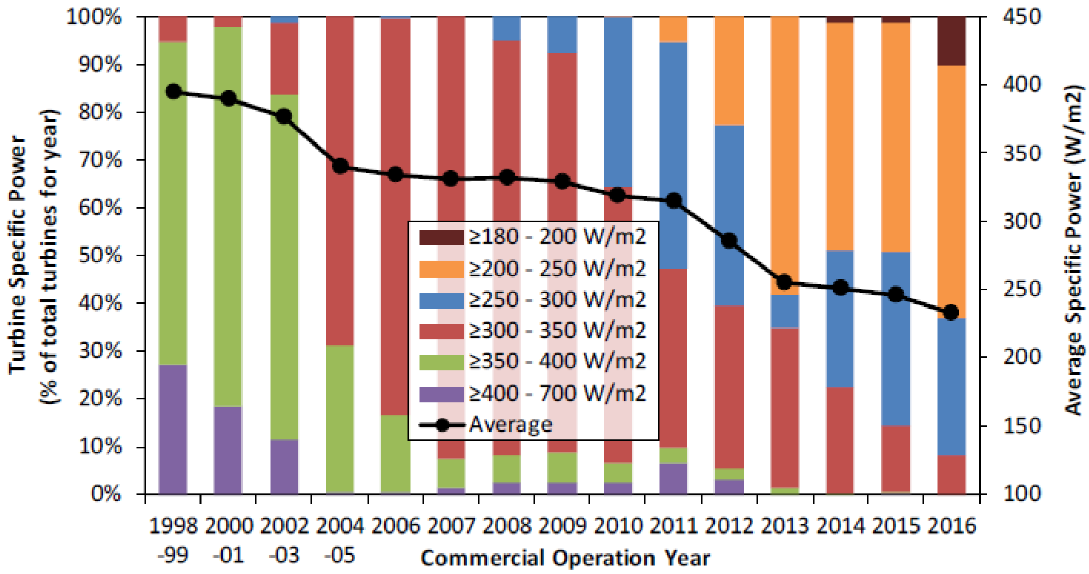
Figure B-8: Trends in Hub Height and Rotor Diameter for Wind



Source: U.S. Department of Energy

Figure B-9 shows how the specific power has decreased over time.

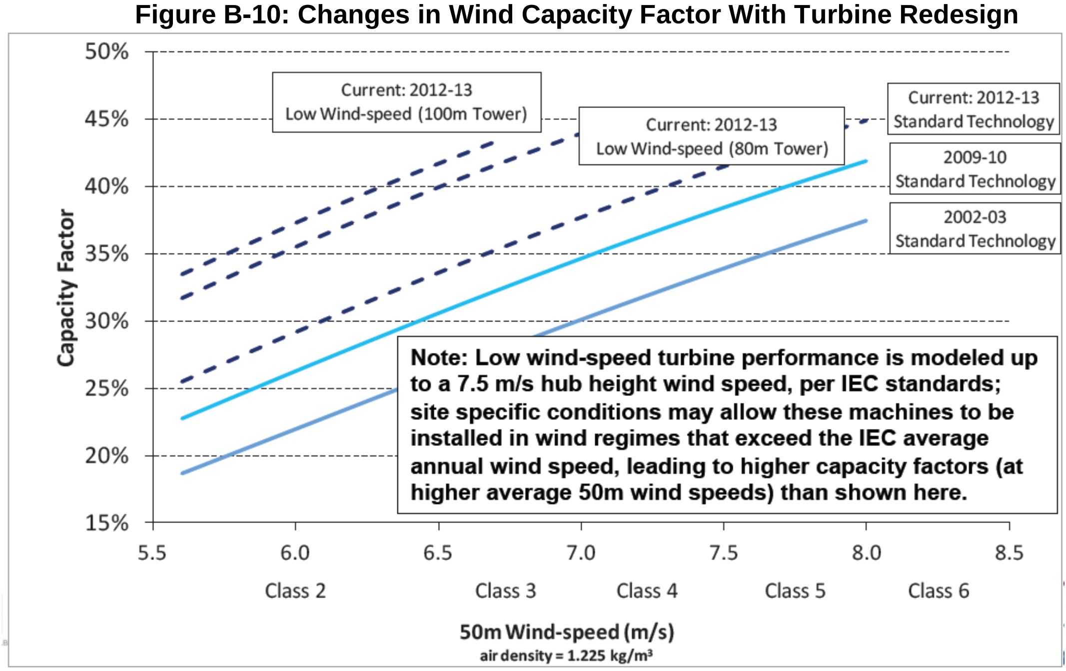
Figure B-9: Trends in Wind Turbine Specific Power



Source: U.S. Department of Energy

Figure B-10 shows how the expected capacity factor has increased with these changes in design.

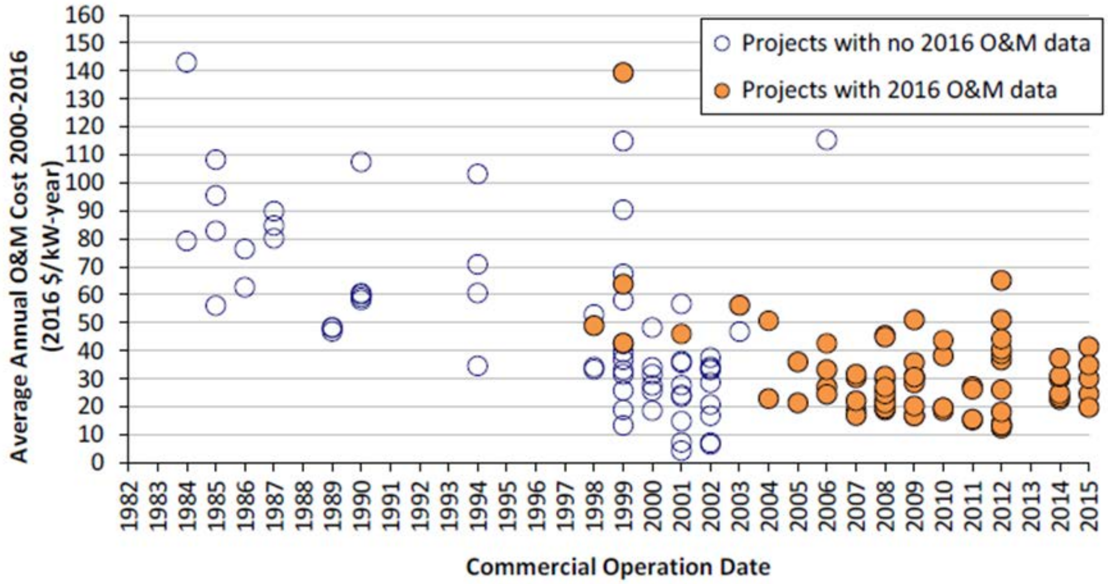
Figure B-10: Changes in Wind Capacity Factor With Turbine Redesign



Source: Lawrence Berkeley National Laboratory

Figure B-11 shows the trend in O&M costs by project on-line date.

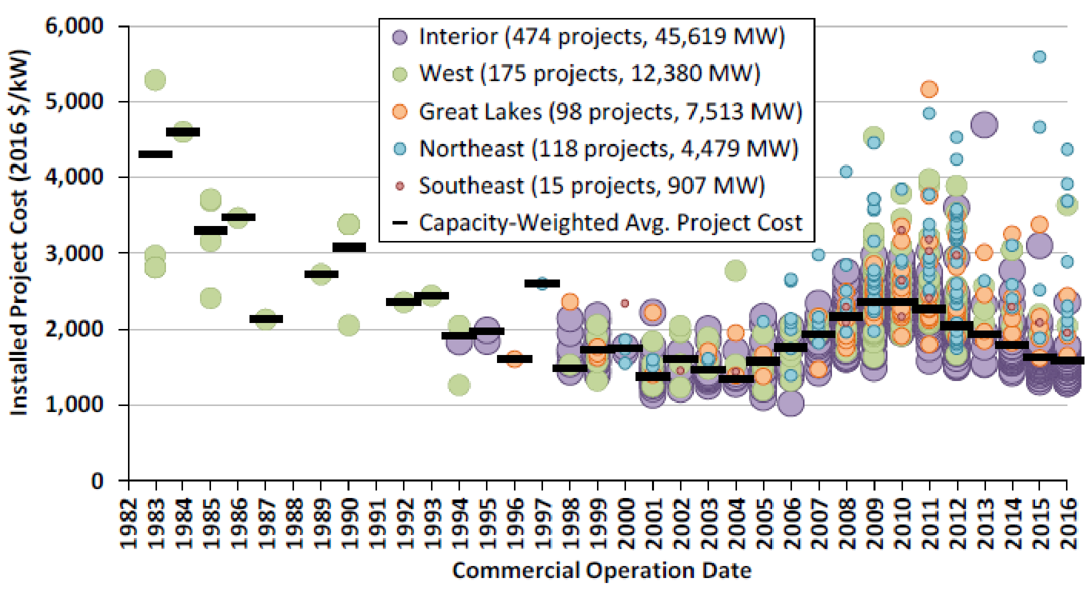
Figure B-11: Average O&M Costs by Commercial On-Line Date



Source: Berkeley Lab; seven data points suppressed to protect confidentiality

Figure B- 12 shows installed wind project costs over time.

Figure B- 12: Installed Project Costs Over Time



Source: Lawrence Berkeley National Laboratory (some data points suppressed to protect confidentiality) and Energy Information Administration

Table B-13 shows the assumed operations and maintenance costs for wind technology, which is held constant in real terms over the forecast period.

Table B-13: Onshore Wind Operations and Maintenance Costs

Technology (Nominal 2018 $)	Mid Case	High Case	Low Case
Wind - 80m Hub Height 100 MW			
Fixed O&M ($/kW-year)	$45.65	$63.22	$35.88
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$14.89	$20.62	$11.70

Source: California Energy Commission

Table B-14 summarizes instant, installed, and levelized costs for wind technologies in 2018 in nominal (2016) dollars.

Table B-14: Summary of 2018 Wind Costs for Merchant Developers

Technology Case (Nominal 2018 $)	Mid Case	High Case	Low Case
Wind - 80m Hub Height 100 MW			
Instant Cost ($/kW)	$1,806	$2,321	$1,447
Ancillary Costs (Interconnection, Land, and Licensing)	$308	$655	$100
Instant Cost Without Ancillary Costs	$1,498	$1,666	$1,347
Installed Cost for Merchant Developer ($/kW)	$1,950	$2,671	$1,494
Levelized Cost of Electricity ($/kW-year)	$162	$315	$97
Levelized Cost of Electricity ($/MWh)	$57	$136	$30

Source: California Energy Commission

Geothermal Technology Cost Assumptions

Staff updated costs and plant characteristics for binary geothermal plants from a review of publicly available reports and studies:

- "Geothermal Energy Association Comments on Renewables Portfolio Standard Calculator Cost Assumptions," Matek, RETI 2.0, 2016
- *Capital Cost Review of Power Generation Technologies*, Olson, et al., Energy+Environmental Economics, 2014
- *California Renewable Energy Resource Potential and Cost Approach*, Olson, Black & Veatch, 2013
- *Geothermal Energy and Greenhouse Gas Emissions*, Holm, et al., GEA, 2012
- *Cost and Performance Data for Power Generation Technologies*, Black & Veatch, NREL, 2012
- *Cost and Performance Assumptions for Modeling Electricity Generation Technologies*, Tidball, et al., NREL, 2010
- *Updated Capital Cost Estimates for Electricity Generation Plants*, Hahn, et al., R. W. Beck, United States Energy Information Administration (U.S. EIA), 2010
- *Factors Affecting Costs of Geothermal Power Development*, Hance, DOE, 2005
- *Geothermal Strategic Value Analysis*, Sison-Lebrilla and Tiangco, California Energy Commission, 2005
- *Cost Contributors to Geothermal Power Generation*, Nathwani and Mines, World Geothermal Conference, 2015

Table B-15 shows the operations and maintenance costs for geothermal binary technology.

Table B-15: Geothermal Flash Operations and Maintenance Costs

Technology (Nominal 2018 $)	Mid Case	High Case	Low Case
Geothermal Binary 30 MW			
Fixed O&M ($/kW-year)	$148.48	$204.99	$106.70
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$19.94	$27.53	$14.33
Geothermal Flash 30 MW			
Fixed O&M ($/kW-year)	$148.48	$204.99	$106.70
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$19.94	$27.53	$14.33

Source: California Energy Commission

Table B-16 summarizes instant, installed, and levelized costs for geothermal technologies in 2018 in nominal (2016) dollars.

Table B-16: Summary of 2018 Geothermal Costs for Merchant Developers

Technology Case (Nominal 2018 $)	Mid Case	High Case	Low Case
Geothermal Binary 30 MW			
Instant Cost ($/kW)	$4,020	$6,644	$2,734
Ancillary Costs (Interconnection, Land, and Licensing)	$365	$900	$227
Instant Cost Without Ancillary Costs	$3,655	$5,744	$2,507
Installed Cost for Merchant Developer ($/kW)	$5,058	$9,378	$3,016
Levelized Cost of Electricity ($/kW-year)	$647	$1,729	$243
Levelized Cost of Electricity ($/MWh)	$104	$347	$32
Geothermal Flash 30 MW			
Instant Cost ($/kW)	$5,091	$7,124	$3,914
Ancillary Costs (Interconnection, Land, and Licensing)	$121	$271	$77
Instant Cost Without Ancillary Costs	$4,970	$6,853	$3,837
Installed Cost for Merchant Developer ($/kW)	$6,207	$9,695	$4,276
Levelized Cost of Electricity ($/kW-year)	$806	$1,800	$384
Levelized Cost of Electricity ($/MWh)	$138	$414	$54

Source: California Energy Commission

Biomass Technology Cost Assumptions

Staff updated the plant data for biomass circulating fluidized bed boilers (CFB) boiler plants from a review of publicly available reports and studies:

- *Capital Cost Estimates for Utility Scale Electricity Generating Plants*, U.S. EIA, 2016
- *Assessment of the National Prospects for Electricity Generation from Biomass*, Nderitu, et al., U.S. Department of Agriculture, 2014
- *California Renewable Energy Resource Potential and Cost Approach*, Olson, Black & Veatch, 2014
- *Cost and Performance Data for Power Generation Technologies*, Black & Veatch, NREL, 2012
- *Cost and Performance Assumptions for Modeling Electricity Generation Technologies*, Tidball, et al., NREL, 2010
- *Updated Capital Cost Estimates for Electricity Generation Plants*, Hahn, et al., R. W. Beck, U.S. EIA, 2010

Table B-17 shows O&M costs for biomass technology.

Table B-17: Biomass Operations and Maintenance Costs

Technology (Nominal 2018 $)	Mid Case	High Case	Low Case
Biomass Fluidized Bed Boiler 20 MW			
Fixed O&M ($/kW-year)	$125.81	$130.45	$121.02
Variable O&M ($/MWh)	$6.98	$8.15	$5.87
Total O&M ($/MWh)	$24.72	$26.53	$22.92

Source: California Energy Commission

Table B-18 summarizes instant, installed, and levelized costs for biomass technology in 2018 in nominal (2016) dollars.

Table B-18: Summary of 2018 Biomass Costs

Technology Case (Nominal 2018 $)	Mid Case	High Case	Low Case
Biomass Fluidized Bed Boiler 20 MW			
Instant Cost ($/kW)	$4,513	$5,663	$3,960
Ancillary Costs (Interconnection, Land, and Licensing)	$513	$1,224	$305
Instant Cost Without Ancillary Costs	$4,000	$4,439	$3,655
Installed Cost for Merchant Developer ($/kW)	$5,106	$6,879	$4,154
Levelized Cost of Electricity ($/kW-year)	$1,111	$1,646	$713
Levelized Cost of Electricity ($/MWh)	$166	$268	$98

Source: California Energy Commission

Natural Gas Technology Cost Assumptions

Staff found that the costs of gas-fired technologies have remained stable since the previous report, while combined-cycle (CC) technologies increased in capacity. Staff held instant and operations and maintenance costs constant for this update, while increasing the size of CCs.

Capacity factors were based on the historical monthly Quarterly Fuel and Energy Report data. The criteria pollutant emission factors for the four gas turbine cases were estimated using permitted emission data from Energy Commission siting cases. The plant costs data for natural gas-fired power plants were obtained from the contractor surveys of power plants in California. Additional details may be found in the previous COG report.

Table B-19 shows estimates capacity factors for gas-fired power plants, including conventional and advanced combustion turbines (CT) and conventional CC plants, with and without duct burning.

Table B-19: Estimated Capacity Factors for Natural Gas Technologies

Technology	Owner	Assumed Capacity Factor		
		Mid Case	High Case	Low Case
Conventional CT (both sizes)	Merchant	4.0%	1.5%	8.0%
	POU	4.5%	1.5%	7.5%
	IOU	4.0%	1.0%	7.0%
Advanced CT	All Owners	7.0%	4.0%	10.0%
Conventional CC	All Owners	57.0%	40.0%	71.0%
Conventional CC w/Duct Burners	All Owners	57.0%	40.0%	71.0%

Note: High and low are based on cost implications, not on the specific value of the capacity factor.

Source: California Energy Commission

Table B-20 shows heat rate assumption for the different gas-fired technology types.

Table B-20: Summary of Estimated Heat Rates (Btu/kWh)

Technology	Mid [a]	High [a]	Low [b]
Conventional CT [c]	10,585	11,890	9,980
Advanced CT	9,880	10,200	9,600
Conventional CC	7,250	7,480	7,030
Conventional CC With Duct Firing	7,250	7,480	7,030

Notes: a Mid and high case recommended values are based on an analysis of mid and high *QFER* heat rates and current turbine technology. (For example, the mid case heat rate for the conventional CT is based on new projects installing the next generation of LM6000 gas turbine.)

b Low case recommended values are based on new and clean heat rates from turbine manufacturers. Mid case heat rates in Cost of Generation Model are presented as a regression formula based on *QFER* data.

c The conventional CT values are recommended for both the single-turbine (49.9 MW) and two-turbine (100 MW) cases and are based on NXGen LM6000 gas turbine efficiencies that are higher than most of the existing LM6000-powered plants.

Source: California Energy Commission

Table B-21 shows permitted criteria pollutant emission factors and emissions for the different gas-fired technologies.

Table B-21: Permitted Emission Factors and Emissions

Technology	NOx	VOC	CO	SOx	PM10
Power Plant Emission Factors (Lbs/MWh)					
Conventional CT[a]	0.279	0.054	0.368	0.013	0.134
Advanced CT	0.099	0.031	0.19	0.008	0.062
Conventional CC	0.070	0.024	0.208	0.005	0.037
Conventional CC w/Duct Firing	0.076	0.018	0.315	0.005	0.042
Power Plant Emissions (Tons/Year)					
Conventional CT 49.9 MW	20.06	3.88	26.46	0.93	9.63
Conventional CT 100 MW	40.20	7.78	53.02	1.87	19.31
Advanced CT	28.45	8.91	54.60	2.30	17.82
Conventional CC	131.56	45.11	390.92	9.40	69.54
Conventional CC w/Duct Firing	157.12	37.21	651.22	10.85	86.83

a. The conventional combustions turbine values are recommended for the single-turbine (49.9 MW) and two-turbine (100 MW) cases.

Source: California Energy Commission

Table B-22 shows estimated CO_2 emissions factors based on the efficiency for each gas technology based on heat rates in **Table B-20.**

Table B-22: Estimated CO_2 Emission Factors (lbs/MWh)

Technology	Mid Case	High Case	Low Case
Conventional CT[a]	1,238.4	1,391.1	1,167.7
Advanced CT	1,156.0	1,193.4	1,123.2
Conventional CC	848.3	875.2	822.5
Conventional CC w/Duct Firing	848.3	875.2	822.5

Note: a The conventional CT values are recommended for the single-turbine (49.9 MW) and two-turbine (100 MW) cases.

Source: California Energy Commission

Table B-23 shows O&M costs for the combined-cycle technology.

Table B-23: O&M Costs for Combined-Cycle Cases

Technology (Nominal 2018 $)	Mid Case	High Case	Low Case
Conventional 640 MW CC Without Duct Firing			
Fixed O&M ($/kW-year)	$41.77	$93.91	$17.00
Variable O&M ($/MWh)	$0.82	$2.37	$0.25
Total O&M ($/MWh)	$9.18	$21.18	$3.66
Conventional 700 MW CC With Duct Firing			
Fixed O&M ($/kW-year)	$41.77	$93.91	$17.00
Variable O&M ($/MWh)	$0.82	$2.37	$0.25
Total O&M ($/MWh)	$9.18	$21.18	$3.66

Source: California Energy Commission

Table B-24 shows O&M costs for combustion turbine technology.

Table B-24: O&M Costs for Combustion Turbine Cases

Technology (Nominal 2018 $)	Mid Case	High Case	Low Case
Conventional 49.9 MW CT			
Fixed O&M ($/kW-year)	$34.42	$85.79	$12.26
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$98.22	$244.84	$34.99
Conventional 100 MW CT			
Fixed O&M ($/kW-year)	$33.24	$83.94	$11.86
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$94.88	$239.56	$33.85
Advanced 200 MW CT			
Fixed O&M ($/kW-year)	$30.54	$79.70	$10.96
Variable O&M ($/MWh)	$0.00	$0.00	$0.00
Total O&M ($/MWh)	$49.81	$129.97	$17.87

Source: California Energy Commission

Table B-25 summarizes instant, installed, and levelized costs for natural gas-fired technologies in 2018 in nominal (2016) dollars. (Note: The high and low values are based on the 10 percentile and 90 percentile values for the evaluated projects.)

Table B-25: Summary of 2018 Natural Gas-Fired Costs

Technology Case (Nominal 2018 $)	Mid Case	High Case	Low Case
Conventional 49.9 MW CT			
Instant Cost ($/kW)	$1,190	$1,706	$778
Ancillary Costs (Interconnection, Land, and Licensing)	$228	$562	$129
Instant Cost Without Ancillary Costs	$961	$1,145	$649
Installed Cost for Merchant Developer ($/kW)	$1,274	$1,901	$792
Levelized Cost of Electricity ($/kW-year)	$248	$428	$159
Levelized Cost of Electricity ($/MWh)	$746	$3,509	$235
Conventional 100 MW CT			
Instant Cost ($/kW)	$1,185	$1,695	$776
Ancillary Costs (Interconnection, Land, and Licensing)	$145	$347	$80
Instant Cost Without Ancillary Costs	$1,040	$1,348	$696
Installed Cost for Merchant Developer ($/kW)	$1,269	$1,889	$790
Levelized Cost of Electricity ($/kW-year)	$246	$424	$158
Levelized Cost of Electricity ($/MWh)	$743	$3,514	$234
Advanced 200 MW CT			
Instant Cost ($/kW)	$971	$1,478	$563
Ancillary Costs (Interconnection, Land, and Licensing)	$193	$446	$109
Instant Cost Without Ancillary Costs	$778	$1,032	$454
Installed Cost for Merchant Developer ($/kW)	$1,054	$1,676	$581
Levelized Cost of Electricity ($/kW-year)	$239	$406	$145
Levelized Cost of Electricity ($/MWh)	$409	$1,235	$171
Conventional 640 MW CC Without Duct Firing			
Instant Cost ($/kW)	$914	$1,088	$700
Ancillary Costs (Interconnection, Land, and Licensing)	$127	$286	$80
Instant Cost Without Ancillary Costs	$787	$802	$621
Installed Cost for Merchant Developer ($/kW)	$996	$1,245	$723
Levelized Cost of Electricity ($/kW-year)	$564	$615	$462
Levelized Cost of Electricity ($/MWh)	$119	$187	$77
Conventional 700 MW CC With Duct Firing			
Instant Cost ($/kW)	$890	$1,075	$664
Ancillary Costs (Interconnection, Land, and Licensing)	$121	$271	$77
Instant Cost Without Ancillary Costs	$768	$805	$587
Installed Cost for Merchant Developer ($/kW)	$970	$1,231	$686
Levelized Cost of Electricity ($/kW-year)*	$560	$612	$457
Levelized Cost of Electricity ($/MWh)	$118	$186	$76

*Mid case levelized cost ($/kW-year) is more than the high case due to fuel and GHG costs.

Source: California Energy Commission staff

Table B-26: Percentage Increase Attributable to Component Costs for Gas-Fired Technologies—Mid Case

Technology Type	Percent Increase Attributable to Component Cost Increase From 2018 to 2030		
	Fuel	Cap-and-Trade	Combined
Generation Turbine 49.9 MW	15.4%	23.3%	38.7%
Generation Turbine 100 MW	15.5%	23.4%	38.9%
Generation Turbine - Advanced 200 MW	22.0%	33.2%	55.3%
Combined Cycle − 2 CTs No Duct Firing 640 MW	34.8%	52.6%	87.4%
Combined Cycle − 2 CTs With Duct Firing 700 MW	34.9%	52.7%	87.6%

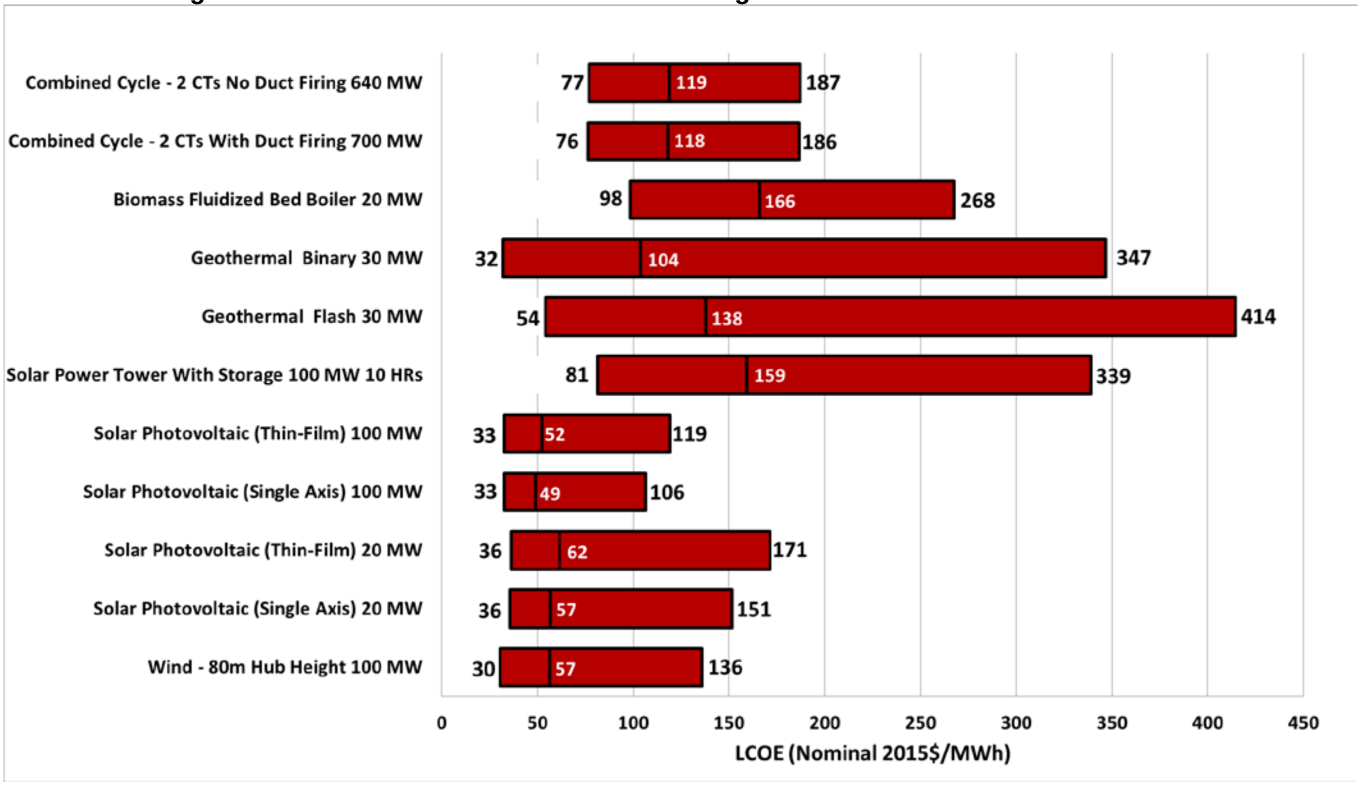
Source: California Energy Commission

APPENDIX C: Probabilistic Analysis Method

The mid case levelized costs are the values most commonly quoted and used in cost studies, which are somewhat misleading, since these single-point cost estimates are not likely to be observed in any specific case. Using point estimates can cause overconfident assessments that can result in poor decisions. Actual costs and, therefore, levelized costs vary across a range of possible values, depending on multiple factors. All studies, including those of levelized costs, need to consider a likely range of costs and, thereby, consider a plausible range of outcomes. Decisions should reflect the range of possibilities. **Figure C-1** shows the estimated range of levelized costs using the deterministic method with current data and a set of technologies for the start year of 2018 (nominal dollars) at the point of interconnection.

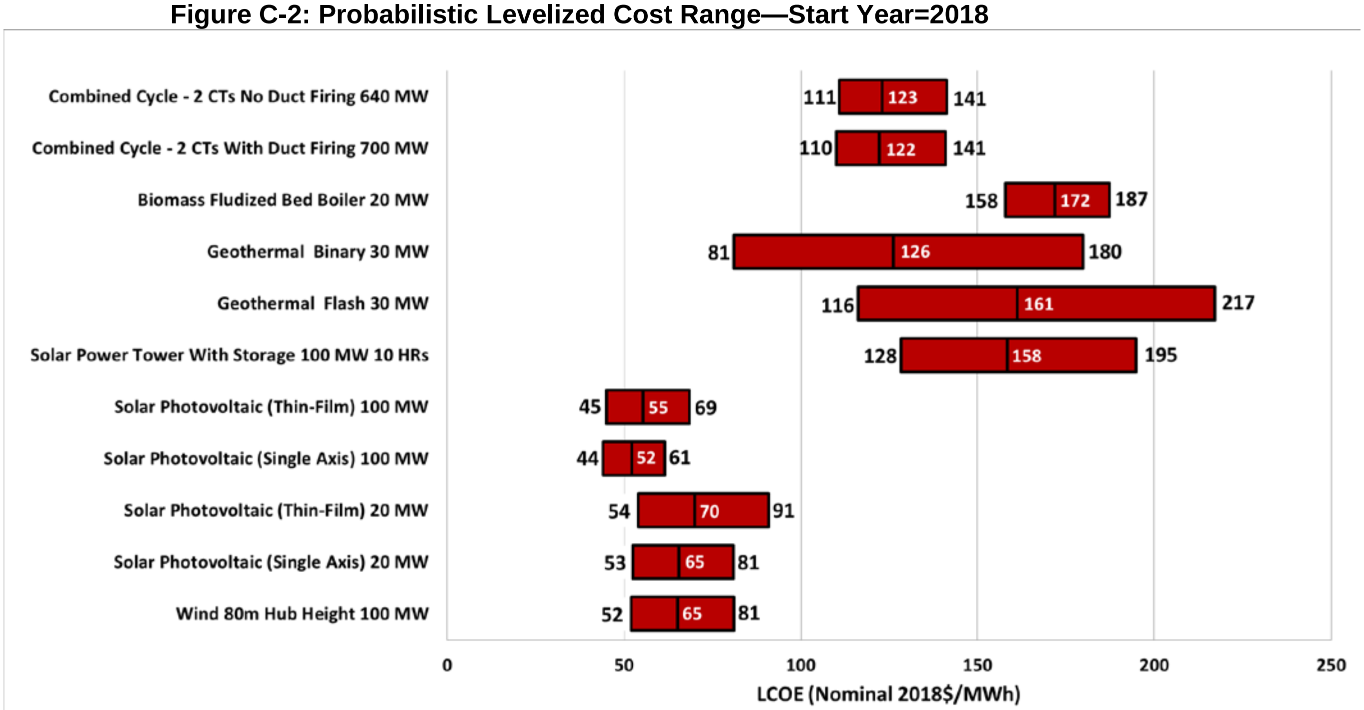
However, the likelihood of all high-cost components occurring coincidentally or all the low-cost components occurring coincidentally is so unlikely as to be outside the range of consideration. Rather than select all high or all low factors simultaneously, staff used the Monte Carlo method to create probabilistic distributions that were bound by the high and low assumptions. This method introduced variability in the technology-specific input variables and cost drivers, randomizing the inputs between the high and low values. The simulation runs the model repeatedly, randomizing the variables between each run and saving the results, to create a probabilistic distribution. **Figure C-2** shows the results of using the Monte Carlo method to estimate probabilistic ranges of levelized cost. While the deterministic low for the solar PV single-axis 100 MW technology is calculated as $33/MWh, the probabilistic low estimate at the 5 percentile is $44/MWh. The probabilistic medians differ from the deterministic mid case solutions and exhibit skewness, which is the degree that the mean differs from the median. These differences are caused by the high case and low case input values not being equal measure from the mid case.

Figure C-1: Deterministic Levelized Cost Range—Start Year=2018



Source: California Energy Commission

Figure C-2: Probabilistic Levelized Cost Range—Start Year=2018



Source: California Energy Commission

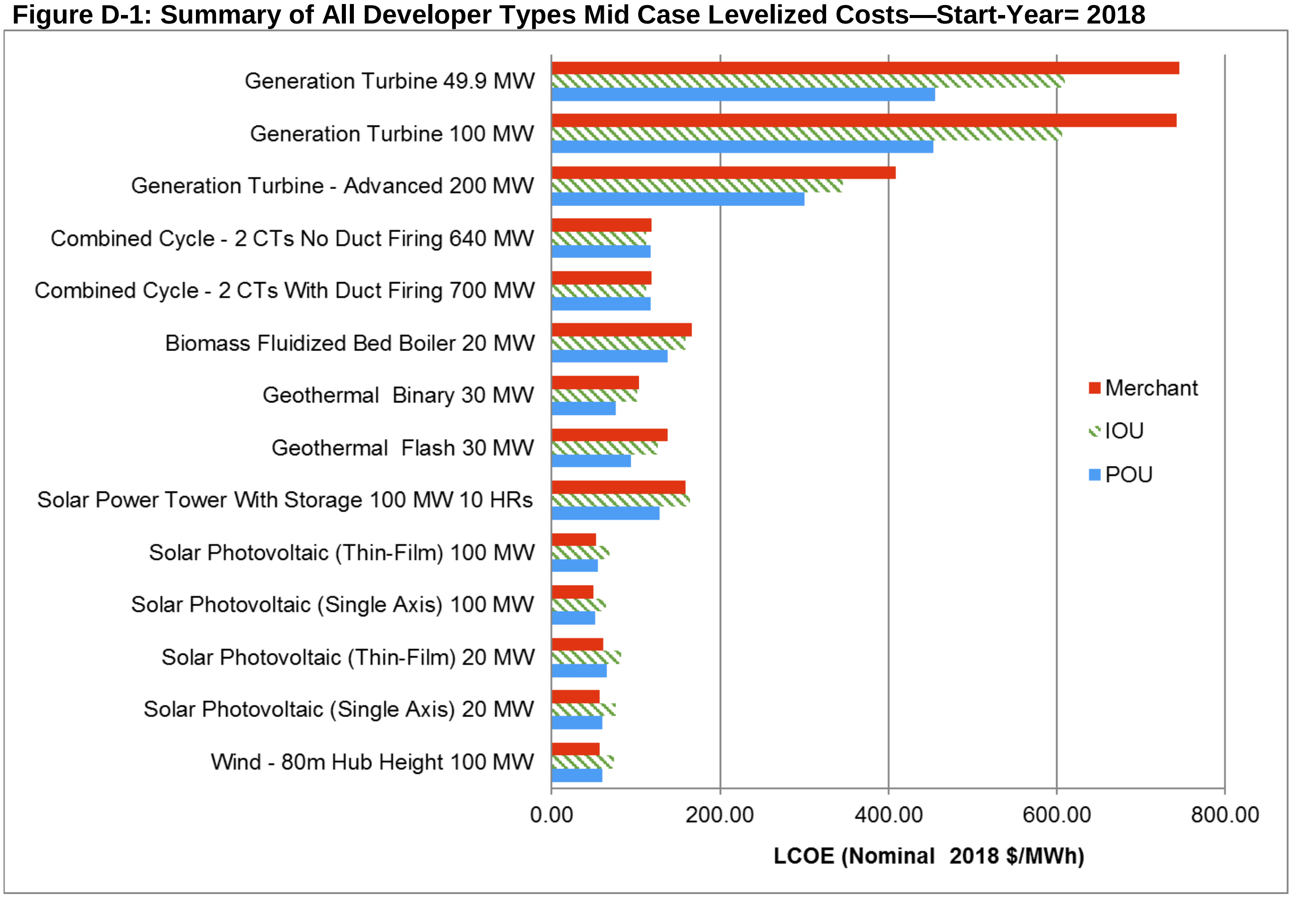
APPENDIX D: Levelized Cost by Developer Type

In general, merchant and POU renewable plants have lower LCOEs than the investor-owned utility (IOU) plants. For merchant plants, this is due to tax credits. For the publicly owned utility (POU) plants, this is largely due to lower financing costs and an exemption from property taxes. For the gas-fired units, the differences are driven by cost of financing and CFs. These differences are most evident in the peaker CTs, where a small difference in CFs can greatly affect LCOE.

Figure D-1 compares the merchant mid case LCOEs with the other developer types, IOU and POU, for plants commencing operation in 2018.

Table D-1 through **Table D-6** provide a comprehensive summary of component LCOEs in \$/MWh and \$/kW-Year, for merchant, IOU and POU plants for the start year of 2018.

Figure D-1: Summary of All Developer Types Mid Case Levelized Costs—Start-Year= 2018



Source: California Energy Commission

Table D-1: Mid Case Component LCOEs for Merchant Plants (Nominal $/MWh)—Start Year=2018

		$/MWh (Nominal 2018$)									
In-Service Year = 2018	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel & Emissions	Variable O&M	**Variable Cost**	**Total Levelized Costs At Interconnection Point**
Generation Turbine 49.9 MW	49.9	395.55	28.03	39.59	103.41	63.10	**629.68**	116.15	0.00	**116.15**	**745.83**
Generation Turbine 100 MW	100	395.42	28.02	39.58	100.21	63.11	**626.33**	116.52	0.00	**116.52**	**742.85**
Generation Turbine - Advanced 200 MW	200	186.51	13.23	18.68	52.35	29.74	**300.51**	108.38	0.00	**108.38**	**408.89**
Combined Cycle - 2 CTs No Duct Firing 640 MW	640	21.85	1.54	2.17	8.82	3.99	**38.38**	79.75	0.82	**80.57**	**118.95**
Combined Cycle - 2 CTs With Duct Firing 700 MW	700	21.27	1.50	2.12	8.82	3.89	**37.59**	79.75	0.82	**80.57**	**118.16**
Biomass Fluidized Bed Boiler 20 MW	20	79.35	5.49	7.98	18.82	-9.33	**102.31**	56.83	6.98	**63.82**	**166.13**
Geothermal Binary 30 MW	30	88.56	5.77	8.53	23.81	-22.86	**103.80**	0.00	0.00	**0.00**	**103.80**
Geothermal Flash 30 MW	30	116.61	7.54	11.15	25.39	-22.93	**137.76**	0.00	0.00	**0.00**	**137.76**
Solar Power Tower With Storage 100 MW 10 HRs	100	177.04	7.06	2.03	19.94	-46.66	**159.40**	0.00	0.00	**0.00**	**159.40**
Solar Photovoltaic (Thin-Film) 100 MW	100	53.15	3.05	0.82	10.13	-14.97	**52.18**	0.00	0.00	**0.00**	**52.18**
Solar Photovoltaic (Single Axis) 100 MW	100	50.31	2.89	0.78	9.07	-14.09	**48.96**	0.00	0.00	**0.00**	**48.96**
Solar Photovoltaic (Thin-Film) 20 MW	20	65.05	3.74	1.01	10.17	-18.31	**61.65**	0.00	0.00	**0.00**	**61.65**
Solar Photovoltaic (Single Axis) 20 MW	20	60.05	3.45	0.93	9.11	-16.82	**56.72**	0.00	0.00	**0.00**	**56.72**
Wind - 80m Hub Height 100 MW	100	45.14	5.10	6.94	15.93	-16.58	**56.53**	0.00	0.00	**0.00**	**56.53**

Source: California Energy Commission

Table D-2: Mid Case Component LCOEs for Merchant Plants (Nominal $/kW-Year)—Start-Year=2018

		$/kW-Year (Nominal 2018$)									
In-Service Year = 2018	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel & Emissions	Variable O&M	**Variable Cost**	**Total Levelized Costs At Interconnection Point**
Generation Turbine 49.9 MW	49.9	131.65	9.33	13.18	34.42	21.00	**209.57**	38.66	0.00	**38.66**	**248.22**
Generation Turbine 100 MW	100	131.18	9.30	13.13	33.24	20.94	**207.79**	38.66	0.00	**38.66**	**246.45**
Generation Turbine - Advanced 200 MW	200	108.82	7.72	10.90	30.54	17.35	**175.33**	63.23	0.00	**63.23**	**238.57**
Combined Cycle - 2 CTs No Duct Firing 640 MW	640	103.52	7.29	10.30	41.77	18.91	**181.81**	377.83	3.86	**381.69**	**563.50**
Combined Cycle - 2 CTs With Duct Firing 700 MW	700	100.78	7.10	10.03	41.77	18.41	**178.09**	377.83	3.86	**381.69**	**559.78**
Biomass Fluidized Bed Boiler 20 MW	20	530.62	36.72	53.35	125.81	-62.39	**684.12**	380.02	46.70	**426.72**	**1110.83**
Geothermal Binary 30 MW	30	552.21	35.95	53.16	148.48	-142.54	**647.27**	0.00	0.00	**0.00**	**647.27**
Geothermal Flash 30 MW	30	681.94	44.12	65.23	148.48	-134.13	**805.64**	0.00	0.00	**0.00**	**805.64**
Solar Power Tower With Storage 100 MW 10 HRs	100	638.85	25.47	7.31	71.95	-168.39	**575.19**	0.00	0.00	**0.00**	**575.19**
Solar Photovoltaic (Thin-Film) 100 MW	100	105.39	6.05	1.63	20.08	-29.68	**103.47**	0.00	0.00	**0.00**	**103.47**
Solar Photovoltaic (Single Axis) 100 MW	100	122.29	7.02	1.89	22.05	-34.25	**119.00**	0.00	0.00	**0.00**	**119.00**
Solar Photovoltaic (Thin-Film) 20 MW	20	128.47	7.38	1.99	20.08	-36.16	**121.76**	0.00	0.00	**0.00**	**121.76**
Solar Photovoltaic (Single Axis) 20 MW	20	145.38	8.34	2.25	22.05	-40.71	**137.32**	0.00	0.00	**0.00**	**137.32**
Wind - 80m Hub Height 100 MW	100	129.39	14.61	19.90	45.65	-47.51	**162.03**	0.00	0.00	**0.00**	**162.03**

Source: California Energy Commission

Table D-3: Mid Case Component LCOEs for IOU Plants (Nominal $/MWh)—Start-Year=2018

		$/MWh (Nominal 2018$)									
In-Service Year = 2018	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel & Emissions	Variable O&M	**Variable Cost**	**Total Levelized Costs At Interconnection Point**
Generation Turbine 49.9 MW	49.9	319.47	15.47	28.31	103.28	25.78	**492.29**	117.40	0.00	**117.40**	**609.69**
Generation Turbine 100 MW	100	319.36	15.46	28.30	100.08	25.80	**488.99**	117.77	0.00	**117.77**	**606.76**
Generation Turbine - Advanced 200 MW	200	151.27	7.32	13.40	52.17	12.24	**236.40**	109.65	0.00	**109.65**	**346.05**
Combined Cycle - 2 CTs No Duct Firing 640 MW	640	17.76	0.86	1.57	8.85	1.92	**30.96**	80.51	0.82	**81.33**	**112.29**
Combined Cycle - 2 CTs With Duct Firing 700 MW	700	17.29	0.84	1.53	8.85	1.87	**30.37**	80.51	0.82	**81.33**	**111.70**
Biomass Fluidized Bed Boiler 20 MW	20	63.67	3.08	5.64	19.23	1.70	**93.32**	58.10	7.17	**65.28**	**158.60**
Geothermal Binary 30 MW	30	69.22	3.35	6.13	24.80	-2.27	**101.23**	0.00	0.00	**0.00**	**101.23**
Geothermal Flash 30 MW	30	90.29	4.37	8.00	26.44	-2.96	**126.14**	0.00	0.00	**0.00**	**126.14**
Solar Power Tower With Storage 100 MW 10 HRs	100	163.48	3.96	1.45	20.27	-24.81	**164.35**	0.00	0.00	**0.00**	**164.35**
Solar Photovoltaic (Thin-Film) 100 MW	100	66.98	1.62	0.59	9.74	-10.17	**68.77**	0.00	0.00	**0.00**	**68.77**
Solar Photovoltaic (Single Axis) 100 MW	100	63.67	1.54	0.56	8.77	-9.66	**64.89**	0.00	0.00	**0.00**	**64.89**
Solar Photovoltaic (Thin-Film) 20 MW	20	81.97	1.98	0.73	9.78	-12.44	**82.03**	0.00	0.00	**0.00**	**82.03**
Solar Photovoltaic (Single Axis) 20 MW	20	76.00	1.84	0.67	8.81	-11.53	**75.79**	0.00	0.00	**0.00**	**75.79**
Wind - 80m Hub Height 100 MW	100	57.00	2.76	5.05	15.56	-6.16	**74.21**	0.00	0.00	**0.00**	**74.21**

Source: California Energy Commission

Table D-4: Mid Case Component LCOEs for IOU Plants (Nominal $/kW-Year)—Start-Year=2018

		$/kW-Year (Nominal 2018$)									
In-Service Year = 2018	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel & Emissions	Variable O&M	**Variable Cost**	**Total Levelized Costs At Interconnection Point**
Generation Turbine 49.9 MW	49.9	106.78	5.17	9.46	34.52	8.62	**164.54**	39.24	0.00	**39.24**	**203.78**
Generation Turbine 100 MW	100	106.40	5.15	9.43	33.34	8.60	**162.92**	39.24	0.00	**39.24**	**202.15**
Generation Turbine - Advanced 200 MW	200	88.82	4.30	7.87	30.63	7.18	**138.81**	64.38	0.00	**64.38**	**203.19**
Combined Cycle - 2 CTs No Duct Firing 640 MW	640	84.11	4.07	7.45	41.90	9.08	**146.62**	381.32	3.88	**385.20**	**531.81**
Combined Cycle - 2 CTs With Duct Firing 700 MW	700	81.89	3.96	7.26	41.90	8.84	**143.84**	381.32	3.88	**385.20**	**529.04**
Biomass Fluidized Bed Boiler 20 MW	20	425.28	20.59	37.68	128.49	11.34	**623.38**	388.11	47.92	**436.03**	**1059.41**
Geothermal Binary 30 MW	30	428.26	20.74	37.95	153.42	-14.07	**626.29**	0.00	0.00	**0.00**	**626.29**
Geothermal Flash 30 MW	30	523.85	25.36	46.42	153.42	-17.16	**731.89**	0.00	0.00	**0.00**	**731.89**
Solar Power Tower With Storage 100 MW 10 HRs	100	588.05	14.24	5.21	72.90	-89.23	**591.17**	0.00	0.00	**0.00**	**591.17**
Solar Photovoltaic (Thin-Film) 100 MW	100	134.46	3.26	1.19	19.56	-20.41	**138.06**	0.00	0.00	**0.00**	**138.06**
Solar Photovoltaic (Single Axis) 100 MW	100	155.87	3.77	1.38	21.48	-23.65	**158.85**	0.00	0.00	**0.00**	**158.85**
Solar Photovoltaic (Thin-Film) 20 MW	20	163.90	3.97	1.45	19.56	-24.87	**164.01**	0.00	0.00	**0.00**	**164.01**
Solar Photovoltaic (Single Axis) 20 MW	20	185.31	4.49	1.64	21.48	-28.12	**184.80**	0.00	0.00	**0.00**	**184.80**
Wind - 80m Hub Height 100 MW	100	163.87	7.93	14.52	44.75	-17.72	**213.35**	0.00	0.00	**0.00**	**213.35**

Source: California Energy Commission

Table D-5: Mid Case Component LCOEs for POU Plants (Nominal $/MWh)—Start-Year=2018

		$/MWh (Nominal 2018$)									
In-Service Year = 2018	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel & Emissions	Variable O&M	**Variable Cost**	**Total Levelized Costs At Interconnection Point**
Generation Turbine 49.9 MW	49.9	174.64	26.18	22.04	97.19	0.00	**320.05**	135.72	0.00	**135.72**	**455.76**
Generation Turbine 100 MW	100	174.58	26.17	22.03	94.18	0.00	**316.96**	136.15	0.00	**136.15**	**453.11**
Generation Turbine - Advanced 200 MW	200	92.52	13.87	11.68	55.49	0.00	**173.55**	126.58	0.00	**126.58**	**300.14**
Combined Cycle - 2 CTs No Duct Firing 640 MW	640	10.72	1.61	1.35	9.32	0.00	**23.01**	93.52	0.87	**94.39**	**117.40**
Combined Cycle - 2 CTs With Duct Firing 700 MW	700	10.44	1.56	1.32	9.32	0.00	**22.64**	93.52	0.87	**94.39**	**117.04**
Biomass Fluidized Bed Boiler 20 MW	20	37.88	5.68	4.78	20.23	0.00	**68.57**	61.12	7.62	**68.74**	**137.31**
Geothermal Binary 30 MW	30	38.84	5.82	4.90	26.33	-0.12	**75.78**	0.00	0.00	**0.00**	**75.78**
Geothermal Flash 30 MW	30	51.64	7.74	6.52	28.08	-0.16	**93.82**	0.00	0.00	**0.00**	**93.82**
Solar Power Tower With Storage 100 MW 10 HRs	100	98.59	7.39	1.24	21.52	-0.89	**127.85**	0.00	0.00	**0.00**	**127.85**
Solar Photovoltaic (Thin-Film) 100 MW	100	41.58	3.12	0.52	10.46	-0.37	**55.30**	0.00	0.00	**0.00**	**55.30**
Solar Photovoltaic (Single Axis) 100 MW	100	39.15	2.93	0.49	9.33	-0.35	**51.55**	0.00	0.00	**0.00**	**51.55**
Solar Photovoltaic (Thin-Film) 20 MW	20	50.88	3.81	0.64	10.50	-0.46	**65.38**	0.00	0.00	**0.00**	**65.38**
Solar Photovoltaic (Single Axis) 20 MW	20	46.73	3.50	0.59	9.37	-0.42	**59.77**	0.00	0.00	**0.00**	**59.77**
Wind - 80m Hub Height 100 MW	100	34.79	5.21	4.39	16.45	-0.31	**60.53**	0.00	0.00	**0.00**	**60.53**

Source: California Energy Commission

Table D-6: Mid Case Component LCOEs for POU Plants (Nominal $/kW-Year)—Start-Year=2018

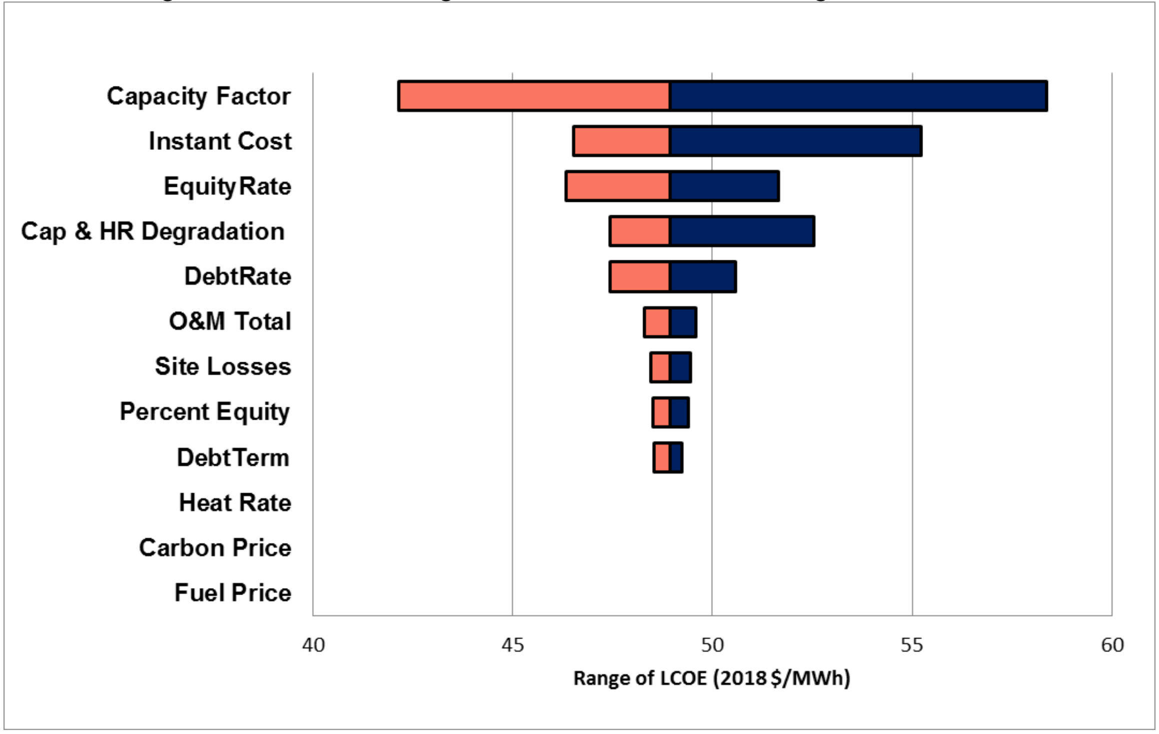
		$/kW-Year (Nominal 2018$)									
In-Service Year = 2018	**Size MW**	Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	**Fixed Costs**	Fuel & Emissions	Variable O&M	**Variable Cost**	**Total Levelized Costs At Interconnection Point**
Generation Turbine 49.9 MW	49.9	65.08	9.75	8.21	36.22	0.00	**119.27**	50.58	0.00	**50.58**	**169.84**
Generation Turbine 100 MW	100	64.85	9.72	8.18	34.99	0.00	**117.74**	50.58	0.00	**50.58**	**168.32**
Generation Turbine - Advanced 200 MW	200	53.59	8.03	6.76	32.14	0.00	**100.53**	73.32	0.00	**73.32**	**173.85**
Combined Cycle - 2 CTs No Duct Firing 640 MW	640	50.57	7.58	6.38	43.96	0.00	**108.49**	441.05	4.10	**445.15**	**553.65**
Combined Cycle - 2 CTs With Duct Firing 700 MW	700	49.23	7.38	6.21	43.96	0.00	**106.78**	441.05	4.10	**445.15**	**551.94**
Biomass Fluidized Bed Boiler 20 MW	20	252.42	37.84	31.85	134.82	0.00	**456.93**	407.29	50.80	**458.09**	**915.02**
Geothermal Binary 30 MW	30	237.42	35.59	29.96	160.98	-0.71	**463.24**	0.00	0.00	**0.00**	**463.24**
Geothermal Flash 30 MW	30	296.04	44.37	37.36	160.98	-0.89	**537.87**	0.00	0.00	**0.00**	**537.87**
Solar Power Tower With Storage 100 MW 10 HRs	100	350.41	26.26	4.42	76.49	-3.16	**454.43**	0.00	0.00	**0.00**	**454.43**
Solar Photovoltaic (Thin-Film) 100 MW	100	81.60	6.12	1.03	20.52	-0.73	**108.54**	0.00	0.00	**0.00**	**108.54**
Solar Photovoltaic (Single Axis) 100 MW	100	94.59	7.09	1.19	22.54	-0.85	**124.56**	0.00	0.00	**0.00**	**124.56**
Solar Photovoltaic (Thin-Film) 20 MW	20	99.46	7.45	1.26	20.52	-0.90	**127.80**	0.00	0.00	**0.00**	**127.80**
Solar Photovoltaic (Single Axis) 20 MW	20	112.46	8.43	1.42	22.54	-1.01	**143.83**	0.00	0.00	**0.00**	**143.83**
Wind - 80m Hub Height 100 MW	100	99.31	14.89	12.53	46.95	-0.89	**172.79**	0.00	0.00	**0.00**	**172.79**

Source: California Energy Commission

APPENDIX E: Tornado Diagrams

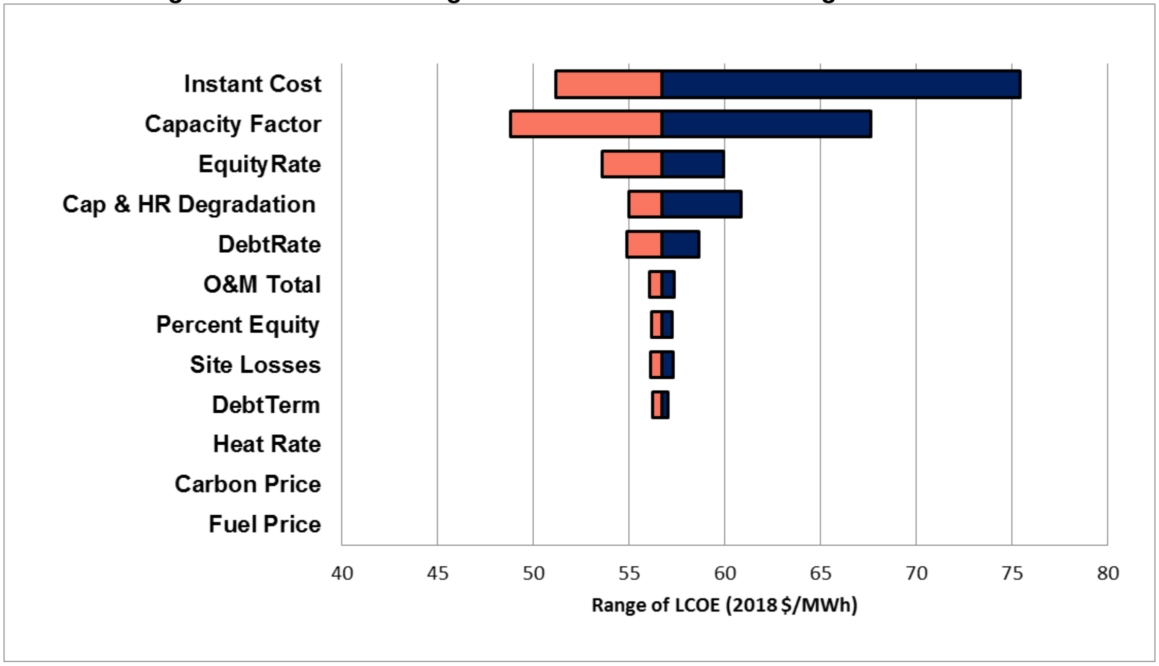
This appendix provides a complete set of tornado diagrams. All the figures are for a start year of 2018 and are in nominal dollars. Each bar in the diagram is derived by resetting the high or low driver in the mid-cost case of the COG Model to the maximum or minimum value, respectively. This variation shows the effect that changing a single variable to the associated extreme assumption would have on the levelized cost of that technology. This is not necessarily the largest driver of overall cost, as the degree of change depends on the range of assumptions. However, it does provide insight into the role each input plays in levelized cost variance and what factors may be of interest to contain the project cost.

Figure E-1: Tornado Diagram—Solar Photovoltaic Single Axis 100 MW



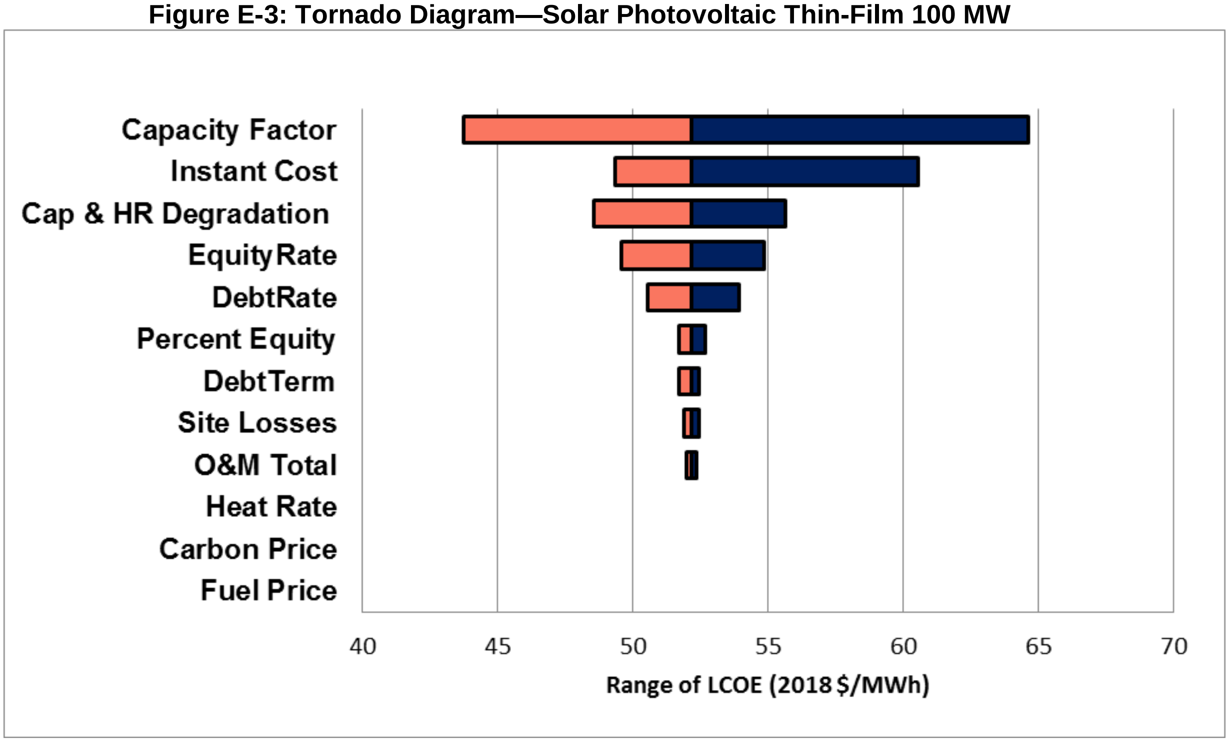
Source: California Energy Commission

Figure E-2: Tornado Diagram—Solar Photovoltaic Single Axis 20 MW



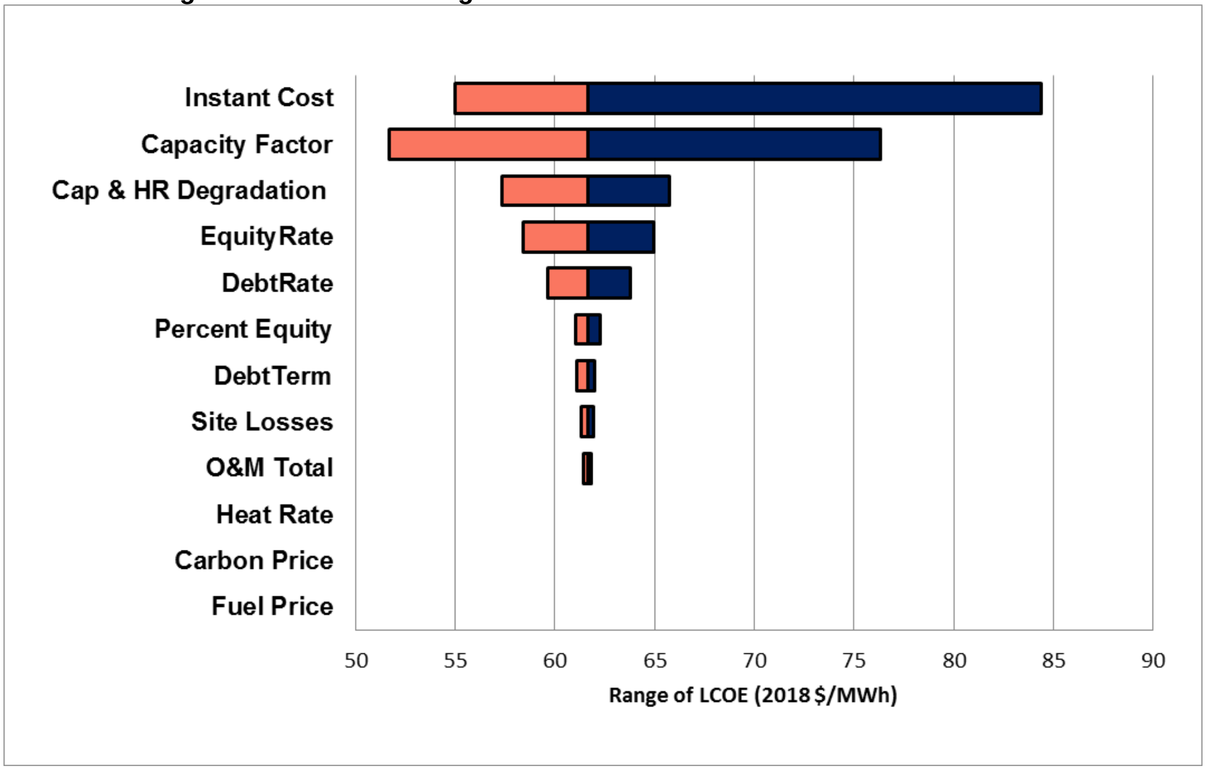
Source: California Energy Commission

Figure E-3: Tornado Diagram—Solar Photovoltaic Thin-Film 100 MW



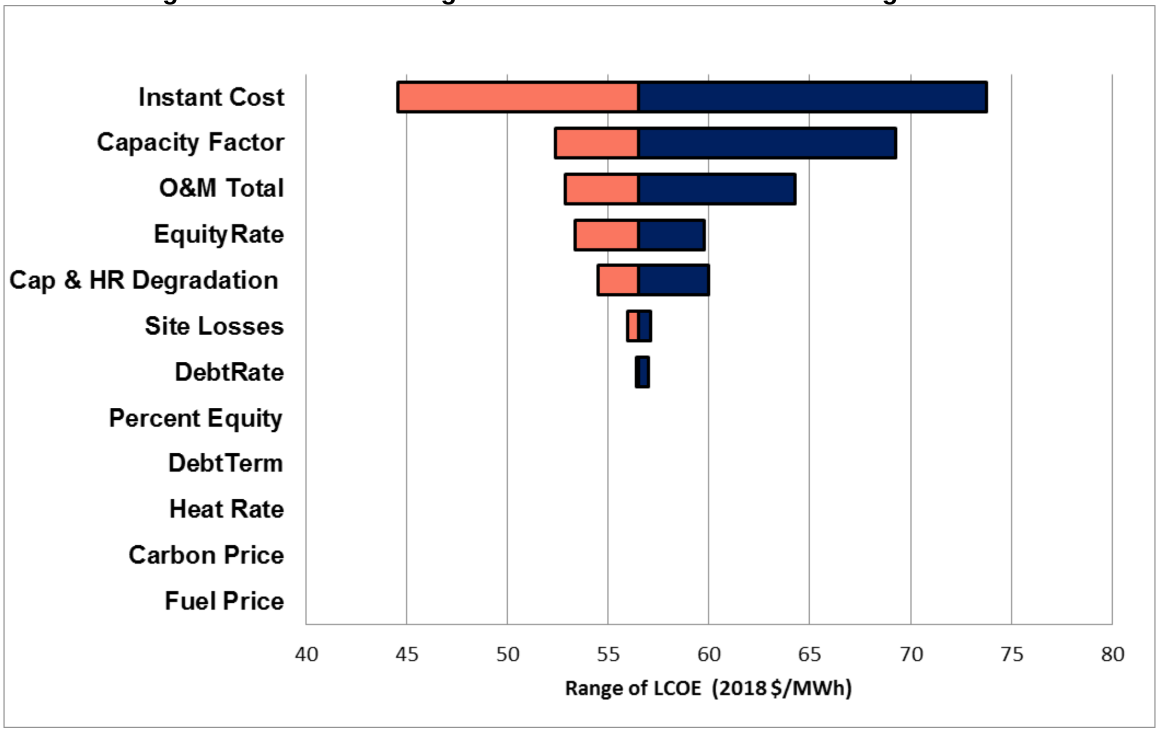
Source: California Energy Commission

Figure E-4: Tornado Diagram—Solar Photovoltaic Thin-Film 20 MW



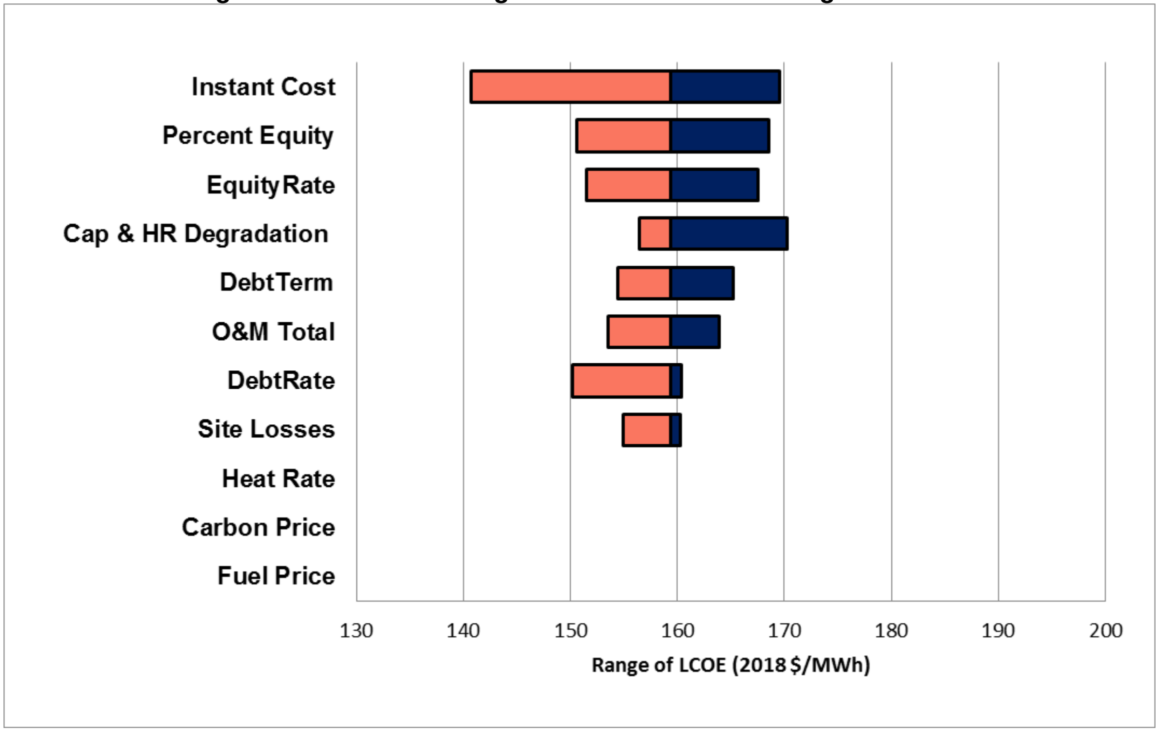
Source: California Energy Commission

Figure E-5: Tornado Diagram—Solar Tower 10 Hours Storage 100 MW



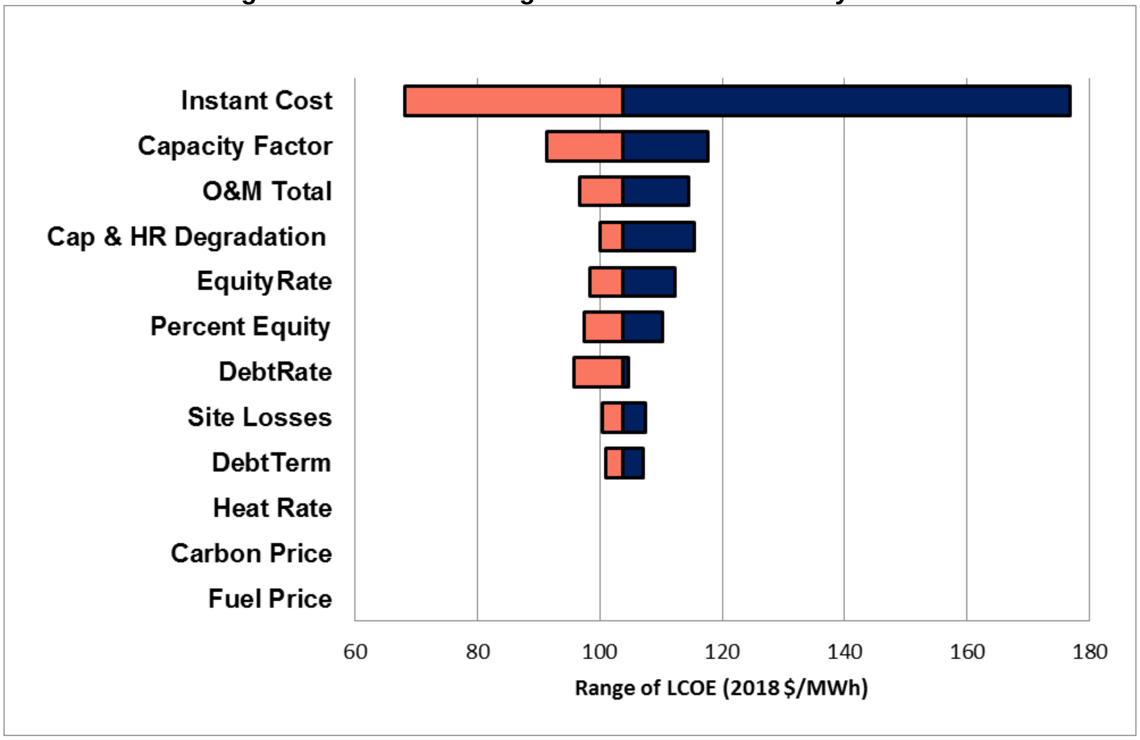
Source: California Energy Commission

Figure E-6: Tornado Diagram—Wind 80m Hub Height 100 MW



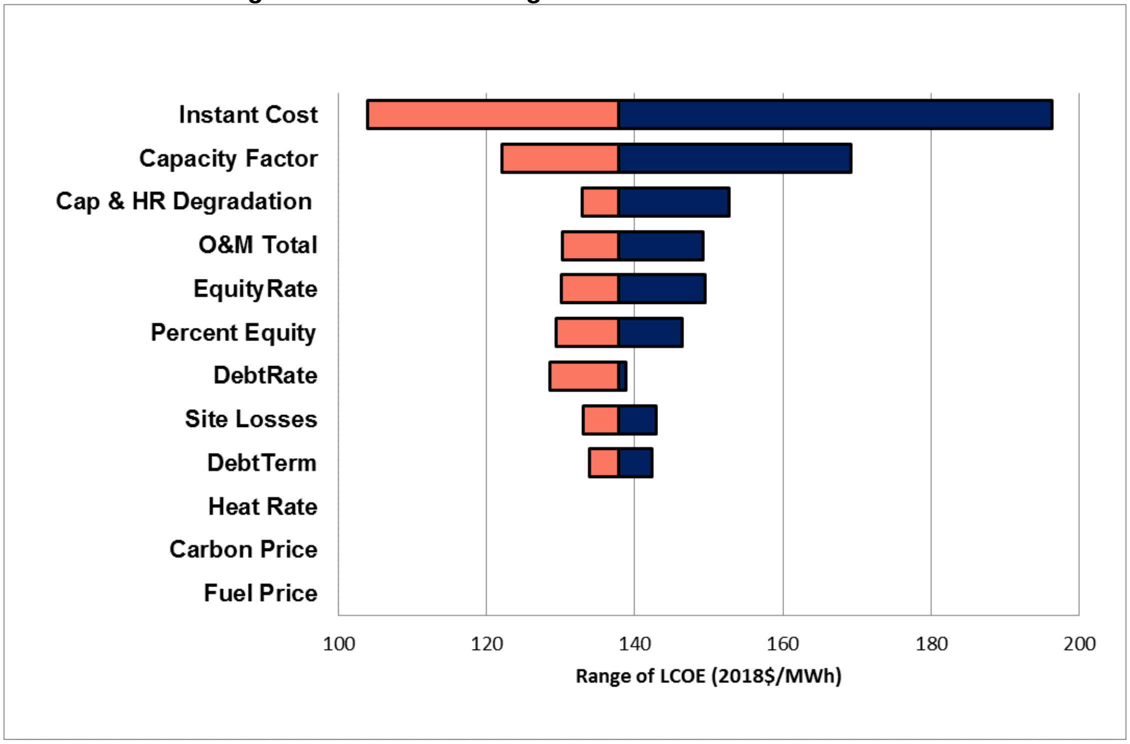
Source: California Energy Commission

Figure E-7: Tornado Diagram—Geothermal Binary 30 MW



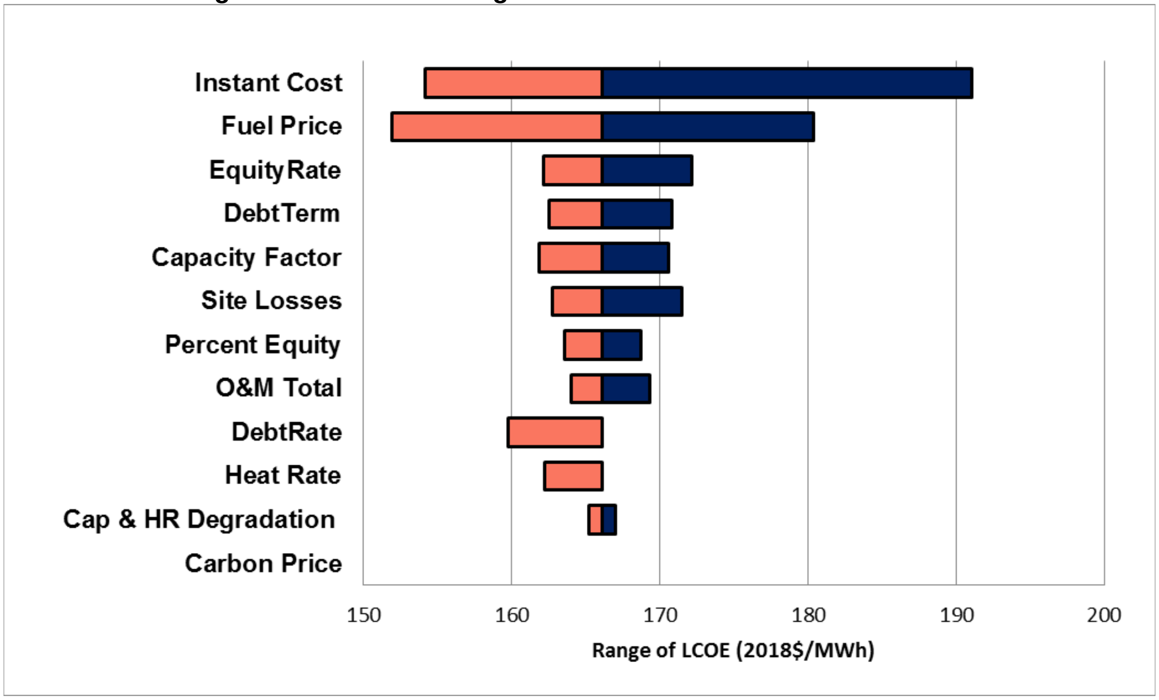
Source: California Energy Commission

Figure E-8: Tornado Diagram—Geothermal Flash 30 MW



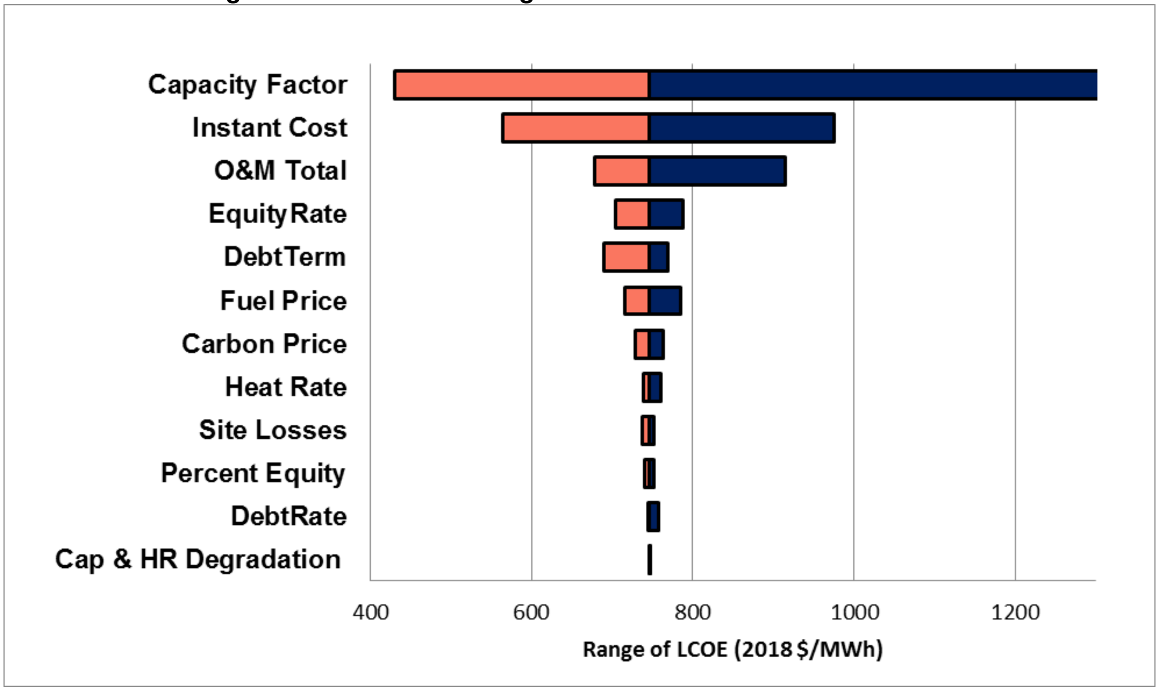
Source: California Energy Commission

Figure E-9: Tornado Diagram—Biomass Fluidized Bed 20 MW



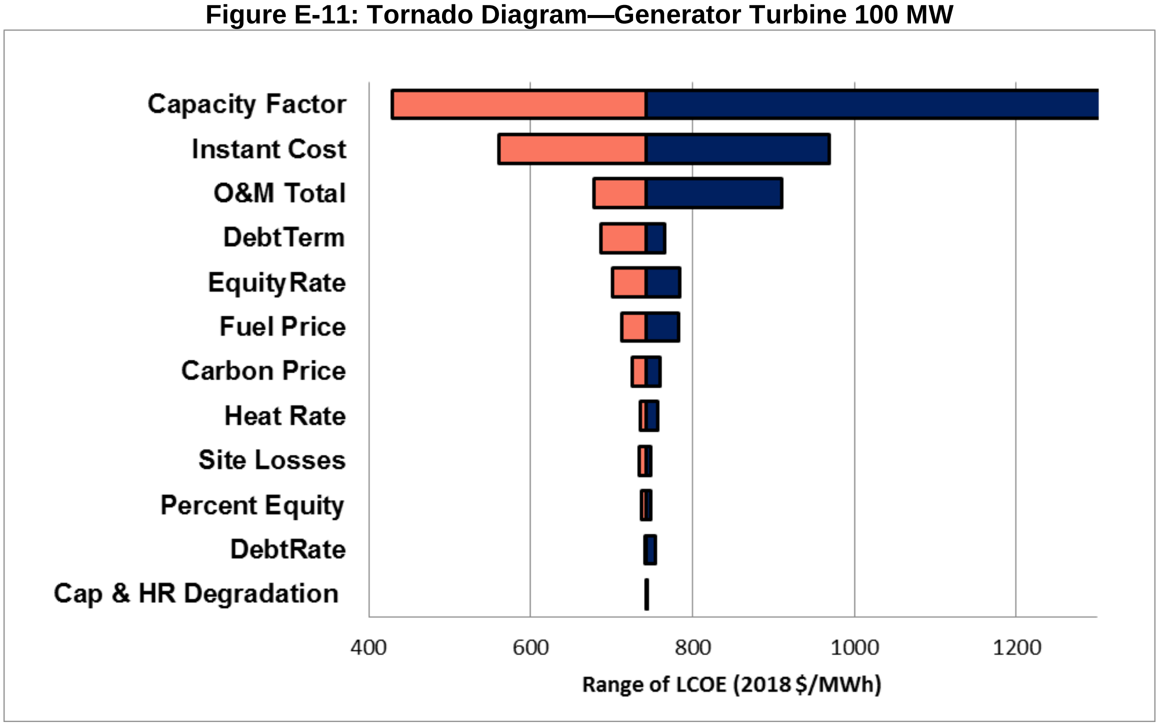
Source: California Energy Commission

Figure E-10: Tornado Diagram—Generator Turbine 49.9 MW



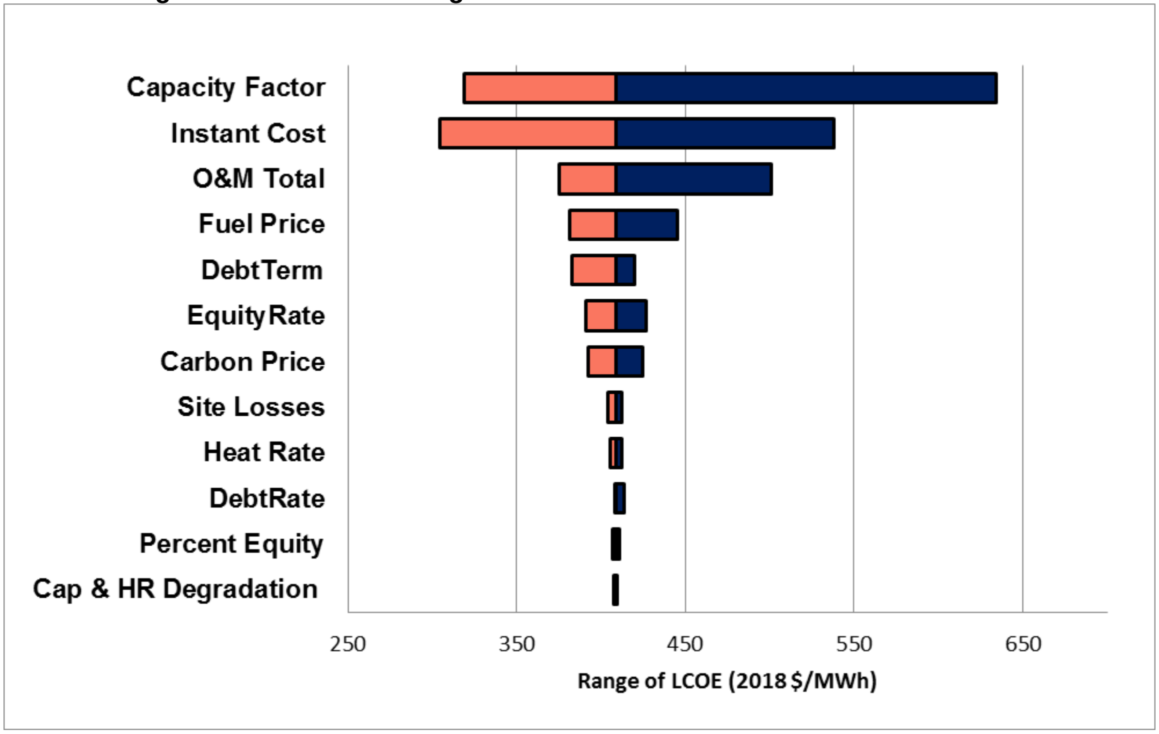
Source: California Energy Commission

Figure E-11: Tornado Diagram—Generator Turbine 100 MW



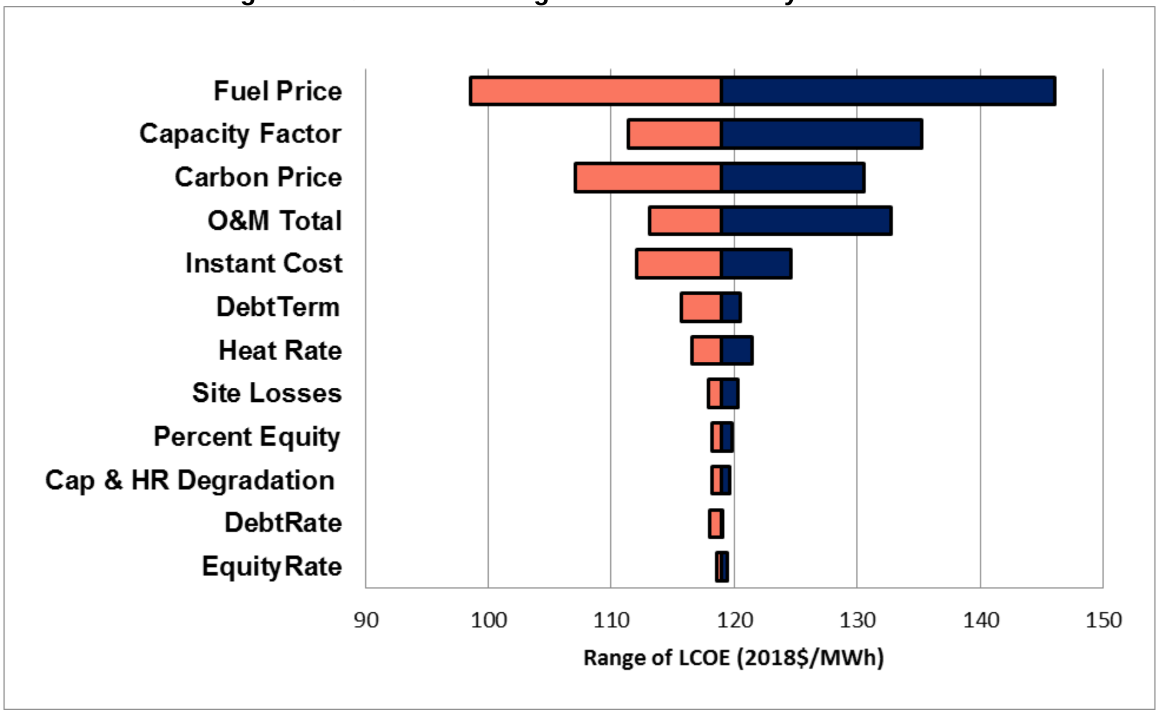
Source: California Energy Commission

Figure E-12: Tornado Diagram—Advanced Generation Turbine 200 MW



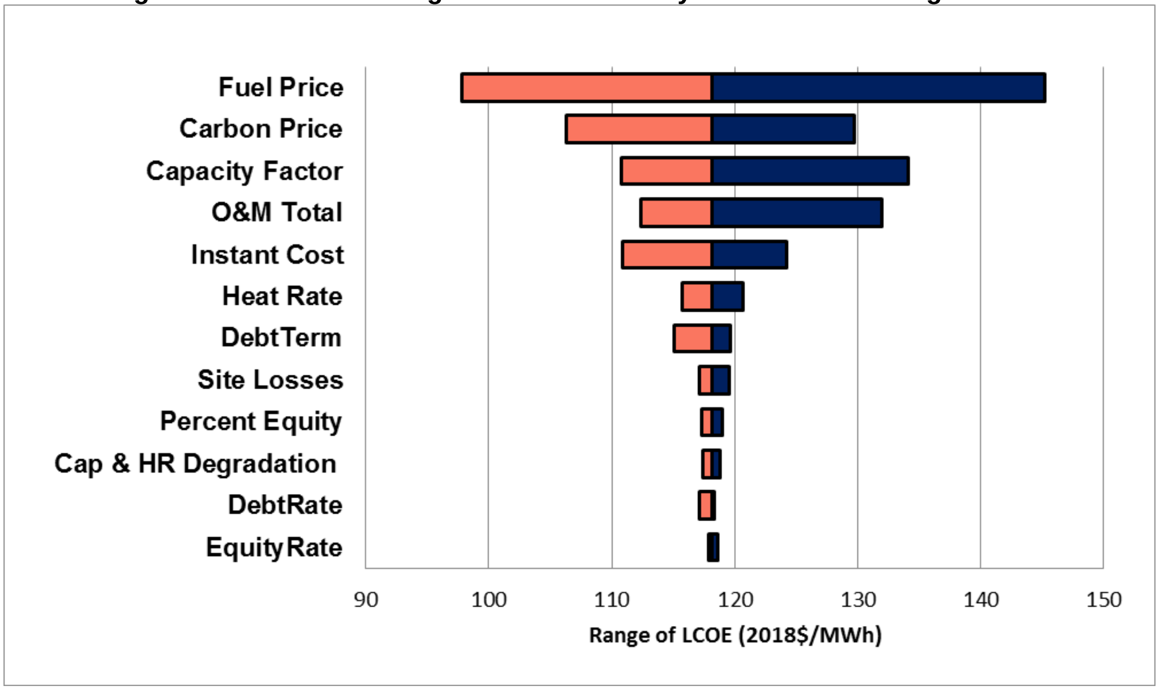
Source: California Energy Commission

Figure E-13: Tornado Diagram—Combined-Cycle 640 MW



Source: California Energy Commission

Figure E-14: Tornado Diagram—Combined-Cycle With Duct Firing 700 MW



Source: California Energy Commission