California Energy Commission

DRAFT STAFF REPORT

ESTIMATED COST OF NEW RENEWABLE AND FOSSIL GENERATION IN CALIFORNIA

CALIFORNIA
ENERGY COMMISSION

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ABSTRACT

This report summarizes the cost trends for utility-scale generation resources that may be built in California over the next decade. These include solar, wind, geothermal, biomass, and gas-fired technologies. Trends in technology, permitting, construction, and financing costs are considered. The instant and installed costs for each type of technology are presented for investor-owned, publicly owned, and merchant-owned generation resources. Finally, the levelized costs necessary to provide financial incentive for development is estimated using an updated Cost of Generation Model. These values are presented with both deterministic and probabilistic ranges of potential costs over the next 10 years.

Keywords: Electricity, natural gas, investor-owned utilities, publicly owned utilities, merchant power plants, instant cost, installed cost, levelized cost, probabilistic estimations, wind, solar, biomass, geothermal, solar thermal, energy storage

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EXECUTIVE SUMMARY

California has a diverse electricity system that includes conventional fossil-fueled generation along with renewable and emerging technologies. This report presents estimates of the current and future costs to build and operate these power plants. The cost to build and operate a new power plant in California depends on which technology is built, where in California it is located, how much it costs to finance the project (typically a function of who owns it), and how much the plant runs. The amount of energy a power plant produces over its lifetime can depend on either its cost to operate relative to other power plants (such as for fossil-fueled generators who must participate in a competitive market) or the availability of the energy source (such as for renewable generators).

This report translates a set of transparent input assumptions into an understandable set of metrics. These output metrics are *instant cost, installed cost,* and *levelized cost*.

- *Instant cost* is the cost to build a utility-scale power plant if the owner could afford to pay cash up front for all initial capital, permitting, and construction costs. Since such an arrangement would mean the owner had no need to borrow money, variations in lending terms, costs of borrowing, or operational profiles have no effect on instant cost. Given the scale of investment necessary, utility-scale power plants in California have never been built on a cash-only basis as implied by the instant cost metric. Instead, this metric provides a common starting point for further analysis.
- *Installed cost* is the real-world cost to permit and build a power plant including all lending costs. Installed cost reflects all of the upfront purchases of generation equipment, such as solar panels or generation turbines, investments, and costs incurred by the owner from inception of the plan to the moment the plant is able to begin generation. It does not include any operational costs such as fuel and maintenance costs. It does, however, include financing and lending costs associated with the project. Functionally, this means that owners who have access to low-cost capital (such as publicly owned utilities who can issue low-cost bonds to raise funds) are able to reflect lower installed costs than other owners despite having the same instant cost to begin with.
- *Levelized cost* is the metric that reflects the lifetime cost of operations and maintenance combined with the installed cost of construction expressed as a constant stream of costs per unit of value over the lifetime of the plant. The most common unit of value is energy, usually measured in megawatt-hours (MWh). When levelized costs are expressed per unit of energy, they are sometimes called the *levelized cost of energy*.

The cost of any new power plant is a result of numerous, sometimes intertwined, factors relating to changing market conditions, labor and resource costs, regulatory issues, and local factors such as real estate market forces and air, water, and land-use planning. Since these costs can vary widely across the state, this report uses a three-scenario approach to create a bracket of possible costs. A mid-cost case was constructed using the best current estimate for costs that are applicable across the state for all factors involved in estimating the future costs of new generation. Around that mid-cost case, a high-cost case and a low-cost case were constructed using the simultaneous highest cost and lowest cost factors. Finally, within these cost cases a more narrow range of more likely cost values was constructed using the Analytica software tool. This probabilistic range of values provides a narrower estimate of cost ranges than are likely to be seen in the marketplace.

These estimates are important for use in a number of policy decisions made at the California Energy Commission, as well as those made at the California Public Utilities Commission (CPUC) and California Independent System Operator (California ISO). This report does not attempt to summarize the cost for every possible size or technology that might be built over the next 25 years. Instead, staff has limited the time horizon to technologies that are commercially available today, since they are the most likely to be built in the next 10 years. Staff has also limited the size to those projects considered "utility-scale"—meaning that they are large enough to connect directly to the high-voltage transmission network rather than the lower voltage distribution network where the majority of smaller projects interconnect.

The authors have also limited the scope of this report to estimating the costs to the developer rather than to the utility or ratepayer. This is important for two reasons. First, the electric grid is a large and dynamic system. Adding a resource at one location may require the utility to alter how it operates the surrounding grid, thus changing the economics of projects already in place. Estimating those effects would be necessary to estimate the total cost to the utility and would require significant additional analysis that is beyond the current limitations of time and resources within the Energy Commission. Second, the value to the developer of a power plant is the stream of payments it will receive from its operation. By limiting the scope of this analysis to the developer, it is possible to estimate the level of payment necessary to achieve a reasonable rate of return and, thus, its value to the developer. Any attempt to estimate value to the utility or to the state would require a dramatic expansion of the assumptions about the size of those values and the ability of the utility or ratepayer to capture those values. Estimates of values to utilities or ratepayers such as environmental benefits, economic or jobs benefits, or grid reliability benefits are beyond the scope of this project.

Financing Costs and Tax Treatment

The costs of financing and taxes are major components of the cost of constructing and owning a power plant. While the financing for any power plant project is unique depending on the project sponsor, the markets, the terms and conditions of power sales agreements, and the technology type, there are a number of trends associated with financing that are likely to influence these costs. The current environment for financing power projects is challenging, as a number of financial institutions who were lead underwriters for power plant projects in the past are no longer financing these projects due to weak balance sheets, changes in corporate direction, and heightened risk aversion.

The roles different financial institutions are willing to play in developing power projects are also changing. Some financial institutions, depending on their willingness to accept risk, will lend only in later phases of projects where there is more assurance the project will meet performance requirements. Some financial institutions want to avoid the risk of long-term, fixed-price financing in favor of shorter time frames, while other institutions, like insurance companies, are willing to provide long-term financing. With fewer lenders willing to provide long-term financing, even when a project has a long-term power purchase agreement, project developers have to secure a sequence of debt instruments covering different phases of the project, which is more difficult and complicated to accomplish.

Another challenge is the lack of tax equity available to certain renewable generation projects. Tax equity is the term to describe when a small company develops a project but does not have sufficient tax liabilities to fully take advantage of the credits to sell those tax credits to larger companies capable of fully using the remainder of the tax benefit. Companies that have traditionally provided tax equity have reduced profits as a result of the financial crisis and economic downturn and are unable to absorb the same level of tax benefits. Like underwriters of a power plant project, there are fewer key players providing tax equity, and new entrants in the tax equity market face a significant learning curve to understand and evaluate the array of renewable energy technologies, project structures, and contract and market risks. Because the equity market is not highly liquid or transparent and involves high transaction costs, the cost of equity financing is more expensive than other sources of capital.

Finally, the cost of borrowing money depends on what investors perceive as the underlying risk of the venture. This risk is tied directly to the type of ownership structure the project has. Municipal utilities are able to borrow money at the lowest price since they are able to issue bonds to cover a portion of the project and have the least risk of default. Investor-owned utilities are able to borrow on terms similar to those of other large corporations by splitting the source of funding between debt (such as corporate bonds or loans from large banks) and equity (or ownership shares with a promised rate of sharing in the profits from a venture). Finally, private developers (referred to in this report as *merchant developers*) have the highest cost of borrowing since they are smaller and more prone to default than large utilities.

Environmental Permitting Costs

Environmental mitigation measures have become increasingly important components of power plant costs, for both fossil-fueled and renewable generators. For natural gas-fired generators, the largest compliance cost component is either criteria pollutant emission reduction credits or greenhouse gas credits, depending on the expected price trajectory for greenhouse gas credits; for renewables it is habitat mitigation and land acquisition. Other compliance costs include the regulatory permit application, processing, and monitoring costs.

The California Air Resources Board (ARB) has tracked reported emission reduction credit prices since 1993. Despite being a "thin" market with wide price variations, prices have shown a general upward trend, particularly for those pollutants that are most tightly regulated, for example oxides of nitrogen, volatile organic compounds, and particulate matter. Oxides of nitrogen and volatile organic compounds emission reduction credits prices have been escalating rapidly in the San Diego and Imperial County air districts. The San Joaquin, Kern, and Mojave Desert air districts also show a significantly increasing price trend in emission credits. This trend is likely to put upward pressure on the operating costs faced by technologies that emit these pollutants, especially fossil-fueled power plants.

Particulate matter volatile organic compounds are also seeing an upward price trend in certain regions. In this case, the San Joaquin Unified Air Pollution Control District and Mojave Desert Air Quality Management District face a rapid increase and are expected to approach the South Coast Air Quality Management District price in later years. In contrast, the San Diego and Imperial County air districts are in compliance and do not require particulate matter volatile organic compounds.

A new source of environmental mitigation costs is for greenhouse gas (GHG) allowances under the ARB California cap-and-trade program. GHG allowances are auctioned by the ARB several times a year. The prices of GHG allowances have been rising slowly with each subsequent auction as the market for these allowances becomes more fully developed.

Fuel Costs

Fuels for biomass and natural gas-fired power plants are major components of the cost of generation**.** Natural gas for electric generation is purchased primarily from regional market hubs for delivery via the major natural gas pipelines in California. These costs have declined a significant 43 percent on a levelized basis since the *2009 Integrated Energy Policy Report*. These prices reflect the national trends in prices. Biomass fuels are produced through a process similar to a blend of farming and forestry, depending on the specific location and design of the plant. This means that prices for biomass fuels tend to be driven by localized factors and are cheaper than more standard fossil fuels such as oil or natural gas. The price projections found by staff remain nearly unchanged from the *2009 Cost of Generation* report, and those values are used again in this report.

Transmission and Interconnection Costs

The cost of connecting a new generation project to the electric grid typically falls to the developer. In addition to the cost of the new transmission infrastructure, there are the costs overcoming of the electric losses between the generating station and point of interconnection. In addition, the California ISO charges plant operators for delivering their energy to customers. The process of taking energy from the source to the end use is known as “wheeling.” The California ISO has adopted a wheeling access charge for generation transmitted within its control area on its high-voltage network.

The wheeling access charge has grown at a steady 7.1 percent per year without inflation. This rate of escalation is used in the mid-cost case. The California ISO has forecasted in its 2013 Transmission Plan that rates will grow at between 5.7 percent and 9.5 percent per year through 2022. The high and low cases are drawn from the highest and lowest five-year segments in the California ISO’s analysis presented in the 2010 Long-Term Procurement Proceeding (LTPP). The range is from 2.2 percent to 15.1 percent per year using this method.

Solar Photovoltaic Technology Costs

Solar photovoltaic (PV) technologies are an important and growing portion of California’s electricity infrastructure. Significant investment in new PV installations is expected to continue for the foreseeable future. This report has chosen to estimate two utility-scale PV technologies; the 100 megawatt (MW) and 20 MW crystalline silicone single-axis tracking system (or single-axis) and the 100 MW and 20 MW thin-film solar technologies.

Two sizes were used to estimate the cost effects of scaling these technologies. While most of the solar PV installations show no economies of scale, the transmission interconnection costs represent a larger portion of the costs to smaller plants than to larger ones. As a result, levelized costs for smaller plants are significantly larger when the transmission costs are accounted for.

The costs for PV modules have come down dramatically in the last few years, leading to much lower system prices for utility-scale plants in California (and elsewhere). The solar industry is experiencing a roughly 20 percent reduction in costs for each doubling of production.

Between 2013 and 2024, single-axis tracking systems are expected to see their instant costs fall by between 16 percent and 51 percent in real dollars for 100 MW installations and 4 percent to 44 percent for 20 MW installations. The primary driver in these reductions is expected to be a combination of research and development fueled by the U.S. Department of Energy SunShot initiative, which is targeting $1/watt solar PV, and the natural process of learning as the industry continues to gain experience.

Instant costs for thin–film, fixed-mount PV systems are expected to decline along the same curves as those for single-axis PV systems. This is due to the highly interrelated research and production improvement. These systems are projected to see a decline over the same time frame (again in real terms) between 16 percent and 48 percent for 100 MW installations and 4 percent to 40 percent for 20 MW installations.

Solar Thermal Technology Costs

Solar thermal plants, also known as *concentrating solar power plants*, collect and convert solar energy into power using conventional steam turbines. There are two predominant commercial embodiments of solar thermal plants—parabolic troughs and solar towers—both of which collect sunlight over large "solar fields." The captured solar energy generates heat, which is transferred to a working fluid (such as pressurized oil). The working fluid is used to generate steam, which is routed through steam turbines to generate electricity.

Both trough and tower concentrating solar power plants may include *thermal energy storage*. Thermal energy storage stores the working fluid at high temperatures and allows the plant operator to have some control over when electricity is generated, thereby increasing the plant's dispatchability. Energy collected earlier in the day can be drawn from storage to generate additional power in the afternoon even as solar input declines. Thermal energy storage is an important concentrating solar power component since it adds both significant additional capital costs and significant expansion of the operational profile, greatly reducing the levelized cost of energy. This report considers solar tower plants with 6 hours and 11 hours of thermal energy storage and without thermal energy storage, while parabolic trough configurations are presented with 6 hours of storage as well as without storage.

While solar thermal plants were featured prominently in California, projects begun under the 2009 American Recovery and Reinvestment Act investment in solar thermal plants have declined as those funds are no longer available. This reduction tends to slow the learning process and therefore make cost declines likely to be more gradual than those experienced by the solar PV industry. However, there is strong interest among renewable developers to find ways to capture the maximum value of solar energy; thermal technologies with storage allow the plant operator to participate in the electricity marketplace in the evening hours after solar PV plants are no longer generating.

Solar tower plants (100 MW) are projected to see their instant costs (meaning the cost before financing) decline between 7 percent and 45 percent in real terms between 2013 and 2024. The largest declines are expected in plants with large storage capacities as these hold the most promise for developers, yet currently have the highest instant costs.

Parabolic trough plants (250 MW) are expected to follow a similar pattern to that projected for solar tower plants. The instant cost improvements for parabolic trough are expected to be between 6 percent and 39 percent between 2013 and 2024 in real terms. This decline is also expected to be driven by a steady growth of investment from developers who will push to lower costs and maximize value.

Wind Technology Costs

Wind technology costs have shown volatility in recent history, with project costs increasing between 2004 and 2010 before beginning a decline. Factors such as the move toward increased rotor diameter and the declining availability of high-quality wind resources have played a role in this trend. While Class 3 wind projects typically have a higher instant cost, progress in rotor and generator technologies has made it possible for these projects to show lower levelized costs due to their ability to harness lower-speed winds.

Instant costs for Class 3 wind projects are not clearly on the decline in all cases. While the current trend is toward declining costs, especially as component costs fall, increases in the cost of available land may have the opposite effect. Mid-case costs are expected to decline in real dollars by only 2 percent in real terms between 2013 and 2014. The range of instant costs over the same period is between a 10 percent increase and a 4 percent decline.

Class 4 wind projects follow similar patterns. Reductions in the available land under Class 4 wind resource areas may drive instant costs up even as the individual components decline in price. The mid-case prices are expected to decline by 1 percent between 2013 and 2024, with the range of possible prices between an 11 percent increase and a 4 percent decrease. Other factors, such as improvements in technology and widespread adoption of best practices or high competition for skilled labor, may result in trends that vary widely from the mid case. This instability is captured in the wide range between the low- and high-cost scenarios.

Geothermal Technology Costs

Geothermal technologies remain viable in California, although they are subject to a number of limitations that are likely to reduce the number of sites developed in California. The most likely technologies to be developed in California are binary and flash. A *binary geothermal plant* uses the heat from the underlying geothermal resource to heat another fluid that is then used to turn a generator. A *flash geothermal plant* uses the fluids drawn directly from the ground that are converted to steam through a "flash" process of dropping the surrounding pressure and then turning a generator.

Geothermal resource costs are driven largely by the highly variable and significant costs of drilling and well development. These costs are unique to each site and represent a significant risk on the part of the developer. While a successful well may be able to produce electricity at low cost, other wells in the same area may require much more investment in time and resources before they are producing efficiently. Costs for new geothermal plants are projected to increase slightly over the coming years. For all geothermal technologies, the range of instant costs is expected to rise by between 0 percent and 3 percent in real terms between 2013 and 2024. Limitations of location and drilling are unlikely to see improvement in California, while nationally there are very few geothermal projects under development.

Biomass Technologies Costs

Biomass technologies are plants that use biological resources, such as forestry waste or farming by-products, to produce electricity through thermal and chemical processes. These technologies are in limited production here in California. While these technologies are designed to harness biological by-products sustainably, they suffer from the limitation of requiring large, reliable fuel sources to produce energy economically.

A further limitation on the economic viability of these installations is the high cost of transporting the fuel from the origination site to the generation site. This limitation exposes the producer to the volatile market for diesel or other petroleum fuels, which can unexpectedly add significant costs. The instant costs of biomass in the high-, mid-, and low-cost cases are expected to increase by between 2.5 percent and 6 percent in real terms over the next decade. The increase is driven entirely by the fact that biomass technologies have to purchase emissions credits in ways similar to other fossil-fueled plants. Increases in permit costs translate into increases in instant costs.

Natural Gas-Fired Technologies Costs

Natural gas-fired generation remains the backbone of California's electricity generation portfolio. While the majority of new generation in the last few years has been renewable, targeted investments in gas-fired generation continue to be discussed and approved on a limited basis by the CPUC. Many of these targeted investments have been to meet local reliability and operational flexibility needs.

The preferred technologies for meeting these needs are gas turbines that blend high efficiency with rapid start and ramping capabilities. The result is extensive investment in combustion turbines (CT) that are based on designs for passenger jets, known as *aeroderivative designs*. These aeroderivative designs dominate the CTs installed in California despite the fact that their levelized costs are higher than their more traditional counterparts (referred to as "frame" type designs). Aeroderivative designs have rapid start-up and ramping capabilities that make them uniquely suited to conditions in California. Among these technologies, this report summarizes three types of CT installations. These include a 49.5 MW CT along with a 100 MW CT that consists of two of the smaller turbines located in a single site. Finally, an advanced design 200 MW CT is also estimated as some developers have begun building these plants in California. These advanced CTs have significantly lower instant costs (per kW), are capable of more efficient operation over a wider range, and are, therefore, becoming more common in California.

Among larger gas-fired power plants, the combined-cycle (CC) design is also presented in this report. CC power plants are a combination of gas turbines (typically of "frame" design), where the hot exhaust gases are used to produce steam in a boiler that is also used to generate electricity, thereby producing a more efficient and complete extraction of the thermal energy originally in the natural gas fuel source. These power plants are seeing their traditional role as baseload generation (power plants that run a high percentage of the time at or near their maximum output) change as the needs of California's electric grid changes.

Most CC power plants that were built expecting to operate 80 percent of the time or more have seen their actual operation well below this threshold. Instead of baseload, these plants have been 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. As a result, the number of CC power plants built in California recently has declined as more uncertainty in the ability to recover the cost of construction and operation now exists.

For this report, staff used actual data in the *Quarterly Fuels and Energy Report* database to accurately represent the capacity factor at which each type of power plant could expect to operate. The counterintuitive result was that the capacity factor of the CT power plants varied by nontrivial amounts between utility ownership types. The difference between publicly owned CTs at 7.5 percent capacity factor and investor-owned CTs at 1.0 percent capacity factor has significant implications for overall levelized costs.

While CT power plants are able to participate in the competitive California ISO marketplace, the majority of the resources owned by investor-owned utilities (IOUs) are "self-scheduled," meaning they are given direction to run by the IOU and then must take the market clearing price established by the California ISO marketplace. This has the effect of removing these resources from competition and making their operation discretionary on the part of the IOU. Any attempt to speculate why IOU-owned CTs operate in this fashion is beyond the scope of this report but stands as a significant insight from this report.

In addition to these uncertainties, both CC and CT power plants need to participate in emission credit markets, as described earlier. The trend toward both increasing costs of particulate and volatile emission credits and GHG emission credits is likely to add significant cost over the lifetime of a fossil-fueled power plant.

The instant costs of CT power plants are expected to increase between 5 percent and 18 percent from 2013 to 2024 in real terms. This is entirely due to the increasing cost of emissions in California as the underlying technologies are mature and their prices stable. CC power plants are expected to see their instant costs increase between 11 percent and 15 percent over the same time horizon. The increase is again driven by rising emission credit prices.

Levelized Costs of Generation

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

The levelized cost formula used in the Cost of Generation (COG) Model first estimates the annual costs over the lifetime of the power plant, then uses a "discount rate" to express all of the costs in terms of the first year's dollar value, also referred to as the *net present value*. The model then sums the net present value of the individual cost components and computes the annual payment with interest required to pay off that present value over some specified period, usually the economic life of the plant (knows as the "booklife" as opposed to the physical life of the plant).

The levelized cost results are presented as a cost per unit of energy over booklife. This 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 years the plant is expected to have economic value. The most common presentation of levelized costs is in dollars per megawatt-hour ($/MWh).

Levelized cost is generated by the COG Model using operational, cost, financial, and tax assumptions described earlier in this report. The COG Model calculates the annual costs for a technology, 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 operational profile of the system.

Levelized costs for solar technologies are expected to follow a downward trend, driven by the steadily decreasing instant costs over the next decade. However, these technologies will see an increase in levelized costs in the years after the expiration of tax credits, followed by a continued decline.

There is a notably wide range of possible levelized costs for solar PV technologies. Solar PV single axis 100 MW has the lowest levelized cost and solar PV thin film 20 MW has the highest. Among solar PV technologies, levelized costs are expected to change between a 22 percent decrease in the low cost 100 MW single axis technology and an increase of 33 percent in the mid case 20 MW thin film technology. All the thermal solar technologies range between these values.

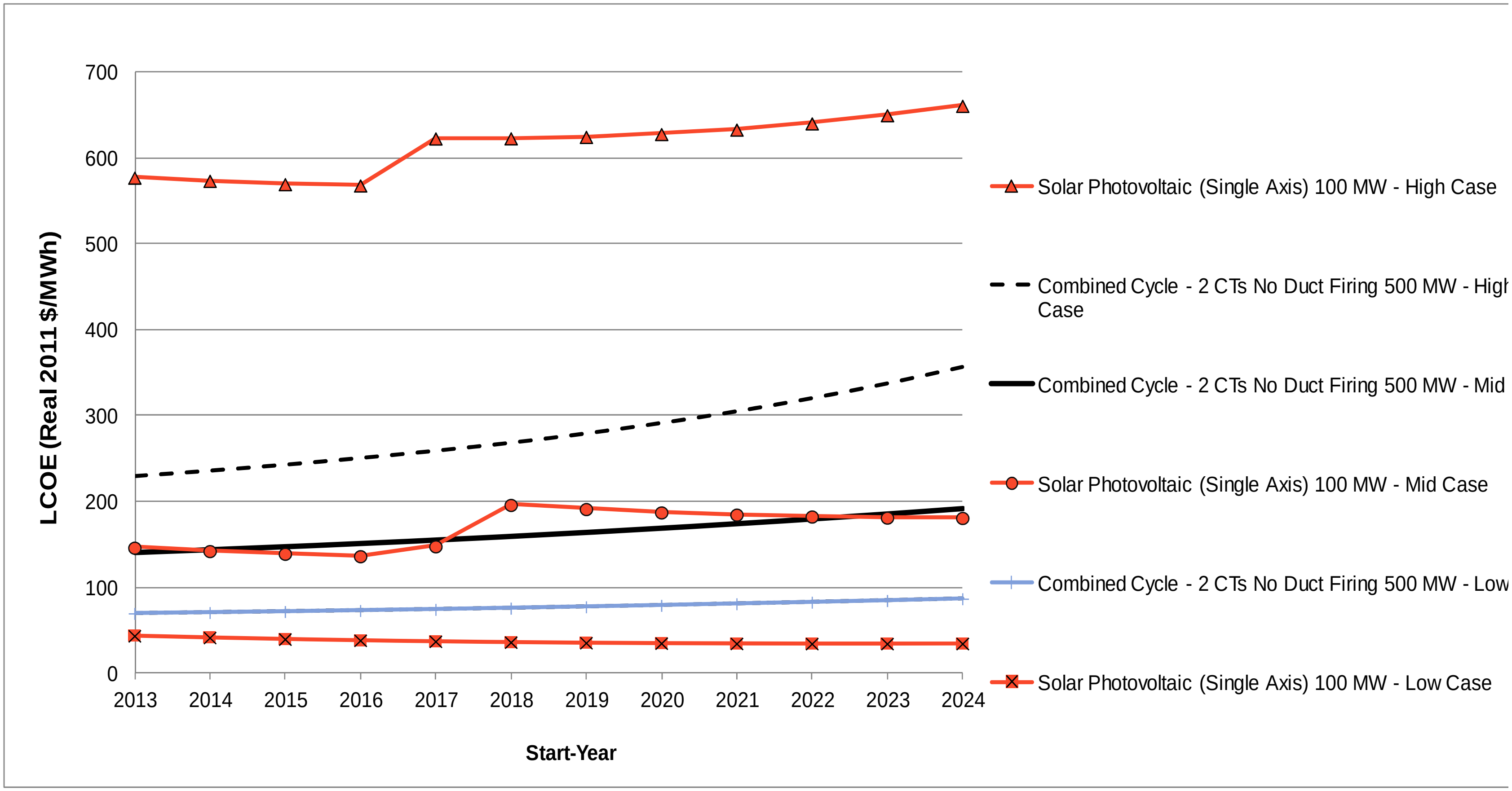
Striking among the results is the large reduction in levelized cost of energy going from 20 MW solar PV to 100 MW solar PV—both for the single axis and thin film PV technologies. This difference is due to interconnection costs (transmission from the project to the existing transmission system), which are assumed to be relatively insensitive to changes in project size (within 3 percent), therefore becoming a much smaller percentage of the total capital costs at the 100 MW size (that is, 5 percent as opposed to 25 percent). In the solar thermal technologies, there is the large reduction in levelized cost of energy for both the solar parabolic trough and the solar tower due to the addition of storage.

Figure 1 shows that from a developer's viewpoint, the cost to develop and operate a new 100 MW solar PV plant has reached the point where, in some cases, it would be nearly equal in cost to a CC unit. This comparison is not meant to suggest that solar PV technology has reached grid parity—the point at which from the grid operator's viewpoint the cost of solar PV is roughly equal to that of the fossil-fueled generator. Since the costs presented below are to the developer, the cost to the utility would represent payments to the developer plus the cost to integrate the resource into the system. Rather, it represents an important milestone along the path toward grid parity.

Staff identified 11 significant drivers of levelized cost of energy for investigation and conducted sensitivity analyses on each of the technology levelized costs. The key insight is that no single factor is the largest driver for all technologies. Instead, a handful of these factors consistently play a large role in determining levelized cost, and, therefore, pose the biggest risks to developers. The most important factors in determining levelized costs depend on the technology but in general were found to be capacity factor, instant cost, debt rate, operations and maintenance, and percentage equity. A change in any of these major drivers is likely to have dramatic effects on the levelized cost and, therefore, the price at which developers are willing to sign contracts to build and operate these plants.

Finally, staff attempted to understand the true range of possible levelized costs by assigning probabilities to each of 11 factors and then analyzed them using the Analytica software. The result was a significant narrowing of the expected range of levelized costs, especially when discussing renewable technologies. The results are not conclusive since the probabilities were constructed using assumed distributions rather than actual sampled data, but are suggestive that the real world range of values to developers may be far narrower than produced by taking the maximums of all input values.

Figure 1: Comparing Levelized Cost of Energy Ranges for Combined-Cycle 500 MW and Solar Photovoltaic Single-Axis 100 MW



Source: COG Model.

Key Insights and Areas for Further Investigation

The primary goal of this project is to produce clear, understandable estimates of the costs associated with building and operating new power plants in California over the next decade. However, throughout this work, several key insights that may be of interest to stakeholders and policy makers presented themselves. In addition, the limitations of the project were often made clear as stakeholders raised excellent questions and issues that unfortunately fell outside the bounds of time and resources allocated to this project. This section summarizes both the key insights as well as the areas for further investigation highlighted throughout the process.

Key Insights

The insights derived from this work are as follows:

- The decline of technology costs associated with solar PV is expected to continue as manufacturers refine production processes and find low-cost solutions to problems.
- All nonsolar renewable technologies have higher capital costs than reported in 2009, with geothermal flash being dramatically higher. This is primarily driven by the data from actual projects that were only cost projections in 2009. As a result, this represents a calibration of data rather than a real-world jump in costs.
- Long-term expectations of low natural gas prices are likely to make gas-fired power technologies, such as CTs and CCs, attractive to investors in the near term.
- Despite their higher levelized costs, CT power plants based on aeroderivative designs are being built almost exclusively in California due to operational profiles that are better suited to the highly variable load produced by large amounts of renewable resources.
- The cost of GHG emissions credits will likely be a major cost factor in future development of natural gas-fired resources.
- The steadily increasing wheeling access charges the California ISO expects to put in place over the next decade represent a growing, significant cost to renewable developers who find their best renewable resources in locations that are distant from demand.

Areas for Further Investigation

The scope of this project was ambitious. However, the list of questions of interest to stakeholders and policy makers is far larger than could be encompassed in this report. The following areas related to the cost of new generation in California were identified as being important and/or interesting to investigate in the future:

- Renewable resources can present challenges to utilities that must meet demand regardless of the availability of any resource. An estimate of the cost of integration from the utility perspective was proposed by several stakeholders.
- As the renewable resource fleet in California ages, some of it will have to be upgraded or replaced. How might the replacement of aging renewable resources with newer technologies affect the expected costs of those projects?

- Many areas of California are constrained with regard to the suitable land available to host a gas-fired power plant. What is the levelized cost of a repower project for a CC or CT on an existing site compared to the same development on a new (or "greenfield") site?
- The developer of a new power plant is not strictly reliant on a single contract to provide the stream of income necessary to recover their costs. Markets such as those for ancillary services (meaning services that support grid stability such as ramping) and resource adequacy can provide additional streams, changing the amount a developer might be willing to accept for a project. A study laying out these options and how they might affect the market for contracts could be of value to policy makers.

CHAPTER 1: Introduction and Overview

Introduction

This report represents an effort by the California Energy Commission to estimate the current and future costs of building and operating new utility-scale [1] (also called *central station*) electric power plants over the next decade. These estimates are used as inputs to multiple studies, including procurement planning studies conducted at the California Public Utilities Commission (CPUC), transmission planning studies conducted at the California Independent System Operator (California ISO) and within the Western Electric Coordinating Council (WECC), as well as in developing studies of policies and strategies to meet California's environmental policy goals conducted by the California Air Resources Board (ARB) and a variety of related academic studies.

In producing these estimates, the Energy Commission recognized that several studies already exist of the current and/or projected costs of new generation. However, these studies suffer from a number of drawbacks from a California policy maker's perspective. First, the majority of the most thorough and well-researched studies present national cost averages rather than California-specific values. California typically experiences higher costs for new generation than the national average. This means that national studies are likely to understate the costs to build resources in California. Second, those studies that produce California-specific cost estimates are usually focused on a single class of generation (such as wind or solar) and ignore other resources that might be considered part of California's future portfolio. In addition, the cost estimates in the various studies are not always directly comparable, as some cost components and other assumptions may be included in one study but excluded in others.

This report seeks to address these issues without unnecessarily replicating high-quality studies. This study uses a combination of national and California-specific estimates of the current and future costs of new utility-scale generation by aggregating and comparing these studies and translating them into California-specific values. This approach has the added benefit of drawing on a wide variety of resources that can illuminate alternative views of the future trends associated with different technology costs. This report also uses new data drawn directly from surveys of natural gas-fired power plant owners in California to add relevant information. Finally, this report brings a harmonizing perspective to the multiple sources and imposes a consistent set of assumptions that allow for direct comparisons that would not otherwise be possible between disparate studies.

1 For this report, utility-scale is considered to be project 20 MW or larger.

Study Perspective

In estimating the costs of building and operating a new utility-scale power plant in California, a large number of assumptions must be made to calculate those costs over a plant lifetime that can span 20 or more years. It is effectively impossible to accurately predict all the factors necessary to estimate lifetime costs of a new power plant that might not even be built for another decade. As a result, this study has adopted the principle of transparency over certainty. This means that rather than make any claim of certainty regarding these values, this report—along with the calculator that was built to support these calculations, known as the Cost of Generation (COG) Model—uses a range of plausible inputs to create scenarios that include transparent input values.

In addition to developing and presenting a range of values, this report also attempts to translate those transparent input values into a widely understood set of metrics. The key output metrics are *instant cost, installed cost,* and *levelized cost*.

Instant cost is the cost to build a utility-scale power plant if the owner could afford to pay cash upfront for all initial capital, permitting, and construction costs. Since such an arrangement would mean the owner had no need to borrow money, variations in lending terms, costs of borrowing, or operational profiles have no effect on instant cost. Given the scale of investment necessary, utility-scale power plants in California have never been built on a cash-only basis as implied by the instant cost metric. Instead, this provides a common starting point for further analysis.

Installed cost is the real-world cost to permit and build a power plant, including all lending costs. Installed cost reflects all of the upfront purchases of generation equipment such as solar panels or generation turbines, investments, and costs incurred by the owner from inception of the plan to the moment the plant is able to begin generation. It does not include any operational costs such as fuel and maintenance costs. It does, however, include the financing and lending costs associated with the project. Functionally, this means that owners who have access to low-cost capital (such as publicly owned utilities who can issue low-cost bonds to raise funds) are able to reflect lower installed costs than other owners despite having the same instant cost to begin with.

Levelized cost is the metric that reflects the lifetime cost of operations and maintenance combined with the installed cost of construction expressed as a constant stream of costs per unit of value over the lifetime of the plant. The most common unit of value is energy, usually measured in megawatt-hours (MWh). When levelized costs are expressed per unit of energy, they are sometimes called the *levelized cost of energy* (LCOE).

Levelized cost is not simply the sum of the annual cost divided by the total energy produced by the plant because costs can fluctuate from year to year. As a result, future costs must be translated into present values. 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.

The first step in calculating levelized cost is to estimate each year's cost. All future costs are then discounted by a discount rate that reflects the willingness of investors to take on these future obligations. Finally, these costs are divided by the expected generation over the lifetime of the plant to produce a single number that reflects the cost per MWh in constant terms over the long life of the plant and that can be compared to other projects competing for the same investment dollars.

The cost of any new power plant is a result of numerous, sometimes intertwined factors relating to changing market conditions, labor and resource costs, regulatory issues, and local factors such as real estate market forces and air, water, and land-use planning. A project developer will be presented with a unique combination of these costs depending on precisely where, when, and how they go about putting the project in place. There is no way to anticipate all of these factors for every new generation resource built in California. This report deals with this issue by developing three cost scenarios.

A mid-cost case was constructed using the best current estimate for costs that are applicable across the state for all factors involved in estimated the future costs of new generation. This case reflects median values for factors such as emissions credit prices and therefore will not be representative of any single project, but rather the portfolio of projects as a whole. Around the mid-cost case, two additional cases were estimated. A high-cost and a low-cost case were constructed using the simultaneous highest cost and lowest cost factors. This provides a bracket of costs that represents how any project under the most favorable (or unfavorable) conditions might fare.

Finally, this project used the Analytica software tool to attempt to assign probabilities to each of the major cost factors associated with new power plants. Using these probabilities, a range of probabilistic costs were estimated. This probabilistic range of values provides a narrower estimate of cost ranges that are likely to be seen in the marketplace. These probabilistic high, low, and mid cases are presented in the chapter on levelized costs.

Background of Report

The first COG report and supporting COG Model date back to the *2003 Integrated Energy Policy Report* (*2003 IEPR*). Assumptions were based on best available data, and levelized costs were calculated as single spreadsheet or calculations for each technology.

The subsequent effort for the *2007 Integrated Energy Policy Report* (*2007 IEPR)* significantly improved the accuracy of the data by surveying power plant developers. A single model was developed to calculate levelized costs for all technologies and for all three classes of developers: merchant, investor-owned utility (IOU), and publicly owned utility (POU).

The *2009 Integrated Energy Policy Report* (*2009 IEPR)* made further improvements in modeling and provided high and low cost assumptions in addition to the traditional mid cost value. The present *2013 Integrated Energy Policy Report* (*2013 IEPR)* effort is further improved through additional data surveys and replacing the *2009 IEPR* levelized cost estimates with ranges based on probability distributions.

Comparison to *2009 Integrated Energy Policy Report* Assumptions

Table 1 compares the key current assumptions to the comparable *2009 IEPR* assumptions. Notable changes include the following:

- Fuel costs for natural gas units have dropped dramatically—43 percent on a levelized cost basis. This reflects the shift in the natural gas markets toward domestic gas resources from shale formations that have driven gas costs to near-record lows and are expected to have downward pressure on prices over the study horizon.
- Advanced combustion turbine (CT) costs have increased significantly—mostly due to having more data to analyze.
- All nonsolar renewable technologies have higher capital costs than reported in 2009, with geothermal flash being dramatically higher. This is driven by the availability of data from actual projects that were not available in 2009. The expected costs of these projects seem to have underestimated the actual costs encountered as this technology undergoes its first major domestic investment surge in more than 15 years.
- Solar capital costs have slightly lower capital costs when compared against projects of the same size (20 MW [megawatts]) but significantly lower costs when comparing against the current larger sized projects (100 MW). The increased size has the largest impact on instant costs, mostly due to being able to spread the transmission costs over a larger gross capacity.
- Operations and maintenance (O&M) costs for most renewable technologies are significantly higher than reported in 2009, but the single-axis solar photovoltaic (PV) technology O&M costs have dropped significantly. This reflects better data for all technologies, as well as improved dissemination of O&M best practices in a rapidly maturing PV marketplace.

Table 1: Comparison of Current Assumptions to *2009 IEPR* Assumptions

Technology	Capacity Factor (%)			Instant Cost ($/kW)			Merchant Installed Cost ($/kW)			Total O&M ($/kW-Year)			Levelized Fuel Cost ($/MMBtu)		
In-Service Year = 2013 (2013$)	2009 IEPR	2013 IEPR	% Change	2009 IEPR	2013 IEPR	% Change	2009 IEPR	2013 IEPR	% Change	2009 IEPR	2013 IEPR	% Change	2009 IEPR	2013 IEPR	% Change
Small Simple-Cycle	5.0%	5.0%	0%	1373	1303	-5%	1459	1457	0%	27.84	28.39	2%	11.74	6.67	-43%
Conventional Simple-Cycle	5.0%	5.0%	0%	1309	1261	-4%	1412	1410	0%	20.80	27.44	32%	11.74	6.67	-43%
Advanced Simple-Cycle	10.0%	7.5%	-25%	879	1007	15%	1142	1141	0%	21.20	25.24	19%	11.74	6.67	-43%
Conventional Combined-Cycle (CC)	75.0%	57.0%	-24%	1162	1025	-12%	1168	1165	0%	30.50	37.62	23%	11.74	6.67	-43%
Conventional CC - Duct-Fired	70.0%	57.0%	-19%	1146	1004	-12%	1145	1142	0%	28.74	37.62	31%	11.74	6.67	-43%
Biomass - Direct Combustion W/ Fluidized Bed	85.0%	80.7%	-5%	3458	4501	30%	3938	5282	34%	143.82	143.63	0%	2.47	2.61	6%
Geothermal – Binary	90.0%	85.0%	-6%	4225	5342	26%	5070	7099	40%	79.78	89.79	13%	N/A	N/A	N/A
Geothermal - Dual Flash	94.0%	85.0%	-10%	3863	6041	56%	4636	7747	67%	96.09	89.79	-7%	N/A	N/A	N/A
Solar - Parabolic Trough	27.0%	26.5%	-2%	3199	3892	22%	3599	4582	27%	73.78	70.95	-4%	N/A	N/A	N/A
Solar - Photovoltaic (Single-Axis) 20 MW	27.0%	26.6%	-1%	3940	3567	-9%	4432	4058	-8%	73.78	37.00	-50%	N/A	N/A	N/A
Solar - Photovoltaic (Single-Axis) 100 MW	N/A	26.6%	N/A	N/A	2864	-27%	3242	3258	-26%	N/A	37.00	N/A	N/A	N/A	N/A
Wind - Class 3	37.0%	42.0%	14%	2072	2573	24%	2338	2998	28%	32.61	62.84	93%	N/A	N/A	N/A
Wind - Class 4	37.0%	39.0%	5%	2072	2312	12%	2338	2694	15%	32.61	60.61	86%	N/A	N/A	N/A

Source: Energy Commission.

Key Insights and Areas for Further Investigation

The primary goal of this project was to produce clear, understandable estimates of the costs associated with building and operating new power plants in California over the next decade. However, throughout this work, several key insights that may be of interest to stakeholders and policy makers presented themselves. In addition, the limitations of the project were often made clear as stakeholders raised excellent questions and issues that unfortunately fell outside the bounds of time and resources allocated to this project. This section summarizes both the key insights as well as the areas for further investigation highlighted throughout the process.

Key Insights

The insights derived from this work are as follows:

- The decline of technology costs associated with solar PV is expected to continue as manufacturers continue to refine production processes and find low-cost solutions to problems.
- All nonsolar renewable technologies have higher capital costs than reported in 2009, with geothermal flash being dramatically higher. This is primarily driven by the increasing availability of data from actual projects that were only cost projections in 2009. As a result, this represents a calibration of data rather than a real-world jump in costs.
- Long-term expectations of low natural gas prices are likely to make gas-fired power technologies such as CTs and CCs attractive to investors in the near term.
- Despite their higher levelized costs, CT power plants based on aeroderivative designs are being built almost exclusively in California due to their operational profiles that are better suited to the highly variable load produced by large amount of renewable resources.
- The cost of greenhouse gas emissions credits will likely be a major cost factor in future development of natural gas-fired resources.
- The steadily increasing wheeling access charges the California ISO expects to put in place over the next decade represent a growing significant cost to renewable developers who find their best renewable resources in locations that are distant from demand.

Areas for Further Investigation

The scope of this project was ambitious. However, the list of questions of interest to stakeholders and policy makers is far larger than could be encompassed in this report. The following areas were identified as being important and/or interesting to investigate in the future related to the cost of new generation in California:

- Renewable resources can present challenges to utilities that must meet demand regardless of any one resources availability. An estimate of the cost of integration from the utility perspective was proposed by several stakeholders.

- As the renewable resource fleet in California ages, some of it will have to be upgraded or replaced. How might the replacement of aging renewable resources with newer technologies affect the expected costs of those projects?
- Many areas of California are constrained with regard to the suitable land available to host a gas-fired power plant. What is the levelized cost of a repower project for a CC or CT on an existing site compared to the same development on a new (or "greenfield") site?
- The developer of a new power plant is not strictly reliant on a single contract to provide the stream of income necessary to recover costs. Markets such as those for ancillary services and resource adequacy can provide additional streams, changing the amount a developer might be willing to accept for a project. A study laying out these options and how they might affect the market for contracts could be of value to policy makers.

Report Overview

Chapter 2 provides the financing assumptions and method for developing those assumptions. It provides cost of capital assumptions by developer and technology for the three cost cases, mid, high, and low. It provides debt service recovery ratios (DSCR) by developer for the three cost cases. It summarizes the tax incentives for each technology, as well as the state and federal tax rates.

Chapter 3 provides the fuel, emissions, and transmission assumptions. It provides the fuel prices by technology for each of the three cost cases, including the method of how these cost cases were developed. It delineates the transmission line losses, California ISO charges, and emission factors.

Chapters 4–9 provide the technology-specific assumptions for the three cost cases. Each chapter delineates the plant costs (instant and installed by developer, O&M, insurance, and ad valorem) and plant characteristics (site losses, capacity factors [CF], heat rates, and capacity degradation factors).

Chapter 10 provides the levelized cost in $/MWh, including total and component costs. Levelized costs are provided for mid-, high-, and low-cost cases as both deterministic and probabilistic values.

Appendix A provides graphical summaries of the relative effects of the various tax benefits on levelized cost. It also provides graphs showing the impact over the 2013 to 2024 time horizon.

Appendix B summarizes the natural gas technology assumptions prepared by Aspen.

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

Appendix D provides a description of the models used. The COG Model is the Energy Commission's model that has been used in past *IEPR*s to develop the necessary levelized costs. Analytica is a probabilistic model owned by Lumina. Analytica Cost of Generation Analysis Tool (ACAT) is a melding of the COG and Analytica to provide probabilistic high and low levelized costs.

CHAPTER 2:
Financing Costs and Tax Treatment

Background

Beyond the capital costs, including equipment, land, and permitting, the cost of financing and taxes represent a major portion of the cost to build a new power plant. The financing and debt costs associated with the construction and ownership of a power project have an important effect on the total cost of energy from a project.

This chapter focuses on "merchant" or nonutility-owned independent power projects because the owners are by far the dominant developers of new renewable power projects. In addition, merchant projects generally are financed on a project-by-project basis, that is, two projects developed by the same firm may have different financing terms. In contrast, almost all IOU projects are financed from the central corporate treasury, so the terms do not vary by project. Projects developed by POUs usually are bond–financed, and those bond rates are more closely tied to the rating for the POU than to the project's characteristics. As a result, merchant financing is more complex and variable and requires more explanation.

The current environment for financing independent power projects is challenging. These challenges include weak corporate profits, changes in corporate direction, and heightened risk aversion. As a result, a number of the financial institutions that were lead underwriters in the past are either pulling out of the market or are taking a lower profile in project financing.

Another factor affecting the market for financing power projects is the differentiation of roles that various players are willing to play. These roles are, to a large extent, driven by the risk profiles of the institutions. Two examples demonstrate this differentiation:

- Some financial institutions are unwilling to lend during the construction phase because of the potentially greater risk of project failure during the early portion of the project. On the other hand, once the project has become operational and demonstrated the ability to meet its performance requirements, these institutions are willing to provide relatively low-cost financing.
- Some financial institutions are realizing that providing relatively long-term, fixed priced financing places their institutions at risk relative to their cost of funds. As a result, these institutions are only willing to finance with a relatively short tenor (for example, seven years) regardless of the duration of a project's power purchase agreement (PPA). At the same time, other institutions have an appetite for longer-term obligations because their sources of funds have a much longer time horizon (for example, insurance companies). Thus, some projects are financed with, in effect, a balloon payment after a relatively

short term with the expectation that the project will refinance once it has established a solid operating history.

A new challenge facing certain projects is difficulty in obtaining "tax equity" financing. Under tax equity financing, small renewable generation owners who have insufficient income to use the full value of a tax benefit can sell the tax benefit to third parties who are eligible to claim it under current tax laws. A number of the key players providing tax equity during the period from about 2003 to 2008 are no longer in the market.[2] New players with an appetite for tax equity have come on the scene (for example, affiliates of IOUs), but this has slowed the financing pipeline because traditional financing syndicates no longer exist, making the financial closing process much slower. (The tax equity market is discussed in more detail below.)

Finally, it is important to understand that each power project's ultimate financing package is unique. The project sponsor(s), the markets, the PPA terms and conditions, and the technology necessarily vary from project to project. While financial institutions attempt to use knowledge and experience gained from previous project financings, the uniqueness of power projects ultimately requires financing institutions to craft an individualized financing package that meets the needs of all participants.

Key Terms

There are a number of interrelated factors that ultimately affect the financing of independent power projects. This section defines these factors and explains these interactions.

- Interest rate: The key factor that quantifies the risk that the lender perceives in a power project is the interest rate. Interest rate is often measured as a spread above an index, such as the London Interbank Overnight Rate (LIBOR). The spread above LIBOR is used to compensate the lender for their perceived risk of lending on the project. (There is a more detailed discussion later in this chapter on how LIBOR could be incorporated into the COG Model.)
- Leverage: The amount of leverage is defined as the ratio of debt issued relative to the total cost of the project (where the total cost of the project is defined as the sum of both debt and equity). Because cash flow is always allocated to make debt service (that is, interest and principal) before payments to equity investors, the greater the leverage, the greater the risk that cash flow will be inadequate to meet debt service.

2 Lehman Brothers was an important participant that no longer exists. Another possibility for the loss of participants is that those entities have no tax appetite as a result of the worldwide recession reducing corporate profitability.

- Debt Service Covergate Ratio (DSCR): The DSCR is equal to the ratio of expected cash flow to debt service. As the amount of debt on a project increases (or the cost of the debt increases), the DSCR decreases. On a forecast basis, lenders typically look at both the average and minimum DSCRs. For projects with relatively certain CF (for example, a baseload geothermal or biomass project) or with relatively certain net revenues (for example, a natural gas-fired project with a tolling agreement), often the average and minimum DSCR targets are similar. However, for projects with uncertain energy sources (for example, wind or solar projects), the average and minimum DSCRs can differ based on the relative likelihood of energy production. In other words, the minimum DSCR would be based on a worst-case wind or solar forecast (the so-called P99 forecast), while the average DSCR is forecast based on an expected wind or solar forecast (the P50 forecast). "P99" is the wind/solar forecast that has a 99 percent probability of being exceeded, while a "P50" forecast has a 50 percent probability of being exceeded. (Lowder, 2011).
- Term of Debt: Lenders view longer-term debt as being at greater risk of repayment than shorter-term debt. This is because over a longer term there is a greater chance of unexpected problems cropping up that could threaten the ability of a project to repay its debt obligations or that could make the loan uneconomic. Also, because so few lenders are willing to provide very long-term financing, lenders that do so have few other entities to which they can sell down their positions if the lender wants to liquidate its position. Thus, even when a project has a long-term PPA, lenders will issue debt with a term (or "tenor") that is shorter than the term of the PPA. However, a project is likely to have a sequence of debt instruments that will extend close to the full term of the project life. The project will refinance at the end of the term of the first debt instrument often with a balloon payment. In these cases, the initial debt instruments may have interest-only payments that reduce the annual debt burden and make the DSCR achievable.
- Quality of Developer/Sponsor: Lenders evaluate the quality of the power project developer/sponsor in determining financing costs. A major player with significant experience with a particular technology and market will generally receive the most favorable financing terms. These developers must be considered "investment grade," and the lending is at the project level, not the holding company level.
- Term of PPA: While there are certain lenders that are willing to accept "merchant risk," most financial institutions want to have a greater level of certainty associated with the revenue stream for the project. The financial institutions obtain this greater certainty by requiring the project to have a PPA with a term that is greater than the term of the debt.
- Technology/Fuel Source: Lenders consider the technology or fuel source when pricing their debt. Technologies with greater perceived risk in fuel source or plant operating costs (for example, geothermal) will typically have higher debt costs. Because of their uncertain fuel source and technology risk, biomass projects also have higher debt costs than do natural gas-fired, wind, or solar projects.

- Incentives: The financing approach for power projects can depend greatly on the types of incentives available to the projects' sponsors. Incentives such as production tax credits, cash grants, or investment tax credits can have an effect on both the leverage of a project and the types of entities that will participate in the financing. For example, if a solar project is eligible for a cash grant, then there will be less need for tax equity in the project.
- Size of Project: The size of the project and the financing requirements will also have an effect on the financing terms being offered to a project sponsor. Large projects present greater risk to a financial institution and, as a result, lenders will impose a higher cost of debt on the project than a smaller project using similar technology located in the same market.

Analytic Methodo for Estimating Financing Terms

The financial structure and base parameters for investor-owned and merchant plant developers are taken from the Board of Equalization's (BOE) *2012 Capitalization Rate Study* (Gau and Thompson, 2012) and adjusted to match December 2012 financial market conditions. This source was chosen because it was developed by another state agency using a public review process. These rates are consistent with the allowed rates of return set by the CPUC for the three large IOUs.[3] Debt costs for all three owner types were derived using public sources available as of December 2012. Derivation of the merchant debt rate is discussed in detail below. The IOU debt rate is taken from the CPUC decision. For POUs, the debt rate is based on public sources for highly rated issuances for 30-year notes (Bond Market Yields, 2012; Composite Bond Rates, 2012).

The appropriate discount rates and allowance for funds used during construction (AFUDC) rates are based on the after-tax weighted average cost of capital (WACC). The WACC is calculated by multiplying the shares from equity and debt sources by the after-tax rate of return for equity[4] and the cost of debt (or interest rate), respectively. For example, assume a project is financed with 40 percent equity and 60 percent debt, and the rate of return for equity is 10 percent and the debt interest rate is 5 percent. Because debt interest is tax-deductible, the debt rate must be adjusted; in this case with a 40 percent corporate tax rate, the after-tax interest rate is 3 percent. In this example, the WACC equals (40 percent x 10 percent) plus (60 percent x 3 percent), or 5.8 percent.

To characterize financing for merchant plants in more detail, the Energy Commission contracted with MRW Consulting (MRW). MRW used a two-part approach to assess the

3 See CPUC Decision 12-12-034.

4 For IOUs, a weighted average mix of common and preferred stock rate of return was calculated to simplify the model equation.

finance market for merchant developers. This information was used to supplement the finance structure and assumptions in the BOE's *Capitalization Rate Study*. First, MRW researched the current assumptions being used by financial institutions to finance the construction of new independent power projects. MRW conducted an informal survey of a number of financial institutions to solicit their views regarding financing trends in the energy market.[5] Based on the responses to the survey, MRW developed ranges of key financial attributes, differentiating financing trends by fuel type (for example, natural gas, solar, wind, biomass, and geothermal) when possible. While MRW indicated to the financial institutions that the focus was on the California market, the questionnaire did not differentiate between California and other regions.

Second, MRW reviewed several recent studies and attended a Webinar that provided some data on financing trends for renewable power projects. MRW also reviewed the publicly available PPAs executed between the California IOUs and renewable energy project developers of renewable energy projects. Their findings are presented in the next section.

Merchant Owners and Developers

Tax Equity Financing and Yields

Many renewable energy projects rely to some degree on the tax equity market for financing. As was noted earlier, the supply of tax equity for renewable energy projects declined substantially during the recent economic downturn. Lower corporate profits meant traditional tax equity providers could not absorb the same level of tax benefits. New entrants in the tax equity market face the significant challenges of understanding and evaluating the array of renewable energy technologies, project structures, and contract and market risks.[6]

Tax equity can be a more expensive form of financing than other sources of capital, such as debt; this is true for several reasons. First, the tax equity market is not very transparent, nor is it highly liquid. In addition, each project is unique, with unique developers and investors. This uniqueness increases the transaction costs of using tax equity for financing. Investors

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5 MRW contacted 10 financial institutions and received responses from 5 of them. The financial institutions providing information for this project are all active in project financing. They are geographically diverse (that is, they are based in Europe, Asia, the United States, and Australia). A number of the financial institutions were very concerned about confidentiality and agreed to participate only on the condition that their identity would be masked. Thus, in the information presented here, MRW has masked the identity of the financial institutions.

6 One estimate puts the number of active players in the tax equity market at about 20 to 22 entities (*State of the Tax Equity Market*, 2012).

are generally earning yields from 7 percent to 9 percent (*State of the Tax Equity Market,* 2012; Mendelshohn and Harper, 2012).

The choice of tax equity financing varies with the type of tax credit that is applicable and most beneficial to a project (Miller and Mulcahy, 2011). When a production tax credit (PTC) is the preferred instrument, as is usually the case with wind, a partnership “flip” is used. The tax equity investor takes 99 percent ownership to the end of the PTC (10 years), and then ownership flips to the developer, who owns 95 percent to the end of the project. For projects using the investment tax credit, largely for solar, a sale/leaseback is most common. The tax equity investor leases the project for less than 80 percent of the project life and provides more than 20 percent of the equity contribution (plus nonrecourse debt).

London Interbank Overnight Rate and the Cost of Generation Model

Renewable power project debt financing is often priced using the LIBOR plus a premium. LIBOR is a daily rate that sets the borrowing costs for financing institutions; it is considered the benchmark for short-term interest rates across the financial system.

Because LIBOR can vary daily, project owners with debt financing linked to LIBOR typically choose to convert the variable rate into a fixed rate. To accomplish this, the project owners use a LIBOR swap, which provides the project with a fixed interest rate over the term of the debt. For purposes of modeling renewable project costs based on a cost of debt input, LIBOR swap rates represent a useful market view of LIBOR over a medium- to long-term period. For these reasons, the COG Model now uses a “LIBOR + adder” approach for determining the cost of debt for merchant/independent power producer (IPP) renewable projects.

This approach applies LIBOR swap rates tied to the debt term in the model, with a risk adder applied on top of that (for example, a project with a 10-year debt term would use a 10-year LIBOR swap rate). In practice, this is similar to the COG Model’s previous approach to using bond rates (an approach consistent with the *BOE Capitalization Rate Study*), however using the “LIBOR + adder” approach better reflects the actual debt financing terms provided to renewable project developers.

Finally, project interest rates often include both a base spread over LIBOR plus periodic “step-ups” in the spread. For example, the step-ups might increase the base spread by 25 basis points every four years.

To account for the LIBOR swaps and the step-ups, an annualized spread over LIBOR is calculated. This annualized spread should result in the same net present value of debt costs as would be found if there was a time-varying spread. The Wall Street Journal Markets Data

Center provides a reliable, public source for LIBOR swap rates for various lengths of loans, known as the *debt tenor*.[7]

Results for Merchant Developers Terms

Based on the approach and assumptions outlined above, MRW identified the following ranges for financing parameters, as well as more qualitative information about the financing trends for power projects. This section presents both quantitative and qualitative findings.

Quantitative Results

Table 2 summarizes the quantitative financing factors collected. This table presents the average of the minimum and maximum values for four key financing terms: average and minimum DSCRs, pricing over LIBOR (that is, the cost of debt), and tenor.

7 The three-month LIBOR rate is the most commonly used benchmark rate. However, other LIBOR rates do exist, including one-month, six-month, and one-year rates. The LIBOR swap rates shown here are for swaps to be paid against the three-month LIBOR rate.

Table 2: Merchant Developers' Financial Parameters

Technology and Case	Premium Over LIBOR Rate	DSCR (Average)	DSCR (Minimum)	Tenor (Years)
Mid-Cost Case				
Gas-Fired Technologies	2.85%	1.37	1.37	10
Biomass Technologies	3.90%	1.72	1.72	20
Geothermal Technologies	3.90%	1.79	1.79	20
Solar Technologies	3.50%	1.35	1.27	20
Wind Technologies	3.50%	1.35	1.27	20
High-Cost Case				
Gas-Fired Technologies	3.10%	1.39	1.39	7
Biomass Technologies	3.17%	1.78	1.78	15
Geothermal Technologies	3.17%	1.88	1.88	15
Solar Technologies	2.90%	1.45	1.30	15
Wind Technologies	2.90%	1.45	1.30	15
Low-Cost Case				
Gas-Fired Technologies	2.60%	1.35	1.35	20
Biomass Technologies	3.08%	1.65	1.65	25
Geothermal Technologies	3.08%	1.70	1.70	25
Solar Technologies	2.55%	1.24	1.24	25
Wind Technologies	2.55%	1.24	1.24	25

Source: Aspen Environmental.

The following observations are drawn from **Table 2**:

- Biomass and geothermal projects are considered riskier than natural gas, solar, and wind projects. This is seen in the lower leverage, higher pricing, and higher DSCRs than for the other generating technologies. The higher level of project risk for biomass and geothermal projects is partly attributed to the technology and fuel sources. Solid fuel power plants require more project infrastructure than do other fuel types. Biomass projects often have a wide range of fuel sources without long-term fuel supply agreements or liquid fuel markets, while geothermal projects have inherently uncertain steam supplies as has been seen at the Geysers. Some of the risk also is based on the relatively small number of these projects being developed.

- Pricing for natural gas projects is slightly higher than for wind or solar projects. Part of this may be due to the somewhat larger size of natural gas projects than typical wind or solar projects.
- Tenors are somewhat longer for wind and solar projects than for natural gas projects. This is not surprising given that PPAs for natural gas-fired projects are often shorter than for renewable projects. However, according to one lender, the tenor for debt for renewable projects has decreased significantly over the past two to three years as lenders face greater pressure on their balance sheets and find more difficulty rationalizing 15- to 20-year tenors for financings. Another lender said that certain lenders are willing to issue longer-term debt (for example, duration of the PPA minus two years). This has also led to hybrid project structures, where banks will finance construction and the first few years of operation, after which the financing will be taken over by institutional investors with much longer financing capabilities (for example, insurance companies).
- DSCRs for natural gas projects are somewhat higher than for wind or solar projects. Also, lenders do not tend to distinguish between minimum and average DSCRs under base case conditions. However, as discussed above, the one-year minimum DSCR for wind or solar projects is typically set at 1.0 for the P99 forecast.
- Leverage is quite similar for natural gas, solar, and wind projects.

One important point is that the parameters described for the debt instruments are not consistent with full long-term financing for most renewable projects. The terms are typically very short-term, for example, less than one-third of the expected life, and the payments are often interest-only with large balloon payments. These balloon payments imply that a second financing will be required, but there is no information on those terms. Because the COG Model looks over the entire life of the project, the model uses terms based on project bond financing, despite that type of financing being fairly rare. The average costs of the different financing mechanisms should be relatively similar so as to minimize the arbitrage opportunities.

Qualitative Results

Aside from the quantitative financing trends presented above, the financial institutions that responded to MRW's request for information provided valuable insights into other issues of importance regarding project financing. These issues are summarized as follows:

- Merchant Risk: Immediately after the meltdown of the merchant generation market in 2002 – 2005, lenders were unwilling to lend to merchant projects that did not have a solid PPA with a creditworthy counterparty. However, as time has passed, lenders have reassessed the risks associated with accepting merchant risk. There are at least two forms of merchant risk that lenders might accept under certain circumstances. First, a small subset of lenders is willing to accept "merchant tail" risk, which is where the tenor of the debt exceeds the duration of the project's PPA. Banks are not typically willing to accept this type of risk; institutional investors are more willing to do so. Also, lenders are willing to accept only a limited amount of such debt (for example, $50/kilowatt [kW] to $100/kW) and require a good "story" regarding the ability of the project to obtain capacity payments after the end of the initial PPA. One lender noted that there are lenders willing to lend higher amounts on a merchant basis (for example, up to $200/kW) in the "Term Loan B" market, which is a high-yield loan. Second, some lenders will lend on projects in which the entire capacity of the project is not contracted but the project sponsor has a good plan for marketing power from the project.

- Technology Risk: Lenders need to be concerned about the long-term viability of a project's technology. Vendors of natural gas-fired generation technology (for example, General Electric, Siemens, and Mitsubishi) have significant balance sheets to ensure performance in case of significant warranty claims. Warranty claims for new generation are not unheard of. For example, when GE introduced the Frame 7F combustion turbine, there were numerous problems that GE had to resolve under warranty. (Tenaska Georgia Partners LP, 2000). However, some lenders are concerned about the ability of certain vendors to meet warranty claims. One stated:

  > In the solar space, most of the module suppliers are very weak financially, so we are now requiring completion guarantees in a form of Contingent Equity from the Sponsors and also Warranty Reserve Letters of Credit for the duration of the project: 10 percent of the module supply cost for the years 1–5, and 1 percent for the years 6–20 assuming the performance test is passed at the end of year 5.

- Continuation of Production Tax Credits: Lenders have mixed feelings about the continuation of these tax credits, with some believing that they will continue to be available, but others expecting that if they continue, they could be reduced in size.
- Loan Tenors: As discussed previously, lenders are issuing loans of different tenors. A financial institution's country of origin apparently is a key driver in determining a bank's preference for the term of debt. For example, the Japanese banks issue the longest-term debt with terms as long as the PPA minus two years, and Canadian banks issue the shortest-term debt (for example, 10 years or less).
- Changing Regulations for Banks: Lenders note that changes in banking regulations will likely have an increasing impact on the banks' flexibility in structuring financing in the future. This tightening regulation resulted from the financial meltdown in 2007 – 2009.

Comparison to Other Studies

MRW identified the following studies as providing reliable, recent data on renewable power project financing trends:

- *Renewable Energy Finance Tracking Initiative Solar Trend Analysis* (Hubbell, et al., 2012)

- *Renewable Energy Project Finance in the United States: 2010 – 2013 Overview and Future Outlook* (Mintz, et al., 2012).

The NREL report presents financing trends only for solar PV and concentrated solar power (CSP) projects that had closed financing but were not yet on-line at the time data were collected. In addition, the NREL report disaggregates the data by project size, with one category for projects less than 1 MW and one category for projects greater than 1 MW. NREL researchers collected the data over the period from the fourth quarter of 2009 to the second half of 2011.

The Mintz report addresses financing trends for utility-scale renewable power projects, including wind, CSP, solar PV, geothermal, and biomass projects.

Table 3 summarizes the quantitative financing factors presented in the two reports reviewed by MRW for this report.

Table 3: Summary of Merchant-Owned Financial Parameters From Other Studies

	NREL Report	Mintz Levin Report
PPA Term	15-20 years, weighted average	N/A
1st Year PPA Price	\$0.079 per kWh (for CSP only)	N/A
Escalation Rate	1.6% (for CSP only)	N/A
Percentage of Debt	Variable	N/A
Cost of Debt	Trending down over time, from high of 8.8% to about 6%	5.5% to 10% (fixed) Lowest for wind and highest for CSP Floating debt rates ranged from LIBOR + 175 basis points to LIBOR + 325 basis points
Term of Debt	18 years (solar PV) 12.1 years (CSP)	Varies by technology and project participants; tenors have started to lengthen in recent years
Debt Service Coverage Ratio	1.3	N/A
Return on Tax Equity	Approximately 14% (solar PV)	

Source: MRW.

These reports also present qualitative information on financing trends that is worth considering. Key points made in the two reports are summarized below:

- Debt terms:[8] As was noted previously, banks are not as willing to provide long tenors for financing. Institutional investors that are looking to invest funds are willing to provide long-term financing. This divergence in preference by investor-type has led to new, hybrid financing structures. In the past European banks would offer long-term financing, but the crisis in the European markets and new regulations[9] have significantly curtailed these banks' ability to participate in the market.
- Cost of Debt: NREL identified a reduction in the cost of debt for large-scale PV projects. NREL's numbers (6 percent to 8.8 percent) are similar to the cost of debt reported by Mintz Levin. In its report, Mintz Levin reported pricing for fixed debt of 7 percent to 8 percent for solar PV and 7.5 percent to 10 percent for CSP. The cost of debt was least expensive for wind projects, ranging from 5.75 percent to 7.25 percent, according to Mintz Levin. The reduction in the cost of debt may reflect an increased use of federal cash grants and loan guarantees in the past few years.
- Length of PPAs. The NREL study noted that the length of PPAs for large-scale solar projects mostly declined over the study period but then rose in the second half of 2011.

Review of Power Purchase Agreements

The CPUC provides a spreadsheet that presents the current status of all renewable power projects under development or operating that the IOUs use for Renewables Portfolio Standard (RPS) compliance.[10] This spreadsheet provides a great deal of information about existing and proposed renewable projects, such as project capacity (in MW), expected generation, technology, PPA term, and operational status. For certain RPS projects, the spreadsheet provides links to the project's PPA.[11]

MRW reviewed the publicly available PPAs for 39 projects for energy price data and escalation factors. The energy prices included in the publicly available PPAs ranged from $40.20 per MWh to $139.00 per MWh.

There was only one PPA with a solar project, and this project had the highest power price ($139/MWh). PPA prices for small hydro were next most expensive ($93.83/MWh). Wind purchase prices ranged from $49.00 to $96.81/MWh, and biomass prices varied from

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8 A recent white paper by Bloomberg New Energy Finance provides a matrix showing the characteristics of potential investors, including investors' time horizon and targeted returns. (Reznick Group, 2012, p. 12).

9 The Basel III regulations may hamper future participation by European banks. The Basel III regulations "require that any loans longer than one year be backed by funding of at least one year." (Reznick Group, 2012, p. 14).

10 RPS_Project_Status_Table, see <http://www.cpuc.ca.gov/NR/rdonlyres/054D164B-9DE5-4631-9F05-9CB4C3745B7B/0/RPS_Project_Status_Table_2012_Sept_Final.xls>

11 The PPAs for RPS projects are confidential for a specified period and then are made public.

$40.20 to $81.00/MWh. There was only one geothermal PPA with a publicly available price ($80.02/MWh).

Most of the PPAs reviewed did not have price terms that allowed escalation at a fixed rate. Of the 39 PPAs studied, only 2 contained an explicit escalation factor: 2 percent for a wind plant and 1 percent for a geothermal plant. Six contracts had escalation factor ranges. The structure of these escalation factors was quite diverse:

- A "collar" (that is, the escalation rate was bounded in a specific range)
- A "CPI +" escalator, where the escalation rate equaled the Consumer Price Index (CPI) plus a fixed adder
- A percentage of the CPI with a not to exceed escalation factor

Most commonly, the PPAs provided a table with specific annual energy prices for 5 to 10 years in to the future but did not provide a specific escalation factor.

Tax Benefits and Treatments

General Tax Rates

Corporate taxes are state and federal taxes as listed by the Franchise Tax Board and Internal Revenue Service. Again, these taxes depend on the type of owner. A POU is exempt from state and federal taxes. The calculation of taxes for a merchant facility or IOU power plant is based on the taxable income. The rates are shown in **Table 4**.

Table 4: Federal and State Tax Rates

Tax	Rate
Federal Tax	35.0%
CA State Tax	8.84%
Total Tax Rate	40.7%

Source: Energy Commission.

Ad Valorem

In California, ad valorem (or property) tax differs depending on the developer:

- The merchant-owned facility tax is based on the market value assessed by the BOE, which is assumed to be equal initially to the installed cost of the facility. The value reflects the market value of the asset but may not increase in value at a rate faster than

2 percent per annum per Proposition 13. An average statewide rate of 1.1 percent is multiplied by the installed cost of the power plant and a property tax depreciation ("percent good") factor from BOE tables.

- The utility-owned plant tax is based on the value assessed by the BOE and is set to the net depreciated book value. An average statewide rate of 1.098 percent is multiplied by the depreciated book value. Counties are allocated property tax revenues based on the share of rate base within each county.
- Publicly owned plants are exempt from paying property taxes but may pay a negotiated in-lieu fee, which in the COG Model is assumed to be equal to the calculated property tax for a utility-owned plant.

New solar units receive a lifetime exemption from ad valorem until the exemption expires in 2017. 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.

Sales Tax

California sales tax is estimated as 8.4 percent based on the 2013 Legislative Analyst's Office estimate (Taylor, 2013). Sales tax is applied against materials only, not against labor. For the wind units and the solar tower with 11 hours storage, the data were collected as installed costs, which included the sales taxes.

Renewable Energy Tax Credits and Incentives

Table 5 summarizes the technologies that are eligible for renewable energy production tax credits (REPTC) and renewable energy production incentives (REPI) for municipal utilities. The table summarizes those plants eligible for federal business energy tax credits or investment tax credits (BETC or ITC, respectively) under the 2005 and 2008 Federal Energy Policy Acts (EPAct), the 2009 American Recovery and Reinvestment Act (ARRA), and the 2012 American Taxpayer Relief Act. The ARRA made most of the technologies that had been eligible for the REPTC also eligible for the ITC if the latter provided a larger benefit. The ARRA also allowed those technologies claiming the ITC to be able to recover the entire benefit in a single year as a "grant" rather than capping the ITC that can be claimed at the amount of net taxable income in any single year, but this provision expired fully by the end of 2012. The REPI amount is adjusted for the proportion that is actually paid out from available federal funds, which is currently zero. For the high-cost and mid-cost cases, these tax credits and exemptions expire after the legal deadline specified for each technology and program. In the low-cost case, the tax benefits are assumed to extend indefinitely.

Table 5: Federal Renewable Energy Tax Incentives

Technology	Wind	Biomass Open Loop (Ag waste)	Biomass Closed Loop	MSW/ Landfill	Geothermal[1]	Solar[3]
Production Tax Credit						
Credit (2011$)/MWh	$21	$10	$21	$10	$21	
Credit (1993$)/MWh	$15	$7.50	$15	$7.50	$15	
Duration (Years)	10	10	10	10	10	
Expiration[5]	2014	2014	2014	2014	2014	
Eligibility	Merchant	Merchant	Merchant	Merchant	Merchant	
Investment Tax Credit						
Credit					10%	*30%/10%*
Depreciable Value Reduced					5%	*15%/5%*
Expiration[5]					NA	2017
Loss Carry Forward Period (Yrs)					20	20
Expiration[5]	2014	2014	2014	2014	2014	2017
Eligibility	Merchant/ IOU	Merchant/ IOU	Merchant/ IOU	Merchant/ IOU	*Merchant*	Merchant/ IOU
Production Incentive[4]						
Tier I Payment	$0.0		$0.0		$0.0	$0.0
Tier II Payment		$0.0		$0.0		
Duration (Years)	10	10	10	10	10	10
Expiration[5]	2027	2027	2027	2018	2027	2027
Eligibility	POU/ Coops	POU/ Coops	POU/ Coops	POU/ Coops	POU/ Coops	POU/ Coops

Source: Aspen Environmental.

Notes:

1. Geothermal ITC does not expire. Unclear as to whether the ARRA increased the ITC for geothermal to 30 percent until 2014, and whether self-sales are eligible.
2. Solar ITC reverts to 10 percent in 2016.
3. REPI payments assumed = 0 percent as these have not been funded since 2009.
4. Expiration formulas are expressed as start year < expiration year so all years are given as the year following the expiration data. For example, for a credit with an expiration date of 12/31/2013, it is listed as 2014.

Financing Assumptions for Different Generation Ownership Structures

The specific financial assumptions used to calculate the levelized cost of a project depend on the terms that are available to the borrower. This means different ownership structures will require different assumptions are made to estimate the cost of a new project. Financial assumptions include capital structure (amount of debt versus equity), debt term, and economic/book life.

Table 6 summarizes the capital cost structure assumptions used in the COG Model to produce levelized costs outlined in Chapter 10. **Table 7** summarizes technology-specific parameters for merchant renewable plants.

the debt-to-equity split is different for merchant natural gas-fired plants than other technology plants (renewables and alternative technologies). The rationale is that financial institutions are likely to see PPAs signed under legislative and regulatory mandates, such as the RPS, as less risky than those signed under open market conditions.

Table 8 summarizes the debt term and book life assumptions used in the COG Model. The debt term and equipment life assumptions determine the period over which the loans must be paid (debt term) and then the period over which costs are incurred and the revenues can be generated (book life). These two assumptions play an important role in determining the levelized cost of a project and, therefore, its economic viability.

Table 6: Capital Cost Structure

Owner	Equity Share	Cost of Equity	Cost of Debt	WACC
Mid Cost Case				
Merchant Fossil	33%	13.25%	4.52%	6.17%
Merchant Alternative	40%	Var*	Var*	Var*
IOU	55.%	10.04%	5.28%	6.93%
POU	N/A	N/A	3.20%	3.20%
High Cost Case				
Owner	**Equity Share**	**Cost of Equity**	**Cost of Debt**	**WACC**
Merchant Fossil	60%	15.00%	6.63%	10.57%
Merchant Alternative	50%	Var*	Var*	Var*
IOU	70%	10.31%	5.65%	8.22%
POU	N/A	N/A	5.96%	5.96%
Low Cost Case				
Owner	**Equity Share**	**Cost of Equity**	**Cost of Debt**	**WACC**
Merchant Fossil	20.00%	10.41%	4.64%	4.28%
Merchant Alternative	25.00%	Var*	Var*	Var*
IOU	9.71%	9.71%	4.55%	6.06%
POU	N/A	N/A	3.02%	3.02%

Source: Energy Commission.

Var= Variable as shown in **Table 7**.

Table 7: Financial Parameters for Merchant-Owned Renewables

Mid Cost Case						
Technology	**Cost of Equity**			**Debt**		**WACC**
	Developer's Cost	Equity Investor's Cost	Weighted Cost of Equity	Percent Debt	Cost of Debt	
Biomass & Geothermal	13.25%	8.00%	12.41%	60.00%	6.31%	7.21%
Solar Technologies	13.25%	8.00%	12.41%	60.00%	5.91%	7.07%
Wind Technologies	13.25%	8.00%	11.34%	60.00%	5.91%	6.64%

High Cost Case						
Technology	**Cost of Equity**			**Debt**		**WACC**
	Developer's Cost	Equity Investor's Cost	Weighted Cost of Equity	Percent Debt	Cost of Debt	
Biomass & Geothermal	15.00%	10.00%	14.20%	50.00%	7.63%	9.36%
Solar Technologies	15.00%	10.00%	14.20%	50.00%	7.36%	9.28%
Wind Technologies	15.00%	10.00%	14.20%	50.00%	7.36%	9.28%

Low Cost Case						
Technology	**Cost of Equity**			**Debt**		**WACC**
	Developer's Cost	Equity Investor's Cost	Weighted Cost of Equity	Percent Debt	Cost of Debt	
Biomass & Geothermal	10.41%	7.00%	9.17%	75.00%	5.12%	4.57%
Solar Technologies	10.41%	7.00%	9.86%	85.00%	4.59%	3.79%
Wind Technologies	10.41%	7.00%	9.17%	85.00%	4.59%	3.69%

Source: Energy Commission.

Table 8: Debt Term and Book Life Assumptions

Technology	Debt Term* (Years)			Book Life (Years)		
	Mid	High	Low	Mid	High	Low
Generation Turbine 49.9 MW	10	7	20	30	20	30
Generation Turbine 100 MW	10	7	20	30	20	30
Generation Turbine - Advanced 200 MW	10	7	20	30	20	30
Combined Cycle - 2 CTs No Duct Firing 500 MW	10	7	20	30	20	30
Combined Cycle - 2 CTs With Duct Firing 550 MW	10	7	20	30	20	30
Biomass Fluidized Bed Boiler 50 MW	20	15	25	30	20	30
Geothermal Binary 30 MW	20	15	25	30	20	30
Geothermal Flash 30 MW	20	15	25	30	20	30
Solar Parabolic Trough W/O Storage 250 MW	20	15	25	30	20	30
Solar Parabolic Trough With Storage 250 MW	20	15	25	30	20	30
Solar Power Tower W/O Storage 100 MW	20	15	25	30	20	30
Solar Power Tower With Storage 100 MW 6 HRs	20	15	25	30	20	30
Solar Power Tower With Storage 100 MW 11 HRs	20	15	25	30	20	30
Solar Photovoltaic (Thin-Film) 100 MW	20	15	25	30	20	30
Solar Photovoltaic (Single-Axis) 100 MW	20	15	25	30	20	30
Solar Photovoltaic (Thin-Film) 20 MW	20	15	25	30	20	30
Solar Photovoltaic (Single-Axis) 20 MW	20	15	25	30	20	30
Wind - Class 3 100 MW	20	15	25	30	20	30
Wind - Class 4 100 MW	20	15	25	30	20	30

Source: Energy Commission.

* Debt term values are for merchant plants, only. IOU and POU are equal to book life for all three cost cases.

The federal and state tax lives are used to set the federal and state tax depreciation periods. Federal is 20 years for gas-fired units and 5 years for renewable technologies. State is 15 years for gas-fired units and 20 for renewable. The base federal tax life is taken from Internal Revenue Service Publication 946 (2008), Appointment B, Asset Class 49, but scenarios were run where the tax life could vary for a technology, for example, generation turbines (IRS, 2014). Accelerated depreciation allowances for certain technologies arise from the energy policy acts dating back to 1992. These accelerated depreciation periods are a tax benefit that is captured in the COG Model and range of calculated levelized costs.

CHAPTER 3:
Emissions, Fuel, and Transmission Costs

While each project and generation technology brings a unique set of costs and underlying trends, there are some costs that are independent of the technology type. These include costs for environmental mitigation such as emissions credits, which do not affect all technologies equally but are based on the emissions profile of the technology; fuel such as natural gas or biomass for power plants; and transmission services to deliver energy from the generator to the interconnection point and from the interconnection point to the load. The following describes the assumptions for these cost components and how they were incorporated in estimating costs for the different technologies.

Costs of Environmental Mitigation

Environmental mitigation measures have become increasingly important components of power plant costs, for both fossil-fueled and renewable generators. For natural gas-fired generators, the largest compliance cost component usually is criteria pollutant emission reduction credits (ERCs); for renewables it is habitat mitigation and land acquisition. Other compliance costs include the regulatory permit application, processing, and monitoring costs. Environmental mitigation generally is incorporated directly into the plant construction cost estimates reported here, as most sources do not separately distinguish those costs. Future research on the magnitude of those costs and the differences across jurisdictions could allow better delineation of those costs.

The exception is the environmental mitigation costs for natural-gas fired plants. Staff conducted a survey of costs for existing plants within California, including environmental permitting and water supply costs. The environmental permitting costs and water supply costs are listed as separate items as inputs to the COG Model based on the survey responses. ERC costs are further segmented because those costs have a distinct trend that can be estimated with historical data.

A new source of environmental mitigation costs is for greenhouse gas (GHG) allowances under the ARB California Cap-and-Trade Program (CCTP). Compliance is based on actual annual operations rather than meeting a specific emission rate threshold, and allowances are auctioned by the ARB several times a year. The costs associated with allowances are more akin to fuel costs and are represented in the COG Model as annual expenses rather than upfront capital investment, as is the case for the ERCs.

New power plants must comply with air quality regulations enforced by local air districts under the state and federal Clean Air Acts, also called New Source Review (NSR). Whether a particular power plant needs to meet emission limits depends on whether the power plant is located is an air basin that is in compliance with federal and state ambient air quality standards.[12] When in a nonattainment area, power plants must meet maximum emission rates and further reduce emissions at other existing regional sources by acquiring ERCs (at an offset ratio ranging from 1.0 to 1.5) to compensate for the new emissions from the power plant. The ERC represents an entitlement to emit at a daily rate (usually pound or tons per day) for the life of the project. Most commonly ERCs are bought through brokers or similar market institutions.

In several cases, most notably the South Coast Air Quality Management District (SCAQMD), ERCs are either available only through a community bank or not at all. SCAQMD'S Rule 1304 provides an exemption to the requirement for ERCs to offset any emission increases for the replacement of an electric steam utility boiler to more efficient or advanced technology. Under this exemption SCAQMD has been retiring offsets from the district's internal account without a fee. A recent change to Rule 1304 allows SCAQMD to charge a fee for utility boiler replacement. However, there is an exemption for utility boiler replacements, provided they are replaced with combined-cycle (CC) or advanced intercooled gas turbines and there is no increase in the MW.

Emission Factors and Permitting Operational Assumptions

ERC costs for any new power plant are a function of three factors: criteria pollutant emission factors, operational parameters used in the permit, and the price per ton permitted. The criteria pollutant emission factors used in the COG Model are based on recent projects are provided in **Table 9**. The criteria pollutant emissions are based on permitted rather than actual emissions, which are assumed to be related to a consistent interpretation of best available control technology requirements within California. Therefore, average, high, and low values do not apply.

These emission factors are then multiplied by the number of hours of operation permitted by the local district. The permitted operations include a large margin for operations beyond the expected typical runtime. For CC plants, the most common assumption is that the plant will be operated as baseload, with a 90 percent CF.[13] For simple-cycle (SC) plants, a typical permit level is for 3,000 hours per year or a 34 percent CF; however, these plants rarely run beyond a 10 percent CF. This operational weighted emission factor is the reported value in the outputs of the COG Model.

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12 "2002 Area Designations" See <http://www.arb.ca.gov/regact/2012/area12/area12.htm>.

13 The average capacity factor for a combined-cycle power plant in California was only 36.8 percent in 2011. This value includes wide variation among plants that operated at very low CFs and those that operated at very high capacity factors. In most cases, plants must obtain permits for the maximum they might operate per year. This means most plants buy enough credits to run at close to 100 percent CF.

Table 9: Recommended Criteria Pollutant Emission Factors (lbs/MWh)

Technology	NO_x	VOC	CO	SO_x	PM10
Conventional SC[a]	0.279	0.054	0.368	0.013	0.134
Advanced SC	0.099	0.031	0.19	0.008	0.062
Conventional CC	0.07	0.024	0.208	0.005	0.037
Conventional CC w/Duct Firing	0.076	0.018	0.315	0.005	0.042
Biomass Fluidized Bed Boiler 50 MW	0.075	0.012	0.105	0.034	0.100
Geothermal Flash 30 MW	0.191	0.011	0.058	0.026	0.000

Source: Energy Commission.

Notes:

a The conventional SC values are used for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

ERC Price Trends

The ARB has tracked reported ERC prices since 1993.[14] These markets are "thin" with few transactions and few participants, so price data can vary widely. Regardless, prices have shown a general upward trend, particularly for those pollutants that are most tightly regulated, for example oxides of nitrogen (NO_x), volatile organic compounds (VOC) and particulate matter (PM).

Staff developed price forecasts for ERCs for these three pollutants in five regions that represent aggregations of several nonattainment districts. [15] These prices are then multiplied by the offset ratios applicable for the specific region or district.

Figure 2 shows the price forecasts for NO_x ERCs for each region based on this regression forecast, except for the SCAQMD. For SCAQMD, the price is based on a 30-year strip of Regional Clean Air Incentives Market (RECLAIM) and RECLAIM Trading Credits (RTC) escalating at the rate of inflation. The RTC prices have been stable since the market was restarted after the 2001 energy crisis. NO_x ERC prices have been escalating rapidly in the San Diego and Imperial County air districts, which are reflected in the trend. The trend for the San Joaquin, Kern, and Mojave Desert air districts also rises significantly.

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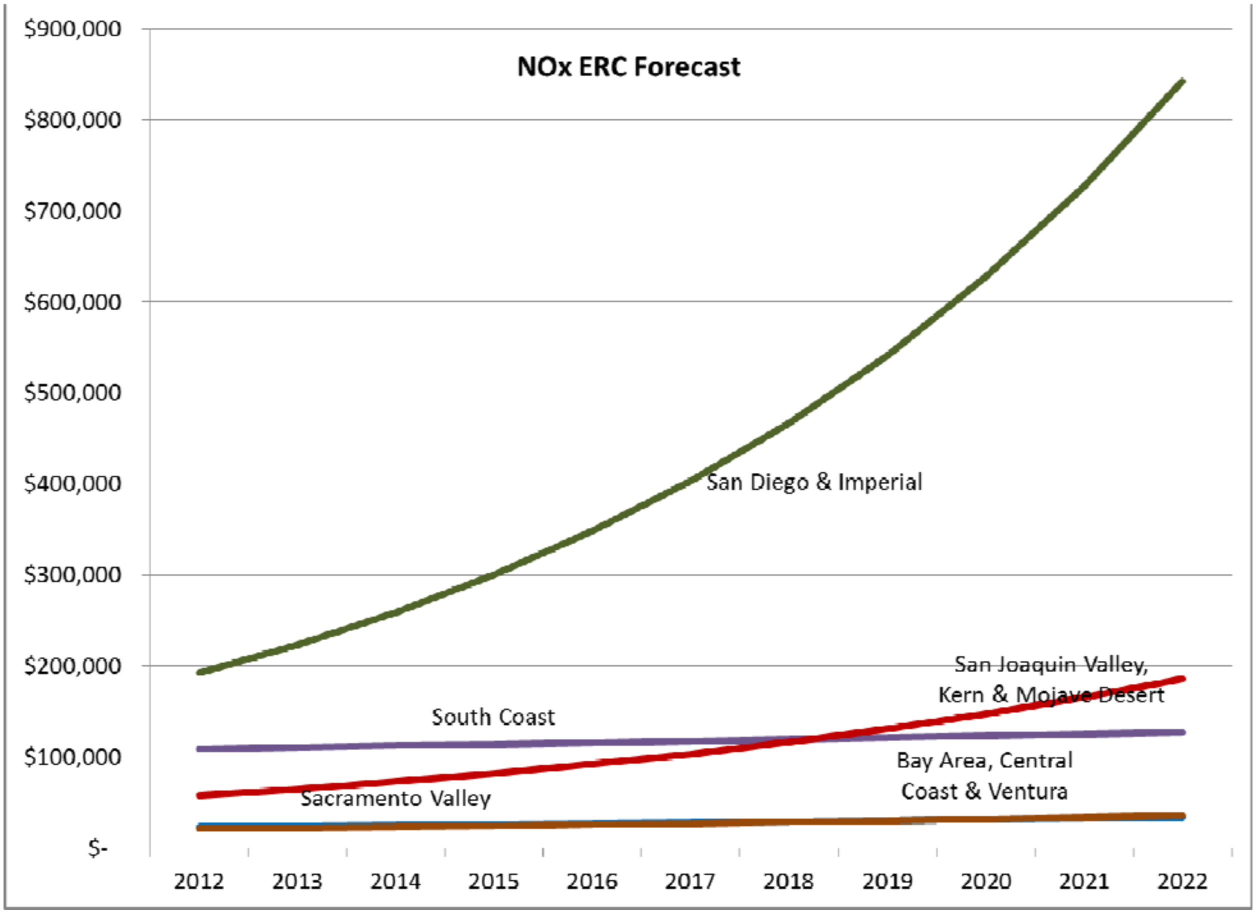
14 "New Source Review…" See <http://www.arb.ca.gov/nsr/erco/erco.htm>

15 The forecasts are pooled time-series across the regions and for the period from 1993 to 2011, with a trend regressed on the log of the ERC prices and multiplicative interactive terms with the regions.

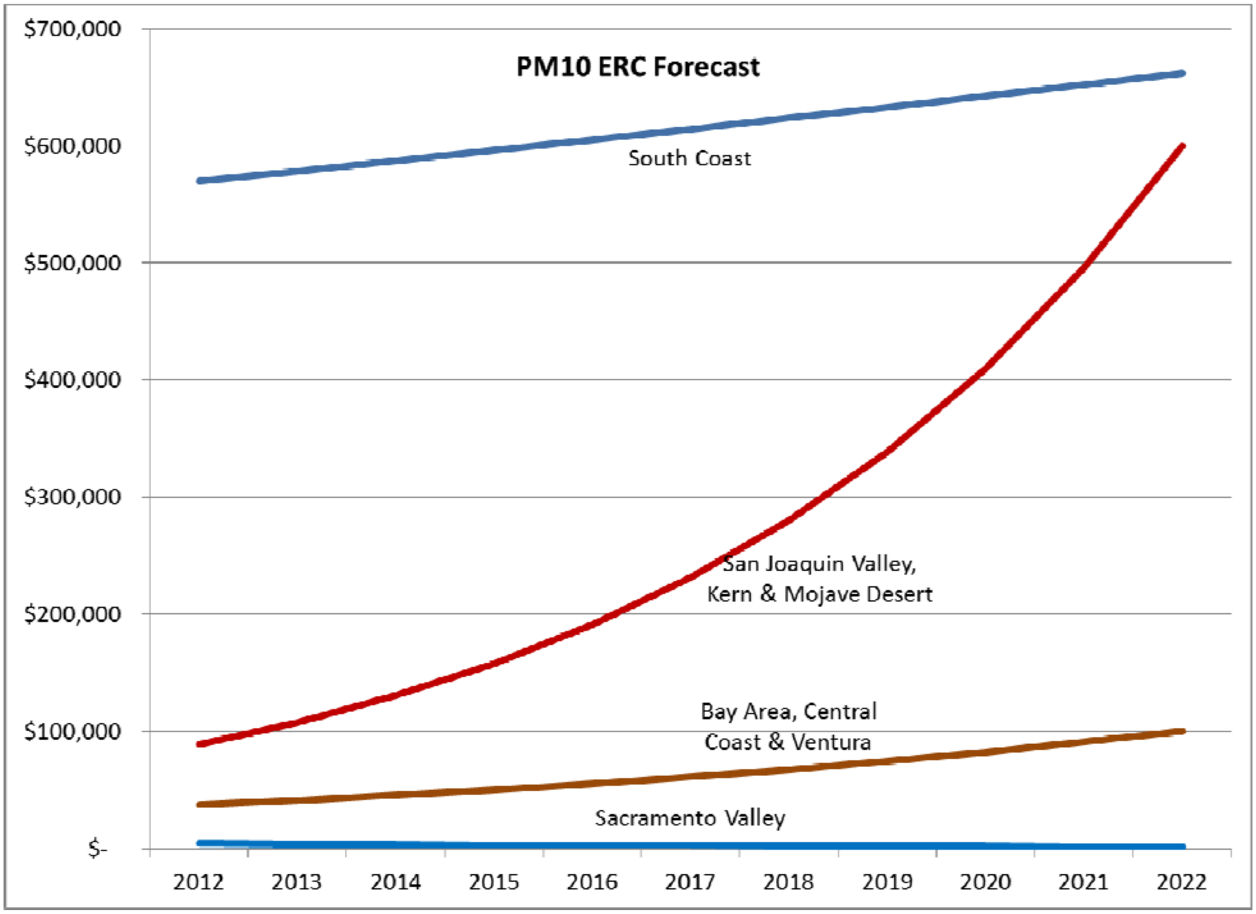
Figure 2: NO_x Emission Reduction Credit Forecast for Five Air District Regions to 2022



Source: Energy Commission.

Figure 3 shows the price forecast for the PM ERCs for each region, again with a separate method for the SCAQMD forecast. In this case, the San Joaquin Valley Air Pollution Control District (APCD) and Mojave Desert AQMD regions face a rapid increase, approaching the SCAQMD price in later years. For the SCAQMD, the forecast is based on the proposed Rule 1304.1 (SCAQMD, 2013) method and linked to the inflation price adjustment calculation specified in Rule 320 (SCAQMD, 2010). The price is based on a weighted average of transactions the previous five years and escalated at the rate of inflation. In contrast, San Diego and Imperial are in compliance and do not require ERCs.

Figure 3: Particulate Matter Volatile Organic Compounds Price Forecast for Five Air District Regions to 2022



Source: Energy Commission.

Greenhouse Gas Allowances

The CCTP is one component of the ARB's program to comply with the objectives in Assembly Bill 32 Global Warming Solutions Act, (Nùñez, Chapter 488, Statutes of 2006) (AB 32), which requires the statewide GHG emissions to reach 1990 levels by 2020. The CCTP officially began operation on January 1, 2013. The primary participants are electric utilities and generators, and industrial sources that emit more than 25,000 tons of carbon dioxide equivalent (CO_{2e}) annually. This includes nearly all fossil-fueled electric generators in California.[16] The ARB first auctioned allowances in November 2012 and has staged subsequent auctions in 2013.

16 Besides fossil-fueled generators, the CCTP also covers large industrial users, such as oil and gas extraction, large food processing plants, and manufacturers of cement and other building products.

Greenhouse Gas Emission Rates

The carbon dioxide emission factors used in the COG Model were determined based on the efficiency for each technology, using an emission factor of 52.87 pounds per million British thermal units (lbs/MMBtu).[17] **Table 10** provides the staff's estimated carbon dioxide emission factors for each technology under three cases. The emission factors were based on the heat rates derived from the *Quarterly Fuel and Energy Report (QFER)* data filings for natural gas and from the studies reviewed for biomass and geothermal referenced in the following applicable sections. The range for biomass reflects how emissions from this technology will be handled. There is dispute among stakeholder as to whether emissions from biomass fuels, which would naturally break down emitting GHGs without being used for electric generation, should be considered a zero net emitter of GHGs. The estimates shown in **Table 10** reflect this uncertainty over whether biomass emissions should be counted on net as total emissions.

Table 10: Carbon Dioxide Emission Factors Used in COG Model (Pounds Per Megawatt Hour [lbs/MWh])

Technology	Average	High	Low
Conventional SC[a]	1239.3	1392.1	1168.5
Advanced SC	1239.3	1392.1	1168.5
Conventional CC	1156.8	1194.2	1124.0
Conventional CC w/Duct Firing	848.8	875.8	823.1
Biomass Fluidized Bed Boiler 50 MW	195.0	195.0	0
Geothermal Binary 30 MW	0	180.0	0
Geothermal Flash 30 MW	264.5	397.0	98.9

Source: Energy Commission.

Notes:

[a] The conventional SC values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

Greenhouse Gas Allowance Prices

Under the CCTP, most participants received free allowances for all or a portion of their emission limit in each year through 2015, with free allowance allocations scheduled to be reduced after that date. California's overall emissions have fallen since the *AB 32 Scoping Plan*[18] was developed in 2008, largely due to the decrease in economic activity from the 2008

17 Emission factor is from the ARB for natural gas with an assumed heating content (HHV [high heating value) between 1,000 and 1,025 Btu/scf.

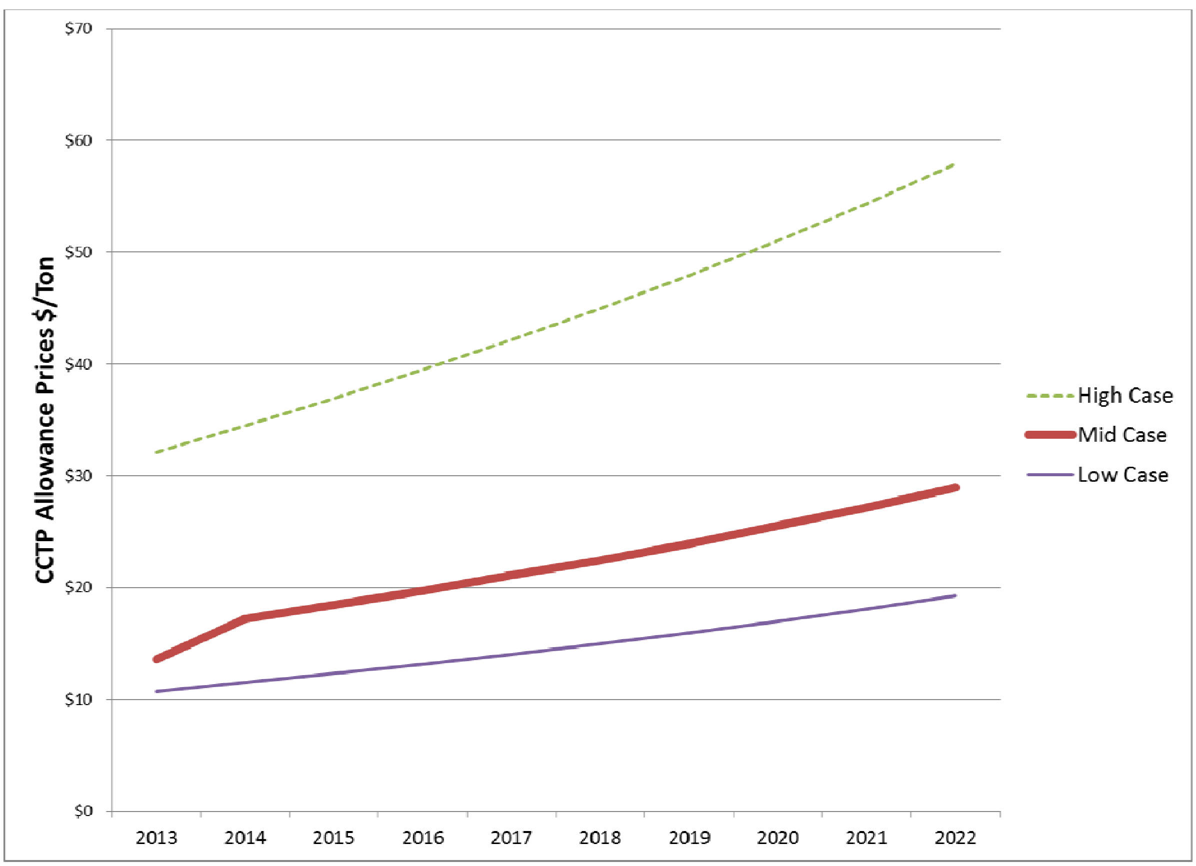
18 http://www.arb.ca.gov/cc/scopingplan/document/adopted_scoping_plan.pdf

recession. For this reason, firms have had an easier time complying with the emission limits than originally anticipated.

CCTP allowances are auctioned four times a year by the ARB. The auction price is bound by a minimum reserve price set at $10 per ton in 2012 and escalated at 5 percent plus inflation each year, and a ceiling of $50 in 2012, again escalated at 5 percent plus inflation per year. A recent report by the ARB's Emission Market Assessment Committee and the Market Simulation Group (EMAC and MSG, respectively) forecasted that the most likely scenarios are for the price to be at either the floor or the ceiling price, with the preponderance of probability at the lower end (Bailey, et al., 2013).

Consistent with the EMA/MSG forecast, the November 2012 auction for 2013 allowances cleared at the floor price, indicating that a surplus of allowances was available. However, in February 2013, the auction price rose to $13.62 for 2013 allowances; similarly secondary market prices rose to near $14 per ton in the period prior to and after the auction. Assuming the persistence of the allowance price remaining above the floor, the mid-case forecast assumes that the price will be 50 percent above the floor price. The high-cost case assumes the price will be three times the floor price unless it is constrained by the reserve price. **Figure 4** shows the price forecast.

Figure 4: California Cap-and-Trade Allowance Price Forecast to 2022



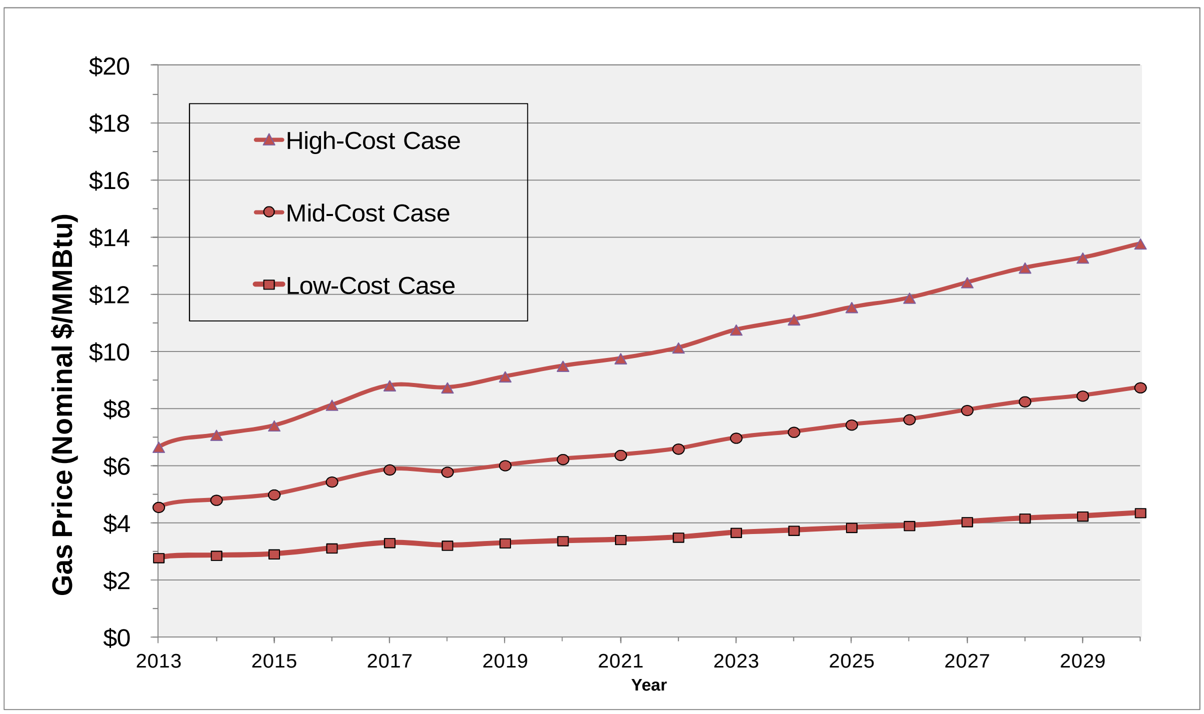
Source: Energy Commission.

Fuel Costs

Fuels for biomass and natural gas-fired power plants are major components of their cost of generation**.** Natural gas for electric generation is primarily purchased from regional market hubs for delivery via the major natural gas pipelines in California. As a result, these prices reflect the national trends in prices. Biomass fuels are produced through a process similar to a blend of farming and forestry, depending on the specific location and design of the plant. This means that prices for biomass fuels tend to be driven by localized factors and are cheaper than more standard fossil fuels, such as oil or natural gas.

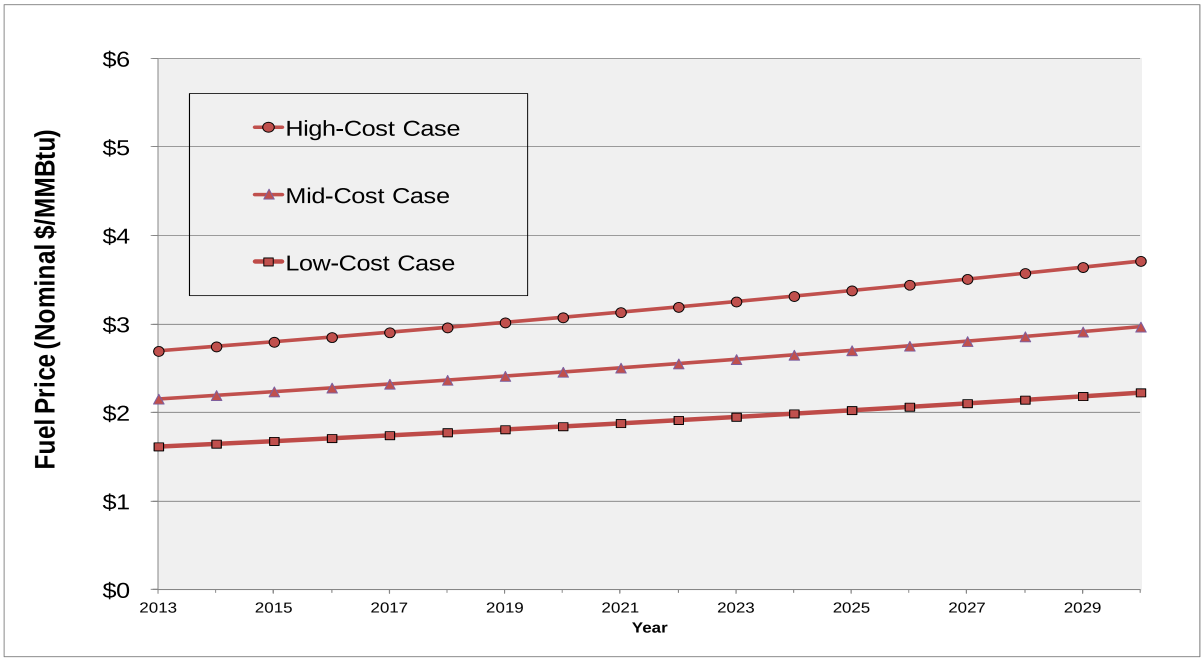
Figure 5 summarizes the natural gas prices through 2030 used in the COG Model, and **Figure 6** shows biomass fuel prices over the same period. These are carried over from the 2009 COG Model and were originally developed under contract by KEMA. These values are adjusted for inflation from the 2009 edition because no new price information was available. Prices are provided for three cost cases and all prices are nominal dollars.

Figure 5: California Natural Gas Prices



Source: Energy Commission.

Figure 6: Biomass Prices in California



Source: Energy Commission (2009 Renewables Study).

Natural gas fuel cost estimates are based on wellhead prices created by the North American Market Gas-Trade Model (NAMGas Model) used by the Energy Commission to produce the *Natural Gas Outlook* report for the *2013 IEPR.*[19] These values were then adjusted by staff to add transportation costs to provide burner tip natural gas prices.[20]

The future price of natural gas is difficult to estimate, despite its importance to estimating the operating cost of natural gas-fired generation. **Figure 7** demonstrates the difficulties inherent in developing point forecasts of natural gas prices and the range of uncertainty experienced over the last 30 years. It compares actual wellhead natural gas prices against historical U.S. Energy Information Administration (U.S. EIA) forecasts.

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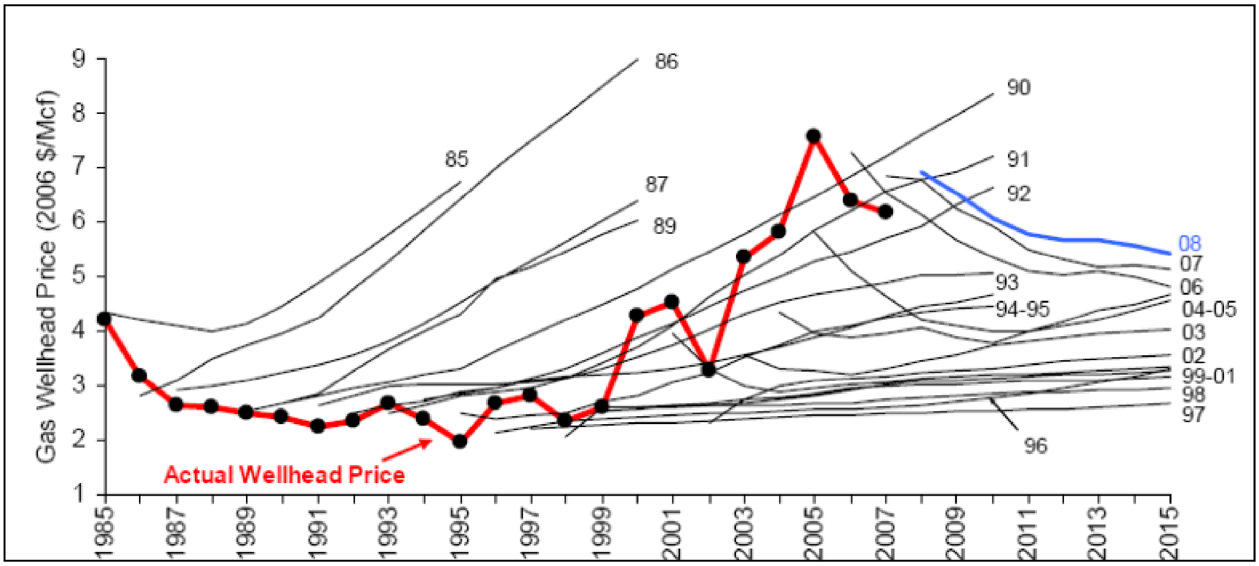
19 "Presentations for the April 24, 2013 Staff Workshop…" see <http://www.energy.ca.gov/2013_energypolicy/documents/index.html#04242013>

20 A "burner tip" price is the full price of gas paid that includes the commodity price, as well as the price to transport it to the plant for consumption.

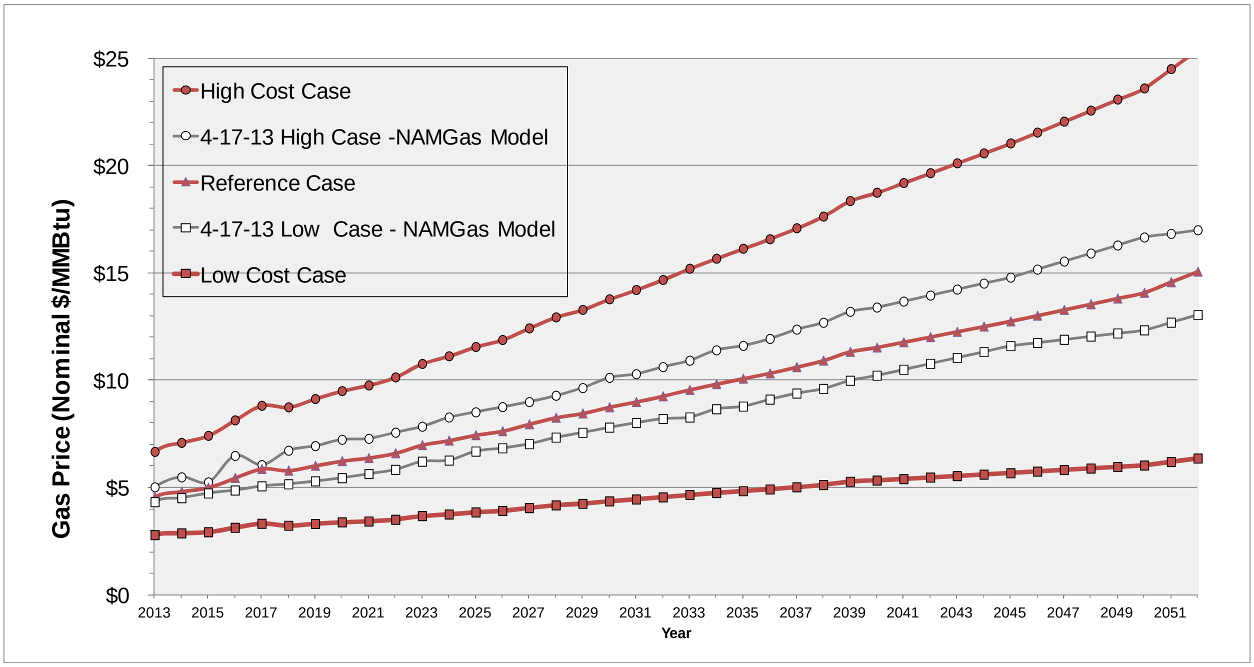
Figure 7: Historical U.S. EIA Wellhead Natural Gas Price Forecast vs. Actual Price



Source: Lawrence Berkeley National Laboratory.

Although the NAMGas Model also provides high-cost and low-cost estimates, they vary in a fairly narrow range, which could imply that there is little uncertainty in underlying trends going forward (Klein, 2010). Staff has, therefore, chosen to supplement the natural gas prices produced by the NAMGas Model by using historical forecast error to provide a wider bandwidth of fuel costs, reflecting a wide range of uncertainty. Staff extrapolated from the past success and failure in natural gas price forecasting by measuring the historical failure rate and projecting that rate into the future. These error bands were applied to the NAMGas Model reference case to produce the high and low natural gas price series used in the COG Model. **Figure 8** shows a comparison of staff's estimated natural gas fuel costs to the NAMGas Model high-low forecasts with those used by the COG Model.

Figure 8: Forecast Compared to NAMGas High-Cost and Low-Cost Forecasts



Source: Energy Commission.

Transmission Costs

There are two factors associated with transmission that impact the cost of generation resources: losses and costs. These are separated into two general categories because of a key difference between conventional and renewable resources. Conventional resources are able locate near load centers and along existing transmission corridors because the fuel can be delivered to the power plant. Renewable resources must be located at the energy source, which typically is far from load centers or transmission corridors. Losses increase with distance, and costs increase with the length of the line.

Another important factor in considering transmission is the difference between "transmission costs" and the allocation of those costs through "transmission rates." The incremental costs of adding transmission to deliver new power can be readily identified by comparing the costs of meeting loads with one set of resources versus another set. However, transmission rates can reflect policy decisions about how to allocate those costs that are not so readily apparent. For example, California ISO policy emphasizes "postage stamp"[21] transmission rates rather than allocating individual project costs to specific generators or

21 *Postage stamp* is a term used in California ISO policy documents to describe a system that simplifies transmission rates among most projects to a single standardized value, similar to the way the United States mail applies a single "First Class" rate on all letters up to a certain size.

customers. Transmission costs based on the incremental costs of new transmission would ignore or exclude the additional costs that are factored into these California ISO rates. [22] Consequently, this analysis incorporates transmission costs through the rates paid by California ISO transmission users.

Interconnection Losses

Interconnection losses occur between the busbar[23] or generator and the point of first interconnection to the transmission grid, 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 vary depending on the voltage and length of the line. **Table 11** shows the estimated losses for various sizes of interconnections. Losses increase as voltage decreases; this means that smaller facilities that are typically connected to lines operating at lower voltages, as is more common for renewables, experience higher losses.

22 As is often the case in analyses, attempting to ignore the consequences of a particular aspect is identical to making an invalid assumption that the parameter equals zero. In all of these cases, it is necessary to make some type of assumption, even if it cannot be validated with rigorous support.

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

Table 11: Interconnection Loss Estimates for Generation Tie-Lines

Nominal Operating Voltage (kV)	Maximum Capacity (MW)	Tie-Line Length (Miles)	Plant Output (MW)	Tie-Line Losses (%)
34.5	13	10	10	9.41%
34.5	17	10	15	9.11%
34.5	30	10	25	6.28%
69	38	10	35	4.35%
69	60	10	50	3.14%
69	75	10	70	3.12%
69	87	10	80	2.67%
115	114	10	100	6.46%
115	137	10	120	1.65%
115	169	10	150	1.45%
230	339	10	325	0.79%
230	382	10	350	0.72%
230	454	10	400	0.62%
500	1,126	10	750	0.20%
500	2,252	10	1,500	0.20%

Source: Dave Larsen, Navigant (2012).

Transmission Losses

Transmission losses represent the power lost from the point of first interconnection to the point of delivery to the load-serving entity in the California ISO control area. This point of delivery is considered to be the substation at the demarcation between the transmission and distribution system. Losses through the distribution system are not included in these transmission losses and would have to be added to make these resources comparable to distributed generation (DG) and demand-side management (DSM).

Table 12 shows losses are estimated from the California ISO reports (California ISO, 2012; California ISO, 2011). In a change from the *2009 IEPR* cost analysis, losses for renewables are estimated at 2.7 percent, down from 5 percent, based on a weighted average from the different areas targeted for renewables development (Klein, 2010).

Table 12: Peak Load Transmission Losses

Area	Busload (MW)	Losses (MW)	Pumps (MW)	Total	Losses	*Source:*
LA Basin	19,300	133	27	19,460	0.7%	*(1)*
San Diego/Imperial Valley	4,990	134		5,124	2.6%	*(1)*
Humboldt	200	10		210	4.8%	*(2)*
North Coast/North Bay Area	1,386	34		1,420	2.4%	*(2)*
Sierra	1,713	103		1,816	*5.7%*	*(2)*
Stockton	1,067	19		1,086	1.7%	*(2)*
Greater Bay Area	9,493	197	264	9,954	2.0%	*(2)*
Greater Fresno Area	3,014	105		3,119	3.4%	*(2)*
Kern Area	1,099	11		1,110	1.0%	*(2)*
Big Creek/Ventura	4,260	78	355	4,693	1.7%	*(2)*
System Average					***1.8%***	
Renewables Areas					***2.7%***	

Source: Energy Commission.

(1) California ISO, *2013 Local Capacity Technical Analysis Addendum to the Final Report and Study Results: Absence of San Onofre Nuclear Generating Station (SONGS)*, August 20, 2012

(2) California ISO, *2012 Local Capacity Technical Analysis Final Report and Study Results*, April 29, 2011

Transmission Access Costs

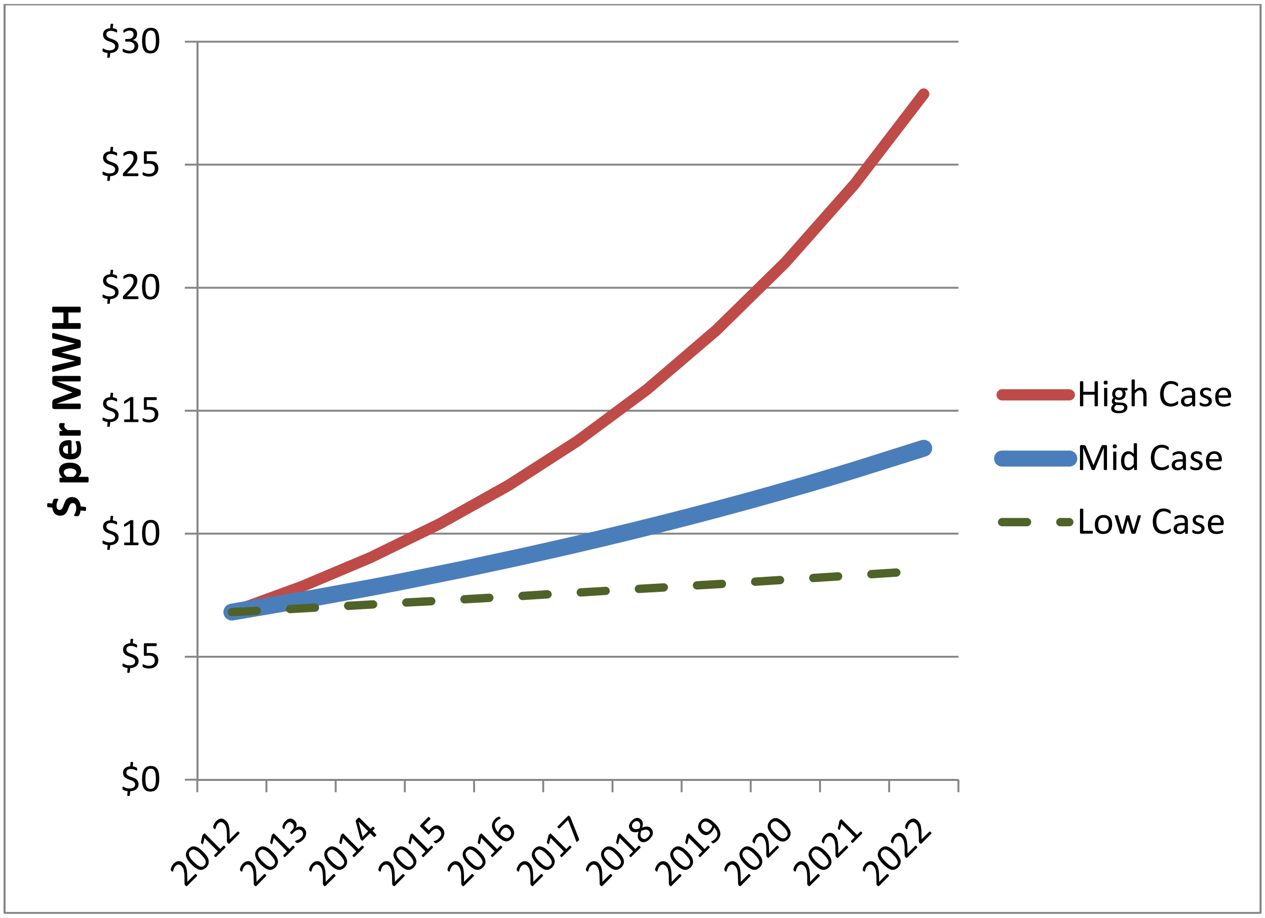
Beyond the added cost of overcoming the interconnection and transmission losses, generation owners must also pay the California ISO for delivering their energy to their customers. The California ISO has adopted the wheeling access charge for generation transmitted within its control area on its high-voltage network. Relatively small charges are added for lower voltage transmission within specific service areas; however, this analysis ignores those smaller amounts to avoid undue complexity.

A forecast of California ISO wheeling charges was developed from a trend analysis of the California ISO's charges from 1998 to 2013. The access charge has grown at a steady 7.1 percent per year without inflation.[24] This rate of escalation is used in the mid-cost case. The California ISO has forecasted, in its *2013 Transmission Plan*, that rates will grow at between 5.7 percent and 9.5 percent per year through 2022 (California ISO/MID, 2013). **Figure 9** shows the projected range of growth in transmission rates used in the COG Model. The mid case forecast of 7.1 percent per year represents the average from the California ISO

24 "Revised Wheeling Access Charge Rates" See <http://www.caiso.com/Documents/RevisedWheelingAccessChargeRatesFeb28_2012.htm>

Transmission Plan. The high and low cases are drawn from the highest and lowest five-year segments in the California ISO's analysis presented in the 2010 Long Term Procurement Proceeding (LTPP) (E3, 2011) The range is from 2.2 percent to 15.1 percent per year using this method.

Figure 9: California ISO Wheeling Access Charge Forecasts



Source: Energy Commission.

This analysis does not estimate a separate transmission charge for generation in other balancing authority areas (BAA) because there is not sufficient information to compute a rate that would be comparable to the California ISO charge. In the case of the Los Angeles Department of Water and Power (LADWP) BAA, this is particularly significant because LADWP owns and operates a large share of the state's transmission network. Further input from the other BAAs would be helpful in developing these cost estimates.

CHAPTER 4:
Solar Photovoltaic Technologies

Overview

Analytic Approach

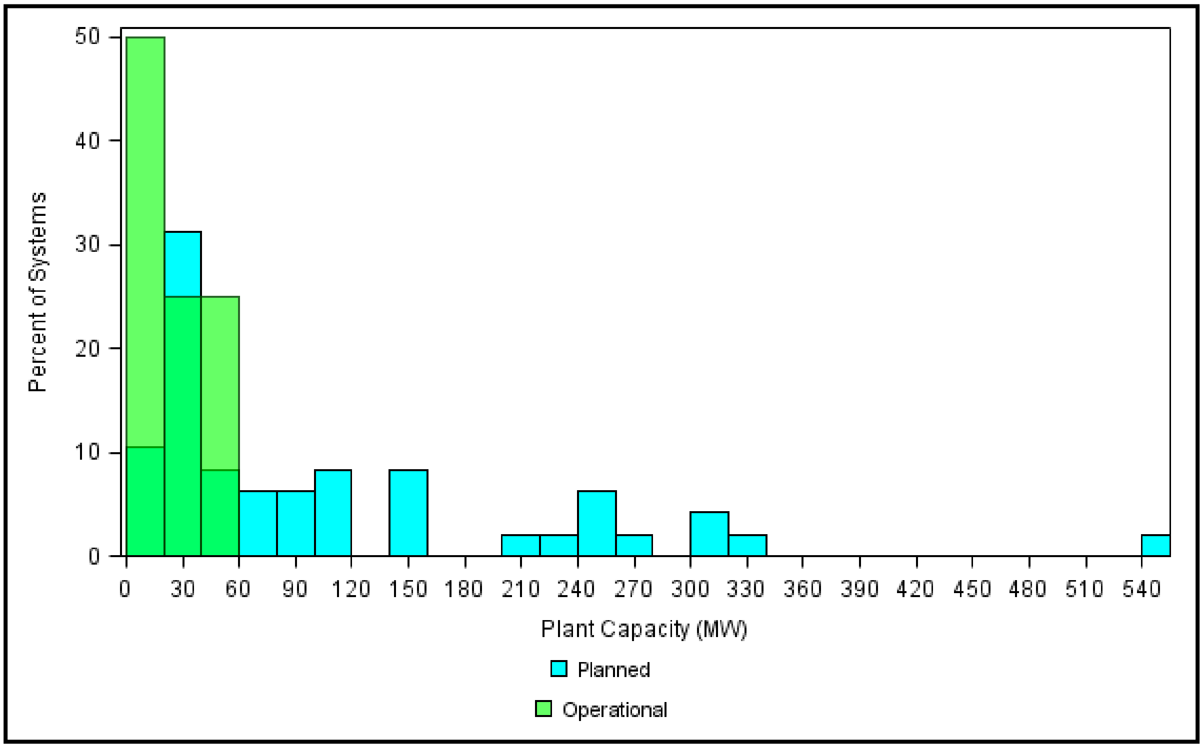
Solar PV technology costs have been the subject of a large number of studies over the last several years. This body of literature has been produced largely by researchers looking at the national marketplace for solar PV at various installation sizes. The Energy Commission hired two contractors, Navigant and Itron, to survey this body of data and extract the relevant information and adjust nationwide estimates into California-specific values. Solar PV panels in California are generally crystalline silicon or thin film. While either can be fixed-axis, crystalline silicon is more commonly used for tracking, and the thin film is generally fixed axis. The two sizes considered were 20 MW and 100 MW. The choice of sizes is meant to capture the cost difference between installations of relatively smaller utility-scale facilities and larger, more cost-effective sites. Energy Commission staff then reconciled and merged the two data sets of Navigant and Itron, using the areas where the two sources differed to understand uncertainties in the marketplace.

Trends in Solar PV Development

Many large-scale PV plants are planned, are under construction, or have been completed throughout the state. These systems are predominantly fixed–axis, thin-film, but there are also some single-axis (tracking) systems that often use higher-efficiency crystalline silicon modules. Sizes range from the planned large 550 MW Dessert Topaz project in San Luis Obispo County to the relatively small 15 MW Boron Solar project in San Bernardino. Most of the plants currently planned or in construction are significantly larger than those currently operational.

Figure 10 shows the percentage of total projects, both planned and operational, by size of plant. The currently operational plants range from 2 MW to 60 MW, but planned solar PV plants range up to 550 MW. Planned projects in the 20 – 40 MW represent more than 30 percent of the planned projects, but these represent less than 8 percent of the planned capacity. Conversely, systems in the 540 to 560 MW range represent less than 5 percent of the planned systems but nearly 10 percent of the planned capacity.

Figure 10: Sizes of Planned and Operational Photovoltaic Plants



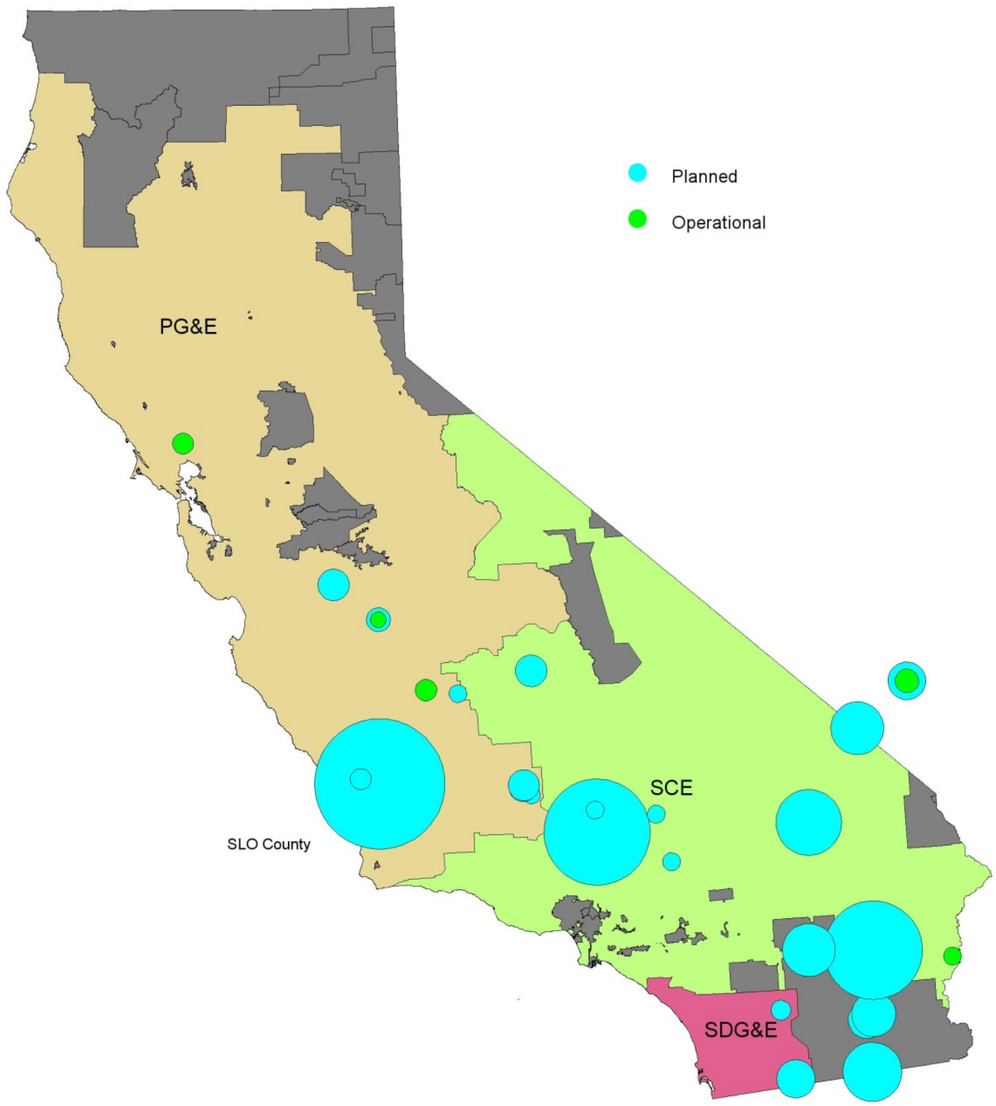
Source: U.S. EIA.

Large-scale PV projects are clustered in the southern part of the state, an area that tends to have more sun than the northern part of the state. A few plants selling power to the California market are located in Nevada and Arizona.

Figure 11 shows locations of PV plants that are tracked by the CPUC's RPS progress status worksheet as of August 2012.[25] These plants are split between planned and operational and the size of the marker scales with the capacity in the area of installation.

25 "RPS Project Status Table August 2012" See
<http://www.cpuc.ca.gov/PUC/energy/Renewables/index.html>

Figure 11: Operational and Planned Photovoltaic Plant Locations



Source:Energy Commission.

San Luis Obispo County has the largest marker on the map with the 550 MW fixed-axis (thin film) Desert Topaz project and the 210 MW (now 250 MW) single-axis–tracking, crystalline silicon SunPower High Plains (now California Valley Solar Ranch) projects.

Cost Trends for PV Components

PV Module Prices

Solar PV cells are typically manufactured in a modular form to make scaling any installation straightforward. While the photovoltaic cell represents the most visible aspect of a solar PV module, the cell is usually encased in a rigid protective housing and wired to a standardized connection point for ease of installation.

Historically, PV system costs have been driven largely by module prices that have constituted the majority of system costs. Recent years have seen drastic reductions in these costs as manufacturers become more efficient and producers have added significantly more manufacturing capacity than the global PV market can absorb. This excess has been due in part to the global recession, but reductions in incentives in Spain and Germany have also played a role. Finally, recent trade sanctions suggest that some countries, such as China, may have been illegally dumping panels. All these factors have worked together to bring costs down.

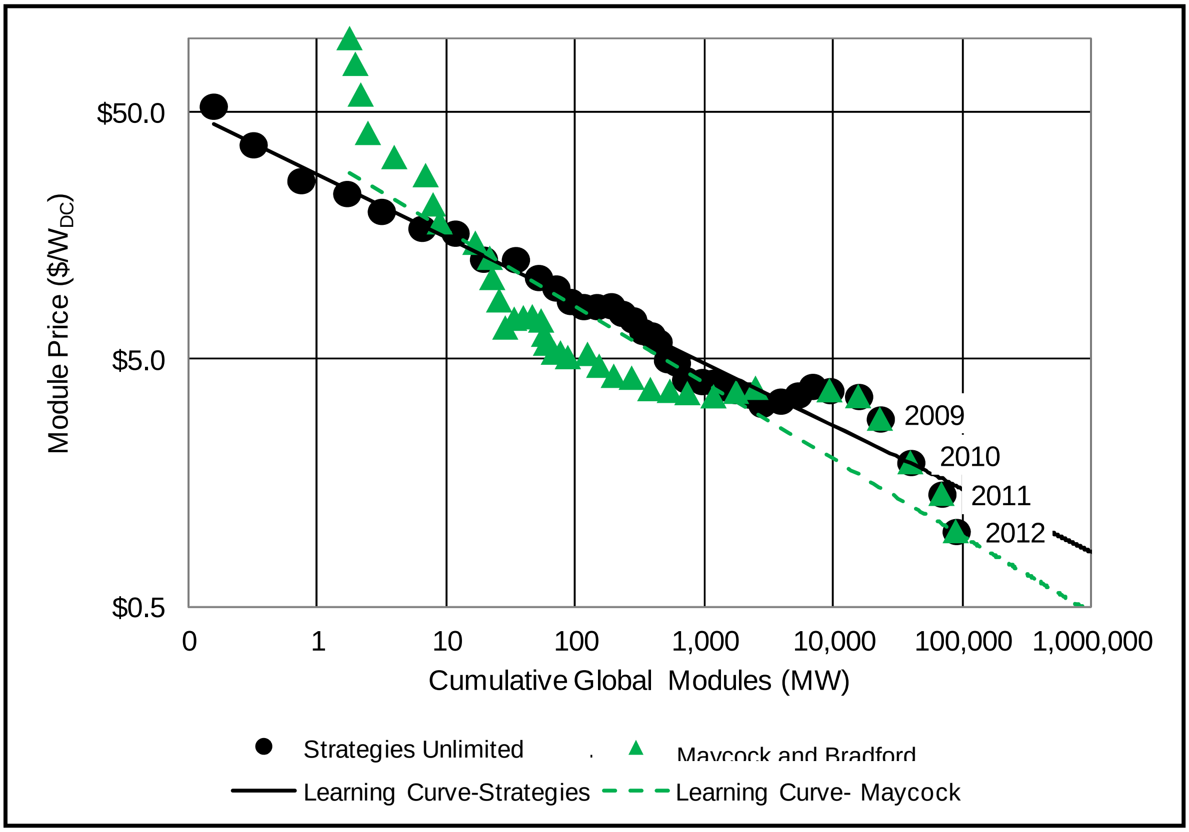
In addition to larger market forces, increased production of new technologies usually brings reduced costs. By fitting the empirical relationship between PV panel cost and cumulative production, a "learning curve" can be estimated and used to project future declines in costs as more modules are produced (Nemet, 2009). The estimated learning rate represents the relative reduction in cost when twice as many units have been produced. For example, a learning rate of 0.2 indicates a 20 percent drop in price for a doubling in cumulative production. **Figure 11** shows two learning curves estimated from a combination of data from two sources.

PV module production and pricing are shown in **Figure 12.** Each data point represents the average module price for one year. Because there is no single consistent time series of sources, this study relies on cost and volume data from several studies and sources representing different vintages, including the following:

- Module prices prior to the mid 2000s usually rely on one of two sources (Strategies Unlimited, 2003; Maycock and Bradford, 2007).
- Beyond 2000 for the former and 2006 for the latter, data are not freely available.
- Module prices from 2000 – 2006 (Mehta and Bradforfd, 2009).
- Module prices for 2007 – 2012 are from *Photon Magazine*.[26]
- Recent panel volumes from 2007 – 2012 and estimates to 2016 are available from the European Photovoltaic Industry Association (EPIA) (EPIA, 2012), in addition to estimates through 2016. Both data sets in the graph use *Photon Magazine* prices and EPIA volumes for 2007 through 2012.

26 Average monthly spot market price from *Photon Magazine*, April 2009 through July 2012.

Figure 12: Historical Photovoltaic Modules Production and Pricing



Source: Aspen Environmental.

The data that begin with Maycock indicate a higher price during the early days of PV in the late 1970s and 1980s, with a slightly lower price in the late 1990s. This results in a steeper slope and correspondingly higher learning rate of 26 percent vs. 16 percent for the Strategies Unlimited *et al* data. Interestingly, the learning curve using Maycock data passes directly through the 2012 price of $1/watt. In 2011 Davis and Fries proposed that the learning rate seen in the Maycock data had flattened out to only 10 percent in the early 1990s (Davis and Fries, 2011). Combining these three learning curves (Maycock, Strategies, and Davis) with module volume estimates provide a range of possible module prices moving forward.

Table 13 presents high, medium, and low bases for learning curves and volume estimates. It also presents what the average linear percent change would be with a starting point of 2012.

Table 13: Different Module Cost and Learning Curve Bases

Cost Range	Learning Curve Basis	Learning Rate	Module Volume Basis	Linearized Annual Percent Change
High	Davis and Fries	13%	10% year over year growth	-2.5%
Mid	Strategies Unlimited	16%	Mid EPIA estimate until 2016, then 20% average year-over-year growth	-5%
Low	Maycock et. al	20%	High EPIA estimate until 2016, then 25% average year-over-year growth	-10%

Source: Aspen Environmental.

Power Electronics/Inverters

Solar PV systems produce electricity in the form of direct current (DC), while the electrical grid in California operates using alternating current (AC). This means that any solar PV installation also requires an electronic part called an "inverter" to convert the DC electricity produced by the solar panels into AC electricity compatible with the electric grid. The inverter also houses control systems and other electronics that help make connection to the grid safer and easier.

Inverters and power electronics form a much smaller percentage of installed system costs than modules. Both inverters and modules are sold on a global market driven by global manufacturing and pricing. Inverters can reasonably be expected to follow a learning curve similar to PV modules since the volumes are interrelated. The ranges for inverter costs (Goodrich, et al., 2012) serve as a good foundation, and then similar learning assumptions and linear annual change rates are then lifted from the PV modules discussion and applied to inverters.

Balance of System—Hardware

For ground-mounted PV systems, the hardware portion of balance of system consists primarily of the structural components required to support the panels and hold them in place. These components usually include concrete or driven pier foundations to anchor the system, galvanized steel structures to support the panels, aluminum or steel clips or clamps to hold the panels to the structure, and the tracking system (controller motor, pivots, and so forth) if the system tracks the sun. This report uses the Black and Veatch (Black and Veatch, 2012) and the United States Department of Energy (U.S. DOE) (U.S. DOE, 2012) reports to provide a range of potential costs and rates of change for these components as shown in **Table 14**.

Table 14: Hardware Balance of System Ranges

Cost Range	Basis	Annual Year-Over-Year Cost Reduction
High	Black and Veatch	1%
Mid	DOE SunShot – Business as Usual	8%
Low	DOE SunShot – Required to Meet SunShot Goal	12%

Source: Energy Commission.

Operations and Maintenance Costs

PV plants do not usually require extensive maintenance. The most common task is to clean the panels regularly to minimize losses due to soiling and cut or trim any vegetation in or around the array to eliminate shading. In addition, inverters typically need to be replaced at least once over the life of a system, and these have an expected life of about 10 to 15 years. Finally, broken or stolen panels or system supports need to be replaced as needed. This sort of replacement is most often needed after large storms or in the case of theft or fire. **Table 15** summarizes the values and assumptions that are in real 2011 dollars.

Table 15: Solar PV Fixed Operating and Maintenance Estimates

Year	Black and Veatch	DOE Sunshot
2010	$50/kW-yr (only for 10 MW size)	$19.93/kW*yr,[27] Inverter replacement at 15 years at $0.17/W. That adds approx ~$6/kW*yr.
2015	$48/kW-yr	
2020	$45/kW*yr	$6.5 $/ kW-yr, inverter replacement at 20 years at $0.10/W

Source: Energy Commission.

27 Based on average O&M costs at Arizona Public Service's single-axis tracking PV installations.

Single-Axis Tracking Systems

Capital and Instant Cost Trends

The costs for photovoltaic modules have come down dramatically in the last few years, leading to much lower system prices for utility-scale plants in California and elsewhere. This reduction in cost, along with the future cost declines estimated from the learning curve described earlier, is reflected in the instant costs shown for crystalline photovoltaic systems in **Figure 13**.

Instant costs are based on two project sizes, 100 MW and 20 MW,[28] and these reflect the 2011 component buildups from aggregated data found in four sources:

- Centralized Solar Projects and Pricing bulletin from Solar Electric Power Association (SEPA)[29]
- Goodrich's NREL report on current PV pricing (Goodrich et al., 2012)
- U.S. DOE's *SunShot Vision Study* (U.S. DOE, 2012)
- Module manufacturer annual and quarterly reports[30]

The instant costs in **Figure 13** represent a composite of costs that would be necessary to construct a new power plant if the plant could be built overnight. They do not include the cost of a construction loan, sales tax, or loan fees. They do not include O&M costs. These costs are classified into four categories: technology costs, land costs, permitting costs, and emissions costs. Technology costs include the cost of the solar panels, inverter, transformer, and other physical elements of the solar array. Land costs include the cost of purchasing and preparing the land for use as a renewable energy site. Permitting costs incorporate the cost of obtaining the needed permits for the site. Here, the authors follow Goodrich and other studies and include both the direct cost of permitting as well as the cost of delays. For solar, there are no emissions, and, therefore, the values are all zero for PV technologies.

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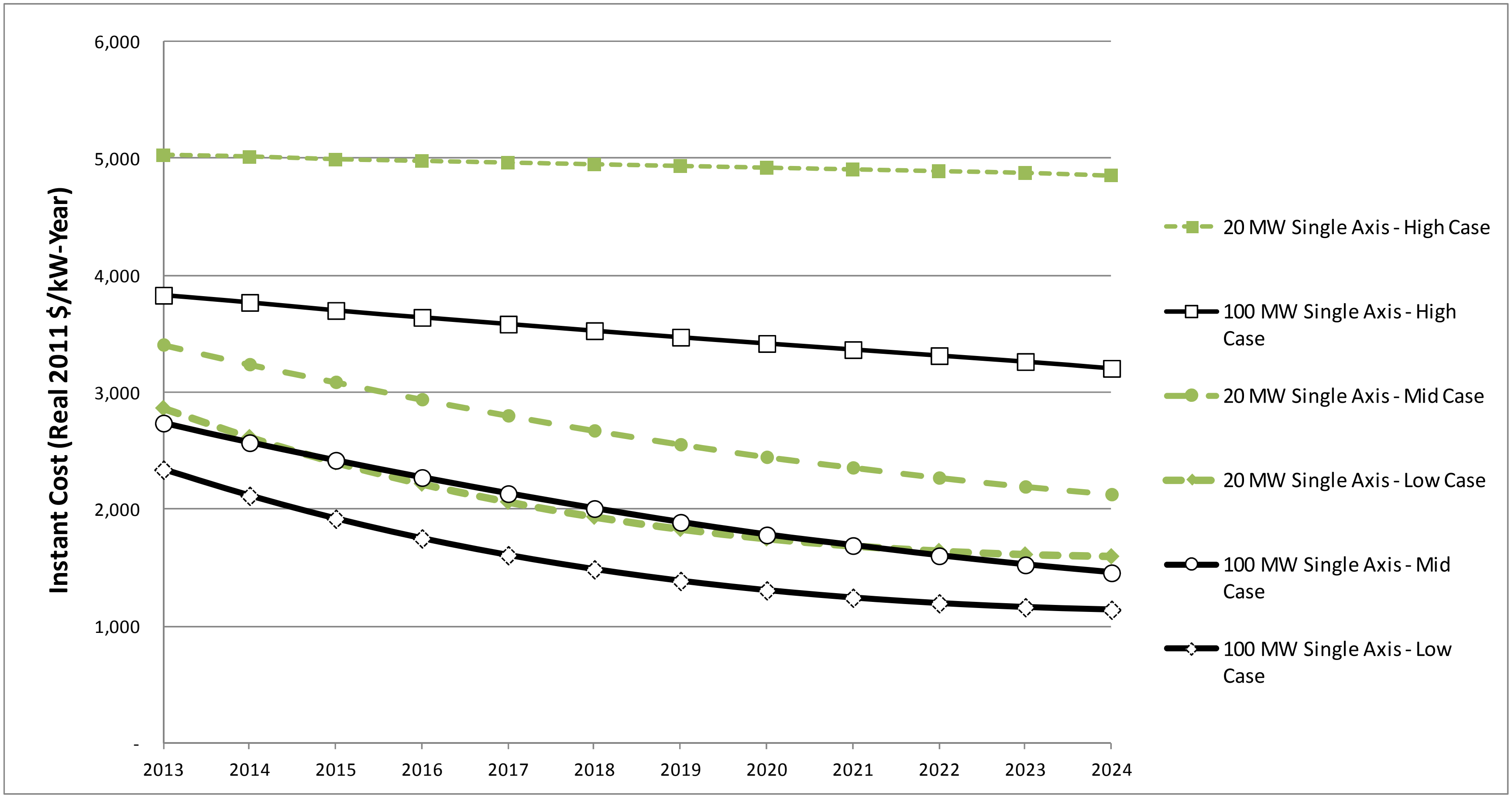
28 All cost assumptions for single-axis tracking systems in the following sections were based on the same two project sizes.

29 *Centralized Solar Projects and Pricing Update Bulletin* (Q1 2012), SEPA, May 2012. See <http://www.solarelectricpower.org/resources/publications.aspx#Centralized_Solar_Projects_QB_February2012>

30 Module manufacturer annual and quarterly reports from SunPower, Trina, SunTech, First Solar, and Yingli.

Figure 13: Single-Axis Tracking Instant Costs



Source: Energy Commission.

Operating and Maintenance Costs

Photovoltaic O&M costs were generally reported to be fixed costs, with no variable component. Several sources for these costs were used, including:

- *SunShot Vision Study* (U.S. DOE, 2012).
- A study by Electric Power Research Institute (EPRI) (EPRI, 2010).
- Bond rating reports for Topaz Solar Farm.
- An article on LCOE in *SolarPro Magazine* (Yates and Hibberd, 2012).

Fixed O&M values from these sources were averaged to find a mid-case value of $35/per kilowatt year (kW-yr) for 2011 (in nominal dollars).[31] A high-case value of $50/kW-yr reflects the upper end of these sources and may assume an inverter replacement reserve instead of purchasing and extended warranty (Black & Veatach, 2012). The low-case value of $20/kW-yr reflects the lower end of these sources.

Table 16 summarizes the major assumptions used in estimating costs for solar PV single axis technologies. Plant characteristics are assumed to be constant over the study period. Instant costs continue to decline, as shown in **Figure 13**. Instant costs do not include land and permitting costs. O&M costs are assumed to have a 0.5 percent per year real rate of escalation, reflecting expected increases in personnel costs.

31 "Mid & Low Cost Value Calculated Using "NREL: PV Jobs and Economic Development Impact (JEDI) Model…" see <http://www.nrel.gov/analysis/jedi/download.html>

Table 16: Summary of Solar Photovoltaic Single-Axis Assumptions

Plant Data	Mid Cost	High Cost	Low Cost
Gross Capacity (MW)	20/100	20/100	20/100
Station Service (%)	13.5%	21.0%	11.0%
Net Capacity Factor (NCF)	26.6%	24.0%	31.5%
Forced Outage Rate (FOR)	1.5%	4.0%	0.5%
Scheduled Outage Factor (SOF)	0.0%	0.0%	0.00
Capacity Degradation (%/Year)	0.55%	1.25%	0.25%
2011 Instant Cost (Nominal $/kW)	$3778/$3017	$4662/$4109	$3319/$2767
2011 Fixed O&M Cost (Nominal $/kW-yr)	$35.00	$50.00	$20.00
2011Variable O&M Cost (Nominal $/MWh)	$0.00	$0.00	$0.00
Insurance	0.30%	0.50%	0.25%

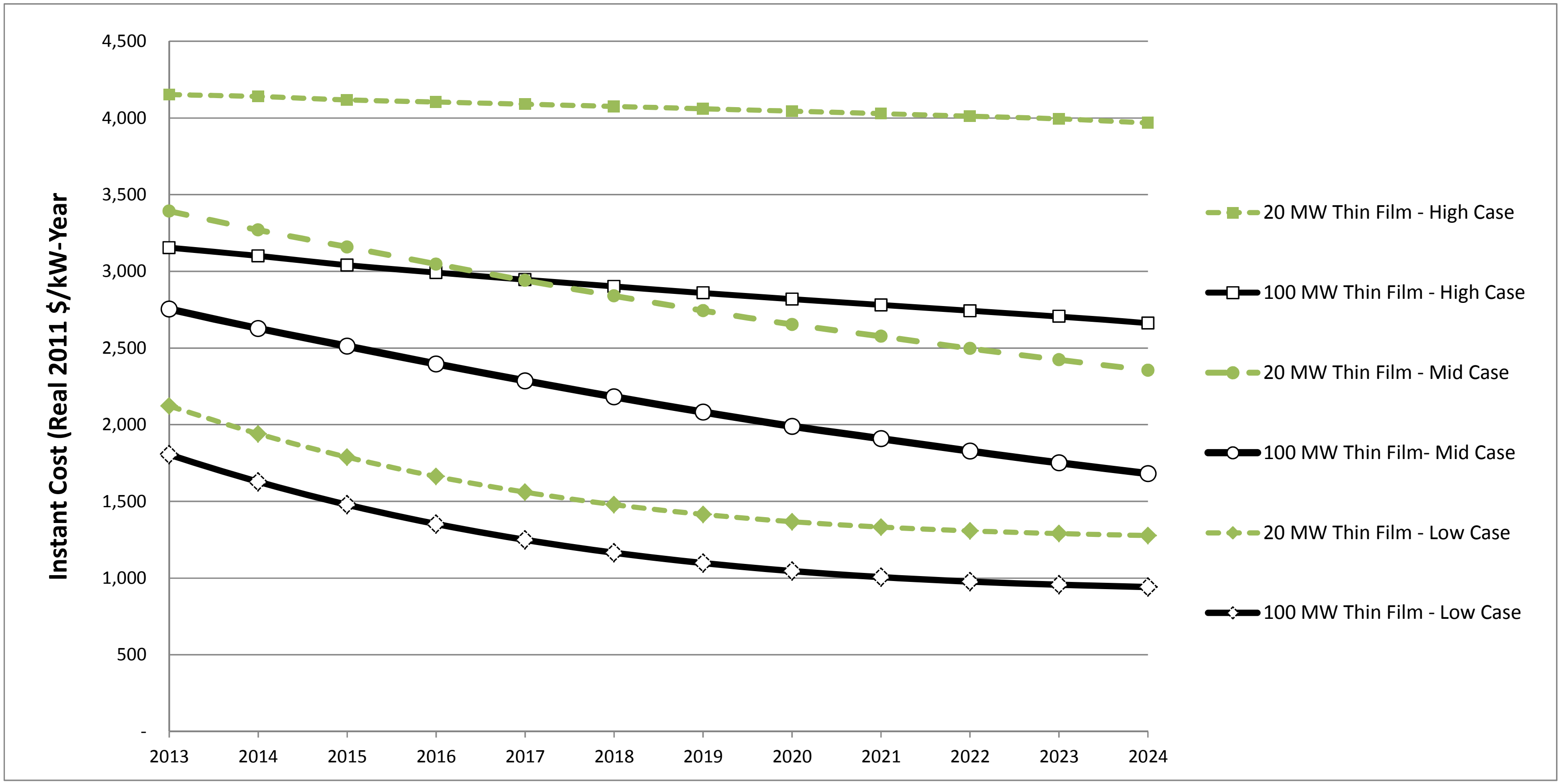
Source: Energy Commission.

100 MW and 20 MW Thin–Film, Fixed-Mount Systems

Capital and Instant Cost Trends

Instant costs for thin–film, fixed-mount PV systems are expected to decline along the same curves as those for single-axis PV systems. This expected decline is due to the highly interrelated research and production infrastructure associated with PV components. **Figure 14** shows the decline of installed costs for utility-scale, fixed-axis (thin-film) PV systems across each of the three cost cases: high, mid, and low.

Figure 14: 100 MW and 20 MW Thin–Film, Fixed-Mount PV Instant Cost



Source: Energy Commission

Operating and Maintenance Costs

The costs of fixed-orientation systems were developed using the same methods and sources as single-axis tracking, with slightly different results: low-, mid-, and high-case values for 2011were found to be $17/kW-yr, $27/kW-yr, and $50/kW-yr in 2011 dollars, respectively. These costs are lower due to reduced maintenance of systems with no moving parts. All three values are escalated in real dollars at 0.5 percent per year.

Table 17 summarizes the assumptions used in estimating costs for solar PV thin film technologies for 2011. The plant characteristics are assumed to be constant over the study period. Instant cost declines as described in **Figure 13**.

Table 17: Summary of Solar Photovoltaic Thin-Film Assumptions

Plant Data	Mid Cost	High Cost	Low Cost
Gross Capacity (MW)	20/100	20/100	20/100
Station Service (%)	13.5%	21.0%	11.0%
Net Capacity Factor (NCF)	21.7%	18.5%	25.3%
Forced Outage Rate (FOR)	1.5%	4.0%	0.5%
Scheduled Outage Factor (SOF)	0.0%	0.0%	0.0%
Capacity Degradation (%/Year)	0.95%	1.60%	0.25%
2011 Instant Cost (Nominal $/kW)	$3,586/$2,900	$4,515/$3,397	$2,948/$2,565
2011 Fixed O&M Cost (Nominal $/kW-yr)	$27.00	$50.00	$17.00
2011Variable O&M Cost (Nominal $/MWh)	$0.00	$0.00	$0.00
Insurance	0.30%	0.50%	0.25%

Source: Energy Commission.

Summary of 2013 Solar Photovoltaic Cost Data

Table 18 summarizes instant and installed costs for these solar PV technologies for 2013 (in 2013 dollars). These costs include all costs, including land and permitting costs.

Table 18: Summary of 2013 Solar Photovoltaic Instant and Installed Costs by Developer

Capital Costs Year = 2013 (Nominal Dollars)	Instant Costs ($/kW)	Installed Costs ($/kW)		
		Merchant	IOU	POU
Mid-Cost Case				
Solar Photovoltaic (Thin-Film) 100 MW	$2,884	$3,264	$3,280	$3,221
Solar Photovoltaic (Single-Axis) 100 MW	$2,864	$3,242	$3,258	$3,199
Solar Photovoltaic (Thin-Film) 20 MW	$3,551	$4,020	$4,040	$3,967
Solar Photovoltaic (Single-Axis) 20 MW	$3,567	$4,038	$4,058	$3,985
High-Cost Case				
Solar Photovoltaic (Thin-Film) 100 MW	$3,302	$4,015	$4,049	$3,961
Solar Photovoltaic (Single-Axis) 100 MW	$4,008	$4,874	$4,915	$4,808
Solar Photovoltaic (Thin-Film) 20 MW	$4,347	$5,286	$5,330	$5,214
Solar Photovoltaic (Single-Axis) 20 MW	$5,260	$6,396	$6,449	$6,309
Low-Cost Case				
Solar Photovoltaic (Thin-Film) 100 MW	$1,889	$2,059	$2,074	$2,043
Solar Photovoltaic (Single-Axis) 100 MW	$2,447	$2,667	$2,686	$2,646
Solar Photovoltaic (Thin-Film) 20 MW	$2,221	$2,421	$2,439	$2,403
Solar Photovoltaic (Single-Axis) 20 MW	$2,996	$3,266	$3,290	$3,241

Source: Energy Commission.

Table 19 summarizes O&M costs for 2013 (in nominal dollars). Costs are assumed to have a real escalation rate of 0.5 percent per year.

Table 19: Summary of Solar Photovoltaic Operating and Maintenance Costs

O&M Costs Year = 2013 (Nominal Dollars)	Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
Mid-Cost Case		
Solar Photovoltaic (Thin-Film) 100 MW	$28.55	$0.00
Solar Photovoltaic (Single-Axis) 100 MW	$37.00	$0.00
Solar Photovoltaic (Thin-Film) 20 MW	$28.55	$0.00
Solar Photovoltaic (Single-Axis) 20 MW	$37.00	$0.00
High-Cost Case		
Solar Photovoltaic (Thin-Film) 100 MW	$52.86	$0.00
Solar Photovoltaic (Single-Axis) 100 MW	$52.86	$0.00
Solar Photovoltaic (Thin-Film) 20 MW	$52.86	$0.00
Solar Photovoltaic (Single-Axis) 20 MW	$52.86	$0.00
Low-Cost Case		
Solar Photovoltaic (Thin-Film) 100 MW	$17.97	$0.00
Solar Photovoltaic (Single-Axis) 100 MW	$21.15	$0.00
Solar Photovoltaic (Thin-Film) 20 MW	$17.97	$0.00
Solar Photovoltaic (Single-Axis) 20 MW	$21.15	$0.00

Source: Energy Commission.

CHAPTER 5: Solar Thermal Technologies

Overview

Analytic Approach

Solar thermal technologies represent a growing share of the total solar portfolio under construction in the United States. The Energy Commission engaged Navigant and Itron to survey the available data, extract the relevant information, and adjust nationwide estimates into California-specific values. Among solar thermal facilities, the parabolic trough and power tower designs are considered to be the most viable in the near future. In addition, these technologies are capable of using thermal storage technologies to extend their hours of operation beyond dusk when PV technologies would stop producing. For both technologies, installations without storage and with 6 hours of storage were explored. In addition, for solar power tower designs, an 11-hour storage option was researched to help provide estimates appropriate to the direction some developers have taken recently by maximizing the storage capacity of these installations.

Trends in Solar Thermal Development

Solar thermal plants, also known as *concentrating solar power plants* (CSP), collect and convert solar energy into power using conventional steam turbines. There are two predominant commercial embodiments of solar thermal plants—parabolic troughs and solar towers—both of which collect sunlight over large “solar fields.” The captured solar energy generates heat that is transferred to a working fluid (such as pressurized oil). The working fluid is used to generate steam, which is routed through steam turbines to generate electricity. Parabolic trough solar plants use linear parabolic collectors to focus the sun’s rays on a pipe at the focal point. These collectors rotate to concentrate direct sunlight onto a pipe located along the focal line of their reflective surfaces. About 50 trough plants are operational worldwide as of 2012.[32] Solar tower plants are surrounded by a field of reflectors (known as *heliostats*) that move to focus direct sunlight onto a receiver atop a central tower. There are about a half-dozen commercial tower plants operational worldwide.[33]

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32 “NREL Concentrating Solar Power Projects….” See <http://www.nrel.gov/csp/solarpaces/projects_by_status.cfm?status=Operational>

33 Ibid.

Both trough and tower CSP plants may include thermal energy storage (TES). TES stores the working fluid at high temperatures and allows the plant operator to have some control over when electricity is generated, thereby increasing the plant's dispatchability. Energy collected earlier in the day can be drawn from storage to generate additional power in the afternoon, even as solar input declines. TES is an important CSP component since it adds both significant additional capital costs and significant expansion of the operational profile, greatly reducing the levelized cost of energy. However, few existing commercial CSP plants include TES. Available CSP plant cost and performance data reflect trough plants both with and without TES. Tower plants are primarily described with TES. This cost of generation analysis considers trough plants with 6 and 11 hours of TES and without TES, while parabolic trough configurations are presented with 6 hours of storage as well as without storage.

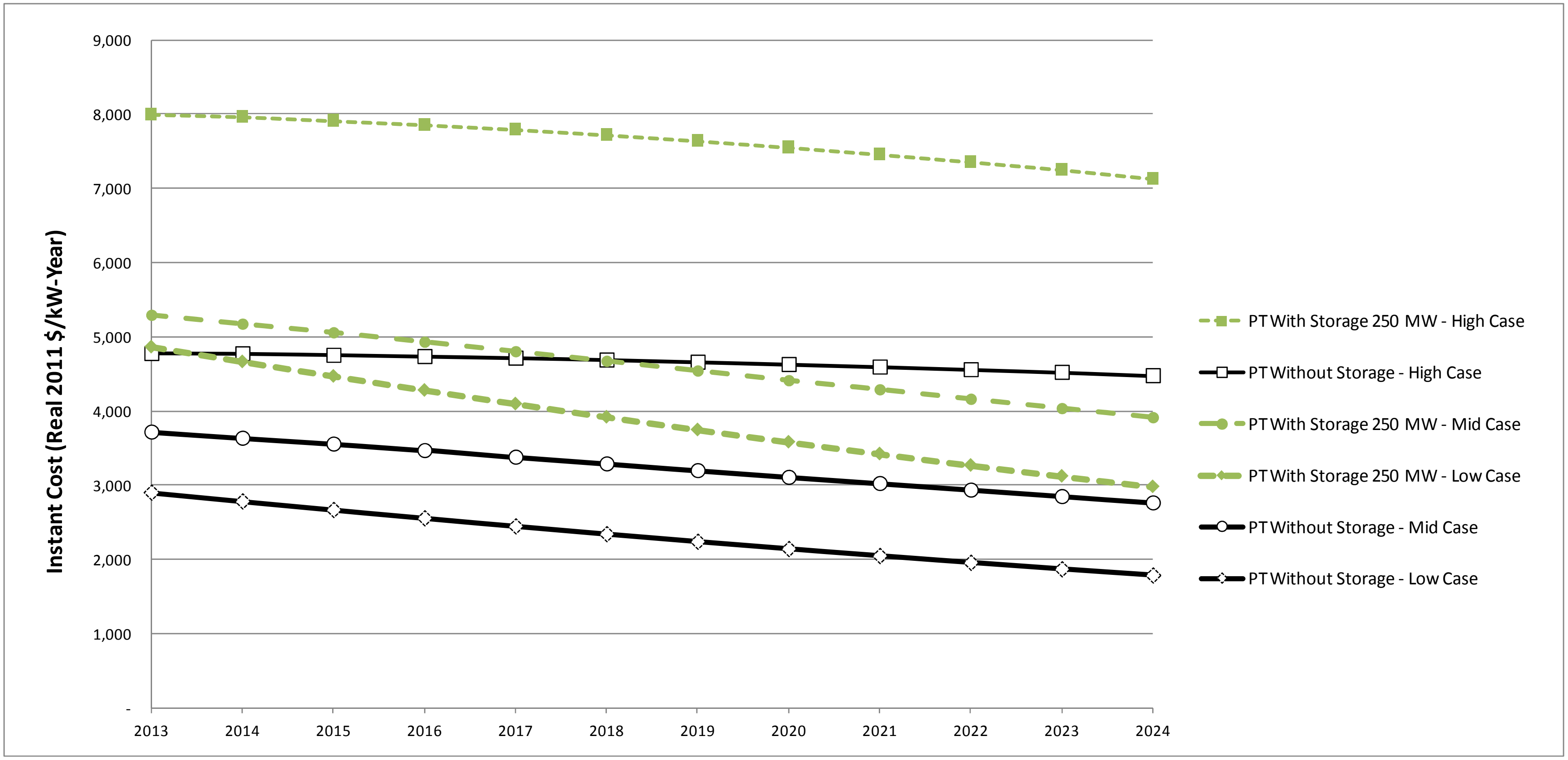
250 MW Parabolic Trough Solar Thermal (With and Without Storage)

Parabolic trough plants are modeled both with 6 hours of TES and without TES. High-, mid-, and low-cost cases are shown for both configurations.

Capital and Instant Cost Trends

Figure 15 shows the cost trends for parabolic instant costs. The costs from these projects are not expected to vary much until this wave of construction is complete. For projects after 2015, Navigant derived a rough average of projected costs from a number of studies, including NREL/Black and Veatch 2011, A.T. Kearney, U.S. EIA, and U.S. DOE.

Figure 15: 250 MW Solar Parabolic Trough Instant Cost—With and Without Storage



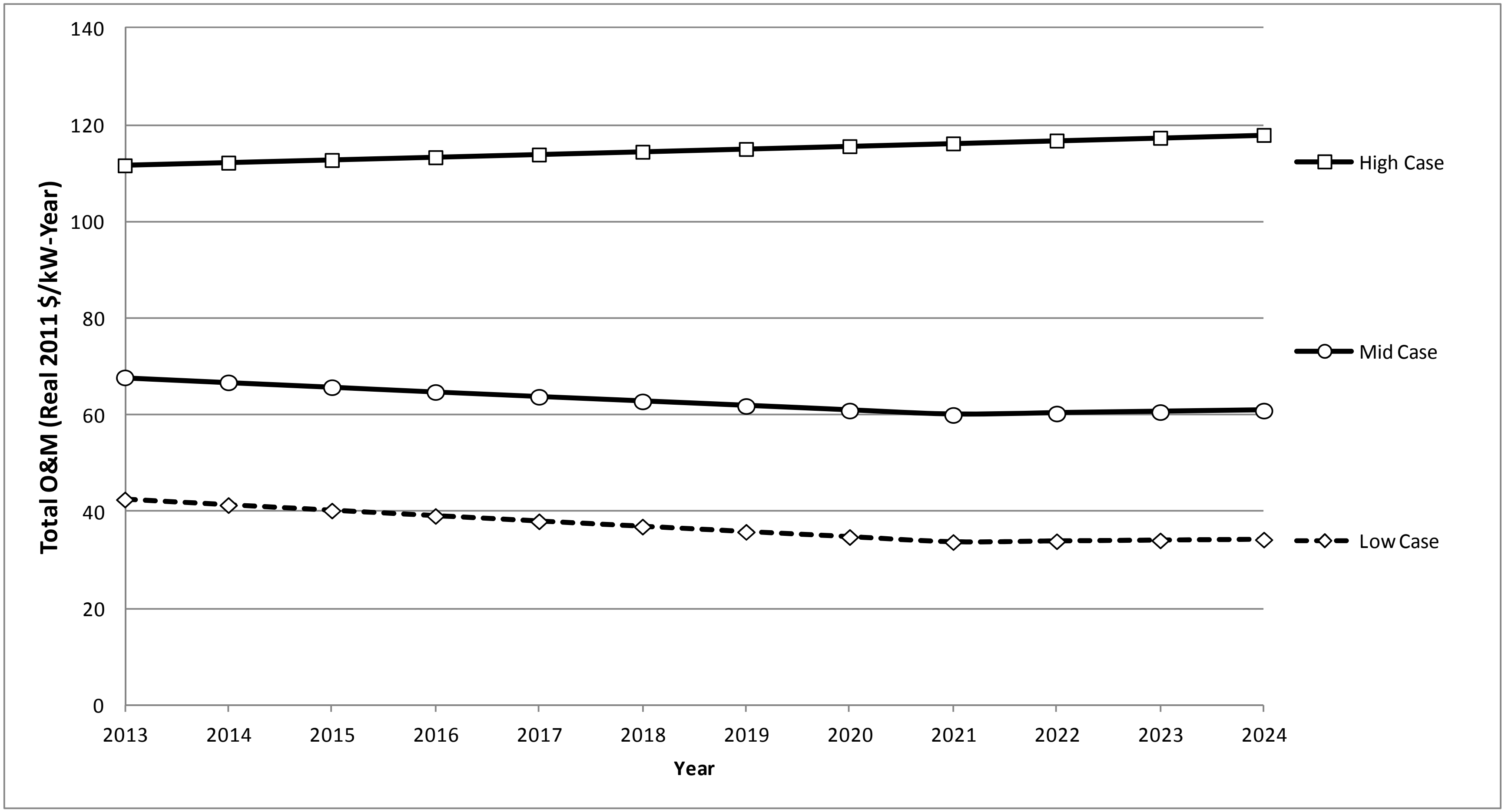
Source: Energy Commission.

Operating and Maintenance Costs

The 354 MW Solar Energy Generating Systems (SEGS) parabolic trough solar thermal plants have been operational in California since 1984. While there has been some construction of parabolic trough plants since the SEGS plants became operational (that is, Nevada Solar One), these are relatively few, and the public data on O&M costs are similarly limited. Therefore, the SEGS costs are used as the best proxy for these costs, with little change since the last COG update in 2009.

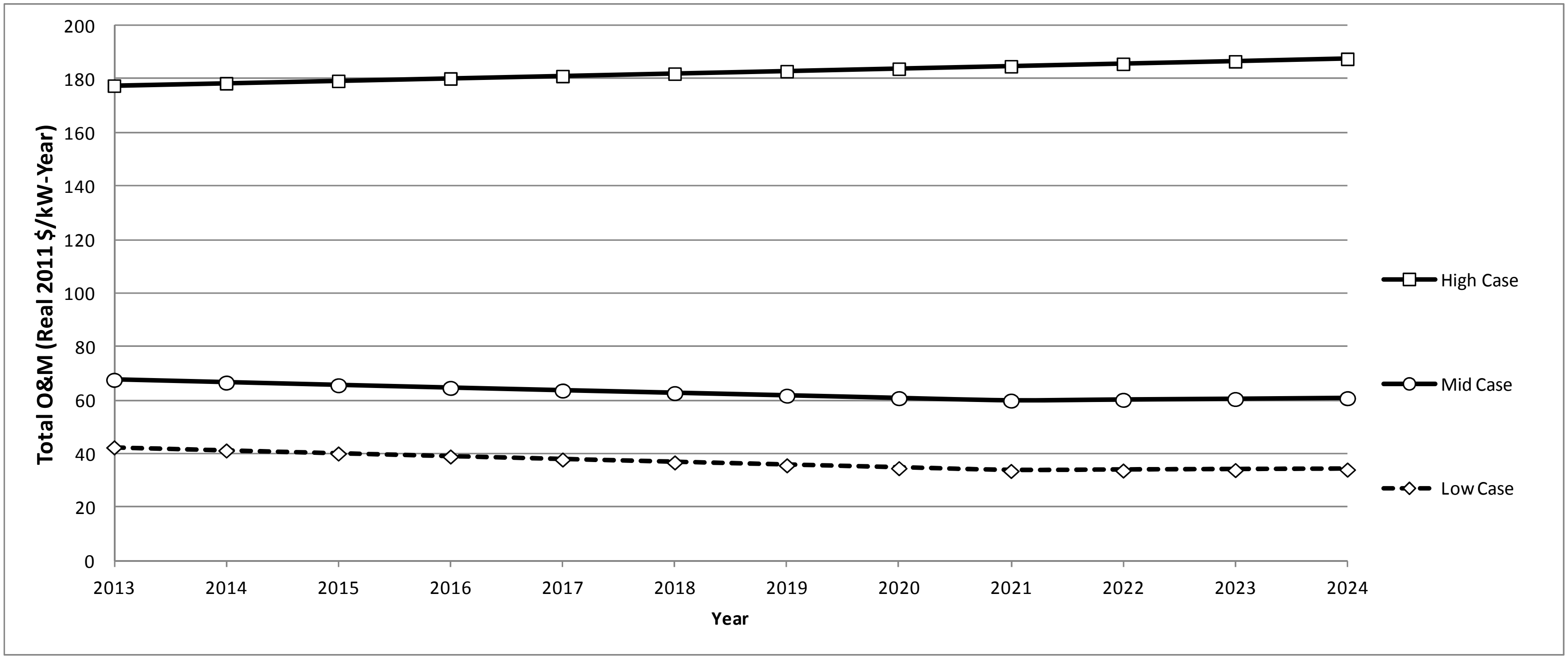
These O&M costs to are expected decline over time; however, with the recent resurgence of CSP technology and further experience with operations, a 11.5 percent O&M cost reduction over the next eight years (2013 – 2021) seems reasonable, corresponding to half of the improvements experienced by the SEGS plants (Cohen, et al., 1999). Beyond Year 8 this study assumes O&M costs escalate at 0.5 percent annual real increase to account for increases in personnel costs. The sum of these two effects is shown in **Figure 16** and **Figure 17**. As expected, O&M costs for solar parabolic troughs are significantly lower when installed without TES since these storage systems require extensive maintenance and upkeep to maintain efficiency and proper operation.

Figure 16: 250 MW Solar Parabolic Trough Without Storage—Total Operating and Maintenance Costs (Real 2011 $/kW-yr)



Source: Energy Commission.

Figure 17: 250 MW Solar Parabolic Trough With Storage—Total Operating and Maintenance Costs (Real 2011$/kW-yr)



Source: Energy Commission.

Table 20 summarizes the major plant characteristics and costs for the solar parabolic technologies, with and without storage. Plant characteristics are assumed to be constant over the study period. Instant costs and O&M costs decline as shown in **Figure 15**, **Figure 16**, and **Figure 17**.

Table 20: Summary of Plant Characteristics and Costs—With and Without Storage

Plant Data	Mid Cost	High Cost	Low Cost
Gross Capacity (MW)	250/250	250/250	250/250
Station Service (%)	10.71%	15.00%	9.00%
Net Capacity Factor (NCF)	26.5% / 43.0%	20.0% /41.0%	29.0% / 45.0%
Forced Outage Rate (FOR)	6.00%	8.00%	1.00%
Scheduled Outage Factor (SOF)	2.00%	4.00%	0.00%
Capacity Degradation (%/Year)	0.50%	1.40%	0.25%
2011 Instant Cost (Nominal $/kW)	$3730/$5366	$4365/$7681	$3094/$5220
2011 Fixed O&M Cost (Nominal $/kW-yr)	$69.88	$93.00/$140.00	$44.88
2011Variable O&M Cost (Nominal $/MWh)	$0.00	$10.00	$0.00
2011 Total O&M Cost (Nominal$/kW-yr)	$69.88	$110.52/$175.92	$44.88
Insurance	0.30%	0.50%	0.25%

Source: Energy Commission.

100 MW Solar Thermal Power Tower

Costs for solar thermal power towers were based on a 100 MW-sized project. Solar thermal power tower plants are modeled with and without thermal storage, similar to the parabolic trough solar thermal case. The storage capacity allows the renewable plant to operate for up to 11 hours after the sun goes down so it can better match peak system loads, which tend to be from 4:00 p.m. to 7:00 p.m. as residential customers come home from work.

Capital and Instant Cost Trends

The mid-cost power tower case without storage is based on information on the $1.6 billion U.S. DOE loan guarantee to the Ivanpah project.[34] Using the debt-to-equity ratio of 81.6 percent debt/18.4 percent equity (About BrightSource, 2013), this translates to $5,004/kW installed.[35] Using the factor 1.228, the instant cost is back-calculated as

34 The Ivanpah Solar Electric Generating System project in the California Mojave Desert is for 370 MW net, but the repeating unit is one-third of this, or 120 MW, which is close to the nominal 100 MW plant size. The nominal plant size matches the 100 MW most discussed in the literature for easier comparison. As more projects are built, nominal plant block sizes will become clearer.

35 1.600 billion/392 MW gross capacity = 4,081.6 $/kW in debt. 4,081.6 * 1.226 = $5,004/kW total.

$4,075/kW. With few other commercial solar power tower projects without storage, the high case was taken to be 20 percent higher than the mid case, and the low case 10 percent lower than the mid case, reflecting typical contingencies on construction projects of this nature.

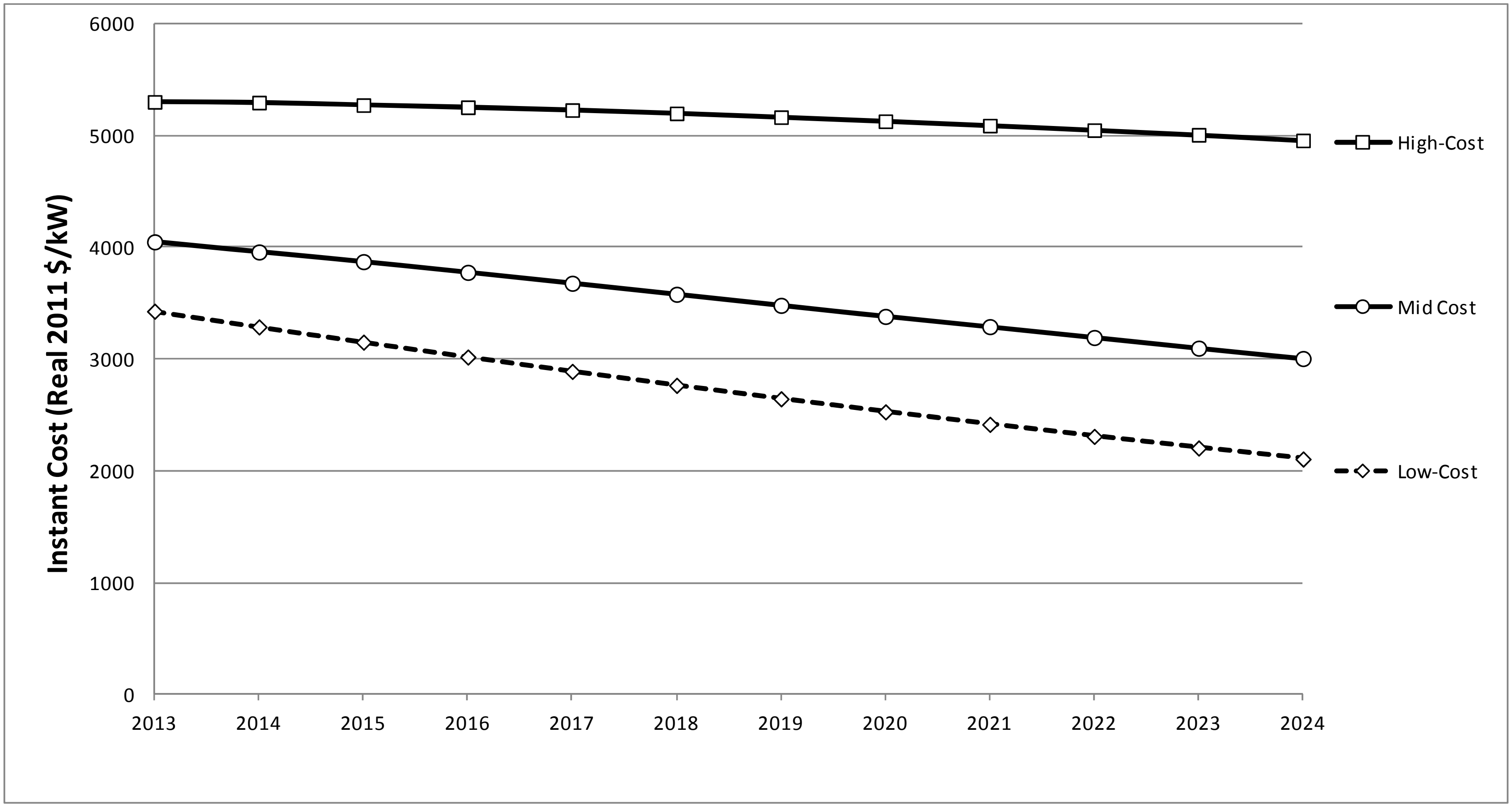
Figure 18 shows cost projections for the no storage case, which is similar in shape to parabolic trough. Costs from project to project are not expected to vary much until this wave of construction is complete. For projects after 2015, Navigant estimated a rough average of projected costs from a number of studies—NREL/Black and Veatch 2011, AEMO, A.T. Kearney, U.S. EIA, and U.S. DOE. **Figure 19** shows the tower case with 6 hours storage, and **Figure 20** shows the 11 hours storage case. **Figure 21** compares the mid-case instant costs for the same with and without storage cases.

Initial costs are derived from public DOE loan guarantee data[36] and recent cost studies, as these appear to be the most accurate public costs available at this time. The mid-cost case for the power tower with storage is based on a recent study conducted by Black and Veatch for NREL (Black and Veatch, 2012). The high case is based on the DOE loan guarantee to the Crescent Dunes Solar Energy Project near Tonopah, Nevada.[37] The low case is based on the Power Tower Solar Advisory Model estimates, which are arrived at through a consensus process with industry (System Advisor Model, 2012).

36 "DOE-Loan Programs" see <https://lpo.energy.gov/?projects=abengoa-solar-inc> and "NREL Concentrating Solar Power Projects Home Page1" see <http://www.nrel.gov/csp/solarpaces>

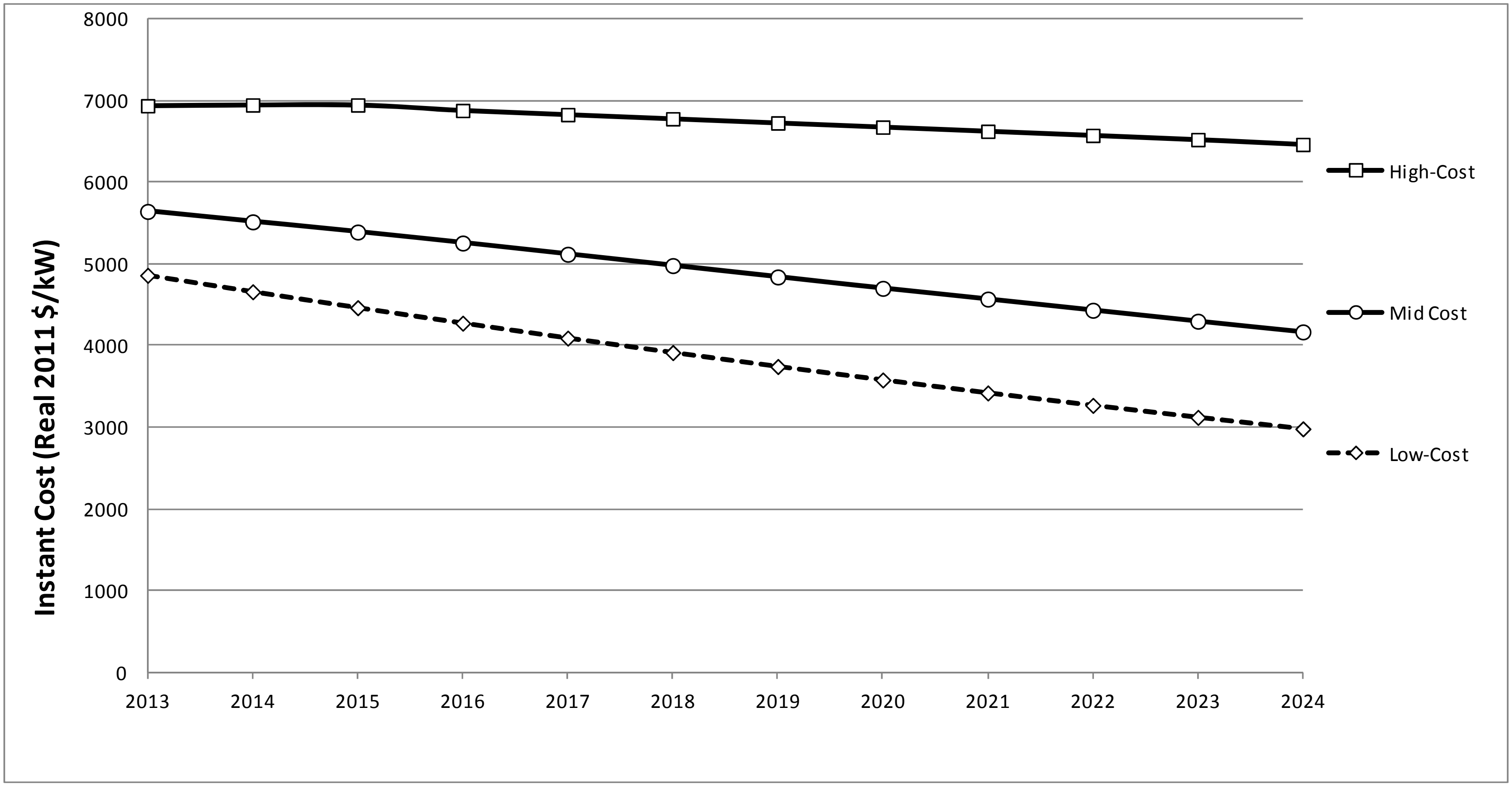
37 737 million/110 MW net capacity = 6,700 $/kW in debt. 6,700 * 1.25 = 8,380 $/kW total.

Figure 18: 100 MW Solar Power Tower Without Storage Instant Costs—Mid-, High-, and Low-Cost Cases



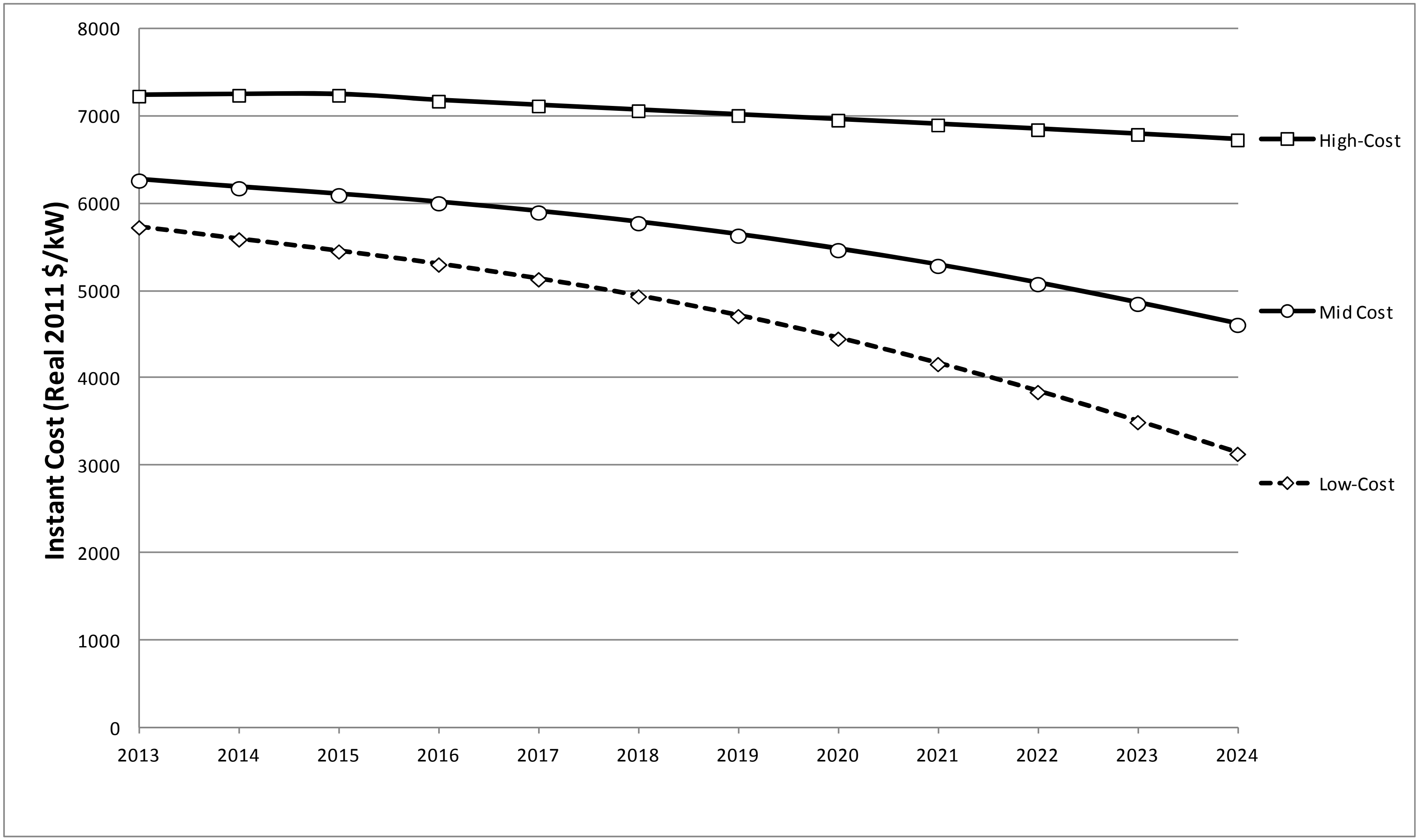
Source: Energy Commission.

Figure 19: 100 MW Solar Power Tower With 6 Hours Storage Instant Costs—Mid-, High-, and Low-Cost Cases



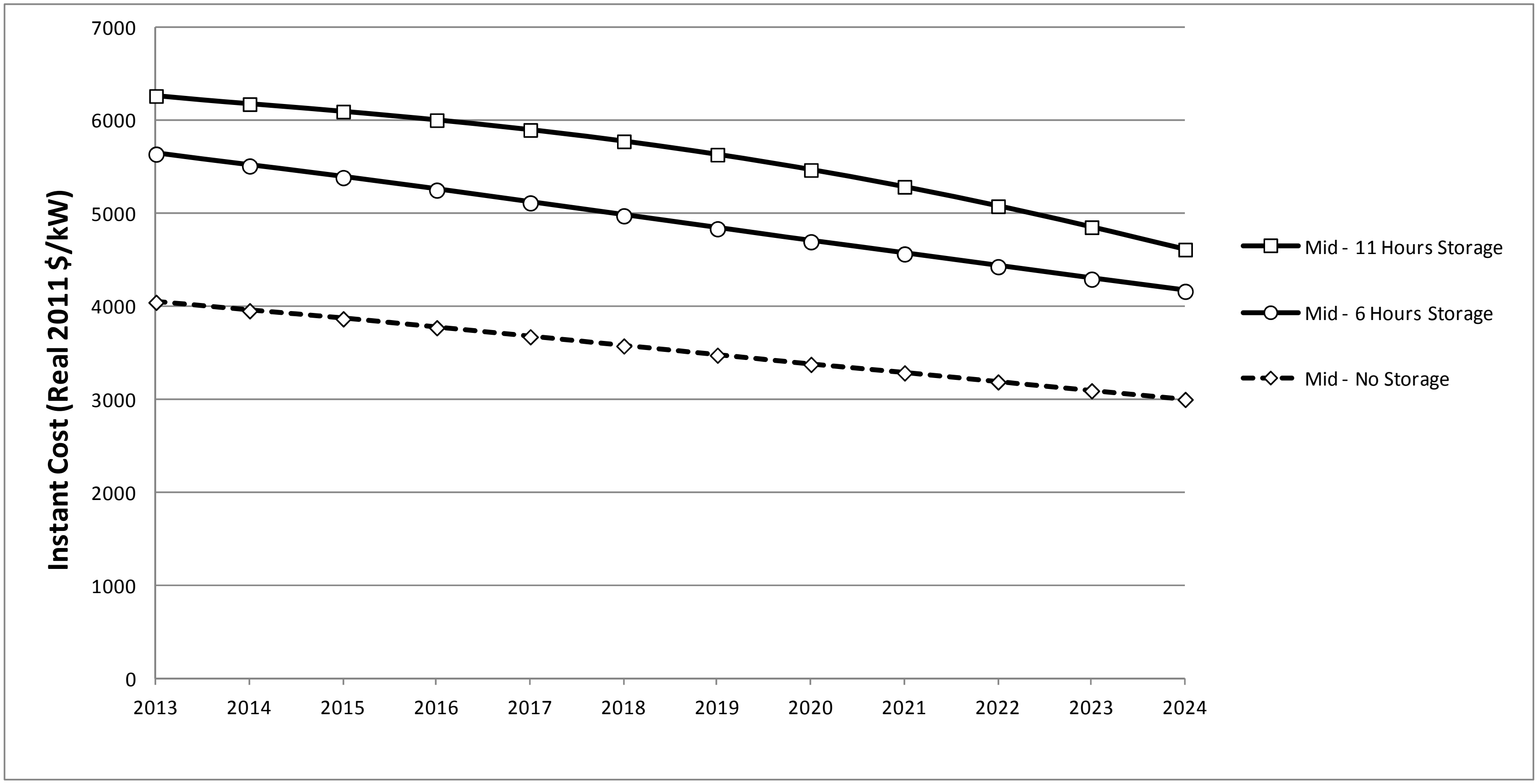
Source: Energy Commission.

Figure 20: 100 MW Solar Power Tower with 11 Hours Storage Instant Costs—Mid-, High-, and Low-Cost Cases



Source: Energy Commission.

Figure 21: 100 MW Solar Power Tower Instant Costs—Mid-Cost Cases



Source: Energy Commission.

Operations and Maintenance Costs

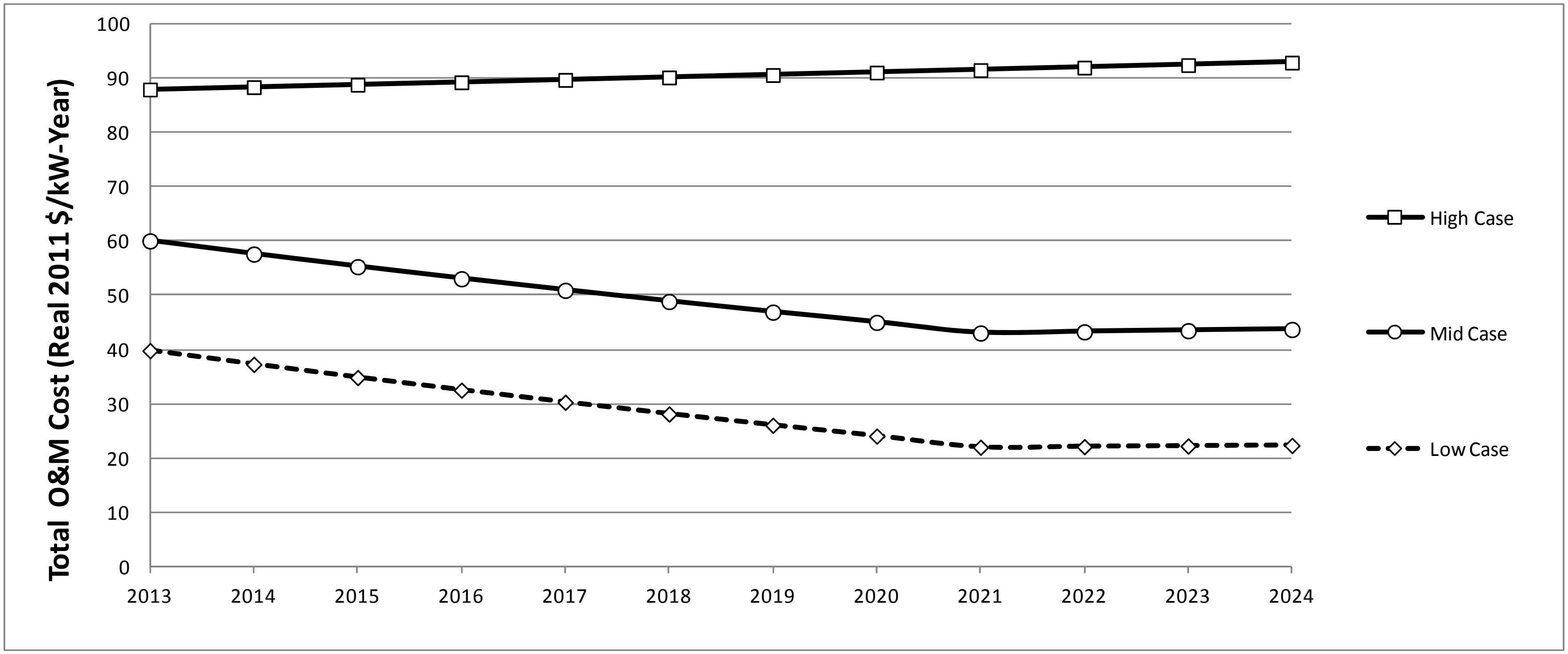
For solar power tower plants, which are emerging and becoming commercially available, reliable public O&M data are not readily available. The best estimates are provided by a recent Sandia report (Kolb, et al., 2011), from which the consensus low was used as the mid case.

Similar to trough plants, a steeper 28 percent cost reduction is expected over the next eight years (2013 – 2021), corresponding to the improvement experienced by the SEGS plants, because power tower technology is not yet mature.[38] After 2021, the Energy Commission's 0.5 percent annual increase in costs is assumed to account for personnel costs. The sum of these two effects is shown in **Figure 22**. **Figure 23** shows O&M costs for units with 6- and 11-hour storage.

The O&M cost of these power tower plants is highly uncertain, as there is limited operating history to make estimates from for this new technology. Therefore, "teething" issues may be expected for this technology, but these costs would properly be accounted for as part of the research and development (R&D) and/or development costs of the technology and, therefore, not included here.

38 Based on work done by Navigant for the Energy Commission.

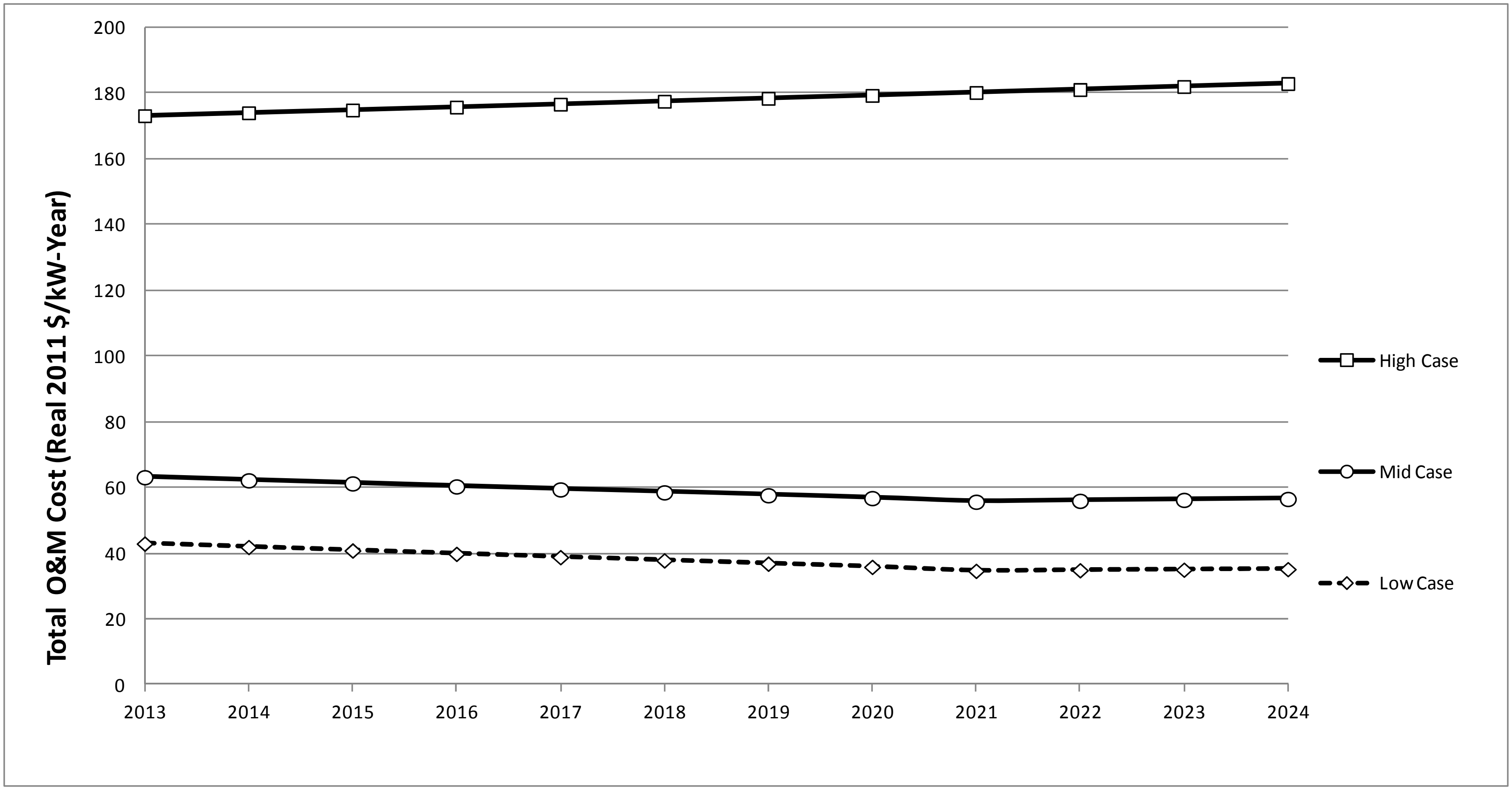
Figure 22: Solar Power Tower Without Storage—Total Operating and Maintenance Costs



Source: Energy Commission.

Figure 23: Solar Tower With Storage (6-Hour and 11-Hour) Total Operating and Maintenance Cost

.



Source: Energy Commission.

Table 21 summarizes plant characteristics and merchant costs for the solar tower technologies. Plant characteristics are assumed to be constant from 2013 – 2024.

Table 21: Plant Characteristics and Costs for Solar Tower Technologies

Plant Data	Mid Cost	High Cost	Low Cost
Gross Capacity (MW)	100	100	100
Station Service (%)			
Without Storage	12.0%	13.0%	7.0%
With 6 Hours Storage	12.0%	13.0%	10.0%
With 11 Hours Storage	12.0%	13.0%	10.0%
Net Capacity Factor (NCF)			
Without Storage	31.0%	30.0%	32.0%
With 6 Hours Storage	40.0%	36.0%	48.2%
With 11 Hours Storage	56.0%	52.3%	62.0%
Forced Outage Rate (FOR)	6.0%	8.0%	1.0%
Scheduled Outage Factor (SOF)	2.0%	4.0%	0.0%
Capacity Degradation (%/Year)	0.50%	1.40%	0.25%
2011 Instant Cost (Nominal $/kW)			
Without Storage	$4,075	$4,890	$3,667
With 6 Hours Storage	$5,733	$6,526	$5,220
With 11 Hours Storage	$6,612	$6,824	$6,160
2011 Fixed O&M Cost (Nominal $/kW-yr)			
Without Storage	$65.14	$87.00	$45.14
With 6 Hours Storage	$65.23	$140.00	$45.23
With 11 Hours Storage	$65.23	$140.00	$45.23
2011 Variable O&M Cost (Nominal $/MWh)			
Without Storage	$0.00	$0.00	$0.00
With 6 Hours Storage	$0.00	$10.00	$0.00
With 11 Hours Storage	$0.00	$10.00	$0.00
2011 Total O&M (Nominal $/kW-yr)			
Without Storage	$65.14	$87.00	$45.14
With 6 Hours Storage	$65.23	$171.54	$45.23
With 11 Hours Storage	$65.23	$185.81	$45.23
Insurance (%/Year)	0.30%	0.50%	0.25%

Source: Energy Commission.

Summary of Solar Thermal 2013 Costs

Table 22 summarizes 2013 instant and installed costs by developer. Installed cost is the instant cost plus the cost of financing the plant during construction, sales tax, and development costs.

Table 22: Summary of 2013 Instant and Installed Costs by Developer

Capital Costs	Instant Costs ($/kW)	Installed Costs ($/kW)		
Start Year = 2013 (Nominal Dollars)		Merchant	IOU	POU
Mid-Cost Case				
Solar Parabolic Trough W/O Storage 250 MW	$3,892	$4,537	$4,582	$4,418
Solar Parabolic Trough With Storage 250 MW	$5,538	$6,456	$6,520	$6,287
Solar Power Tower W/O Storage 100 MW	$4,240	$4,942	$4,991	$4,812
Solar Power Tower With Storage 100 MW 6 HRs	$5,906	$6,884	$6,952	$6,704
Solar Power Tower With Storage 100 MW 11 HRs	$6,560	$7,647	$7,722	$7,446
High-Cost Case				
Solar Parabolic Trough W/O Storage 250 MW	$5,000	$6,140	$6,204	$6,036
Solar Parabolic Trough With Storage 250 MW	$8,369	$10,276	$10,383	$10,103
Solar Power Tower W/O Storage 100 MW	$5,550	$6,815	$6,886	$6,700
Solar Power Tower With Storage 100 MW 6 HRs	$7,259	$8,914	$9,007	$8,763
Solar Power Tower With Storage 100 MW 11 HRs	$7,571	$9,297	$9,394	$9,140
Low-Cost Case				
Solar Parabolic Trough W/O Storage 250 MW	$3,038	$3,312	$3,347	$3,274
Solar Parabolic Trough With Storage 250 MW	$5,088	$5,546	$5,606	$5,483
Solar Power Tower W/O Storage 100 MW	$3,590	$3,913	$3,955	$3,868
Solar Power Tower With Storage 100 MW 6 HRs	$5,087	$5,545	$5,605	$5,482
Solar Power Tower With Storage 100 MW 11 HRs	$6,000	$6,540	$6,611	$6,465

Source: Energy Commission.

Table 23 summarizes O&M costs for 2013 (in 2013 dollars). Costs are assumed to have a real escalation rate of 0.5 percent per year.

Table 23: Summary of 2013 Operation and Maintenance Costs

O&M Costs Start Year = 2013 (Nominal Dollars)	Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)	Total O&M ($/kW-Yr)
Mid-Cost Case			
Solar Parabolic Trough W/O Storage 250 MW	$70.95	$0.00	$70.95
Solar Parabolic Trough With Storage 250 MW	$70.95	$0.00	$70.95
Solar Power Tower W/O Storage 100 MW	$62.81	$0.00	$62.81
Solar Power Tower With Storage 100 MW 6 HRs	$66.25	$0.00	$66.25
Solar Power Tower With Storage 100 MW 11 HRs	$66.25	$0.00	$66.25
High-Cost Case			
Solar Parabolic Trough W/O Storage 250 MW	$98.33	$10.57	$116.85
Solar Parabolic Trough With Storage 250 MW	$148.02	$10.57	$185.99
Solar Power Tower W/O Storage 100 MW	$91.98	$0.00	$91.98
Solar Power Tower With Storage 100 MW 6 HRs	$148.02	$10.57	$181.36
Solar Power Tower With Storage 100 MW 11 HRs	$148.02	$10.57	$196.46
Low-Cost Case			
Solar Parabolic Trough W/O Storage 250 MW	$44.52	$0.00	$44.52
Solar Parabolic Trough With Storage 250 MW	$44.52	$0.00	$44.52
Solar Power Tower W/O Storage 100 MW	$41.67	$0.00	$41.67
Solar Power Tower With Storage 100 MW 6 HRs	$45.10	$0.00	$45.10
Solar Power Tower With Storage 100 MW 11 HRs	$45.10	$0.00	$45.10

Source: Energy Commission.

CHAPTER 6: Wind Technology

Overview

Wind generation technologies, like solar, have been the subject of much study and discussion over the last several years. The following presents assumptions and estimates of California specific lifetime costs of building and operating Class 3 and 4 wind generation resources[39] built between 2013 and 2024. These assumptions and estimates are derived from a review of the literature and collation of the relevant values.

Technology Description

A wind energy system transforms the kinetic energy of the wind into electrical energy that can be harnessed for practical use. The main components of a wind turbine are:

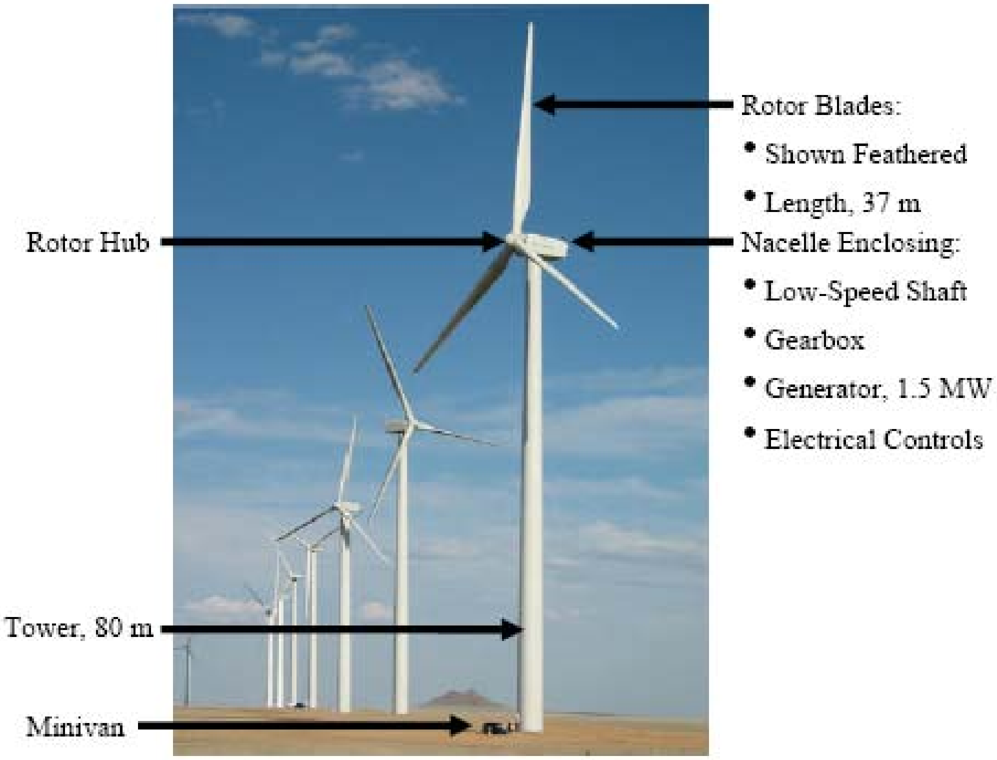
- A rotor, or blades, which convert the energy of the wind into rotational shaft energy.
- A nacelle (enclosure) containing a drivetrain, usually including a gearbox and a generator.
- A tower to support the rotor and drivetrain.
- Electronic equipment, such as controls, electrical cables, ground support equipment, and interconnection equipment.

Some wind turbines use direct-drive generators and do not need a gearbox. Maintaining a gearbox can be a critical cost component.

Typical wind power plant units today consist of 1.5 MW to 2.5 MW turbines atop 80 meter towers, as shown in **Figure 24**. Wind farms can range in size from a few MW to hundreds of MW in capacity composed of dozens of turbines. Wind power plants are *modular*, which means they consist of small individual modules (the turbines) and can easily be made larger or smaller as needed. Turbines can be added as electricity demand grows. Today, a 50 MW wind farm can be completed in one to two years (O'Connell, et al., 2007). Most of that time is needed for measuring the wind and obtaining construction permits. The wind farm itself can be built in less than six months (Reategui and Tegen, 2008).

39 Wind resources are classified by the average wind speeds available on site. Class 4 wind resources have higher average wind speeds than Class 3. Specifications for all wind classes are given in **Table 24**

Figure 24: A Modern 1.5 MW Wind Turbine Installed in a Wind Power Plant



Source: U.S. DOE, EERE, (U.S. DOE and EERE, 2008).

Regions

Wind resources are ranked by the strength and consistency of the wind in a particular region. **Table 24** shows wind resources classified by a combination of wind power density[40] and wind speed as measured at two different heights. Some areas of California have good (Class 3 and 4) to excellent (Class 5, 6, and 7) wind resources. However, virtually all of the higher speed resources are offshore. Construction of offshore wind not has occurred in California because offshore wind often engenders local opposition, since many consider such wind facilities unsightly, and because accessing offshore resources can be cost-prohibitive. These obstacles are expected to continue for the foreseeable future; therefore, offshore wind is not included in this assessment. The majority of the most consistent (Class 4 and 5) sites in California already have extensive development. Future development is

40 *Wind power density* is a measure of the availability of power (measured in watts) on average in a location per square meter of space.

most likely to occur at Class 3 sites. This analysis focuses on Class 3 and Class 4, reflecting resource potential in California.

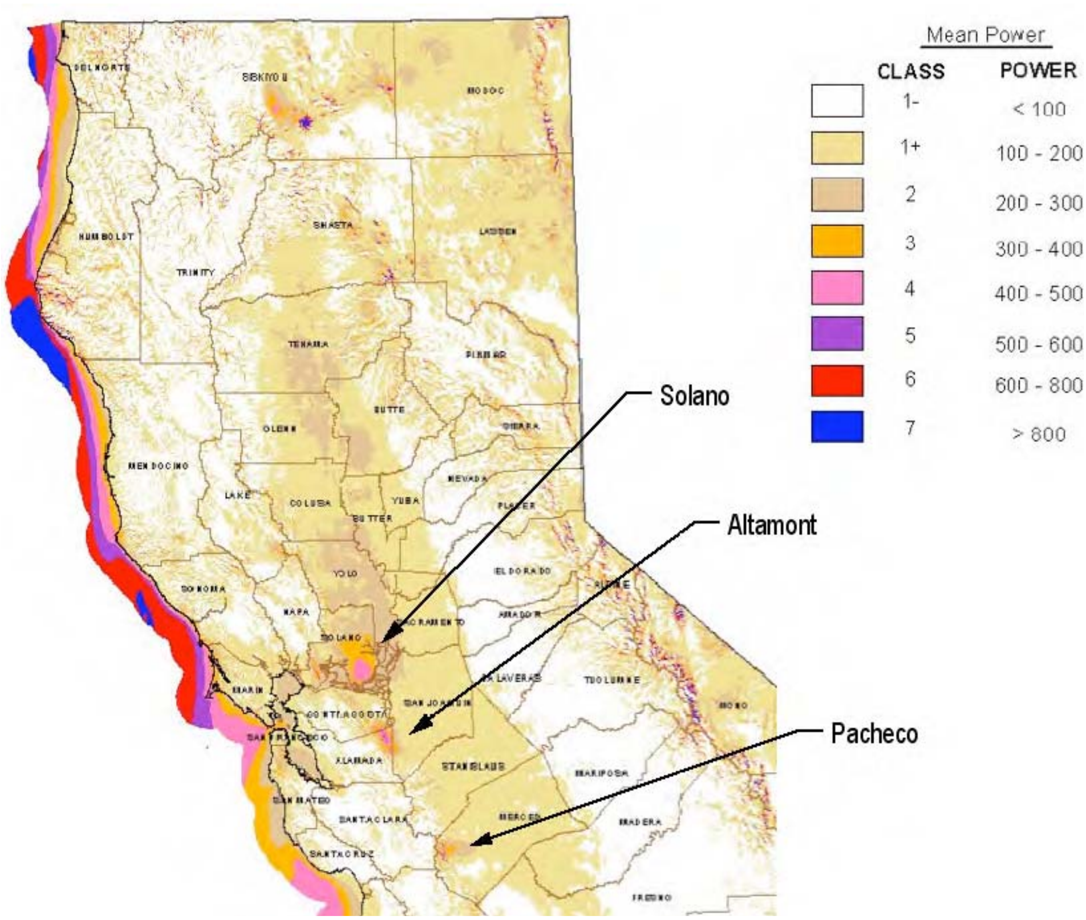
Table 24: Wind Power Classifications

Wind Power Class	10 Meter		50 Meter	
	Wind Power Density (W/m2)	Wind Speed m/s (mph)	Wind Power Density (W/m^2)	Wind Speed m/s (mph)
1	0	0	0	0
2	100–150	4.4 (9.8)/5.11 (11.5)	200–300	5.6 (12.5)/6.4 (14.3)
3	150–200	5.1 (11.5)/5.6 (12.5)	300–400	6.4 (14.3)/7.0 (15.7)
4	200–250	5.6 (12.5)/6.0 (13.4)	400–500	7.0 (15.7)/(16.8)
5	250–300	6.0 (13.4)/6.4 (14.3)	500–600	7.5 (16.8)/8.0 (17.9)
6	300–400	6.4 (14.3)/7.0 (15.7)	600–800	8.0 (17.9)/8.8 (19.7)
7	>400	>7.0 (15.7)	>800	>8.8 (19.7)

Source: Interwest Energy Alliance Website: www.interwest.org/wiki/index.php?title=Wind_power_classes.

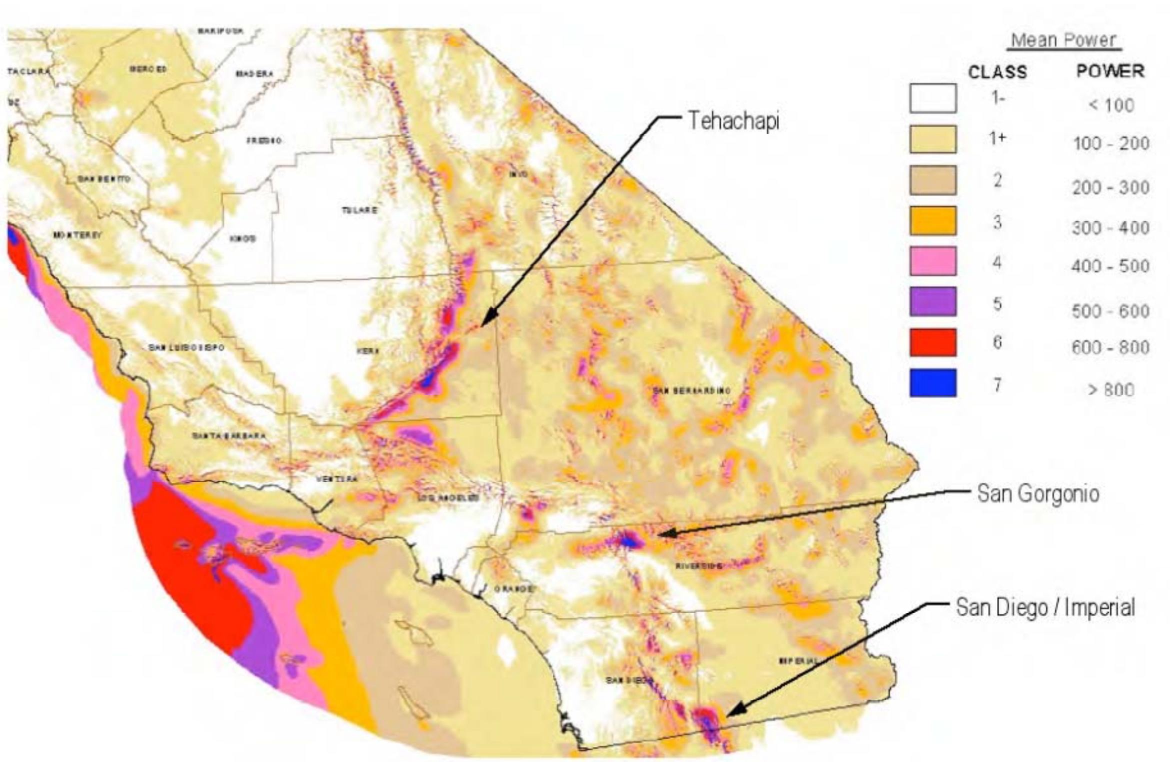
Figure 25 and **Figure 26** show the locations of California's existing wind resources as well as the generally recognized names of the wind resource areas currently under development. In Northern California, the Solano, Altamont, and Pacheco resource areas are the most productive, and all have wind farms located within their regions. In Southern California, the Tehachapi, San Gorgonino, and San Diego/Imperial resource areas are also home to existing wind installations.

Figure 25: Wind Resource Map of Northern California With Project Developments



Source: Energy Commission. *Wind Power Generation Trends at Multiple California Sites*. *Public Interest Energy Research (PIER) Interim Project Report*, CEC-500-2005-185.

Figure 26: Wind Resource Map of Southern California With Project Developments



Source: Energy Commission. *Wind Power Generation Trends at Multiple California Sites*. *PIER Interim Project Report*, CEC-500-2005-185.

Capital and Instant Cost Trends

Wind power plant installations consist of multiple wind turbines connected to a single electrical meter. This means they are modular with the capability to add new turbines within each development, thus increasing overall plant size. Often multiple wind power plants are clustered together to create a wind farm. Wind farm size in California varies dramatically from less than 1 MW to 150 MW, and many of the newer installations are within the same general area as preexisting installations.

The installation of new wind farms in California is expected to continue for the foreseeable future based on continual active participation by wind developers in California renewable markets such as the Renewable Auction Mechanism (RAM)[41] (Renewable Auction Mechanism, 2013). In addition to the continued installation of new wind facilities, there is also a trend toward larger turbines.

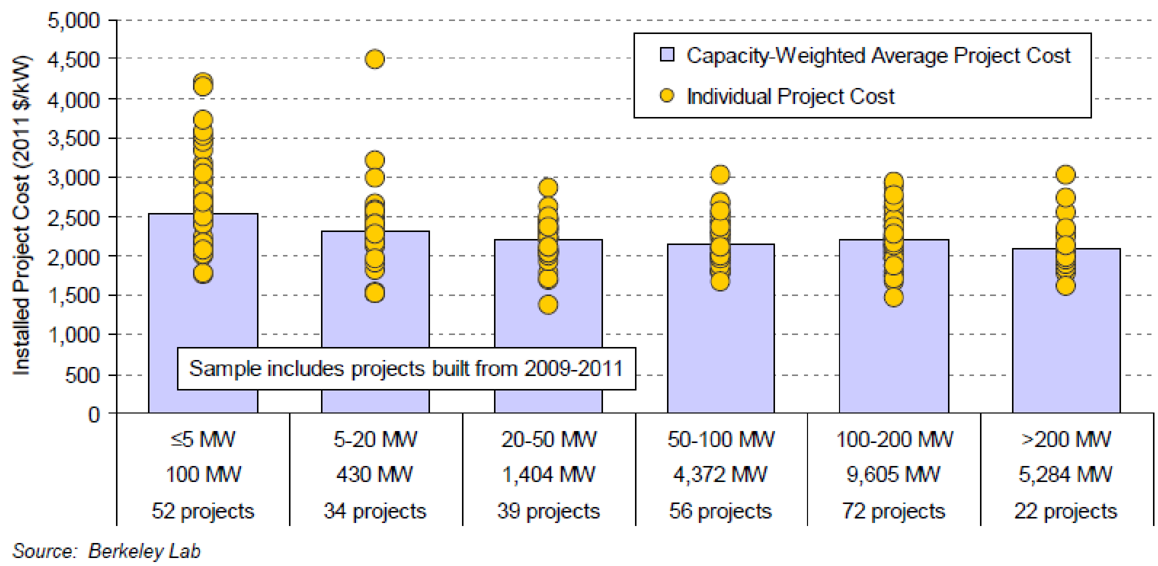
[41] The Renewable Auction Mechanism is a simplified market-based procurement mechanism for renewable distributed generation projects greater than 3 MW and up to 20 MW

Each of these trends primarily affects turbine prices, which are typically 75 percent of overall project installation costs (O'Connell, et al., 2007). General project cost drivers are:

- Turbine cost.
- Reliability.
- Permitting and site selection.
- Land acquisition.
- Transmission costs.

Some stakeholders consider economies of scale to be a cost driver for lowering costs. Since wind power plants are a modular technology, very few economies of scale have been seen from larger installations, as shown in **Figure 27**. However, this assessment does not include the cost of the interconnection equipment (transmission from the power plant to the existing transmission). Obviously, the cost per kW can be reduced by larger installations sharing the cost of expensive interconnection.

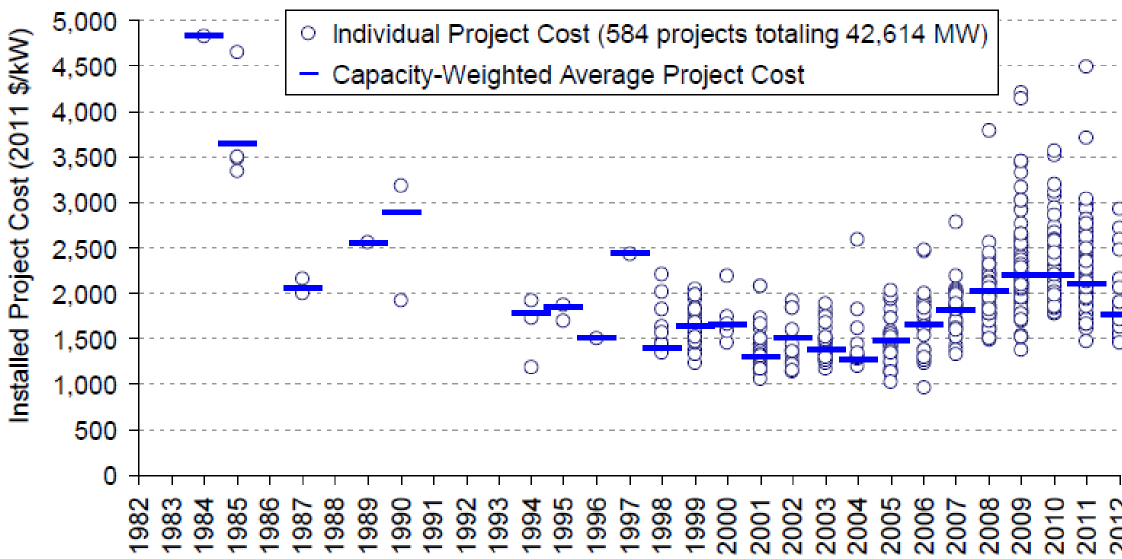
Figure 27: Installed Wind Project Costs as a Function of Project Size: 2009 – 2011 Projects



Source: Wiser and Bollinger, *2011 Wind Technologies Market Report*, EERE, 2012.

As shown in **Figure 28** (Wiser and Bollinger, 2012), the cost of wind power installations across the United States showed a steady decline from the early 1980s until 2002 (Wiser and Bollinger, 2012). The trend nationally in turbine costs is from a Lawrence Berkeley National Laboratory (LBNL) study of actual installations over time. Costs then rose, peaking in 2009 for many of the same reasons that power plant construction costs for other technologies peaked, such as increased labor, materials, and energy costs. The cost trend has reversed for now. The consolidation of wind manufacturers has created some instability and uncertainty in the wind turbine marketplace. No strong trend indicators are foreseen by industry observers.

Figure 28: Installed Wind Project Costs Over Time to 2012



Note: 2012 data represent preliminary cost estimates for a sample of 20 projects totaling 2.6 GW that have either already been or will be built in 2012, and for which substantive cost estimates were available.
Source: Berkeley Lab (some data points suppressed to protect confidentiality)

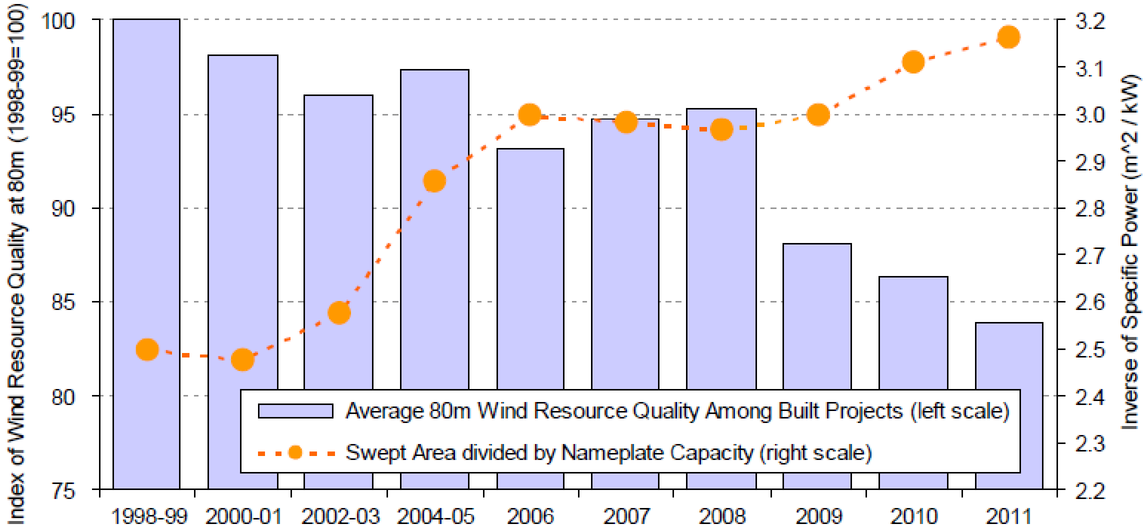
Source: Wiser and Bollinger, *2011 Wind Technologies Market Report*, EERE, 2012.

Wind is considered a variable resource, meaning its output is determined by the daily patterns of weather rather than by a central dispatcher. The economic viability of a wind project is often determined by the average amount of energy it can produce relative to its total theoretical capacity (sometimes called *nameplate capacity*). This ratio of actual output to theoretical output is the capacity factor (CF). CFs have stalled after steady improvement for many years. Increased hub heights and increased care in selecting turbine location for higher wind sites can increase CF but can also contribute to increased installed costs. Hub heights have increased only a small amount since 2006.

Figure 29 shows a decline in the average resource quality[42] over the last decade, and turbine designers have responded with turbines that capture more of the wind energy through a longer blade length (also known as *swept area*) and, therefore, more exposure to the force of the wind.

42 *Resource quality* is an index number intended to capture the relative changes in power density of wind resources under development.

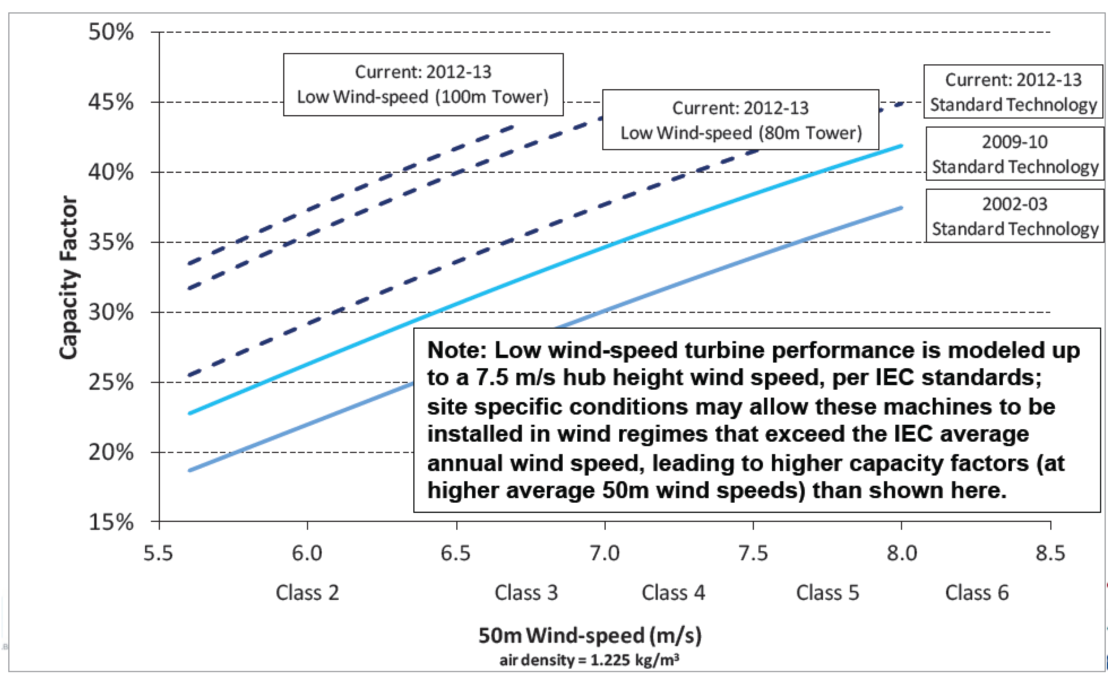
Figure 29: Wind Resource Quality Compared to Wind Turbine Design Changes



Source: Wiser and Bollinger, *2011 Wind Technologies Market Report,* EERE, 2012.

In response to the declining quality of available wind resource sites, manufacturers are offering taller turbines designed to increase overall output at lower speeds. **Figure 30** shows how the expected CF has increased with these changes in design.

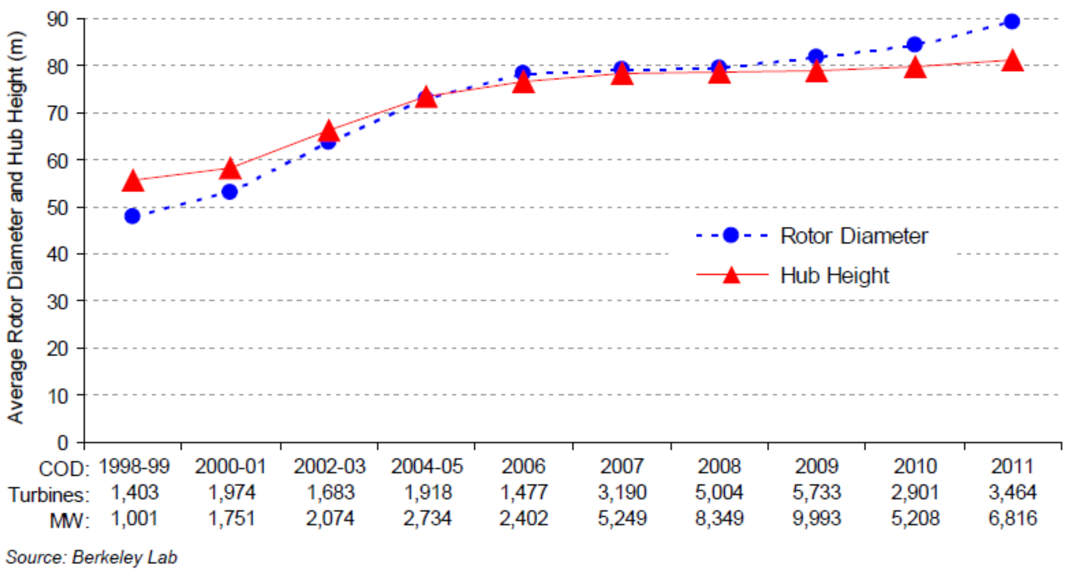
Figure 30: Changes in Capacity Factor With Turbine Redesign



Source: Ryan Wiser, and others, *Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects*, LBNL, February 2012.

Wind turbine size (ratings in MW) has increased over time, which drives rotor diameter and hub height. The increased equipment costs will be at least partially offset by increased CF. **Figure 31** shows the historical trends in hub height and rotor diameter.

Figure 31: Trends in Hub Height and Rotor Diameter



Source: Wiser and Bollinger, *2011 Wind Technologies Market Report*, EERE, 2012.

Current Costs and Plant Characteristics

For Class 4 projects, 2011 instant cost ranged from a low case of $1,386/kW to a high case of $2,002/kW, with a midpoint estimate of $1,890/kW. Unless otherwise indicated, this and subsequent assumptions in this section are based on information from several studies (Lazard, 2011; Black & Veatch, 2012; Wiser and Bollinger, 2012; Wiser, 2012). These costs do not include land and permitting costs. Costs that include these ancillary costs can be found in **Table 25**.

For Class 3 projects, 2011 instant costs ranged from a low case of $1,581/kW to a high case of $23,94/kW, with a midpoint estimate of $2013/kW. Again, these costs do not include land and permitting costs. Costs that include these ancillary costs can be found in **Table 26**.

CFs were found to range from 30 to 45 percent, with 39 percent being the mid-case value for Class 4 projects. These CFs are somewhat higher than the current industry average for operational plants in commercial service, as study authors expect. For Class 3 projects, CFs range from 30 percent to 43 percent, with the mid case set at 42 percent.

Notably, a recent study from LBNL reports significant losses from station service load or losses, although no details are offered. This effectively reduces the output capability of the wind farm and increases price. Capacity can degrade up to 0.8 percent per year, with an average value of 0.3 percent (Milborrow, 2013; Bach, 2012).

O&M costs are shown for 2011 in **Table 25** and **Table 26** are in 2011 dollars; they are identical for both Class 3 and 4 projects. The O&M values escalate 0.5 percent per year in real dollars, driven largely by personnel costs. Total O&M cost is the combination of fixed and variable O&M and is reported to standardize the values as they are reported across technologies.

Table 25: Class 4 Wind Project Costs

Plant Data	Mid Cost	High Cost	Low Cost
Gross Capacity (MW)	100	100	100
Station Service (%)	15.0%	16.5%	14.0%
Net Capacity Factor (NCF)	39.0%	30.0%	45.0%
Forced Outage Rate (FOR)	1.0%	1.0%	1.0%
Scheduled Outage Factor (SOF)	0.0%	0.0%	0.0%
Capacity Degradation (%/Year)	0.3%	0.8%	0.0%
2011 Instant Cost (Nominal $/kW)	$1,890	$2,002	$1,368
2011 Fixed O&M Cost (Nominal $/kW-yr)	$30.00	$30.00	$30.00
2011Variable O&M Cost (Nominal $/MWh)	$8.00	$10.00	$6.00
2011 Total O&M Cost (Nominal $/kW-yr)	$57.33	$56.28	$53.65
Insurance	0.60%	0.60%	0.60%

Source: Energy Commission.

Table 26: Class 3 Wind Project Costs

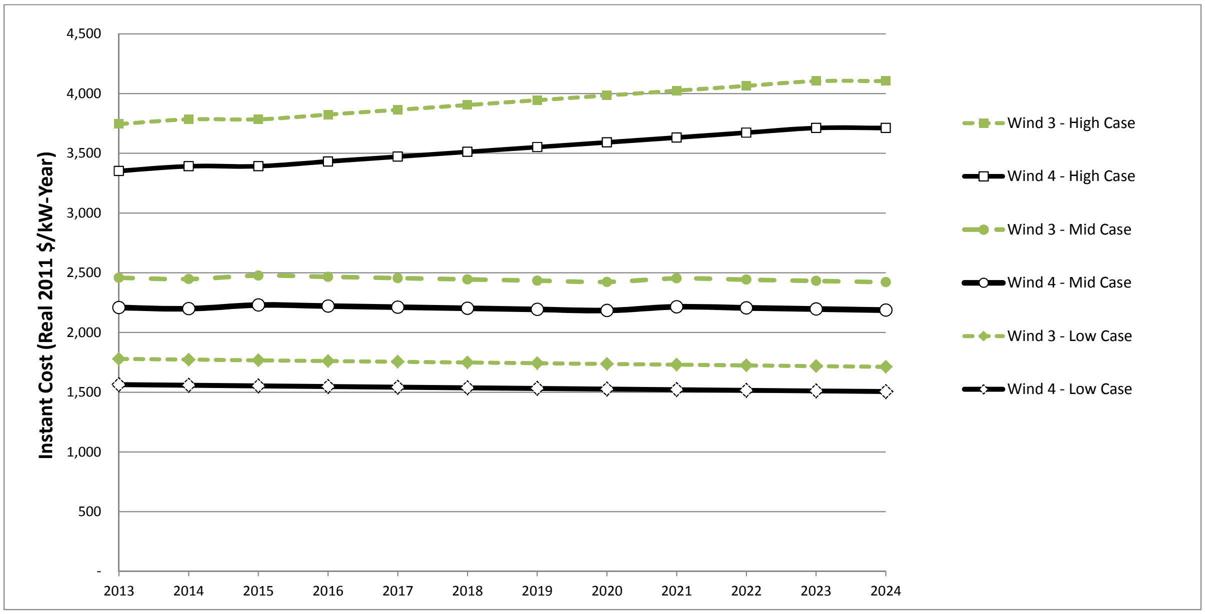
Plant Data	Mid Cost	High Cost	Low Cost
Gross Capacity (MW)	100	100	100
Station Service (%)	15.0%	16.5%	14.0%
Net Capacity Factor (NCF)	42%	30.0%	43.0%
Forced Outage Rate (FOR)	1.0%	1.0%	1.0%
Scheduled Outage Factor (SOF)	0.0%	0.0%	0.0%
Capacity Degradation (%/Year)	0.3%	0.8%	0.0%
2011 Instant Cost (Nominal $/kW)	$2,013	$2,394	$1,581
2011 Fixed O&M Cost (Nominal $/kW-yr)	$30.00	$30.00	$30.00
2011Variable O&M Cost (Nominal $/MWh)	$8.00	$10.00	$6.00
2011 Total O&M Cost (Nominal$/kW-yr)	$57.33	$56.28	$53.65
Insurance	0.60%	0.60%	0.60%

Source: Energy Commission.

Projected Instant Costs

Figure 32 shows projected Wind Class 3 and Class 4 instant costs. Mid-case costs are expected to decline in real dollars only very slightly, if at all. Other factors, such as improvements in technology and widespread adoption of best practices or high competition for skilled labor, may result in trends that vary widely from the mid case. This instability is captured in the wide range between the low- and high-cost scenarios.

Figure 32: Projected Wind Instant Costs



Source: Energy Commission.

Summary of 2013 Instant and Installed Costs

Installed costs reflect the need for most projects to seek financing and repay that financing arrangement over time, adding to the total cost of the project. Since the borrowing costs vary depending on the credit risk (as discussed in Chapter 2), the installed cost for the same technology will vary depending on the ownership structure. **Table 27** summarizes the 2013 instant and installed costs for the wind technologies. The values shown are calculated within the COG Model. **Table 28** summarizes the corresponding O&M costs.

Table 27: Summary of 2013 Instant and Installed Costs

Plant Costs Year = 2013 (Nominal Dollars)	Instant Costs ($/kW)	Installed Costs ($/kW)		
		Merchant	IOU	POU
Mid-Cost Case				
Wind - Class 3 100 MW	$2,458	$2,849	$2,864	$2,809
Wind - Class 4 100 MW	$2,208	$2,560	$2,574	$2,524
High-Cost Case				
Wind - Class 3 100 MW	$3,744	$4,655	$4,700	$4,582
Wind - Class 4 100 MW	$3,352	$4,167	$4,207	$4,102
Low-Cost Case				
Wind - Class 3 100 MW	$1,779	$1,961	$1,975	$1,946
Wind - Class 4 100 MW	$1,563	$1,723	$1,735	$1,710

Source: Energy Commission.

Table 28: Summary of 2013 Operation and Maintenance Costs

O&M Costs Year = 2013 (Nominal Dollars)	Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)	Total O&M	
			($/kW-Year)	$/MWh
Mid-Cost Case				
Wind - Class 3 100 MW	$31.72	$8.46	$17.08	$62.84
Wind - Class 4 100 MW	$31.72	$8.46	$17.74	$60.61
High-Cost Case				
Wind - Class 3 100 MW	$31.72	$10.57	$22.64	$59.50
Wind - Class 4 100 MW	$31.72	$10.57	$22.64	$59.50
Low-Cost Case				
Wind - Class 3 100 MW	$31.72	$6.34	$14.76	$55.61
Wind - Class 4 100 MW	$31.72	$6.34	$14.39	$56.72

Source: Energy Commission.

CHAPTER 7: Geothermal Technology

Technology Overview

Geothermal energy is derived from heat beneath the earth's surface that flows to the surface through a variety of pathways from hot water, steam reservoirs, or heated rock formations. Heat is carried continuously upward to the earth's surface as steam or hot water flows through permeable rock. About 94 percent of all known U.S. geothermal resources are located in California. [43]

Most geothermal resources fall into one of the following categories: vapor-dominated, liquid-dominated, geo-pressure, hot dry rock, and magma. Each of these is explained later in this chapter. Of these resources, only vapor- and liquid-dominated resources have been developed commercially for utility-scale power generation.

This study addresses two technology types of geothermal power plants associated with liquid dominated geothermal resources, which are described more fully later on in the chapter:

- Binary Power Plants—These plants use hot liquid (called *brine*) drawn from deep beneath the earth's surface to cause another fluid to boil. The vapor created is then used to drive power turbines.
- Flash Power Plants—These plants use the hot brine drawn from the well and convert the liquid directly to steam by reducing the pressure on the liquid (called *flashing*).

Dry steam technology power plants, in which only steam is extracted from the geothermal well instead of brine, are not included in this cost of generation study since they are applicable to only one resource in the Western United States, which is the Geysers located in Northern California. This study focuses on geothermal resource cost modeling applicable to a wider geography.

Liquid-dominated resources are characterized by reservoir temperatures ranging from 25 degrees Celsius (°C) (77 degrees Fahrenheit [°F]) to more than 315°C (599°F). In these geothermal systems, water migrates into a well from the reservoir by a path of least resistance. In California, liquid-dominated resources are quite abundant and far more

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43 *Geothermal resources* refer to the use of thermal energy stored below the surface of the earth for converting the energy into electricity.

widespread than vapor-dominated resources. They make up more than 90 percent of known geothermal resources in the state.

Different technologies are used to generate power from geothermal resources, depending on the temperature of the resource. High-temperature geothermal resources (reservoirs with temperatures greater than 176°C [349°F]) generally use flashed steam systems. At resource temperatures lower than 176°C [349°F]), these technologies become inefficient and economically unattractive, making the binary cycle system more attractive. A binary cycle plant can use moderate temperature resources (reservoirs with temperatures between 104°C [219°F] and 176°C [349°F]) 40 percent to 60 percent more efficiently than a flashed steam facility.

Liquid-Dominated Resource Development

Exploration of liquid-dominated geothermal resources in California began in 1967, when Unocal and Morton Salt Company deployed small, experimental geothermal turbines at the Salton Sea geothermal field. However, problems with silica scaling and high salt concentrations prevented commercial development of the resource at that time. In those early days, there were a number of impediments to developing liquid-dominated geothermal resource, including a high degree of risk, higher capital costs, an adverse regulatory climate, and the relative immaturity of exploration, drilling, and production.

With the passage of the Public Utility Regulatory Policy Act (PURPA) in 1978, a more progressive regulatory environment, coupled with federal tax credits and loan guarantees, created incentives to develop geothermal resources. In implementing PURPA, the Federal Energy Regulatory Commission (FERC) directed state regulators to require that utilities purchase power from independent power producers (IPPs) at the utility's full avoided cost and to make the utility's transmission system available to deliver the power to market. Because geothermal power is a baseload resource, the sale of that power to a utility displaces capacity that utilities would otherwise have to build. This allowed geothermal power to receive a capacity payment as well as an energy charge, which was a significant benefit to the geothermal industry.

The result of these regulatory and financial incentives was a shift from utility development of a dry steam resource at the Geysers to independent development of liquid-dominated resources at multiple locations throughout the state. It also established the IPP segment of the industry and increased its power generating capacity from zero to roughly one-third of the total installed capacity (in MW). Production from liquid-dominated resources is also about one-third of total production.

During the 1980s, several liquid-dominated geothermal projects were developed, including the following:

- The initial commercial power development of a liquid-dominated geothermal resource occurred in November 1979, at the East Mesa field in Imperial County, where a 13.4 MW binary application was constructed using isobutane as the secondary working fluid.
- In June 1980, Southern California Edison (SCE) began operation of a 10 MW experimental power plant at the Brawley geothermal field, also in Imperial County. However, after a few years of operation further development was ceased due to corrosion, reservoir uncertainties, and the presence of high salinity brines.
- In 1982, Unocal initiated electrical power generation from the Salton Sea geothermal resource with a 12 MW plant; two additional generation units were added for a total of 83 MW of electrical generation.
- In late 1985, Magma Power Company commenced continuous production from its first 40 MW power plant at the Salton Sea field and added three more units within two years to increase its total to 145 MW.

Today, CalEnergy Corporation operates the entire Salton Sea field, consisting of eight power plants totaling 288 MW of installed capacity. To generate electricity economically using liquid-dominated resources, reservoir temperatures generally must exceed 104.4°C (220°F). There are several areas within California where liquid-dominated resources above this temperature are being developed, including the Imperial Valley, Coso Hot Springs (Inyo County), Mono-Long Valley (Mono County), and Wendel-Amadee (Lassen County). Other areas that exhibit temperatures above this minimum and where exploration has begun include Glass Mountain, Lassen, and Surprise Valley. Since the temperature and quality of these resources vary significantly from site to site, different types of generating systems are needed. In the Imperial Valley, there are 16 plants operating with a combined installed capacity of 527.3 MW. At the Coso Hot Springs resource, there are nine dual-flash operating plants[44] with a combined installed capacity of 229.5 MW.

Factors Affecting Future Geothermal Development

California's relative abundance of geothermal resources in comparison to the rest of the United States does not mean that geothermal power production would be viable or cost-effective everywhere in the state. Developers must consider multiple factors of cost and viability when deciding where to locate new geothermal plants. In turn, these considerations drive the estimates of future costs of new geothermal power plants in California. Considerations for developing geothermal power plants in liquid-dominated resources include (Kagel, 2006):

[44] A "dual-flash" plant creates steam by dropping the pressure on hot liquid once, then does so again in a second chamber by inducing an even lower pressure.

- Exploration Costs—Exploration and mapping of the potential geothermal resource is a critical and sometimes costly activity. It effectively defines the characteristics of the geothermal resource.
- Confirmation Costs—These are costs associated with confirming the energy potential of a resource by drilling production wells and testing their flow rates until about 25 percent of the resource capacity needed by the project is confirmed.
- Site/Development Costs—Covering all remaining activities that bring a power plant on line, including:
    - Drilling—The success rate for drilling production wells during site development average 70 percent to 80 percent (Entingh, et al., 2012). The size of the well and the depth to the geothermal reservoir are the most important factors in determining the drilling cost.
    - Project leasing and permitting—Like all power projects, geothermal plants must comply with a series of legislated requirements related to environmental concerns and construction criteria.
    - Piping network—The network of pipes are needed to connect the power plant with production and injection wells. Production wells bring the geothermal fluid (or *brine*) to the surface to be used for power generation, while injection wells return the used fluid back to the geothermal system to be used again.
    - Power plant design and construction—In designing a power plant, developers must balance size and technology of plant materials with efficiency and cost effectiveness. The power plant design and construction depends on type of plant (binary or flash) as well as the type of cooling cycle used (water or air cooling).
    - Transmission—Includes the costs of constructing new lines, upgrades to existing lines, or new transformers and substations.

Another important factor contributing to overall costs is O&M costs, which consist of all costs incurred during the operational phase of the power plant (Hance, 2005). Operation costs consist of labor; spending for consumable goods, taxes, royalties; and other miscellaneous charges. Maintenance costs consist of keeping equipment in good working status. In addition, maintaining the steam field, including servicing the production and injection wells (pipelines, roads, and so forth) and make-up well drilling[45], involves considerable expense.

Development factors are not constant for every geothermal site. Each of the above factors can vary significantly based on specific site characteristics. Other key variable factors that

45 Make-up drilling aims to compensate for the natural productivity decline of the project start-up wells by drilling additional production wells.

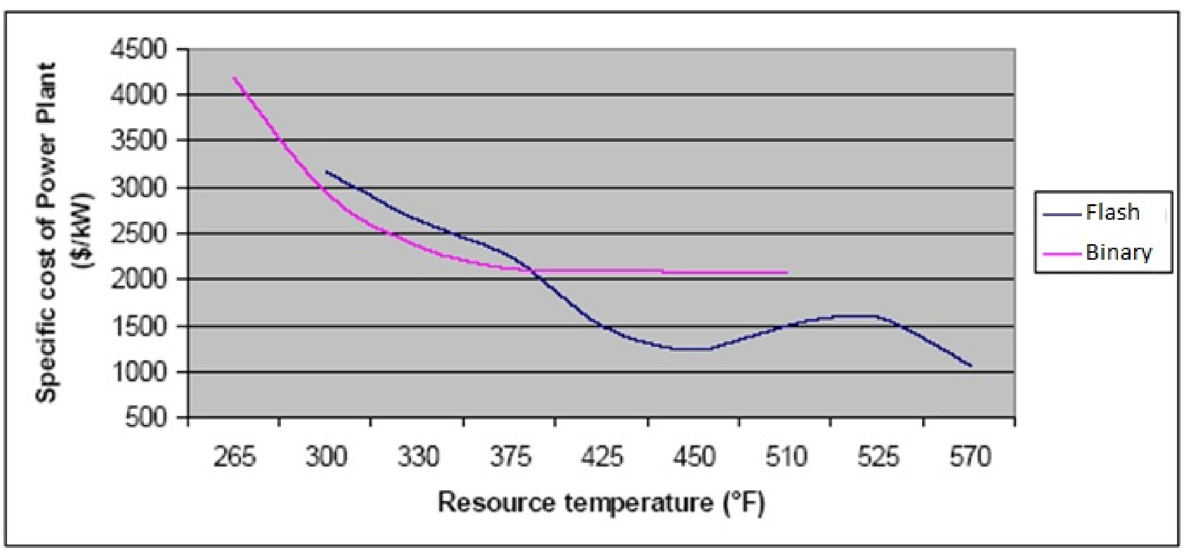
drive costs for geothermal plants (not mentioned directly above since they are highly project specific) are project delays, temperature of the resource, and plant size.

The temperature of the resource is an essential parameter influencing the cost of the power plant equipment. Each power plant is designed to optimize the use of the heat supplied by the geothermal fluid. The size, and thus cost, of various components (for example, heat exchangers) is determined by the temperature of the resource. As the temperature of the resource increases, the efficiency of the power system increases, and the specific cost of equipment decreases as more energy is produced with similar equipment. Since binary systems use lower resource operating temperatures than flash steam systems, binary costs can be expected to be higher. **Figure 33** provides estimates for cost variance due to resource temperature. As the figure shows, binary systems range in cost from $2,000/kWh to slightly more than $4,000/kWh, while flash steam systems range from $1,000/kWh to just above $3,000/kWh (Hance, 2005).

Geothermal—Binary

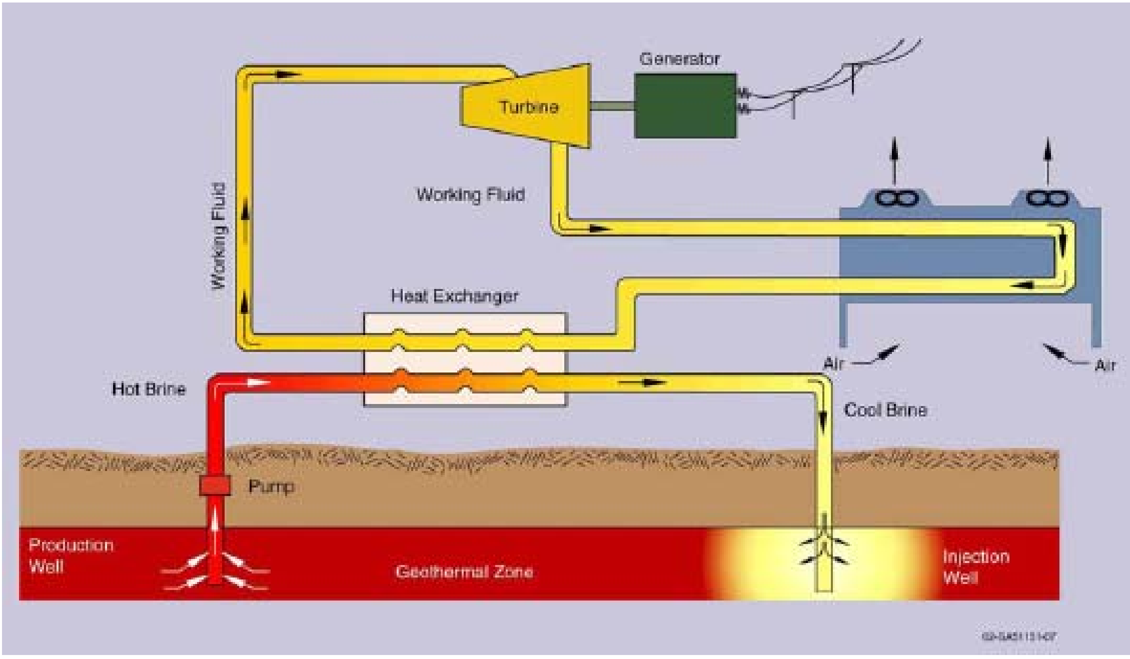
Binary cycle geothermal power plants pass moderately hot geothermal water (called brine) by a secondary fluid with a much lower boiling point than water as shown in **Figure 34**. This causes the secondary fluid to boil, creating vapor, which then drives the turbines. California binary plants range in size from 0.7 to 47.8 MW, with most between 20 and 30 MW. Each of these plants can have several generators. The average generator size in use in California is about 4 MW.

Figure 33: Specific Cost of Geothermal Power Plant Equipment vs. Resource Temperature



Source: Hance, *Factors Affecting Costs of Geothermal Power Development*.

Figure 34: Binary Geothermal Power Plant



Source: Idaho National Laboratory.

Binary geothermal is a mature technology with plants operating in California since the mid-1980s. Several specific sites have been identified in California suitable for binary plant development. Current California binary geothermal installations total 140 MW (Geothermal Power, 2012). An additional 240 MW of potential development could use binary technology (Sison-Lebrilla and Tiangco, 2005). Should these sites be developed, the less expensive sites (greatest return on investment) would be first, with the more expensive sites to follow. As a result, any learning curve in binary system development would most likely be a cost avoidance rather than a cost saving, making cost reduction trends unlikely.

Current Costs and Plant Characteristics

Current costs and plant characteristics for binary geothermal plants shown in **Table 29** were derived from review of publicly available reports and studies (EIA, 2010; Hahn, et al., 2010; Lazard, 2011; Black and Veatch, 2012; Tidball, et. al., 2010; Gifford and Grace, 2011; Geothermal, 2012; ANG, 2011). Only studies that distinguished between binary and flash technology were used for capital cost components.

Instant costs ranged from a low case (EIA, 2010; Hahn, et al., 2010) of $4,173/kW to a high case (Geothermal, 2012) of $6,264/kW, with a midpoint (Tidball, et al., 2012) estimate of $4,993/kW. Costs are in 2011 dollars. Instant costs are for equipment and construction only and do not include costs such as land and permitting costs, which would increase mid costs by about 2 percent. (See summary table at end of chapter.) Instant costs are assumed to remain constant in real dollars. These capital costs can vary widely due to a number of factors, the most important of which are well drilling costs and success rate. Well costs can be more than half of the capital costs.

The fixed O&M costs reflect the total O&M costs because the power plants are operated as baseload and variable O&M is assumed to be zero.[46]

Fixed O&M costs range from a low case (Tidball, et al., 2010) of $84.93 $/kW-yr to a high case (Geothermal, 2012) of $146.40 $/kW, with a midpoint (EIA, 2010; Hahn, et al., 2010) estimate of $84.93 per kW. Costs are for 2011 and are given in 2011 dollars. The O&M cost is assumed to have a real escalation rate of 0.5 percent over the study period.

CFs were found to range from 77 to 95 percent, with 85 percent being the mid case value (Tidball, et al., 2010). These CFs are consistent with operational plants in commercial service. Capacity can degrade up to 2 percent per year, and thermal efficiency (known as heat rate) can decline up to 5 percent a year (Gifford and Grace, 2011).

Most estimates of emissions show no 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.

Geothermal resources are typically built on public lands and are often required to make royalty payments. Royalty payments to the U.S. Bureau of Land Management (BLM) typically run 3 percent of power sale revenues but can vary between 0 and 5 percent (Gifford and Grace, 2011).

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

Table 29: Binary Geothermal Physical and Cost Parameters

Plant Data	Mid Cost	High Cost	Low Cost
Gross Capacity (MW)	30	30	30
Station Service (%)	11.5%	14.5%	8.5%
Net Capacity Factor (NCF)	85.0%	77.1%	95.0%
Capacity Degradation (%/Year)	0.5%	2.0%	0.0%
Heat Rate Degradation (%/Year)	3.0%	5.0%	0.0%
Heat Rate (Btu/kWh)	34.377	34,633	34,120
Forced Outage Rate (FOR)	2.5%	2.8%	2.2%
Scheduled Outage Factor (SOF)	4.0%	12.0%	2.0%
Emission Factors			
NO_X (lbs/MWh)	N/A	N/A	N/A
VOC/Reactive Organic Gases (ROG) (Lbs/MWh)	N/A	N/A	N/A
CO (Lbs/MWh)	N/A	N/A	N/A
CO_2 (lbs/MWh)	-	120	-
SO_X (lbs/MWh)	N/A	N/A	N/A
PM_{10} (lbs/MWh)	N/A	N/A	N/A
2011 Instant Cost (Nominal $/kW)	$4,993	$6,264	$4,173
2011 Fixed O&M Cost (Nominal $/kW-yr)	$84.93	$146.40	$84.93
2011Variable O&M Cost (Nominal $/MWh)	N/A	N/A	N/A
Insurance (%/Year)	0.60%	0.60%	0.60%
Royalties	3.0%	5.0%	0.0%

Source: Energy Commission.

Geothermal—Flash

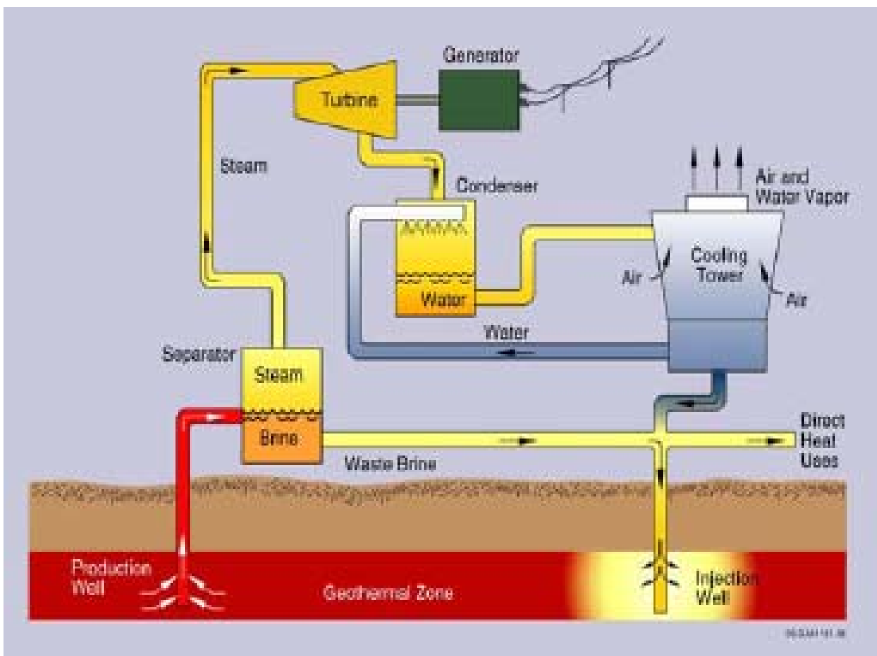
Current Status and Technical Potential

Flash steam plants pull deep, high-pressure hot water into lower-pressure tanks and use the resulting flashed steam to drive turbines. This is the most common type of geothermal plant in operation today. In a flash steam system, as shown in **Figure 35**, geothermal brine typically between 104°C and 176°C is brought to the surface and piped to a separation tank where the pressure is reduced, causing the fluid to flash into steam. In a single-flash system, hot fluid is drawn to the surface. A fraction of the hot water "flashes" to steam when exposed to the lower pressure within the separator.

The steam is then passed through a turbine to generate power. Typically the liquid fraction is then injected back into the reservoir. During this process as much as 60 percent of the usable heat extracted from the reservoir may be lost. To improve efficiency, a variation on the flash design known as *dual-flash systems* are used in which the geothermal fluid is flashed twice, increasing the amount of steam to the turbine. Dual-flash technology imposes a second stage separator onto a single-flash system. This second stage steam has a lower pressure and is put into either a later stage of a high-pressure turbine or a second lower-pressure turbine. The steam exiting the turbine is condensed. Dual-flash technology is in the range of 10 percent to 20 percent more efficient than single-flash technology.

Most California plants use one generator, but some use two or three generators. Total plant capacities range from 10 MW to 52 MW, with most at about 30 MW. Current California flash geothermal installations total 700 MW (Geothermal Power, 2012). The additional potential development of flash technology is 2,220 MW (Sison-Lebrilla and Tiangco, 2005).

Figure 35: Geothermal Flash Power Plant



Source: Idaho National Laboratory.

Technology Development Considerations

In addition to the cost factors listed in the previous section of the report addressing geothermal binary plants, for some flash plants a corrosive geothermal fluid may require the use of resistive pipes and cement. Adding a titanium liner to protect the casing may significantly increase the cost of the well. This kind of requirement is rare in the United States, found only in the Salton Sea resource in Southern California(Hance, 2005).

Current Costs and Plant Characteristics

The current costs and plant characteristics for flash geothermal plants shown in **Table 30** were derived from review of publicly available reports and studies (EIA, 2010; Hahn, et al., 2010; Lazard, 2011; Black & Veatch, 2012; Tidball, et al., 2010; Gifford and Grace, 2011; Geothermal, 2012; ANL, 2011; Stora and Rundquist, 2010; Holm, 2012). As with the binary plants, only studies that distinguished between binary and flash were used for developing capital cost components.

Estimated instant or overnight cost (expressed in 2011 $/kW) ranges from a low case (Tidball, et al., 2010) of $3,559/kW to a high case (Geothermal, 2012) of $7,496/kW, with a mid case (EIA, 2010; Hahn, et al., 2010) estimate of $5,622/kW. Costs are for 2011 and are in 2011 dollars[47]. Capital costs are for equipment only and do not include costs such as land and permitting costs, which would increase mid case costs by about 3 percent. This accounts for the differences with the **Table 30** values. This cost is assumed to remain constant in real dollars over the study period. As with the binary plants, these capital costs can vary widely due to a number of 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.[48] The costs range from a low case of $81.48 $/kW-yr to a high case of $172.69 $/kW, with a midpoint estimate of $84.93 $/kW. Costs are for 2011 and are given in 2011 dollars. O&M costs are assumed to have a real escalation rate of 0.5 percent.

CFs were found to range from 72 percent (Tidball, et al., 2010) to 95 percent (Geothermal, 2012), with 85 percent (Tidball, et al., 2010) being the mid case value. These CFs 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 (Gifford and Grace, 2011).

GHG emissions range from 99 pounds per MWh (Holm, et al., 2012) to 397 pounds per MWh (Geothermal, 2012), with a mid case of 264 pounds per MWh (Walters, 2013). Royalty payments to the BLM typically run 3 percent of power sale revenues but can vary between 0 and 5 percent, with an average value of 3 percent.

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47 Costs are expressed initially in 2011$ since the majority of sources use 2011 as the base year. These values are updated to 2013$ later in the chapter and prior to being used in the COG Model.

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

Table 30: Flash Geothermal Physical and Cost Parameters

Plant Data	Mid Cost	High Cost	Low Cost
Gross Capacity (MW)	30	30	30
Station Service (%)	17.0%	20.0%	14.0%
Net Capacity Factor (NCF)	85.0%	71.8%	95.0%
Capacity Degradation (%/Year)	0.5%	2.0%	0.0%
Heat Rate Degradation (%/Year)	3.0%	5.0%	0.0%
Heat Rate (Btu/kWh)	34.377	34,633	34,120
Forced Outage Rate (FOR)	2.5%	2.8%	2.2%
Scheduled Outage Factor (SOF)	4.0%	12.0%	2.0%
Emission Factors			
NO_X (lbs/MWh)	0.191	0.191	0.191
VOC/ROG (Lbs/MWh)	0.011	0.011	0.011
CO (Lbs/MWh)	0.058	0.058	0.058
CO_2 (lbs/MWh)	264.5	397.0	98.9
SO_X (lbs/MWh)	0.026	0.026	0.026
PM_{10} (lbs/MWh)	0.000	0.000	0.000
GHG (lbs/MWh)	264	397	99
Capital Cost (2011l $/kW)	$5,622	$7,496	$3,559
Fixed O&M Cost (2011 $/kW-yr)	$84.93	$172.69	$81.48
Variable O&M Cost (2011 $/MWh)	N/A	N/A	N/A
Insurance (%/Year)	0.60%	0.60%	0.60%
Royalties	3.0%	5.0%	0.0%

Source: Energy Commission.

Summary of Geothermal Cost Data

Table 31 summarizes instant and installed costs for 2013 in nominal 2013 dollars. Instant costs include all costs plus land and permitting costs. Installed cost is the instant cost plus the cost of financing the plant during construction, sales tax, and development fees, which are assumed to hold constant in real dollars.

Table 31: Summary of 2013 Instant and Installed Costs

Capital Costs Year = 2013 (Nominal Dollars)	Instant Costs ($/kW)	Installed Costs ($/kW)		
		Merchant	IOU	POU
Mid Cost Case				
Binary Geothermal 30 MW	$5,342	$7,099	$7,228	$6,486
Flash Geothermal 30 MW	$6,041	$7,747	$7,863	$7,196
High Cost Case				
Binary Geothermal 30 MW	$6,869	$10,055	$10,260	$9,493
Flash Geothermal 30 MW	$8,189	$11,560	$11,764	$11,000
Low Cost Case				
Binary Geothermal 30 MW	$4,410	$5,098	$5,176	$4,926
Flash Geothermal 30 MW	$3,816	$4,350	$4,408	$4,222

Source: Energy Commission.

Table 32 summarizes O&M costs for 2013 in nominal dollars. Costs are assumed to have a real escalation rate of 0.5 percent per year.

Table 32: Summary of Operating and Maintenance Costs

O&M Costs Year = 2013 (Nominal Dollars)	Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
Mid Cost Case		
Geothermal Binary 30 MW	$89.79	$0.00
Geothermal Flash 30 MW	$89.79	$0.00
High Cost Case		
Geothermal Binary 30 MW	$154.78	$0.00
Geothermal Flash 30 MW	$182.58	$0.00
Low Cost Case		
Geothermal Binary 30 MW	$89.79	$0.00
Geothermal Flash 30 MW	$86.15	$0.00

Source: Energy Commission.

CHAPTER 8: Biomass Technology

Technology Overview

Biomass is plant-based material, agricultural vegetation, or agricultural wastes used as fuel and has three primary technology pathways:

- Pyrolysis—transformation of biomass feedstock materials into fuel (often liquid "biofuel") through the application of heat in the presence of a catalyst.
- Combustion—transformation of biomass feedstock materials into useful energy through the direct burning of those feedstocks using a variety of burner/boiler technologies also used for burning materials such as coal, oil, and natural gas.
- Gasification—transformation of biomass feedstock materials into synthetic gas through the partial oxidation and decomposition of those feedstocks in a reactor vessel and oxidation.

Of these technology pathways, only direct combustion of biomass is commercially available for utility-scale plants and, thus, is the focus of this section. Gasification methods are used in some small-scale applications but are not yet viable for utility-scale applications. Active research into pyrolysis for biofuel production is ongoing but is not used for electricity production.

Combustion technologies are widespread and include the following general approaches:

- Stoker boiler combustion uses similar technology for coal-fired stoker boilers to combust biomass materials, using either a traveling grate or a vibrating bed.
- Fluidized bed combustion uses a special form of combustion where the biomass fuel is suspended in a mix of silica and limestone through the application of air through the silica/limestone bed. This is similar to technology used in newer coal-fired boilers. Fluidized bed combustion boilers are classified as either bubbling fluidized bed (BFB) or circulating fluidized bed (CFB) units.
- Biomass-cofiring uses biomass fuel burned in conjunction with coal products in current pulverized-coal boiler technology used in utility-scale electricity production.

Recent sources of data and analysis have focused on the fluidized bed technology. It is also the most likely biomass technology to be installed in California. The remainder of this chapter will focus on fluidized bed technology.

Biomass Combustion—Fluidized Bed Boiler

Technology Description

For biomass fuels, fluidized bed combustion appears to be the current technology of choice for biomass power generation applications. A traditional-style boiler burns the solid fuel in a stationary bed, similar to the way logs burn on a fire. A fluidized bed style, however, mixes the fuel and keeps it suspended in a column of hot gases that increases the quality of combustion. In addition to keeping the biomass fuel suspended in hot gases, modern fluidized bed boilers also use a nonburning combustion media to help retain heat and improve combustion. This medium is typically a mix of silica and/or alumina.

The inherent fuel versatility of fluidized bed systems provides a plant operator the ability to burn many biomass resource types, including those feedstocks with significant moisture variations.[49] The major reason for this is that the fluidized bed carrying medium provides a thermal *flywheel* effect that maintains constant heat output and flue gas quality even when burning fuels of varying moisture content (Overend, 2002).

Fluidized bed boilers are characterized as either BFB or CFB, depending on how the bed material is used within the boiler. In a BFB unit, the bed material stays within a fixed zone in the boiler, while in a CFB unit, the material is suspended above an air zone and is circulated through a return loop back to the combustion zone.

For both BFB and CFB units, due to the high-quality combustion and near-complete carbon burnout (99 percent – 100 percent) of biomass fuel sources, ash is carried over into the flue gas stream, necessitating the addition of postcombustion ash removal equipment such as cyclones and baghouses[50]. The post-combustion controls allow particulate removal to meet New Source Performance Standards (NSPS) for PM10.

Development Considerations

When planning for and developing biomass, the following considerations affect the potential viability and costs:[51]

49 Moisture variations can produce wide swings in energy output in conventional boiler technologies. Since 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.

50 Cyclones remove ash by rapidly changing the direction of the air, causing particles to fall out. A baghouse uses large filters to remove particles.

51 These considerations are not quantified here as that is beyond the scope of this study.

- Biomass fuel type and uniformity—The type and uniformity of delivered biomass fuel supply are a primary cost driver for any biomass technology. Given the variation of the delivered moisture content and heating value of biomass fuel feedstocks, along with fuel processing issues, the handling and processing costs of biomass fuels can vary greatly. As a result, the type and characteristics of the different biomass fuels can have a material impact on the capital cost of the boiler design, as well as the overall fuel handling and operations cost.
- Fuel transport and handling costs—The availability of sufficient biomass fuel resources near the plant location is a critical driver for operating cost. Most biomass fuel is transported by truck to a plant site. To maintain commercially reasonable prices, the effective economic radius from the plant location to the aggregate fuel supply is limited to about 100 miles. The varied nature of biomass fuel feedstocks also necessitates special handling equipment and larger numbers of dedicated staff than are needed for coal-fired combustion power plants of equivalent size. As a result, the typical maximum size of biomass plants is limited to about 50 MW in California (McCann, et al., 1994).
- Boiler island cost—Capital cost of the boiler island is a critical cost driver that can account for roughly 40 to 60 percent of the overall plant cost, depending on the type of biomass combusted and the need for postcombustion pollution controls. The choice of source and type of fuels to be combusted is an important cost driver. In addition, the escalation trends for raw materials used in manufacturing the boiler island, primarily steel cost, are factors that can influence delivered boiler island cost.
- Long-term fuel supply contracts—Most current biomass fuel supply contracts are of short-term duration and can entail varying fuel qualities. A key cost barrier to promoting biomass circulating bed combustion in California is the ability to develop and achieve performance on long-term (for example, five years duration and longer) fuel supply contracts for available fuel sources.
- Plant scale—While current CFB technology has been proven to utility-scale applications of up to 300 MW, supply availability limits potential plant scale. Steam-generator scale economies are substantial, with a 50 MW biomass plant likely to cost substantially more per kW than a 500 MW coal-fired plant of the same technology (McCann, et al., 1994).
- Emissions control costs—Costs of emission control needed to satisfy air quality and permitting requirements can increase the cost of biomass plants. Post-combustion emissions control technologies, such as selective catalytic reduction/selective noncatalytic reduction technologies for NO_x control, and additional particulate matter controls, are important cost drivers that can significantly increase the capital and operating costs of biomass plants.
- Retrofit versus greenfield new site—For many biomass fluidized bed applications, repowering is a commercially viable option that can save 20 percent to 40 percent of the capital cost of a new greenfield site where all the remainder of plant systems would need to be constructed.

- O&M capitalization—The extent to which the long-term operations and maintenance of a biomass fluidized bed facility is capitalized through a long-term maintenance contract with an original equipment manufacturer supplier is a cost driver. These long-term maintenance contracts trade risk for maintenance cost predictability and can slightly change the operating cost profile of a commercial biomass fluidized bed boiler plant.

Current Costs and Plant Characteristics

Plant data for biomass CFB boiler plants shown in **Table 33** were derived from review of publicly available reports and studies (EIA, 2010; Hahn, et al., 2010; Tidball, et al., 2010; Lazard, 2011; Black & Veatch, 2012; McCann, 2012). Costs are adjusted from U.S. averages to California sites based on cost indices contained in the R.W. Beck study.

Plant capacities for biomass fluidized bed boilers were established in a range of 15 MW to 70 MW, with 50 MW being used as a typical plant capacity. The capacity range is primarily set by the effective biomass fuel supply range, along with the most common sizes of biomass CFB designs today.

Instant (or overnight) cost data for biomass CFB plants from R. W. Beck ranged from a low case of $3,143/kW to a high case of $5,060/kW, with a midpoint estimate of $4,191/kW. Costs are for 2011 and are in nominal dollars; these are assumed to remain constant in real dollars. Instant costs are for equipment and construction only and do not include costs such as land and permitting costs, which would increase mid costs by about 2 percent. As discussed in the previous section, these capital costs can vary widely due to a number of factors, including type of fuel and fuel mix burned, size/scale of the plant, whether the site is a brownfield redevelopment or a greenfield site, and the amount of post-combustion pollution controls. Typically, the boiler island comprises 40 – 60 percent of the total instant plant cost.

O&M costs are broken into fixed and variable components. Therefore, mid, high and low costs need to be compared on a total O&M basis. Total O&M varies from a low of $18.50/MWh to $28.87/MWh, with a mid cost value of $19.22/MWh. Costs are for 2011 and are given in 2011 dollars. The O&M cost is assumed to have a real escalation rate of 0.5 percent over the study period.

CFs were found to range from 78 percent to 85 percent, with 81 percent being the mid case value. These CFs are consistent with operational CFB 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. Heat rates can vary for biomass CFB systems due to fuel moisture content and heating value.

No significant experience curve effects or learning effects are taken into consideration in the analysis, as CFB technology is considered a mature technology. Cost drivers should not have a significant effect on the long-term levelized cost values, absent a disruptive shift in the current technology and approach to biomass CFB combustion.

Table 33: Biomass Physical and Cost Parameters

Plant Data	Mid Cost	High Cost	Low Cost
Gross Capacity (MW)	50	50	50
Station Service (%)	4.0%	7.0%	2.0%
Capacity Factor	80.7%	78.2%	85.0%
Capacity Degradation (%/Year)	0.10%	0.20%	0.00%
Heat Rate Degradation (%/Year)	0.15%	0.20%	0.10%
Heat Rate (BTU/kWh)	14,500	14,500	13,500
Forced Outage Rate (FOR)	9.0%	9.0%	0%
Scheduled Outage Factor (SOF)	7.6%	7.6%	0%
2011 Instant Cost (Nominal $/kW)	$4,191	$5,060.00	$3,143.00
2011 Fixed O&M Cost (Nominal $/kW-yr)	$100.50	$95.00	$100.50
2011Variable O&M Cost (Nominal $/MWh)	$5.00	$15.00	$5.00
2011 Total O&M Cost (Nominal $/kW-yr)	$135.85	$197.75	$137.73
Insurance	0.60%	0.60%	0.60%
Emission Factors			
NO_X (lbs/MMBtu)	0.075	0.075	0.075
VOC/ROG (Lbs/MWh)	0.012	0.012	0.012
CO (Lbs/MWh)	0.105	0.105	0.105
CO_2 (lbs/MWh)	195.0	195.0	0.0
SO_X (lbs/MWh)	0.034	0.034	0.034
PM10 (lbs/MWh)	0.100	0.200	0.025

Source: Energy Commission.

Summary of 2013 Biomass Cost Data

Table 34 is a summary of instant and installed costs for 2013 in nominal dollars. Instant costs include all costs, including land and permitting costs. Installed cost is the instant cost plus the cost of financing the plant during construction, sales tax, and development fees. Capital costs are assumed to remain constant in real dollars.

Table 34: Summary of 2013 Instant and Installed Costs

Capital Costs Year = 2013 (Nominal Dollars)	Instant Costs ($/kW)	Installed Costs ($/kW)		
		Merchant	IOU	POU
Mid Cost Case				
50 MW Biomass	$4,501	$5,282	$5,318	$5,125
High Cost Case				
50 MW Biomass	$5,532	$6,922	$6,986	$6,772
Low Cost Case				
50 MW Biomass	$3,344	$3,628	$3,647	$3,583

Source: Energy Commission.

Table 35 summarizes O&M costs for 2013 in nominal 2013 dollars. O&M costs are assumed to have a real escalation rate of 0.5 percent per year.

Table 35: Summary of Operating and Maintenance Operative and Maintenance Costs

O&M Costs Year = 2013 (Nominal Dollars)	Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)	Total O&M ($/MWh)
Mid Cost Case			
50 MW Biomass	$106.26	$5.29	$20.32
High Cost Case			
50 MW Biomass	$100.44	$15.86	$30.52
Low Cost Case			
50 MW Biomass	$106.26	$5.29	$19.56

Source: Energy Commission.

CHAPTER 9: Natural Gas-Fired Technologies

Natural gas-fired generation technologies form the backbone of California's generation portfolio today, making up about one-half of the generation in the state. Between 2001 and 2012, the Energy Commission certified 47 new natural gas power plants. While California has identified zero-emissions generation resources such as solar and wind, along with energy-saving efficiency measures, as the preferred resources for meeting growing demand, natural gas continues to play an important bridge role in supporting the growing portfolio of renewable resources and stabilizing the generation system.

In California, the cost to build and operate natural gas-fired technologies depends heavily on the project location, the specific type of natural gas-fired technology used, and the cost of natural gas used as a fuel source. There are two basic types of natural gas technologies – combustion turbine (CT) and combined cycle (CC).

In California, CT (also known as simple cycle) power plants closely resemble the jet engine of a large commercial airliner. This design is sometimes referred to as an "aeroderivative." The alternative commercial design (called a "frame" design) uses a turbine and combustion arrangement that more closely resembles a steam turbine. These turbines, such as the F Class, are used widely outside California but have not been built in California in recent years. Aeroderivative designs give faster ramping and operational flexibility to grid operators—a necessity in a grid with large amounts of intermittent resources such as solar and wind. In California, there is a growing tendency to build advanced versions of the aeroderivative CT units that provide greater fuel efficiency, reduced costs, and reduced emissions.

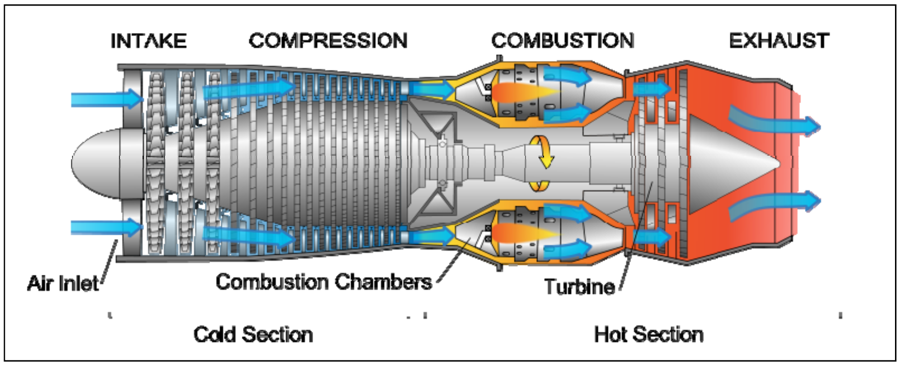
CC power plants use a frame design combustion turbine fueled by natural gas, and then use the hot exhaust gasses (sometimes with a small amount of additional natural gas heating) to create steam, which is also used to turn turbines and generate electricity. This increases the output and overall efficiency of the power plant. The tradeoff in this case is to reduce the operational flexibility of the plant and make start-up and shutdown a more lengthy and costly endeavor. CC power plants are classified in this report as either "duct firing"—a reference to plants that add heat to the exhaust gas stream through additional burners in the ducting—or as conventional CCs.

While there is one advanced design of CC power plants currently operating in California (specifically the Inland Empire Energy Generating Center in Menifee, Riverside County), this plant provides insufficient data from which to generate valid estimates of future construction and operation costs; therefore, this technology is not included in this report.

Conventional Combustion Turbine

This technology is most commonly referred to as a *CT* or *natural gas turbine*. The combustion turbines included herein are aeroderivatives that were developed from jet engines. They produce thrust from the exhaust gases, as illustrated **Figure 36**.

Figure 36: Aeroderivative Gas Turbine



Source: 2004 Airplane Flying Handbook, U.S. Federal Aviation Administration

F-Class gas turbines without additional boilers to extract energy from the exhaust gasses are often used in other areas of the country, but there is not a single F-Class turbine currently operating in this configuration in California. Due to the lower efficiency of the F-Class turbine alone, such use within California in the future is unlikely. The GE LM6000 gas turbine, which is the most prevalent conventional CT in California, is used for characterization in this report.

Advanced Combustion Turbine Power Plant

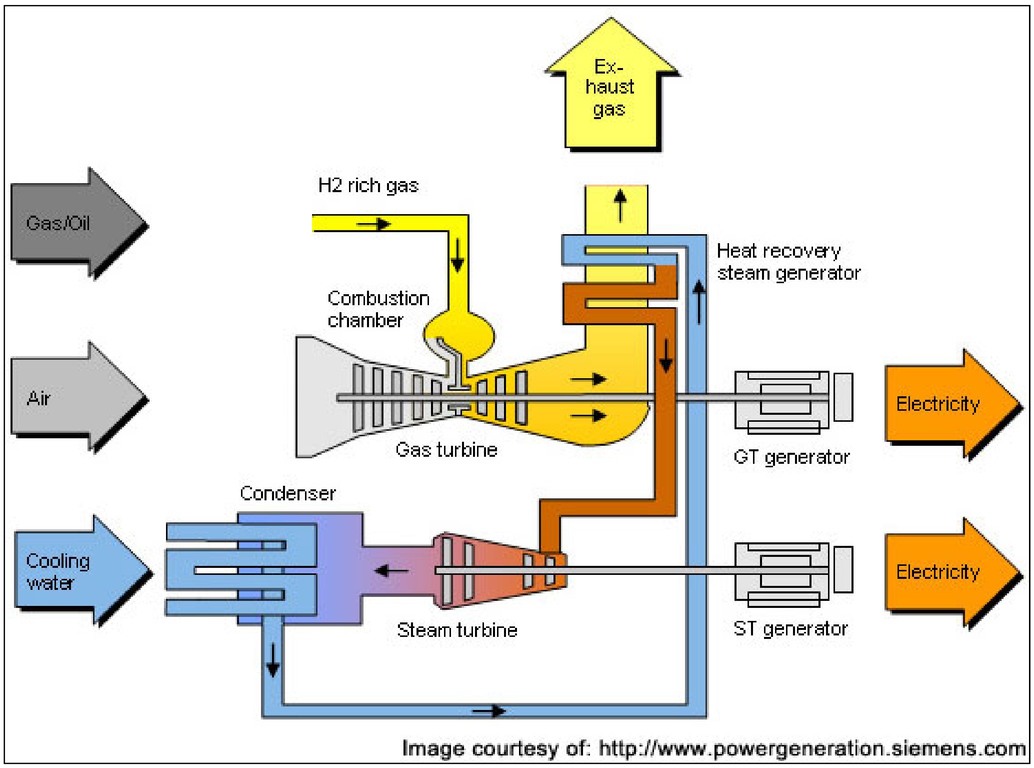
The advanced CT selected for evaluation is the GE LMS100 gas turbine. The LMS100, an aeroderivative gas turbine, provides increased power output due to the addition of an intercooling system. The intercooling system takes compressed air from the low-pressure compressor, cools it to optimal temperatures, and then redelivers it to the high-pressure compressor, reducing the work of compression and increasing the pressure ratio and mass flow through the turbine. The LMS100 can achieve 44 percent thermal efficiency, which is a roughly 10 percentage point improvement over other turbines in its size range (Ecomagination, 2013).

Due to the intercooling systems, the LMS100 requires significantly more cooling infrastructure than other aeroderivative gas turbines. This cooling can be accommodated by a wet cooling tower, a wet-surface air condenser, or an air-cooled condenser. The use of a wet cooling tower is assumed in this report.

Conventional Combined Cycle

This technology combines a conventional steam turbine with one or more CT units to derive a higher level of efficiency than would be possible with just the turbine alone. The exhaust heat of the CT unit is used to heat steam in the heat recovery section that leads to the steam turbine, as shown in **Figure 37**.

Figure 37: Combined-Cycle Process Flow



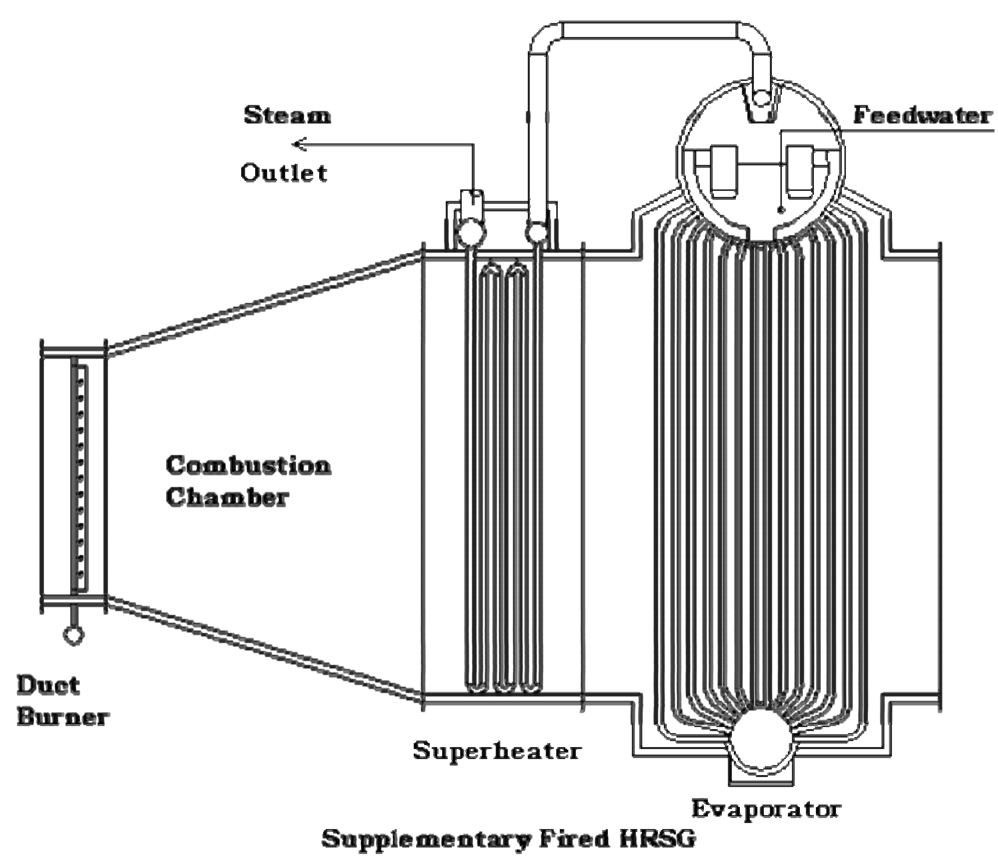
Source: See http://www.powergeneration.siemens.com.

The typical CC power plant built in California is based on the F-Frame gas CT and typically consists of two CTs and one steam turbine. However, the number of gas turbines and steam turbines vary significantly between the existing gas turbine CC power plants in California.

Conventional Combined Cycle with Duct Firing

CC systems can integrate duct burners after the gas turbine and before the heat recovery steam generator (HRSG) to increase power production. Duct firing affects power production only in the steam cycle portion of the CC power system and so is an inherently less efficient use of natural gas than the natural gas used to fire the gas turbine and make steam. Duct firing primarily provides peaking power and, if the CF of a plant is determined based on the total duct-fired rating, will cause a corresponding decrease in the annual CF of a plant due to the limited use of the duct burners. The efficiency for duct firing, essentially the steam cycle efficiency, is similar to the efficiency of conventional CT gas turbines but less efficient than advanced CT gas turbines. The general layout of a CC power plant HRSG, showing the added duct burners and combustion chamber on the far left, is provided in **Figure 38**.

Figure 38: Combined-Cycle Power Plant HRSG



Source: See http://www.nawabi.de/chemical/hrsg/HRSGimg5_9d.gif.

Plant Operational Characteristics

To estimate the cost of construction and operation of CC plants, it is necessary to define and estimate several physical plant characteristics. These characteristics vary by model and technology. These data generally have been collected through a survey conducted by Energy Commission staff and supported by consultants hired by the Energy Commission. Other sources are noted, where relevant.

Gross Capacity (MW)

The gross capacity assumed for the five natural gas-fired technologies selected for estimation in the COG Model are provided in **Table 36**. This is the capacity of the plant prior to any corrections for site losses or degradation.

Table 36: Gross Capacity Ratings for Typical Configurations

Technology Case	Gross Capacity
Conventional CT—One LM6000 Turbine	49.9 MW
Conventional CT—Two LM6000 Turbines	100 MW
Advanced CT—Two LMS100 Turbines	200 MW
Conventional CC (no duct firing)—Two F-Class Turbines	500 MW
Conventional CC (duct firing)—Two F-Class Turbines	550 MW

Source: Energy Commission.

The selected gross capacities assume that some form of air preconditioning is used to increase/stabilize the generating capacity while operating at high temperature and that the turbines are not significantly derated by operating at high elevation.

Outage Rates

Outages are divided into two categories: those that are foreseen or scheduled, and those that are unforeseen or forced. Outages differ from curtailments in that curtailments are considered to be caused by either discretionary choices (for example, responses to economic signals) or by resource shortages (for example, lack of fuel or renewable energy sources). Curtailments are represented in a plant's CF.

Scheduled outage factor (SOF) includes planned outage hours that are hours during the year when the plant is forced out of service by equipment failure or other means but the repairs can be scheduled beyond the next weekend, and can therefore be characterized as scheduled. SOF also captures the effect of some maintenance being done that requires the plant to be at partial power but not off.

SOF for California natural gas power plants were derived from North American Electric Reliability Corporatino (NERC) Generating Availability Data System data for California generation resources. The SOF values[52] used to calculate levelized costs aggregate actual outages and temporary planned reductions in capacity.

52 Data used in the analysis are specifically from the category "effective scheduled outage factor" dataset.

Likewise, the term *forced outage rates* (FOR) is used for simplicity, but the data are actually collected as equivalent FOR (EFOR) to recognize that during partial outages, the unit is forced to operate at partial power but not actually shut down. The EFOR is measured against the period when the unit is operating or attempting to operate but is not able to, that is, it excludes nonoperational hours due to maintenance or curtailments. EFOR demand (EFORd) is a more recent correction to EFOR that gives more realistic results for low CF resources, such as CT units. It is the EFORd values are used in the COG Model.

Capacity Factor

The CFs were determined for the existing California conventional LM6000 CT power plants and F-Class CC power plants based on the historical monthly *QFER* data from 2001 to 2011 for 25 CT facilities and 22 CC facilities. All data are provided in Appendix B.[53]

The CT units used in the analysis include Anaheim, Glenarm, Grayson, Malaga, MID Ripon, Niland, and Riverside are owned by POUs, while Barre, Center, Etiwanda, and Mira Loma by owned by IOUs. The other power plants used in the analysis are all merchant facilities.

The CF for the CC units are based on the annual average capacity for each facility. For duct-fired plants, the duct-fired CF was used. Magnolia (Burbank) and Cosumnes (Sacramento County) power plants are owned by POUs, and the Palomar Energy Center (Escondido, San Diego County) and Mountainview Power Company (San Bernardino County) owned by IOUs. The other power plants are all merchant facilities. The staff estimated CFs by examining both historical CF data in the Energy Commission's *QFER* database (summarized in **Appendix B) Table 37** provides the mid case, high case, and low case CFs that were used to estimate levelized cost.

53 The CFs were derived using the following simple equation: *QFER net generation (MWh) /(facility generation capacity(MW) x hrs/year) = capacity factor.*

Table 37: Estimated Capacity Factors

Technology Case	Owner	Assumed Capacity Factor		
		Mid	High	Low
Conventional CT (both sizes)	Merchant	5.0%	2.5%	7.00%
	POU	7.5%	4.0%	14.%
	IOU	1.0%	1.0%	1.0%
Advanced CT	Merchant	7.5%	3.75%	10.50%
	POU	11.25%	6.0%	21.0%
	IOU	1.5%	1.5%	1.5%
Conventional CC	All Owners	57%	40%	71%
Conventional CC w/Duct Burners	All Owners	57%	40%	71%

Source: Energy Commission.

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

The increases in both CT and CC CFs seen in the *2009 IEPR* (in both the *QFER* and California ISO *Annual Report on Market Issues and Performance)* have reversed in recent years. The recommended capacity factors for both types of plants are now generally significantly lower than those used in the previous version of the COG Model. The advanced CT CFs were increased 50 percent above the assumed conventional CT CFs due to an assumption of increased use due to higher efficiency and the experience of the CTs in the database.

Plant-Side Losses

The plant-side losses, also referred to as site losses, were estimated by analyzing the same *QFER* database used for calculating CFs, based on monthly data from 2001 to 2008 for CT facilities and CC facilities. The plant-side losses were determined by using the difference in the reported gross vs. reported net generation for the existing California conventional LM6000 CT power plants and F-Class CC power plants. Based on these data, the mid-cost, high-cost, and low-cost plant-side losses are shown in **Table 38**. Staff does not have data to suggest significantly different plant-side loss factors for high-efficiency CC facilities. The advanced CT facilities may have increased plant-side losses due to the power required for the turbine intercooling auxiliary facilities; however, staff has no specific information to obtain values different from those determined for the LM6000 gas turbine facilities used.

Table 38: Summary of Recommended Plant-Side Losses (%)

Technology	Mid	High	Low
All CC	2.9%	4.0%	2.0%
All CT	3.4%	4.2%	2.3%

Source: Energy Commission.

Heat Rate

The heat rate of a natural gas-fired power plant describes how much natural gas must be burned (measured in Btu) to generate 1 kWh of energy.[54] Higher heat rates are an indication of lower efficiency in converting fuel to electricity. Staff determined heat rates, reported as higher heating value (HHV), for the existing California conventional LM6000 CT power plants and F-Class CC power plants based on the monthly *QFER* data from 2001 to 2011 for 25 CT facilities and 22 CC facilities. The actual heat rates are provided in Appendix B.

Table 39 provides the mid-cost, high-cost, and low-cost heat rates that were recommended for use in the COG Model. These values are higher (in other words, less efficient) than those reported by manufacturers and often used in studies because these values include real-world operations, such as start-ups and load following.

Capacity and Heat Rate Degradation

As a natural gas plant ages, both the capacity and heat rate degrade. These are measured as degradation factors that represent the percentage that the capacity will decrease or that the heat rate will increase per year. These increases are driven by normal wear and tear on the generation turbine but are mitigated by maintenance. For this report, the capacity and heat rate degradation factors are assumed to have the same values, which are summarized in **Table 40**.

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

Table 39: Summary of Recommended Heat Rates (Btu/kWh, HHV)

Technology	Mid [a]	High [a]	Low [b]
Conventional CT [c]	10,585	11,890	9,980
Advanced CT	9,880	10200	9600
Conventional CC	7,250	7,480	7,030
Conventional CC With Duct Firing	7,250	7,480	7,030

Source: Energy Commission.

Notes:

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

[b] Low-cost recommended values are based on new and clean heat rates from turbine manufacturers. Mid cost heat rates in COG 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.

Table 40: Summary of Capacity and Heat Rate Degradation Factors

Technology Case	Owner	Degradation Factors		
		Mid	High	Low
Conventional CT (both sizes)	Merchant	0.055%	0.027%	0.082%
	POU	0.082%	0.044%	0.153%
	IOU	0.011%	0.011%	0.011%
Advanced CT	Merchant	0.082%	0.042%	0.124%
	POU	0.124%	0.066%	0.230%
	IOU	0.016%	0.016%	0.016%
Conventional CC	All Owners	0.178%	0.108%	0.240%
Conventional CC With Duct Firing	All Owners	0.178%	0.108%	0.240%

Source: Energy Commission.

These values were estimated using General Electric data provided by Energy Commission contractors as part of the survey of available literature. Their rule of thumb for CTs is that they degrade 3 percent between overhauls[55], which is about every 24,000 hours. The actual time between overhauls, therefore, is a function of CF as shown in **Table 41** or the mid cost

55 An overhaul represents a complete tearing down and rebuilding of the major turbine elements. This can include replacement of major portions of a turbine or other generation system components.

case. **Table 41** shows that the expected book life[56] of the turbines will be exhausted before 24,000 hours of operation is reached. **Figure 39** shows the degradation pattern for the merchant CT, which is 0.055 percent a year[57]. The IOU and POU degradation factors for combustion turbines are 0.011 percent and 0.082 percent, respectively.

Table 41: Years Between Overhauls vs. Capacity Factor—Mid Cost Case

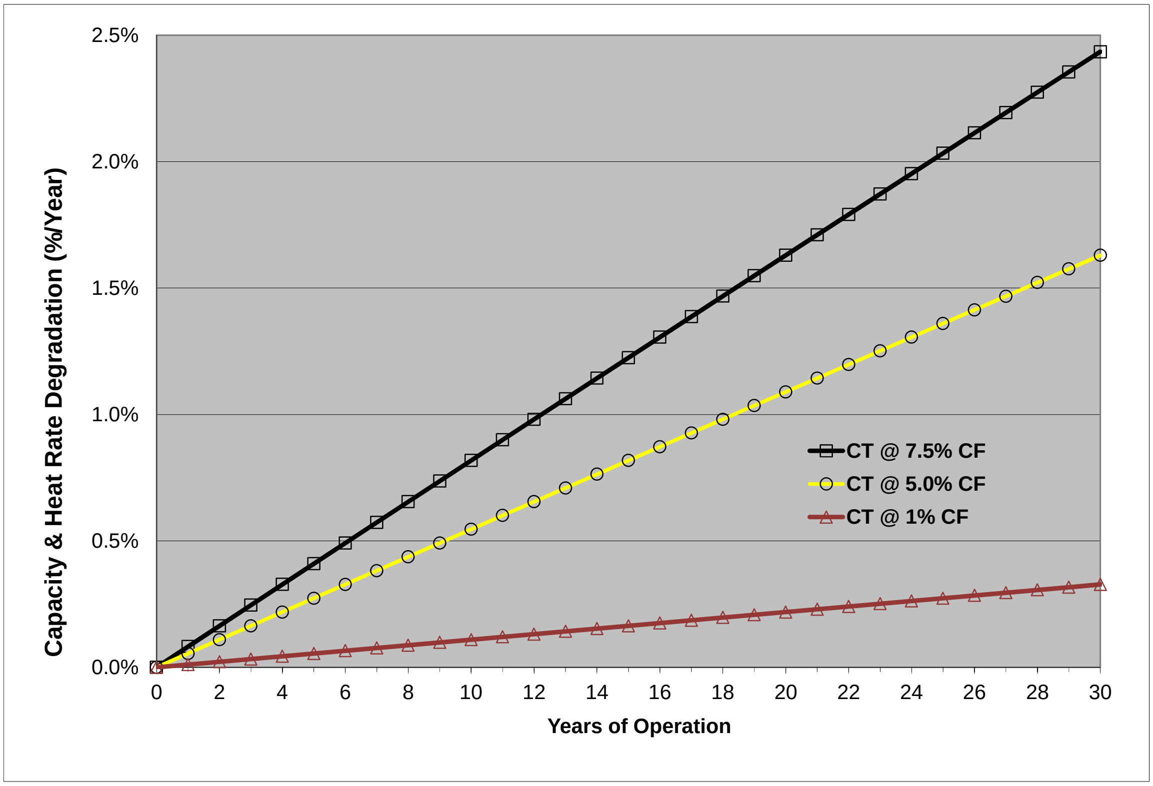
Technology	Assumed Capacity Factor	Years Between Overhauls
IOU CT	1%	274
Merchant CT	5%	55
POU CT	7.5%	37
Advanced CT	7.5%	37
CC Units	57%	4.8

Source: Energy Commission.

56 *Book life* is the amount of time a major piece of equipment will have value on which an owner will have to pay taxes. It is typically shorter than the useful life of the equipment.

57 The merchant degradation factor is calculated as follows: 1.64%/30 years= 0.055%. The same calculation is used for the IOU and POU degradation factors.

Figure 39: Combustion Turbine Capacity and Heat Rate Degradation—Mid Cost



Source: Energy Commission.

The computation for the CC units is more complex due to the higher CF, estimated to be above 57 percent for the mid cost case, which means an overhaul every 4.8 years.[58] Staff simplified this assumption to 5 years, which results in five major overhauls during its 30-year book life, as shown in **Figure 40**.[59] The degradation factor is equal to the slope of the equivalent degradation curve, or 0.178 percent per year. There are a number of approximations associated with this estimate, but since this factor has a small effect on levelized cost, these approximations have very little effect on the calculated LCOEs for these natural gas-fired technologies. The details of this process can be found in the *COG Model User's Guide*.

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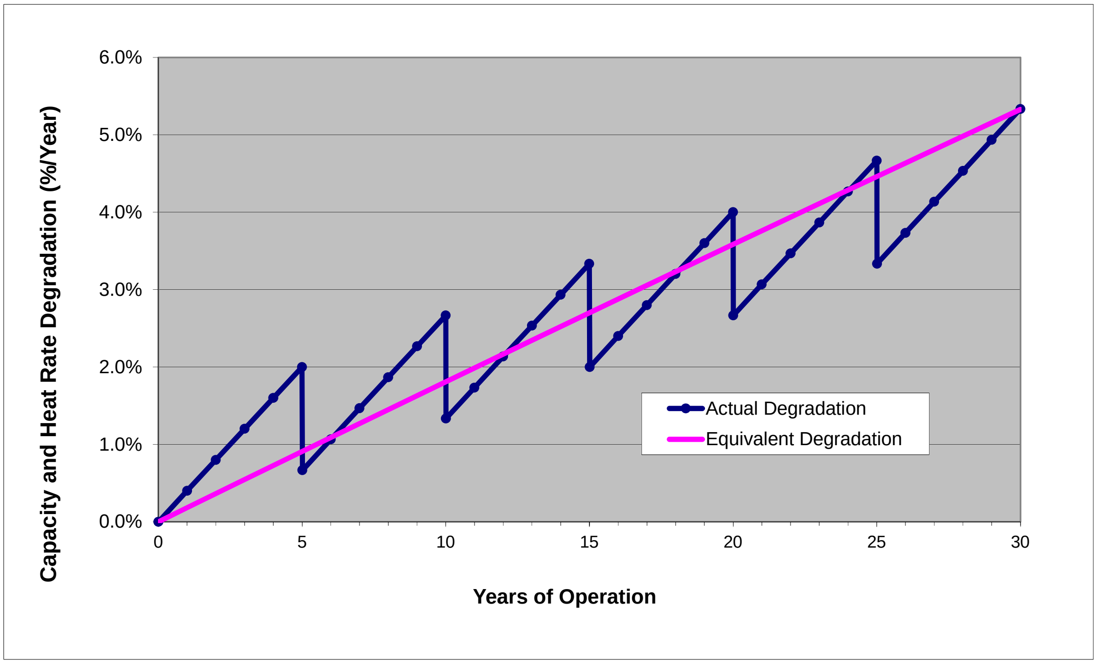
58 This translates into one overhaul every 4.8 years through the following calculations: 24,000 hours/ (0.57 x 8760 hours per year = 4.8 years).

59 The SC units will degrade 3 percent during each five-year period. Since the steam generator portion is roughly one-third of the system and remains essentially stable, and the overall system deteriorates two-thirds of the 3 percent of the simple cycle during the five-year period, which is 2 percent, and recovers two-thirds of its 2 percent deterioration during the overhaul, which is 1 and 1/3 percent (2/3*2 = 4/3 percent = 1.333 percent).

Figure 40: Combined Cycle Heat Rate Degradation—Mid Cost



Source: Energy Commission.

Emission Factors

The criteria pollutant emission factors for the four gas turbine cases were estimated using permitted emission data from the following recent Energy Commission siting cases:

- Conventional CT (both cases) – Riverside Energy Resource Center Units 3 and 4
- Advanced CT—Panoche Energy Center (western Fresno County)
- Conventional CC (no duct firing)—Carlsbad Energy Center (Carlsbad, San Diego County)
- Conventional CC (duct firing)—Avenal Energy (Avenal, Kings County)

The criteria pollutant emission factors and emissions used in the COG Model to calculate levelized cast are based on these recent projects provided in **Table 42**.

The criteria pollutant emissions are based on permitted rather than actual emissions; therefore, mid, high, and low values do not apply as the permitted emissions are assumed to be related to a consistent interpretation of best available control technology requirements within California.

Table 42: 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

Source: Energy Commission.

[a] The conventional CT values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

The CO_2 emission factors were determined based on the efficiency for each technology based on a natural gas emission factor of 52.87 lb/MMBtu.[60]

Table 43 provides the CO_2 emission factors for each technology case based on the heat rates shown above in **Table 39**.

Table 43: Estimated Carbon Dioxide Emission Factors (lbs/MWh)

Technology	Mid	High	Low
Conventional CT[a]	1,239.29	1,392.08	1,168.46
Advanced CT	1,156.75	1,194.22	1,123.97
Conventional CC	848.83	875.76	823.07
Conventional CC w/Duct Firing	848.83	875.76	823.07

Source: Energy Commission.

Notes:

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

60 The emission factor is from the ARB for natural gas with an assumed heating content (HHV) between 1,000 and 1,025 British thermal units per standard cubic foot (Btu/scf).

Plant Cost Data

The plant costs data for natural gas-fired power plants were obtained from the contractor surveys of power plants in California. Costs are adjusted for the physical performance parameters, and the instant costs are converted to installed costs using the financial parameters described in Chapter 2 of this report. All projects are assumed to have selective catalytic reduction for control of NO_x emissions and an oxidation catalyst for control of carbon monoxide emissions. Plant costs also include acquisition of ERCs; criteria pollutants are included in the capital costs, and GHG emissions are included in the annual operating costs.

Combined Cycle Capital Costs

Table 44 provides the assumed design configuration of the two CC cases**.** The projects with announced instant or installed cost data that were evaluated to determine the recommended mid, high, and low capital cost values for the three combined CC cases are shown in **Table** 44.

Table 44: Base Case Configurations—Combined Cycle

500 MW Combined Cycle Base Configuration
1) 500 MW Plant W/O Duct Firing
2) Two F-Frame Turbines With One Steam Generator
550 MW Combined Cycle Base Configuration
1) 500 MW Plant W/Duct Firing
2) Two F-Frame Turbines With One Steam Generator
3) 50 MW of Duct Firing

Source: Energy Commission.

Table 45 shows the estimated instant costs for the two CC configurations for 2011 and are in 2011 dollars. These cost estimates exclude land acquisition, environmental permitting, and air emission reductions credit acquisition, which are incorporated separately into the COG Model and usually vary for local and jurisdictional circumstances.

Table 45: Total Instant Costs for Combined Cycle Cases—Year=2011

Combined Cycle (Nominal 2011$)	Mid ($kW)	High ($kW)	Low ($kW)
Conventional 500 MW CC Without Duct Firing	$902	$992	$738
Conventional 550 MW CC With Duct Firing	$880	$980	$707

Source: Energy Commission.

Note: The high and low values are based on the 10 percentile and 90 percentile values for the evaluated projects.

Combustion Turbine Capital Costs

Table 46 provides the assumed design configuration of the three CT cases**.** The projects with announced instant or installed cost data that were evaluated to determine the recommended mid, high, and low capital cost values for the three CT cases.

Table 46: Base Case Configurations—Combustion Turbines

49.9 MW Combustion Turbine Base Configuration
1) 49.9 MW Plant
2) One LM6000 Gas Turbine w/Chiller Air Pretreatment
100 MW Combustion Turbine Base Configuration
1) 100 MW Plant
2) Two LM6000 Gas Turbines w/Chiller Air Pretreatment
200 MW Advanced Combustion Turbine Base Configuration
1) 200 MW Plant
2) Two LMS100 Gas Turbines w/Evaporative Cooler Air Pretreatment

Source: Energy Commission.

Table 47 shows the estimated instant costs for the three CC cases in the COG Model, which are for 2011 and are in 2011 dollars. As with the CC data, these costs estimates exclude land acquisition, environmental permitting, and air emission reductions credit acquisition, which are incorporated separately into the COG Model and usually vary for local and jurisdictional circumstances. The advanced CT case cost is based on very limited data for a different advanced gas turbine type.

Table 47: Total Instant Costs for Combustion Turbine Cases—Year=2011

Combustion Turbine (Nominal 2011$)	Mid ($/kW)	High ($/kW)	Low ($/kW)
Conventional 49.9 MW CT	$1,080	$1,503	$717
Conventional 100 MW CT	$1,080	$1,503	$717
Advanced 200 MW CT	$891	$1,313	$527

Source: Energy Commission.

Note: The high and low values are based on the 10 percentile and 90 percentile values for the evaluated projects.

Construction Periods

The estimated construction periods used in this report are based on an analysis of the facilities surveyed for the *2007 IEPR* and other known project construction periods. **Table 48** provides the construction periods used in the mid-cost, high-cost, and low-cost scenarios.

Table 48: Summary of Estimated Construction Periods (Months)

Technology	Mid	High	Low
Conventional CC	24	36	20
Conventional CC With Duct Firing	24	36	20
Conventional CT[a]	9	16	4
Advanced CT[b]	15	20	12

Notes:

[a] The conventional CT values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

[b] Engineering estimate using the anticipated 18-month Panoche case construction duration as slightly higher than average value due to it being a four-turbine project rather than a two- turbine project.

Source: Energy Commission.

Construction periods can be influenced by many factors, including whether the site is greenfield or brownfield, the overall complexity of the facility design, the size and location constraints, and a myriad of other factors. The estimated values assume a typical range of factors and do not include extraordinary circumstances.

Fixed and Variable Operating and Maintenance Costs

Combined-Cycle Operating Costs

The operating costs consist of three components: fixed O&M, variable O&M, and fuel.

Fixed O&M is composed of two components: staffing costs and nonstaffing costs. Nonstaffing costs are composed of equipment, regulatory filings, and other direct costs (ODCs)[61].

Variable O&M is composed of the following components:

- Outage Maintenance—Annual maintenance and overhauls and forced outages.
- Consumables Maintenance—Maintenance to repair parts that are designed to wear out (or be "consumed") during normal operations.
- Water Supply Costs—The cost of providing cooling water for plant operations.

Combustion Turbine Operating Costs

Similar to CCs, the operating costs for CT consist of two components: fixed O&M and variable O&M. **Table 49** and **Table 50** summarize the fixed and variable O&M components, respectively. Costs are for 2011 and are in 2011 dollars. Fixed O&M is composed of two components: staffing costs and nonstaffing costs. Nonstaffing costs are composed of equipment, regulatory filings, and ODCs. As with the CC fixed costs, staffing costs for CT units, and thus total fixed O&M, were found to vary with plant size. In this case, outage costs were found to vary little with the historical generation. This may be because these costs are driven more by the number of starts than by the hours of operation. For this reason, these costs were placed in fixed costs instead. This practice appears to be consistent with the cost estimates developed by other agencies and analysts.Variable O&M is composed of the following components: consumables maintenance and water supply costs.

Table 49: Fixed Operation and Maintenance Year=2011 (Nominal$)

Technology	Mid	High	Low
Small CT	$26.85	$71.09	$9.44
Conventional CT	$25.95	$69.57	$9.14
Advanced CT	$23.87	$66.11	$8.45
Conventional CC	$32.69	$77.96	$13.04
Conventional CC With Duct Firing	$32.69	$77.96	$13.04

Source: Energy Commission.

61 "Other Direct Costs" is an accounting category to capture the miscellaneous costs that accrue directly from plant operations and go toward upkeep of the plant.

Table 50: Variable Operation and Maintenance—Year=2011 (Nominal$)

Technology	Mid	High	Low
Small CT	$0.00	$0.00	$0.00
Conventional CT	$0.00	$0.00	$0.00
Advanced CT	$0.00	$0.00	$0.00
Conventional CC	$0.58	$1.79	$0.18
Conventional CC With Duct Firing	$0.58	$1.79	$0.18

Source: Energy Commission.

Insurance

Insurance is calculated as 0.6 percent of the installed cost for merchant and POU plants. For IOU plants it is calculated as 0.6 percent of the assessed value of the plant, which is the installed cost minus depreciation. This same value is used for all natural gas-fired technologies and for all three cost cases.

Summary of 2013 Natural Gas-Fired Generation Costs

The cost of building and operating a natural gas-fired generation facility in California depends on a large number of factors—described in the previous section—that may push those costs away from any estimated median value. TO create reasonable approximations of costs, a range of high, mid, and low cost factors were combined to create a range of estimated outcomes.

Table 51 summarizes instant and installed costs for the natural gas-fired technologies for 2013 (2013 dollars). Installed cost is the instant cost plus the cost of financing the plant during construction, sales tax, and development costs.

Table 51: Natural Gas-Fired Instant and Installed Costs by Developer

Capital Costs	Instant Costs ($/kW)	Installed Costs ($/kW)		
Year = 2013 (Nominal Dollars)		Merchant	IOU	POU
Mid Cost Case				
CT 49.9 MW	$1,303	$1,457	$1,469	$1,459
CT 100 MW	$1,261	$1,410	$1,421	$1,412
Advanced CT 200 MW	$1,007	$1,141	$1,158	$1,135
CC Without Duct-Firing 500 MW	$1,025	$1,166	$1,185	$1,160
CC - Duct-Firing 550 MW	$1,004	$1,142	$1,161	$1,138
High Cost Case				
CT 49.9 MW	$1,956	$2,319	$2,318	$2,290
CT 100 MW	$1,836	$2,177	$2,176	$2,150
Advanced CT 200 MW	$1,548	$1,848	$1,877	$1,840
CC without Duct-Firing 500 MW	$1,209	$1,457	$1,484	$1,453
CC - Duct-Firing 550 MW	$1,193	$1,438	$1,466	$1,435
Low Cost Case				
CT 49.9 MW	$834	$889	$887	$891
CT 100 MW	$823	$877	$876	$879
Advanced CT 200 MW	$584	$632	$635	$629
CC Without Duct-Firing 500 MW	$824	$892	$895	$888
CC - Duct-Firing 550 MW	$795	$860	$863	$857

Source: Energy Commission.

Table 52 summarizes O&M costs for 2013 (nominal dollars). Costs are assumed to have a real escalation rate of 0.5 percent per year.

Table 52: Natural Gas-Fired Technology Operation and Maintenance Costs

O&M Costs Year = 2013 (Nominal Dollars)	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Total O&M ($/kW-yr)
Mid Cost Case			
CT 49.9 MW	$28.39	$0.00	$28.39
CT 100 MW	$27.44	$0.00	$27.44
Advanced CT 200 MW	$25.24	$0.00	$25.24
CC Without Duct-Firing 500 MW	$34.56	$0.61	$37.62
CC - Duct-Firing 550 MW	$34.56	$0.61	$37.62
High Cost Case			
CT 49.9 MW	$75.16	$0.00	$75.16
CT 100 MW	$73.55	$0.00	$73.55
Advanced CT 200 MW	$69.90	$0.00	$69.90
CC Without Duct-Firing 500 MW	$82.42	$1.89	$89.06
CC - Duct-Firing 550 MW	$82.42	$1.89	$89.06
Low Cost Case			
CT 49.9 MW	$9.98	$0.00	$9.98
CT100 MW	$9.66	$0.00	$9.66
Advanced CT 200 MW	$8.93	$0.00	$8.93
CC Without Duct-Firing 500 MW	$13.79	$0.19	$14.97
CC - Duct-Firing 550 MW	$13.79	$0.19	$14.97

Source: Energy Commission.

CHAPTER 10:
Levelized Cost Estimates

The cost data provided in earlier chapters of this report can be used in a number of studies,but are most commonly used to produce LCOE studies. LCOE provides a cost metric that investors and planners can use in conjunction with other metrics in determining where to invest from among a range of options. Besides cost, electricity system planners must consider environmental, system, and regulatory requirements in deciding what types of new generation to add to the system.

This chapter summarizes the estimated LCOEs for the 19 technologies covered in this report, using the COG Model and Lumina's Analytica Model. The combination of models, designated as the ACAT, allowed the preparation of not just the traditional levelized cost of different generation types, but potential ranges of costs under probabilistic assumptions. This chapter also compares LCOE estimates to those from the *2009 IEPR*.

Definition 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 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 COG 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 individual 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 levelized cost results are presented as a cost per unit of energy over the period under investigation. This 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 dollars per megawatt-hour ($/MWh) or cents per kilowatt-hour (¢/kWh). A common alternative presentation is in dollars per kilowatt year ($/kW-yr.)

Levelized cost is generated by the COG Model using operational, cost, financial, and tax assumptions described earlier in this report. The COG 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 operational profile of the system. For example, for a natural gas-fired CC unit, a CF 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 CFs of the existing CC units—or for that matter, the operation of any existing technology in the system. LCOEs presented in this report assume *ceteris paribus*, or, all other things held constant, for the different cost cases.

Definition of Levelized Cost Components

Levelized costs consist of fixed and variable cost components, as shown in **Table 53**. All of these costs vary depending on whether the project is a merchant facility or owned by an IOU or a POU. In addition, the costs can vary with location because of differing costs of land, fuel, construction, operational, and environmental licensing.

Table 53: Summary of Levelized Cost Components

Fixed Costs
Capital and Financing—The total cost of construction, 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
Transmission Costs
Transmission Losses
California ISO Wheeling Charges—From interconnection to the delivery point

Source: Energy Commission.

Capital and Financing Costs

The capital cost includes the total costs of construction, including land purchase and development; permitting, including ERCs; the power plant equipment; interconnection, including transmission; and environmental control equipment. The financing costs are those incurred through debt and equity financing by the developer annually, similar to financing a home. The annual costs are irregular, generally front-loaded, and are levelized in this cost structure.

Insurance Cost

Insurance is the cost of insuring the power plant, similar to insuring a home. The annual costs are based on an estimated first-year cost and are then escalated by nominal inflation throughout the life of the power plant. The first-year cost is estimated as a percentage of the installed cost per kW for a merchant facility and POU plant. For an IOU plant, the first-year cost is a percentage of the book value.[62]

Ad Valorem

Ad valorem costs are annual property taxes paid as a percentage of the assessed value and are usually transferred to local governments. POU power plants are generally exempt from these taxes but may pay in-lieu fees. The assessed values for IOU power plants are set by the State Board of Equalization as a percentage of book value and as depreciation-factored value for a merchant facility.

Fixed Operating and Maintenance

Fixed O&M costs are the costs that occur regardless of how much the plant operates. These costs are not uniformly defined by all interested parties but generally include staffing, overhead and equipment (including leasing), regulatory filings, and miscellaneous direct costs.

Corporate Taxes

Corporate taxes are state and federal taxes on revenues or earnings, which are not applicable to a POU. Due to differences in eligibility for tax incentives, the calculation can differ between merchant and IOU owners. Neither calculation method lends itself to a simple explanation, but in general the taxes depend on net operating income depreciated values and are adjusted for interest on debt payments and depreciation. The federal taxes are adjusted for the state taxes, similar to an adjustment for a homeowner.

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62 *Book value* is the net of all assets less all liabilities.

Fuel Cost

Fuel cost is the cost of fuel, such as biomass or natural gas, most commonly expressed in $/MWh. For a thermal power plant, it is the heat rate (in Btu/kWh) multiplied by the cost of the fuel (in dollars per million Btu [$/MMBtu]). This includes start-up fuel costs, as well as the on-line operating fuel usage. Allowance is made in the calculation for the degradation of a power plant's heat rate over time. The COG Model relies on the *average annual* heat rate, rather than a *full load* or otherwise *optimal operation* heat rate, which is commonly quoted in vendor specifications.

Greenhouse Gas Cost

GHG costs are represented by the allowance prices under the ARB's California's Cap-and Trade Program multiplied by the average GHG emission rate per MWh. The method for forecasting these costs is discussed in Chapter 3.

Variable Operations and Maintenance Cost

Variable O&M costs are a function of the number of hours a power plant operates. Most importantly, this includes yearly maintenance and overhauls. Variable O&M also includes repairs from forced outages, consumables (nonfuel products), water supply, and annual environmental costs.

Transmission Cost

The transmission cost is the cost of transmitting power from the substation at the receiving end of the generation tie to a load center in California on high-voltage lines. It is the combination of transmission losses and service costs charged by the California ISO, as described in Chapter 3.

Summary of Estimated Levelized Costs

Table 54 summarizes mid-case levelized costs for the 19 generation technologies by developer (merchant owners, IOUs, and POUs)[63] The levelized costs are provided in $/kW-yr, $/MWh, and ¢/kWh. All costs are in 2013 dollars and are for generation units that began operation in 2013. **Table 55** shows the corresponding estimates for the technologies

63 Energy Commission mid cases are based on simple averages, where sufficient data are available. In cases where very limited data are available, the mid cases are based on an assessment of the cost that is most likely to occur—a sort of nominal value.

beginning operation in 2024, in 2024 dollars. **Figure 41** and **Figure 42** show the $/MWh LCOEs as graphs.

Comparing the 2013 levelized costs to 2024 levelized costs, staff notes a number of relationships. In 2013, the IOU plants generally have the highest LCOEs, and merchant plants have the lowest. Merchant plants have the lowest LCOE mostly due to renewable tax benefits. In 2024, after the tax benefits are assumed to have expired, merchant plants have equal or larger LCOEs. That is, except for the CT units, where the IOUs have extremely high LCOEs, driven by their very small CFs (as low as 1 percent). In 2024, POU technologies have the lowest LCOE, primarily because of lower financing costs, but also due to their exemption from ad valorem (property tax).

Table 54: Summary of Mid Case Levelized Costs (LCOE)—Start-Year=2013

Start-Year = 2013 (Nominal$/MWh)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Generation Turbine (CT) 49.9 MW	49.9	308.69	784.83	78.48	203.14	2570.64	257.06	222.07	378.04	37.80
Generation Turbine (CT) 100 MW	100	300.36	780.85	78.09	196.84	2547.02	254.70	217.71	378.96	37.90
Generation Turbine (CT) - Advanced 200 MW	200	279.09	460.38	46.04	170.26	1394.72	139.47	233.60	258.61	25.86
CC - 2 CTs No Duct Firing 500 MW	500	683.26	147.74	14.77	618.55	133.64	13.36	629.40	136.56	13.66
CC - 2 CTs With Duct Firing 550 MW	550	679.48	146.92	14.69	615.86	133.06	13.31	627.89	136.23	13.62
Biomass Fluidized Bed Boiler 50 MW	50	988.79	156.94	15.69	1126.21	178.78	17.88	1037.09	165.02	16.50
Geothermal Binary 30 MW	30	745.67	130.84	13.08	940.10	165.08	16.51	740.33	131.55	13.15
Geothermal Flash 30 MW	30	838.25	156.83	15.68	1048.42	196.30	19.63	849.37	160.93	16.09
Solar Parabolic Trough W/O Storage 250 MW	250	396.30	210.31	21.03	522.81	277.56	27.76	402.78	216.38	21.64
Solar Parabolic Trough With Storage 250 MW	250	506.29	165.58	16.56	714.55	233.78	23.38	544.39	180.23	18.02
Solar Power Tower W/O Storage 100 MW	100	418.42	202.91	20.29	555.66	269.57	26.96	424.87	208.57	20.86
Solar Power Tower With Storage 100 MW 6 HRs	100	517.51	194.50	19.45	739.14	277.90	27.79	554.53	210.97	21.10
Solar Power Tower With Storage 100 MW 11 HRs	100	587.98	158.75	15.87	834.06	225.27	22.53	633.50	173.14	17.31
Solar PV (Thin Film) 100 MW	100	241.81	178.64	17.86	348.04	257.31	25.73	264.05	199.61	19.96
Solar PV (Single Axis) 100 MW	100	264.69	153.68	15.37	368.38	213.97	21.40	288.70	169.89	16.99
Solar PV (Thin Film) 20 MW	20	281.08	213.71	21.37	411.49	313.10	31.31	305.71	237.86	23.79
Solar PV (Single Axis) 20 MW	20	306.52	183.16	18.32	435.20	260.17	26.02	332.58	201.42	20.14
Wind - Class 3 100 MW	100	373.40	135.87	13.59	443.84	161.42	16.14	374.58	137.20	13.72
Wind - Class 4 100 MW	100	340.23	133.32	13.33	406.41	159.17	15.92	345.01	136.09	13.61

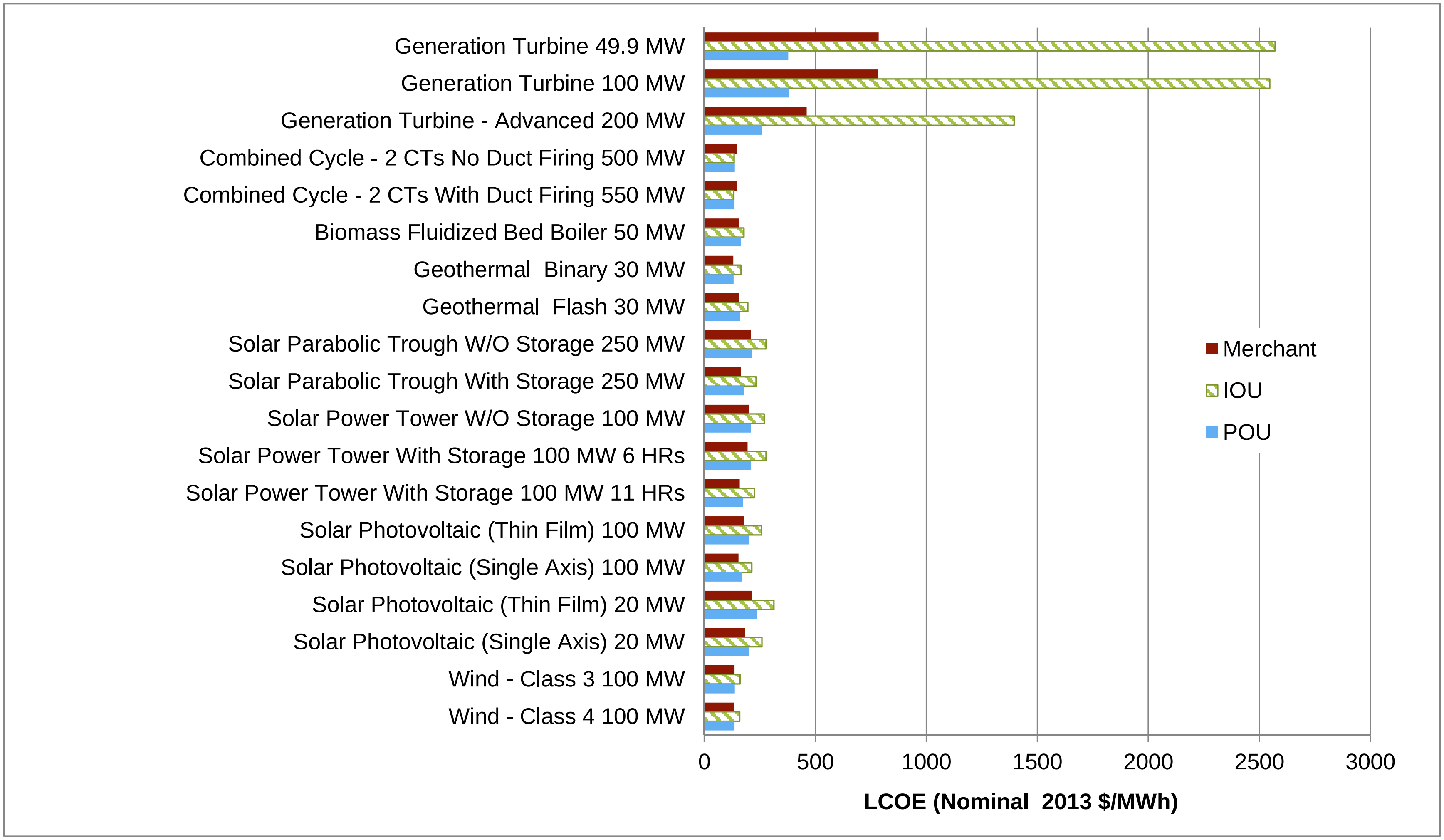
Source: Energy Commission.

Table 55: Summary of Mid Case Levelized Costs—Start-Year=2024

Start-Year = 2024 (Nominal $MWh)	Size	Merchant			IOU			POU		
	MW	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh	$/kW-Yr	$/MWh	¢/kWh
Generation Turbine (CT) 49.9 MW	49.9	432.22	1098.91	109.89	274.03	3467.72	346.77	330.14	562.01	56.20
Generation Turbine (CT) 100 MW	100	421.21	1095.02	109.50	265.71	3438.15	343.81	324.42	564.70	56.47
Generation Turbine (CT) - Advanced 200 MW	200	390.45	644.08	64.41	223.41	1830.16	183.02	356.86	395.08	39.51
CC - 2 CTs No Duct Firing 500 MW	500	1115.21	241.14	24.11	1023.39	221.11	22.11	1072.90	232.79	23.28
CC - 2 CTs With Duct Firing 550 MW	550	1112.95	240.65	24.07	1021.77	220.76	22.08	1072.02	232.60	23.26
Biomass Fluidized Bed Boiler 50 MW	50	1729.84	274.55	27.46	1687.89	267.94	26.79	1574.65	250.56	25.06
Geothermal Binary 30 MW	30	1441.04	253.15	25.32	1431.59	251.39	25.14	1160.33	206.18	20.62
Geothermal Flash 30 MW	30	1639.14	307.04	30.70	1624.58	304.18	30.42	1351.63	256.09	25.61
Solar Parabolic Trough W/O Storage 250 MW	250	624.74	331.95	33.19	628.23	333.52	33.35	499.65	268.42	26.84
Solar Parabolic Trough With Storage 250 MW	250	873.01	285.87	28.59	876.58	286.80	28.68	698.47	231.24	23.12
Solar Power Tower W/O Storage 100 MW	100	656.22	318.62	31.86	659.00	319.70	31.97	519.67	255.11	25.51
Solar Power Tower With Storage 100 MW 6 HRs	100	889.36	334.66	33.47	893.27	335.85	33.59	696.57	265.01	26.50
Solar Power Tower With Storage 100 MW 11 HRs	100	1033.07	279.26	27.93	1036.32	279.90	27.99	830.53	226.99	22.70
Solar PV (Thin Film) 100 MW	100	377.33	279.40	27.94	381.08	281.73	28.17	311.21	235.27	23.53
Solar PV (Single Axis) 100 MW	100	391.17	227.42	22.74	391.60	227.46	22.75	342.66	201.64	20.16
Solar PV (Thin Film) 20 MW	20	471.68	359.46	35.95	476.84	362.82	36.28	369.88	287.79	28.78
Solar PV (Single Axis) 20 MW	20	486.46	291.08	29.11	487.28	291.30	29.13	401.29	243.04	24.30
Wind - Class 3 100 MW	100	684.39	248.84	24.88	665.07	241.87	24.19	586.59	214.86	21.49
Wind - Class 4 100 MW	100	629.37	246.44	24.64	612.08	239.72	23.97	542.67	214.06	21.41

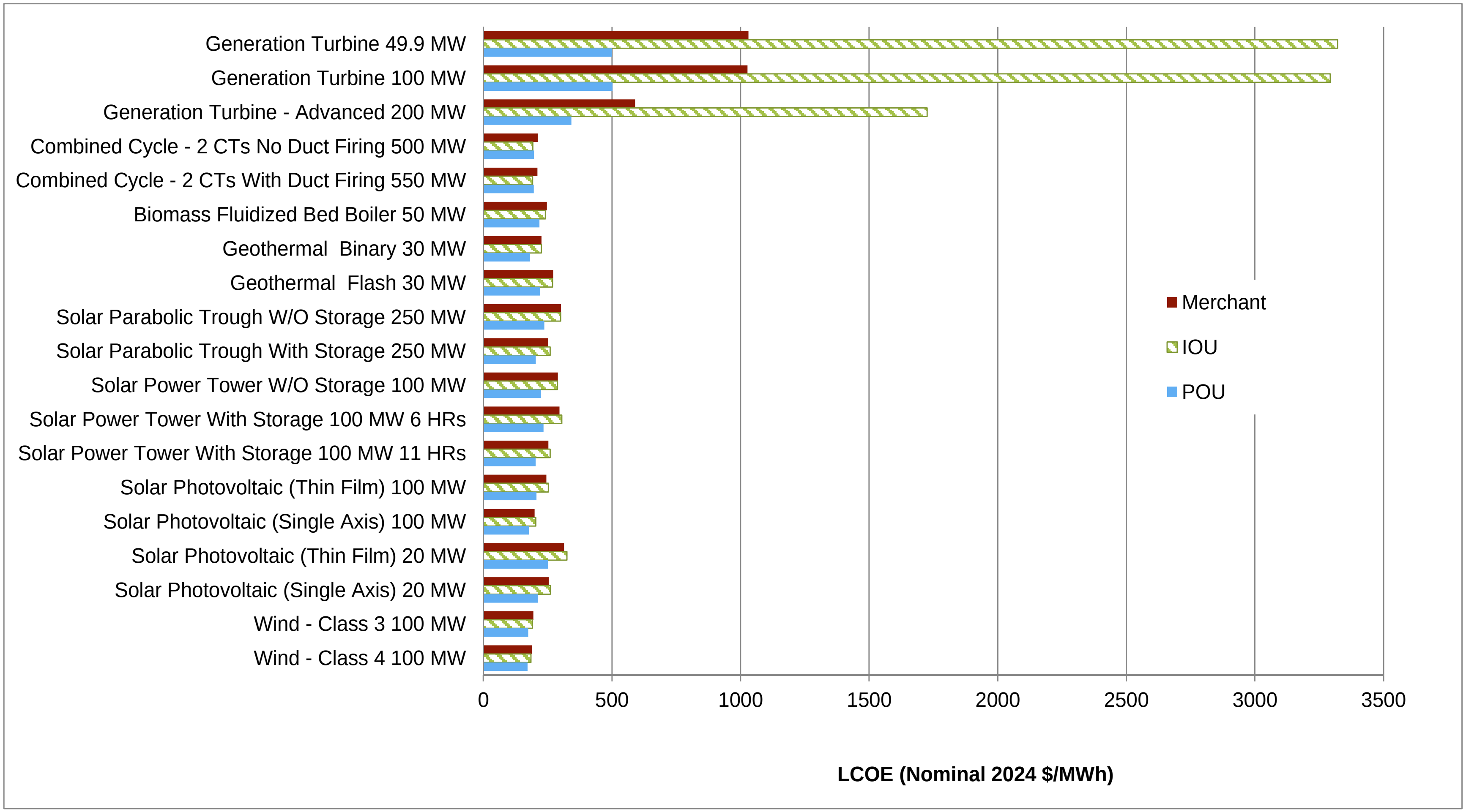
Source: Energy Commission.

Figure 41: Summary of Mid Case Levelized Costs (LCOE)—Start-Year=2013



Source: Energy Commission.

Figure 42: Summary of Mid Case Levelized Costs—Start-Year= 2024



Source: Energy Commission.

Component Levelized Costs

The corresponding component LCOE delineated in **Table 53** are provided in **Table 56** for the singular case of merchant financing of the technologies beginning operation in 2013. **Appendix D** provides the component costs for all three developers for plants beginning operation in 2013 and 2024, both in $/MWh and $/kW-yr.

Costs are shown both at the busbar and point of delivery. The difference is the cost of transmission, consisting of transmission losses, and California ISO service charges.

Levelized Cost Trends—2013 – 2024

Figure 43 shows the merchant LCOE trends in solar technologies in real 2011 dollars. The small jump in LCOE in 2017 reflects the expiration of the solar ad valorem exemption. The large jumps in 2018 and 2019 reflect the expiration of federal renewable tax credits.[64]

It is striking that technology LCOE spreads over a very large range, with solar PV single-axis 100 MW the least cost, and solar PV thin-film 20 MW being the most expensive. Both are solar PV technologies, with all the thermal solar technologies falling somewhere between.

Also striking is the large reduction in LCOE in going from 20 MW solar PV to 100 MW solar PV—both for the single-axis and thin-film PV technologies. This difference is due to interconnection costs, which are assumed to be relatively insensitive to changes in project size (within 3 percent) and, therefore, become a much smaller percentage of the total capital costs at the 100 MW size (that is, 6 percent as opposed to 25 percent). In the solar thermal technologies, there is the large reduction in LCOE for both the solar parabolic trough and the solar tower due to the addition of storage.

Figure 44 shows the merchant LCOE trends for non-solar renewable technologies. Again, there are jumps in levelized cost due to expiration of renewable tax credits. One technology (geothermal) split between two categories (flash and binary) brackets the range with both the highest and lowest LCOE.

Figure 45 shows the merchant LCOE trends in the natural gas-fired technologies. The increasing penetration of advanced CTs in California can largely be attributed to its cost advantage, as it falls about one-half the way between the CTs and the CCs.

64 The expiration does not occur in the same year as the availability for this tax benefit depends on the year construction starts, not on the start year.

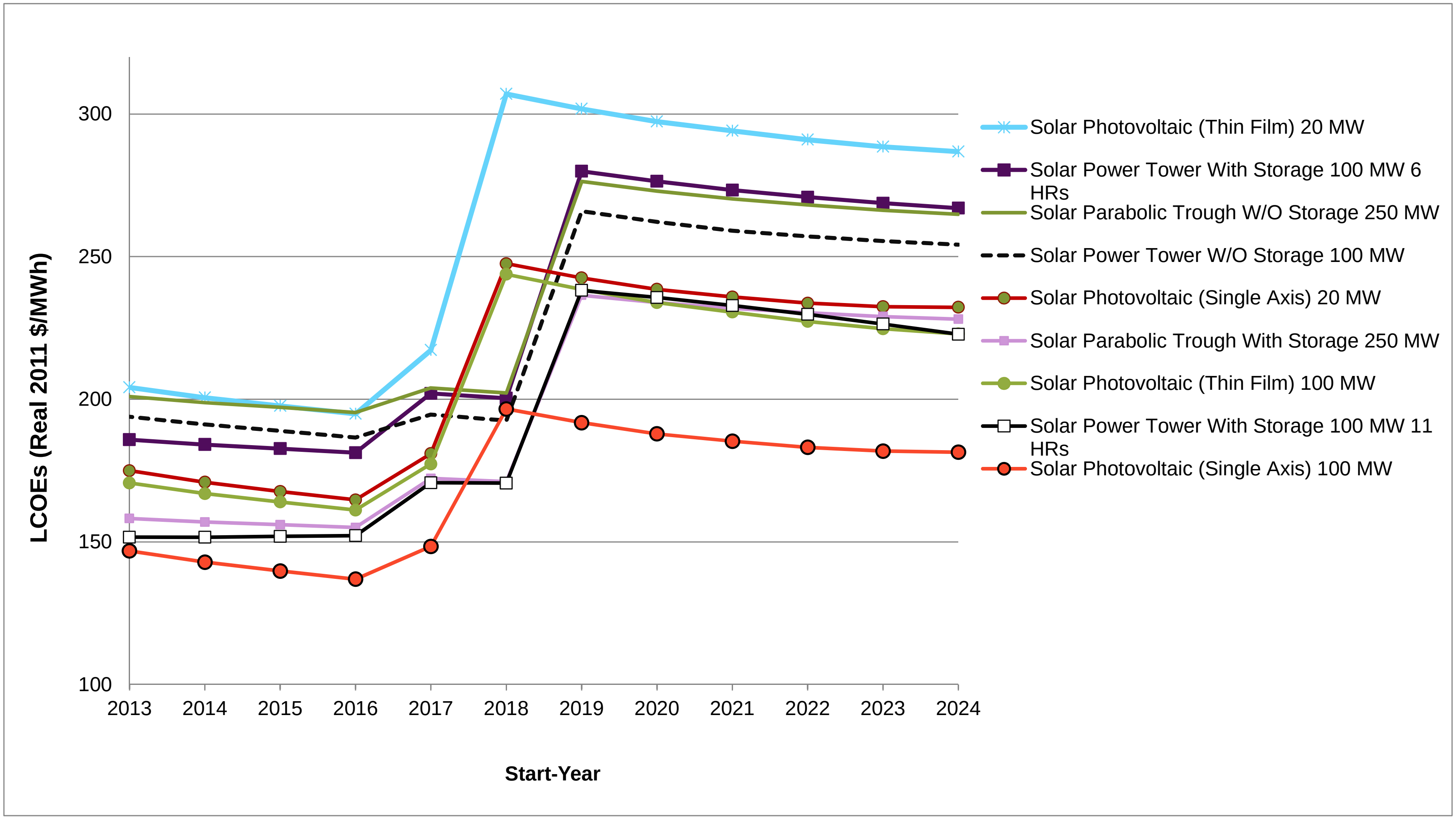
Table 56: Mid Cost Component LCOE for Merchant Financed Plants—Start Year=2013

In-Service Year = 2013	Size MW	$/MWh (Nominal 2013$) Capital & Financing	Insurance	Ad Valorem	Fixed O&M	Taxes	Fixed Costs	Fuel	Variable O&M	Variable Cost	Total Levelized Costs at Busbar	Transmission Cost	Total Levelized Costs To Delivery Point
Generation Turbine 49.9 MW	49.9	360.18	24.68	35.79	84.83	104.33	**609.81**	101.99	0.00	**101.99**	**711.80**	73.02	**784.83**
Generation Turbine 100 MW	100	348.47	23.88	34.62	81.98	100.97	**589.93**	101.99	0.00	**101.99**	**691.92**	88.93	**780.85**
Generation Turbine - Advanced 200 MW	200	188.19	12.91	18.72	50.41	54.44	**324.68**	95.46	0.00	**95.46**	**420.14**	40.24	**460.38**
Combined Cycle - 2 CTs No Duct Firing 500 MW	500	25.86	1.74	2.53	9.13	8.55	**47.81**	70.37	0.79	**71.17**	**118.98**	28.76	**147.74**
Combined Cycle - 2 CTs With Duct Firing 550 MW	550	25.33	1.71	2.48	9.13	8.37	**47.01**	70.37	0.79	**71.17**	**118.18**	28.75	**146.92**
Biomass Fluidized Bed Boiler 50 MW	50	65.05	5.54	8.18	19.61	-25.42	**72.97**	43.85	6.82	**50.68**	**123.64**	33.30	**156.94**
Geothermal Binary 30 MW	30	93.00	7.97	11.76	17.73	-36.85	**93.61**	0.00	0.00	**0.00**	**93.61**	37.23	**130.84**
Geothermal Flash 30 MW	30	108.26	9.27	13.68	18.90	-42.85	**107.26**	8.35	0.00	**8.35**	**115.61**	41.22	**156.83**
Solar Parabolic Trough W/O Storage 250 MW	250	183.91	8.11	13.13	44.64	-73.82	**175.97**	0.00	0.00	**0.00**	**175.97**	34.34	**210.31**
Solar Parabolic Trough With Storage 250 MW	250	161.16	7.11	2.09	27.51	-64.78	**133.09**	0.00	0.00	**0.00**	**133.09**	32.49	**165.58**
Solar Power Tower W/O Storage 100 MW	100	173.89	7.66	12.41	34.27	-69.62	**158.61**	0.00	0.00	**0.00**	**158.61**	44.30	**202.91**
Solar Power Tower With Storage 100 MW 6 HRs	100	187.52	8.27	2.44	28.01	-75.30	**150.94**	0.00	0.00	**0.00**	**150.94**	43.55	**194.50**
Solar Power Tower With Storage 100 MW 11 HRs	100	149.67	6.60	1.94	20.13	-60.05	**118.29**	0.00	0.00	**0.00**	**118.29**	40.45	**158.75**
Solar Photovoltaic (Thin Film) 100 MW	100	173.75	7.71	2.27	23.73	-70.81	**136.65**	0.00	0.00	**0.00**	**136.65**	41.99	**178.64**
Solar Photovoltaic (Single Axis) 100 MW	100	136.26	6.02	1.77	24.17	-54.89	**113.33**	0.00	0.00	**0.00**	**113.33**	40.35	**153.68**
Solar Photovoltaic (Thin Film) 20 MW	20	214.13	9.50	2.80	23.73	-87.10	**163.04**	0.00	0.00	**0.00**	**163.04**	50.67	**213.71**
Solar Photovoltaic (Single Axis) 20 MW	20	169.83	7.50	2.21	24.17	-68.29	**135.42**	0.00	0.00	**0.00**	**135.42**	47.74	**183.16**
Wind - Class 3 100 MW	100	80.93	6.97	10.18	13.06	-27.79	**83.34**	0.00	12.38	**12.38**	**95.73**	40.14	**135.87**
Wind - Class 4 100 MW	100	78.18	6.74	9.85	14.06	-27.82	**81.02**	0.00	12.38	**12.38**	**93.40**	39.92	**133.32**

Source: Energy Commission.

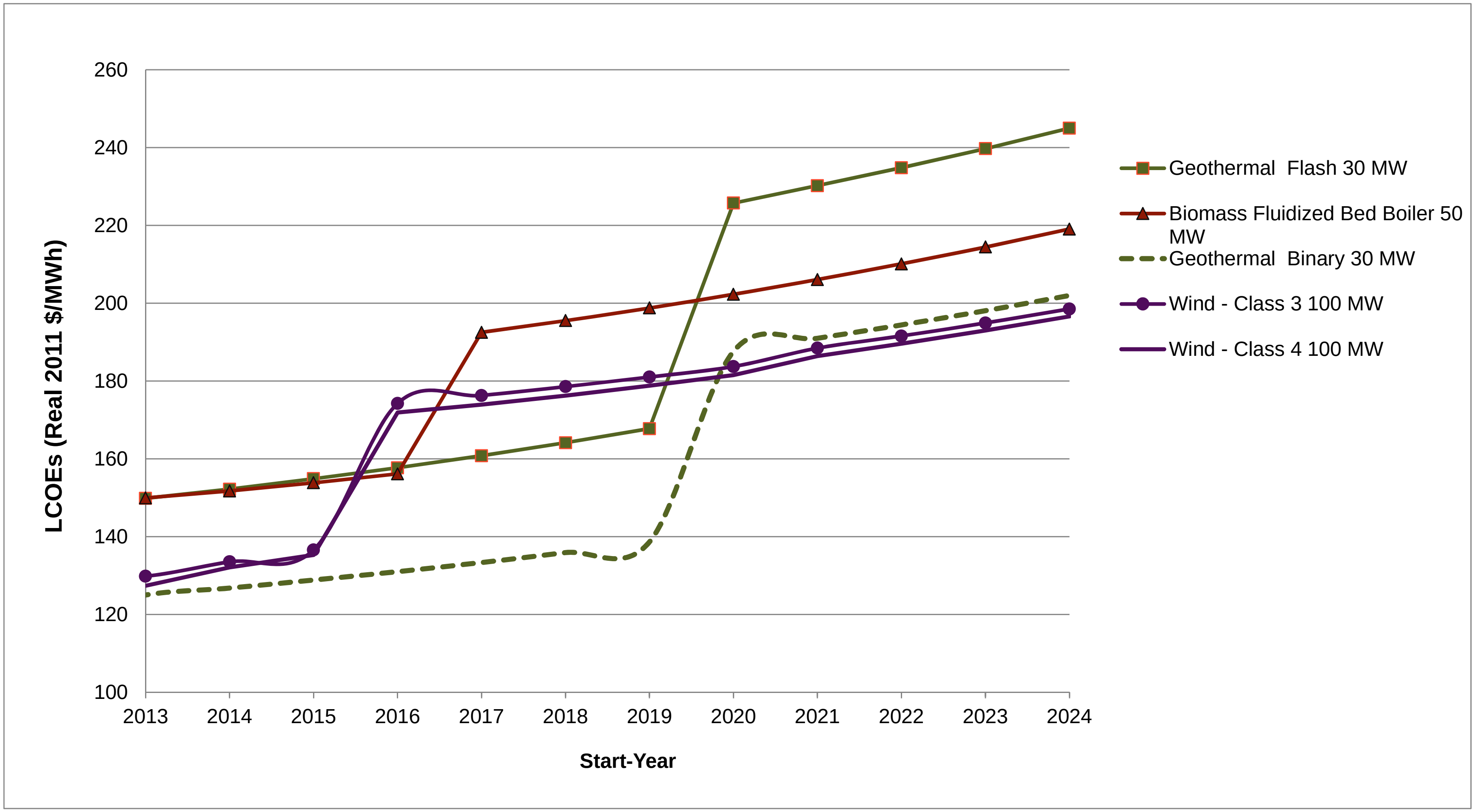
Note: Transmission cost includes transmission losses and California ISO transmission service cost.

Figure 43: Merchant Mid Case Levelized Costs for Solar Technologies



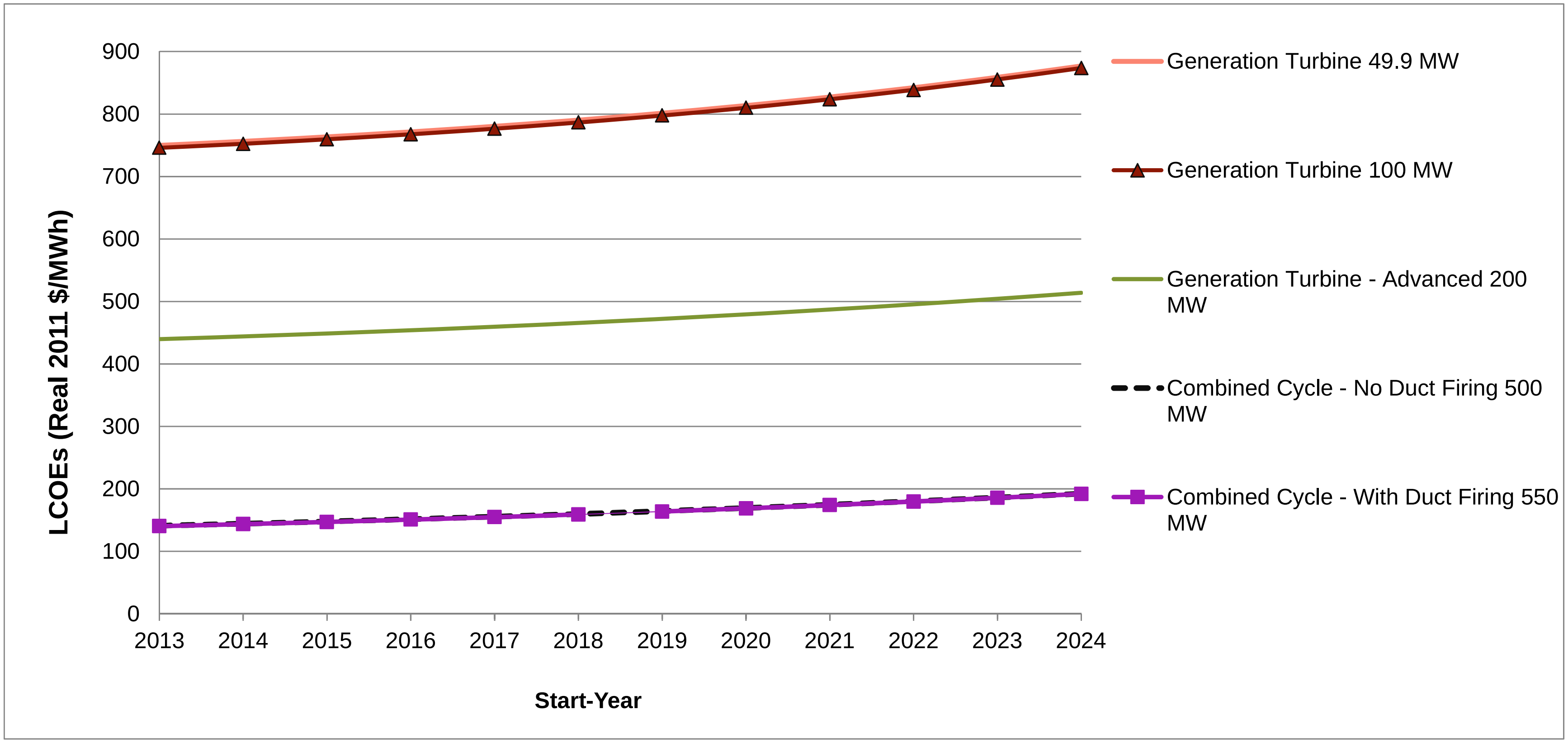
Source: Energy Commission.

Figure 44: Merchant Mid Case Levelized Costs for Nonsolar Renewable Technologies



Source: Energy Commission.

Figure 45: Merchant Mid Case Levelized Costs for Natural Gas-Fired Technologies

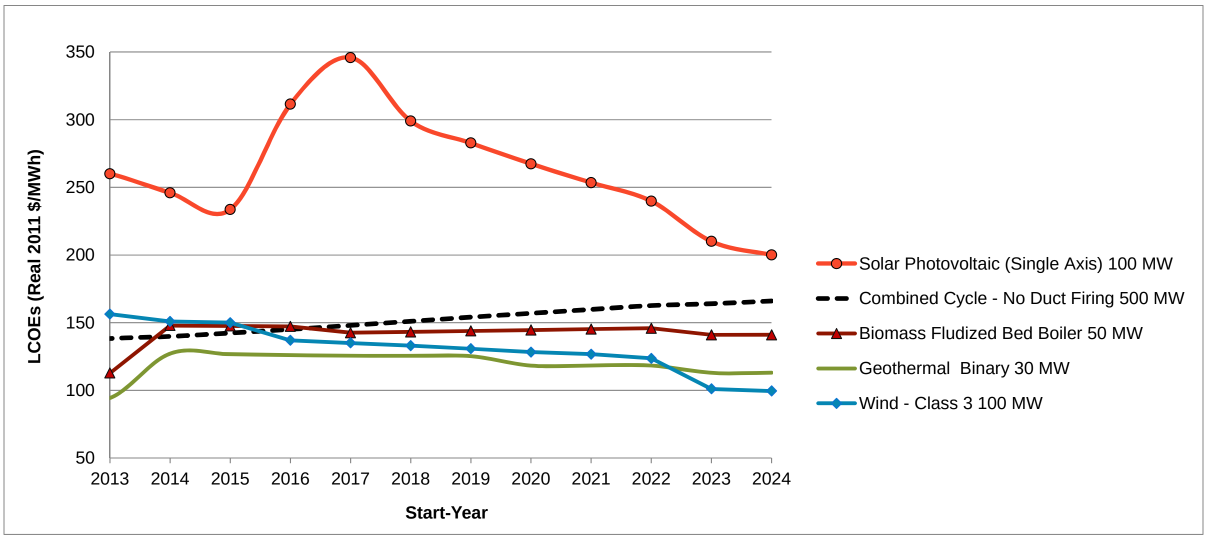


Source: Energy Commission.

Improvement in Solar Photovoltaic Levelized Cost

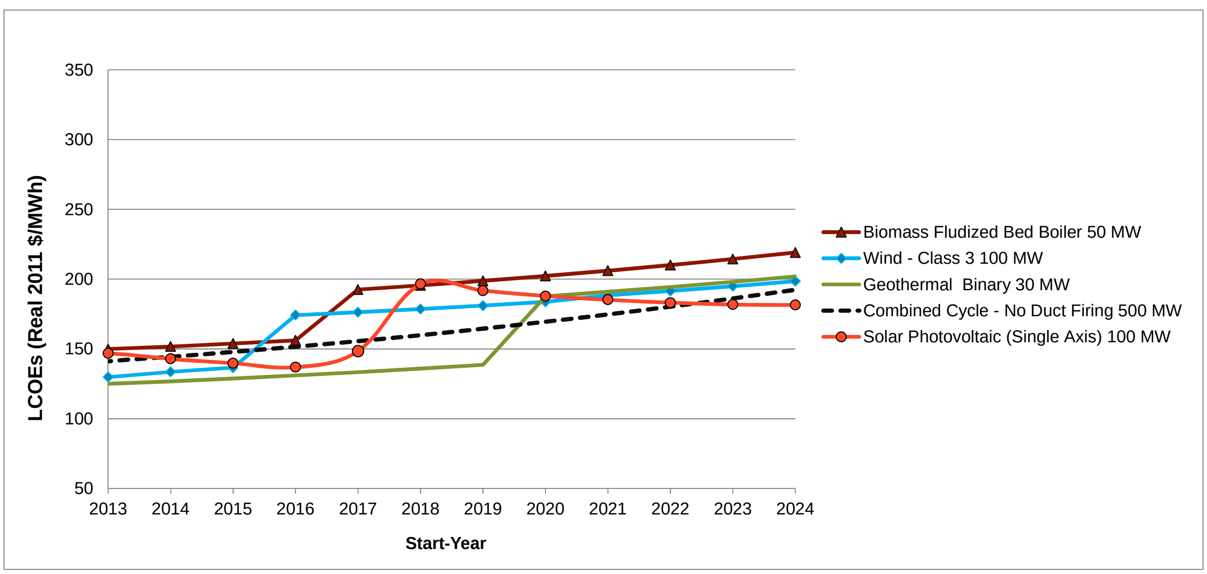
Solar PV levelized costs have improved dramatically since the last assessment in the *2009 IEPR*. **Figure 46** shows the *2009 IEPR* LCOE for selected technologies. **Figure 47** shows those same technologies for the current LCOE forecast. Not only is solar now highly competitive in the early years when it has the benefit of tax credits, it becomes highly competitive in the later years even when the tax credits are assumed to have expired. **Figure 48** compares the range of the current solar PV 100 MW to that of the 500 MW natural gas-fired CC, showing the lower potential cost of the solar unit.

Figure 46: Levelized Cost of Energy for Selected Technologies—*2009 IEPR Forecast*



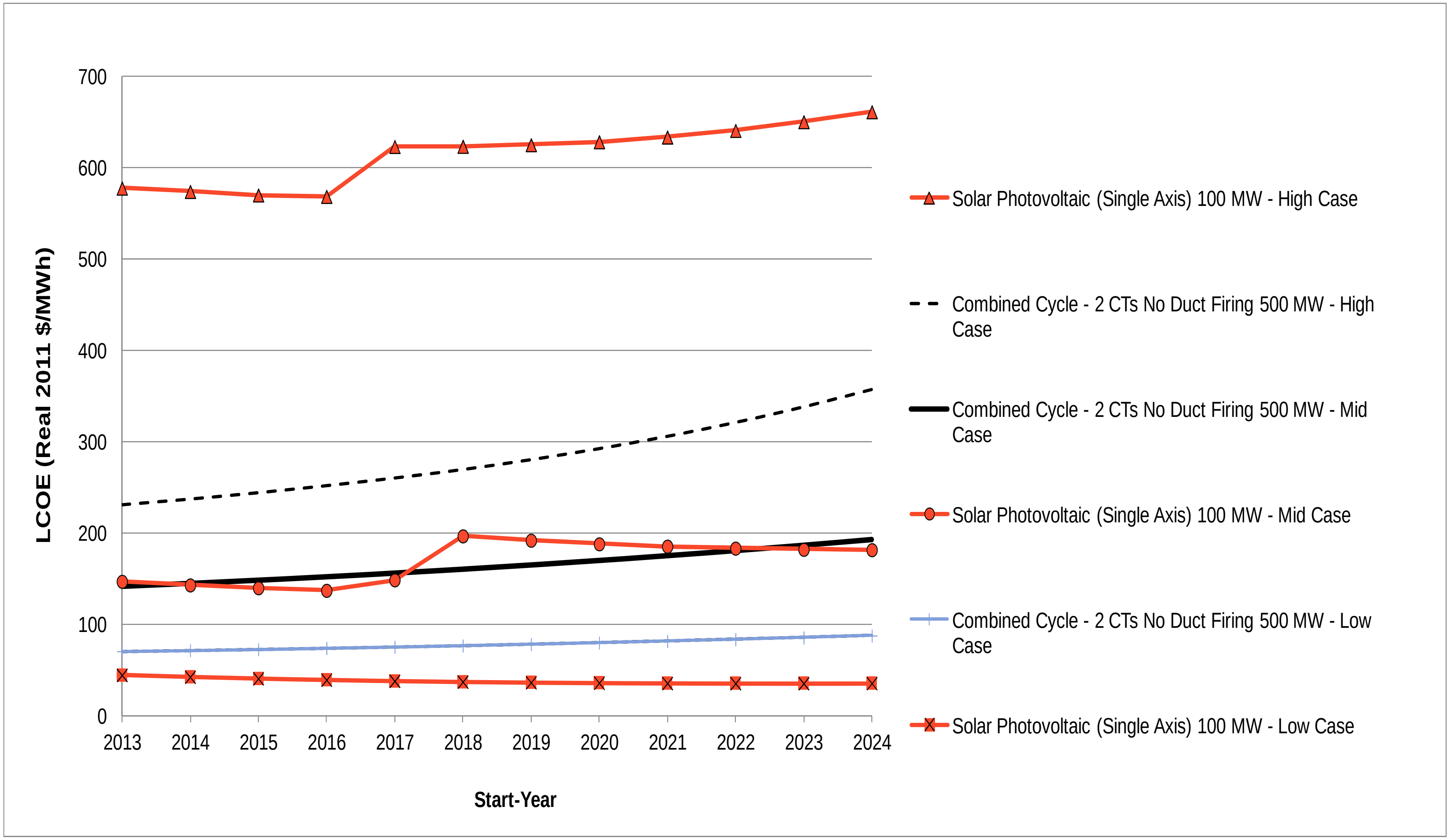
Source: Energy Commission.

Figure 47: Levelized Cost of Energy for Selected Technologies—Current Forecast



Source: Energy Commission.

Figure 48: Comparing Levelized Cost of Energy Ranges for Combined-Cycle 500 MW and Solar Photovoltaic Single-Axis 100 MW

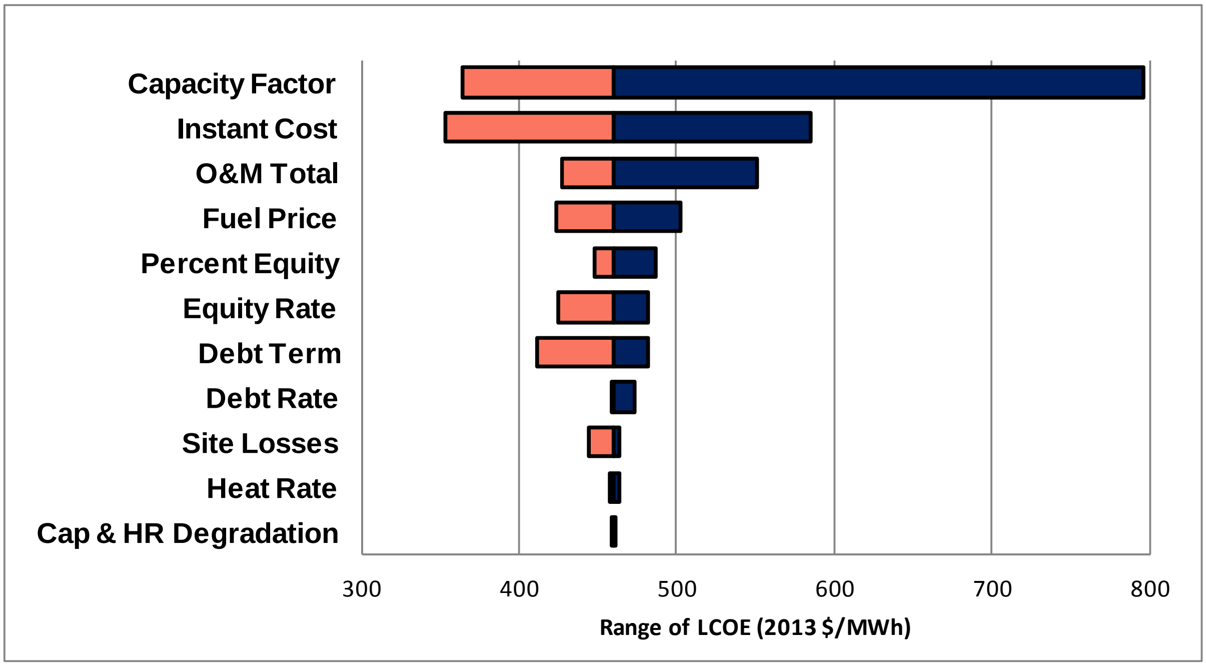


Source: Energy Commission.

Significant Drivers of Levelized Cost

A key part of estimating a range of levelized costs is identifying the factors that influence these costs. Staff identified 11 significant drivers, illustrated for selected technologies in **Figure 49 – Figure 52**.[65] The technologies shown highlight now the drivers change in order of significance depending on the technology selected. Each shows the range of LCOE that is caused by the respective drivers for the start year 2013. These representations of the ranges of costs are referred to as "tornado diagrams," due to the appearance. **Appendix C** provides tornado diagrams for all 19 technologies.

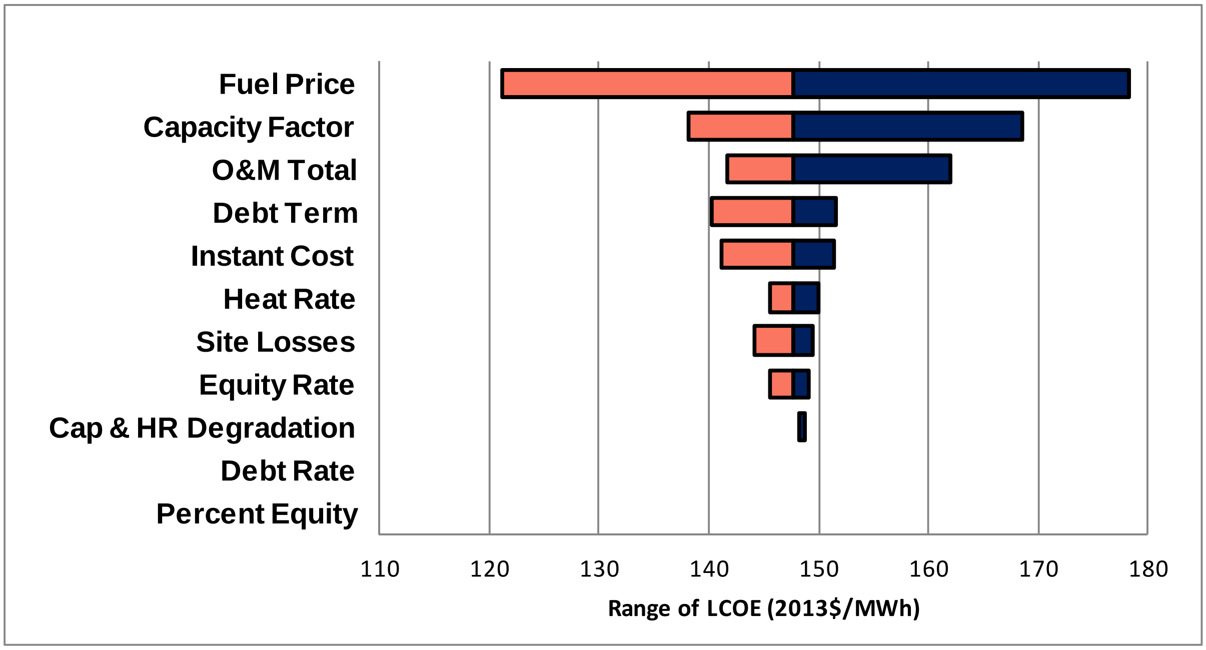
Figure 49: Tornado Diagram—Advanced Generation Turbine



Source: Energy Commission.

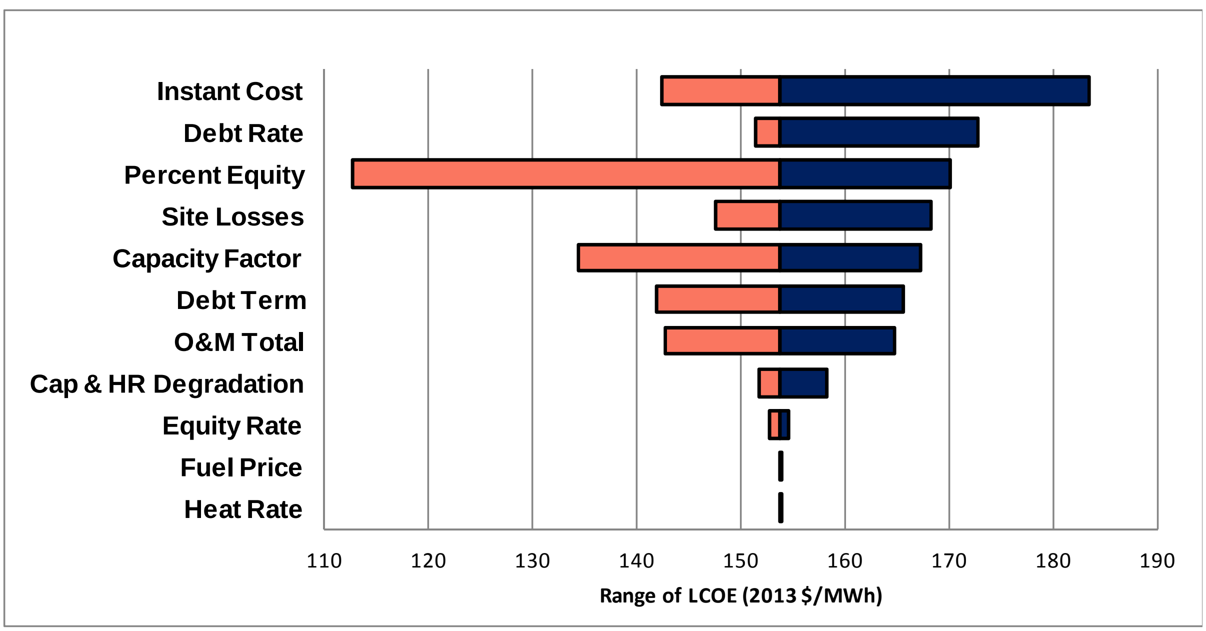
65 *Cap & HR degradation* denotes the effect of heat rate and capacity degradation over the life of the power plant.

Figure 50: Tornado Diagram—Combined-Cycle 500 MW



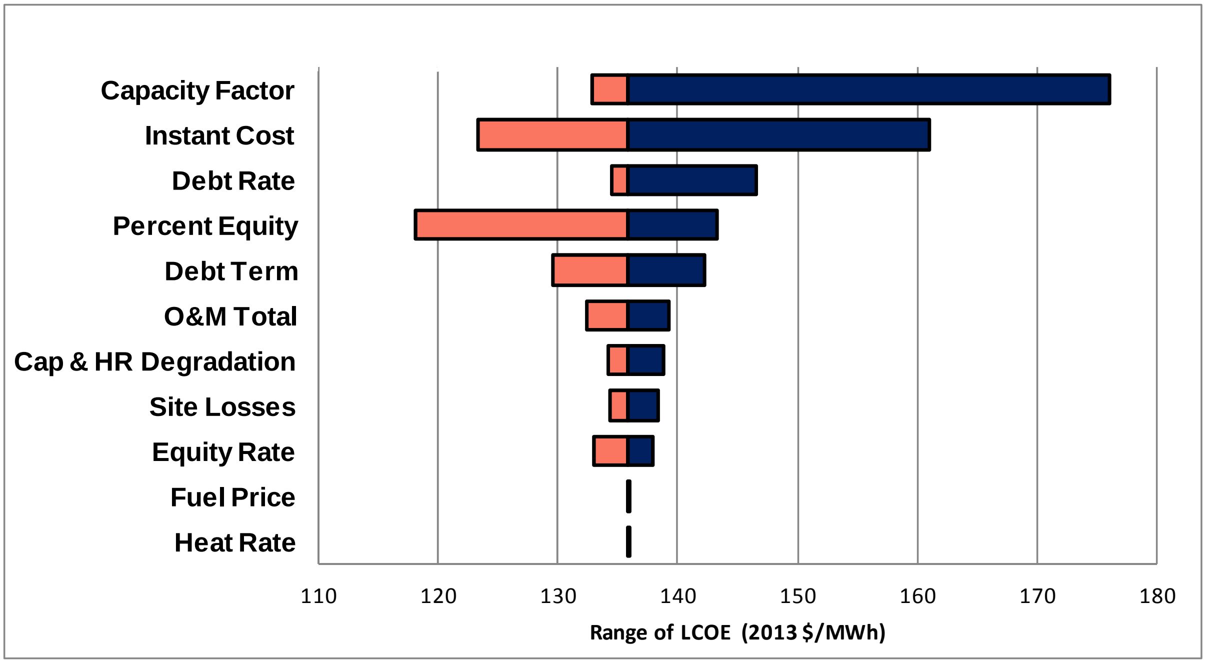
Source: Energy Commission.

Figure 51: Tornado Diagram—Solar Photovoltaic Single-Axis 100 MW



Source: Energy Commission.

Figure 52 Tornado Diagram—Wind Class 3 100 MW



Source: Energy Commission.

External Costs

ERC, GHG mitigation, and transmission costs (beyond the interconnection point) are external costs of the technology but are a significant portion of the total LCOE.[66] **Table 57** shows the contribution of each of these to the LCOE. **Table 58** shows the effect of each external cost as a range of percentages. **Figure 53** and **Figure 54** show the same data graphically for 2013 and 2024, respectively.

External costs are responsible for as much as 32 percent of the total LCOE in 2013 and 46 percent in 2024. ERCs and GHGs are significant cost factors, but with the exception of the CTs, it is the transmission cost (transmission losses cost and the California ISO wheeling charges [67]) that are the most dramatic. The California ISO charges are responsible for lion's share of this cost (typically 80 percent – 90 percent). In 2013, the transmission cost is 5 percent to 26 percent of the total LCOE, depending on the technology—5 percent for small CT, 22 percent for large solar PV, and 26 percent for wind. By 2024, the transmission costs of the wind units are 36 percent of the total LCOE.

66 For ERCs, the San Diego air basin is used.

67 *Interconnection costs* are the transmission from the plant to the existing transmission line and are considered an integral part of the capital costs—as are the losses associated with this interconnection transmission.

Table 57: Effect of External Costs on LCOE—Merchant Mid Case

LCOE (2013 $/MWh)	Base	ERCs	GHG	Trans. Losses	CAISO	Total
Generation Turbine 49.9 MW	694.33	24.59	24.78	13.90	27.22	784.83
Generation Turbine 100 MW	688.71	25.14	25.34	13.83	27.83	780.85
Generation Turbine - Advanced 200 MW	396.68	6.66	22.51	8.15	26.37	460.38
Combined Cycle - 2 CTs No Duct Firing 500 MW	101.24	1.56	16.46	2.62	25.87	147.74
Combined Cycle - 2 CTs With Duct Firing 550 MW	100.29	1.71	16.46	2.60	25.87	146.92
Biomass Fluidized Bed Boiler 50 MW	122.36	0.81	3.78	4.30	25.69	156.94
Geothermal Binary 30 MW	99.10	0.00	0.00	3.59	28.14	130.84
Geothermal Flash 30 MW	112.72	0.66	9.15	4.29	30.00	156.83
Solar Parabolic Trough W/O Storage 250 MW	177.82	0.00	0.00	5.77	26.72	210.31
Solar Parabolic Trough With Storage 250 MW	134.31	0.00	0.00	4.54	26.73	165.58
Solar Power Tower W/O Storage 100 MW	168.78	0.00	0.00	5.56	28.58	202.91
Solar Power Tower With Storage 100 MW 6 HRs	160.58	0.00	0.00	5.34	28.58	194.50
Solar Power Tower With Storage 100 MW 11 HRs	125.67	0.00	0.00	4.34	28.74	158.75
Solar Photovoltaic (Thin Film) 100 MW	145.31	0.00	0.00	4.89	28.45	178.64
Solar Photovoltaic (Single Axis) 100 MW	120.35	0.00	0.00	4.20	29.13	153.68
Solar Photovoltaic (Thin Film) 20 MW	178.60	0.00	0.00	5.85	29.27	213.71
Solar Photovoltaic (Single Axis) 20 MW	148.19	0.00	0.00	5.00	29.97	183.16
Wind - Class 3 100 MW	101.51	0.00	0.00	3.72	30.64	135.87
Wind - Class 4 100 MW	99.02	0.00	0.00	3.66	30.64	133.32

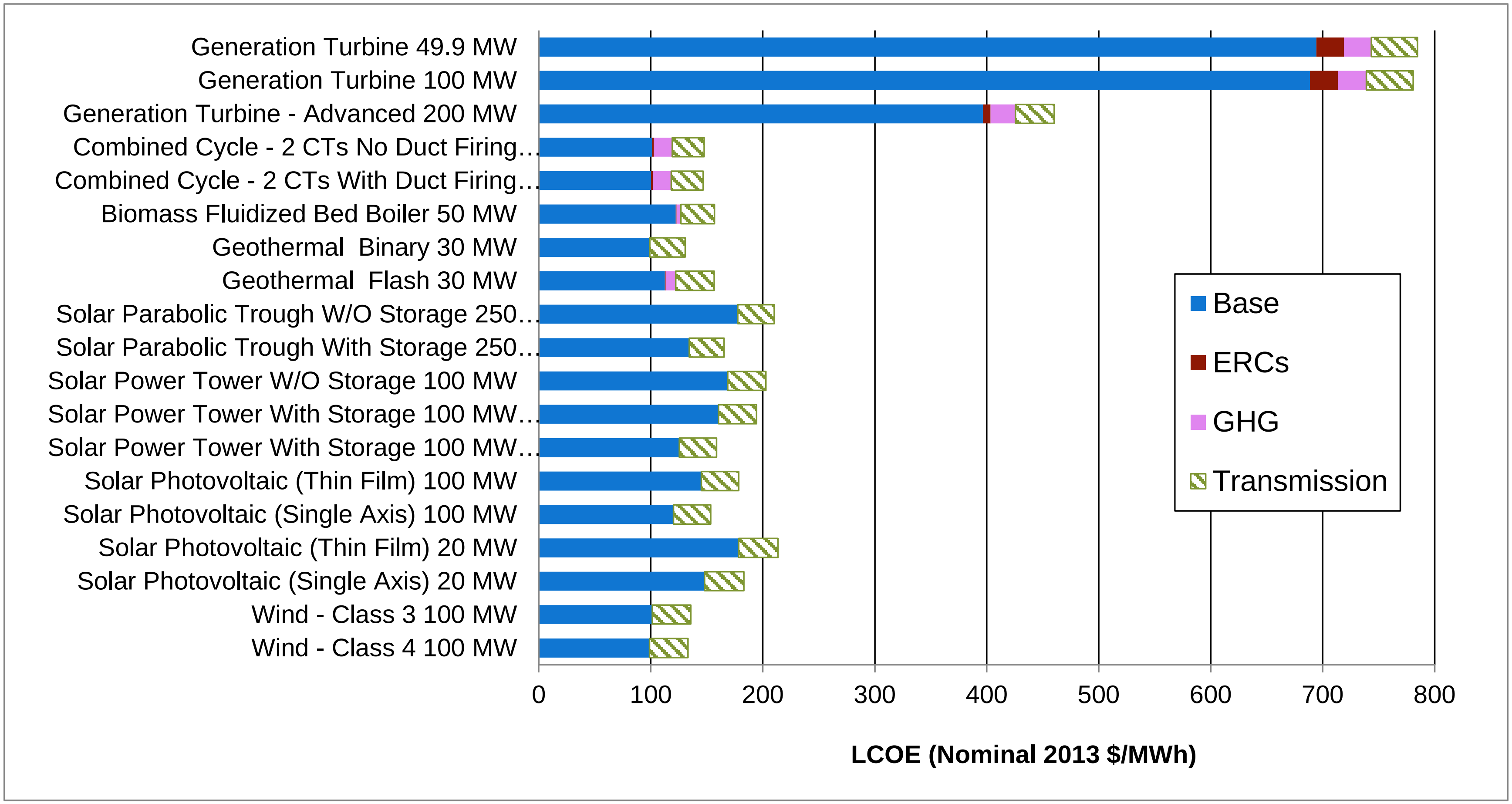
Source:Energy Commission.

Table 58: External Costs as a Percentage of the Total Levelized Cost of Energy

	2013		2024	
	Low	**High**	**Low**	**High**
ERCs	0%	3%	0%	10%
GHG	0%	11%	0%	14%
Trans	5%	26%	8%	36%
ALL	12%	32%	22%	46%

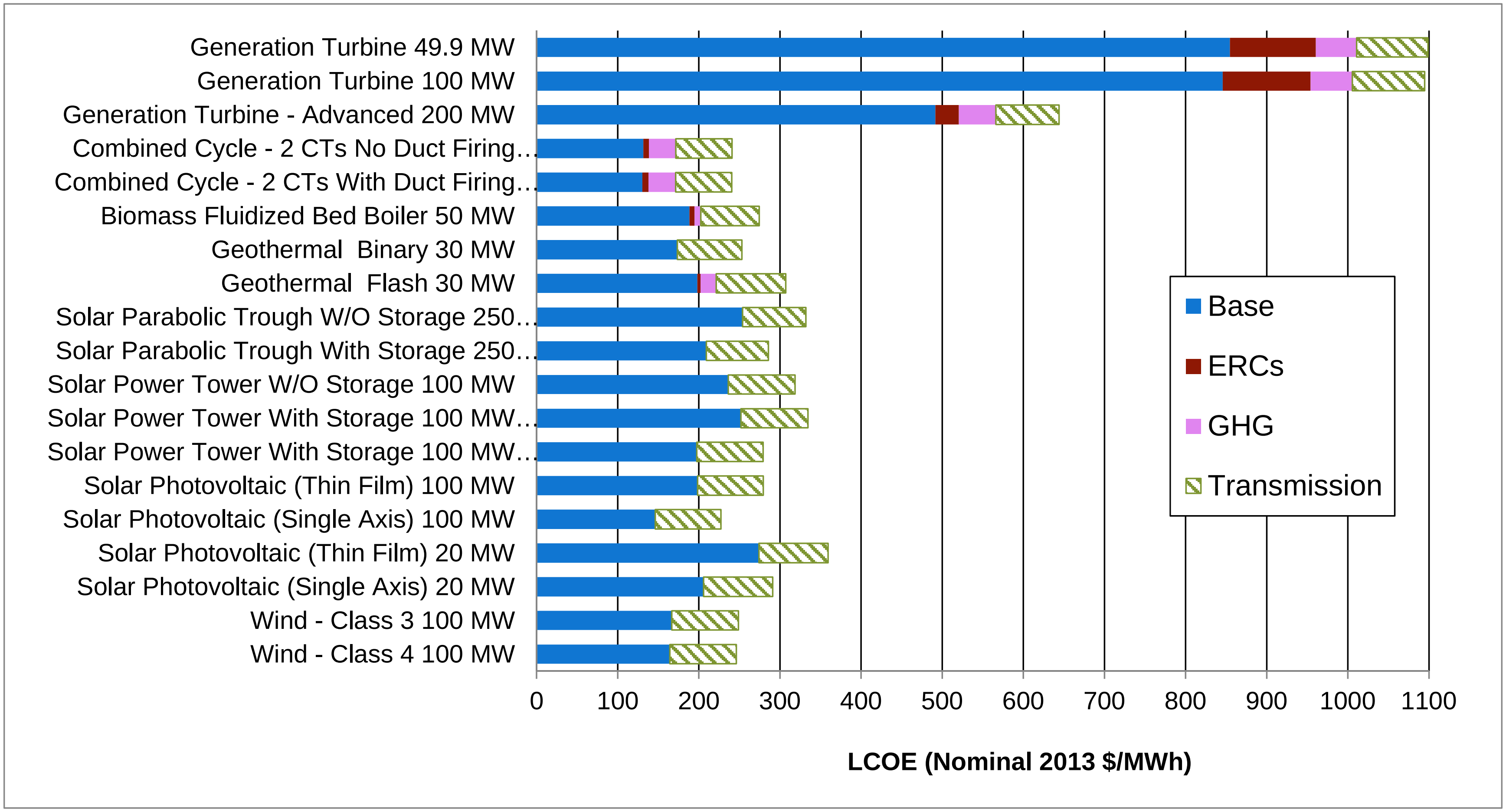
Source: Energy Commission.

Figure 53: Effects of External Costs Levelized Cost of Energy—Merchant Plants With Start Year=2013



Source: Energy Commission.

Figure 54: Effects of External Costs on Mid Case Levelized Cost of Energy—Merchant Plants With Start Year=2024



Source: Energy Commission.

Range of Levelized Costs—Highs and Lows

The mid case LCOEs 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.[68] Actual costs and, therefore, LCOEs vary across a range of possible values depending on multiple factors. Using point estimates can cause overconfident assessments that can result in poor decisions. 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.

In the *2009 IEPR*, staff provided a range of LCOEs for the first time, in recognition of the limitations of point forecasts. These high-low costs can be found as an output of the COG Model in juxtaposition to mid-cost cases. Although this was a step forward, it was a simplistic deterministic technique for setting high-low ranges and is flawed in that the high and low LCOEs are based on the respective coincident high and low cost assumptions. 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. The estimates shown in **Figure 55** use the *2009 IEPR* method to estimate the range of levelized costs using the current data for the current set of technologies at the point of interconnection, for the start year of 2013 and is in 2013 nominal dollars—at the point of delivery (load center).

Staff sought a better approach for this report. Rather than select all high or all low factors simultaneously, this approach expresses uncertainty about each cost driver using probability distributions. Staff has applied a probabilistic approach to this analysis. Staff generated ranges of LCOE using the ACAT, a model developed using Lumina's Analytica software in conjunction with the Energy Commission's deterministic, spreadsheet-based COG Model (Sherwin and Henrion, 2013; Lumina, 2013). ACAT treats the low, mid, and high values for each input respectively as the 10th, 50th, and 90th percentiles of a fitted probability distribution. **Figure 56** shows the results of using the ACAT model to estimate probabilistic ranges of LCOE. ACAT allows the user to select the shape of the distributions. Cubic spline distributions were used in these results.[69]

68 Energy Commission mid cases are based on simple averages where sufficient data are available. In other cases where very limited data are available, mid cases are based on an assessment that this is the cost most likely to occur—a sort of nominal value.

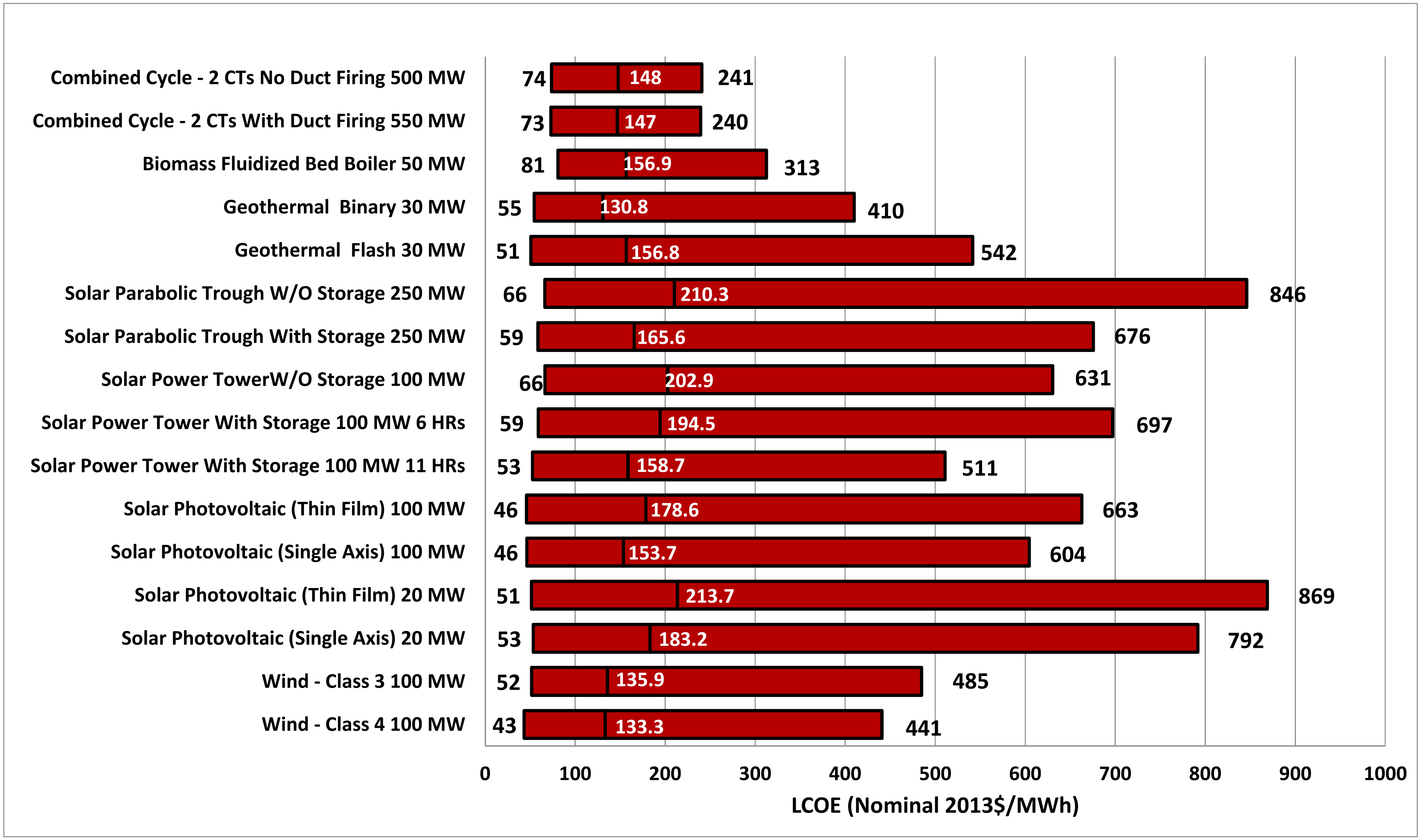
69 Although triangular distributions are commonly used as a proxy where the actual distribution is unknown, the cubic spline was used herein as it assumes a more realistic smoothness - and in the Energy Commission's case gave much more believable mid-cost values. It is set to fit the estimated 10th, 50th, and 90th percentiles. It creates a bell-shaped density function with finite bounds on upper and lower tails (Spline, 2013).

ACAT randomly samples from the distributions for the inputs for each selected technology. It passes each set of values to the COG Model spreadsheet and records the resulting LCOE. ACAT runs COG Model many times to perform Monte Carlo simulations to generate a random sample of LCOE values from which it estimates the resulting probability distributions.

Figure 57 compares the ACAT probabilistic levelized costs to the deterministic COG Model levelized costs for selected technologies, which illustrates the dramatic difference in range of costs. Whereas the deterministic low for the solar PV single-axis 100 MW technology is calculated as $46/MWh, realistically only $114/MWh can be achieved within the 10 percentile limit.

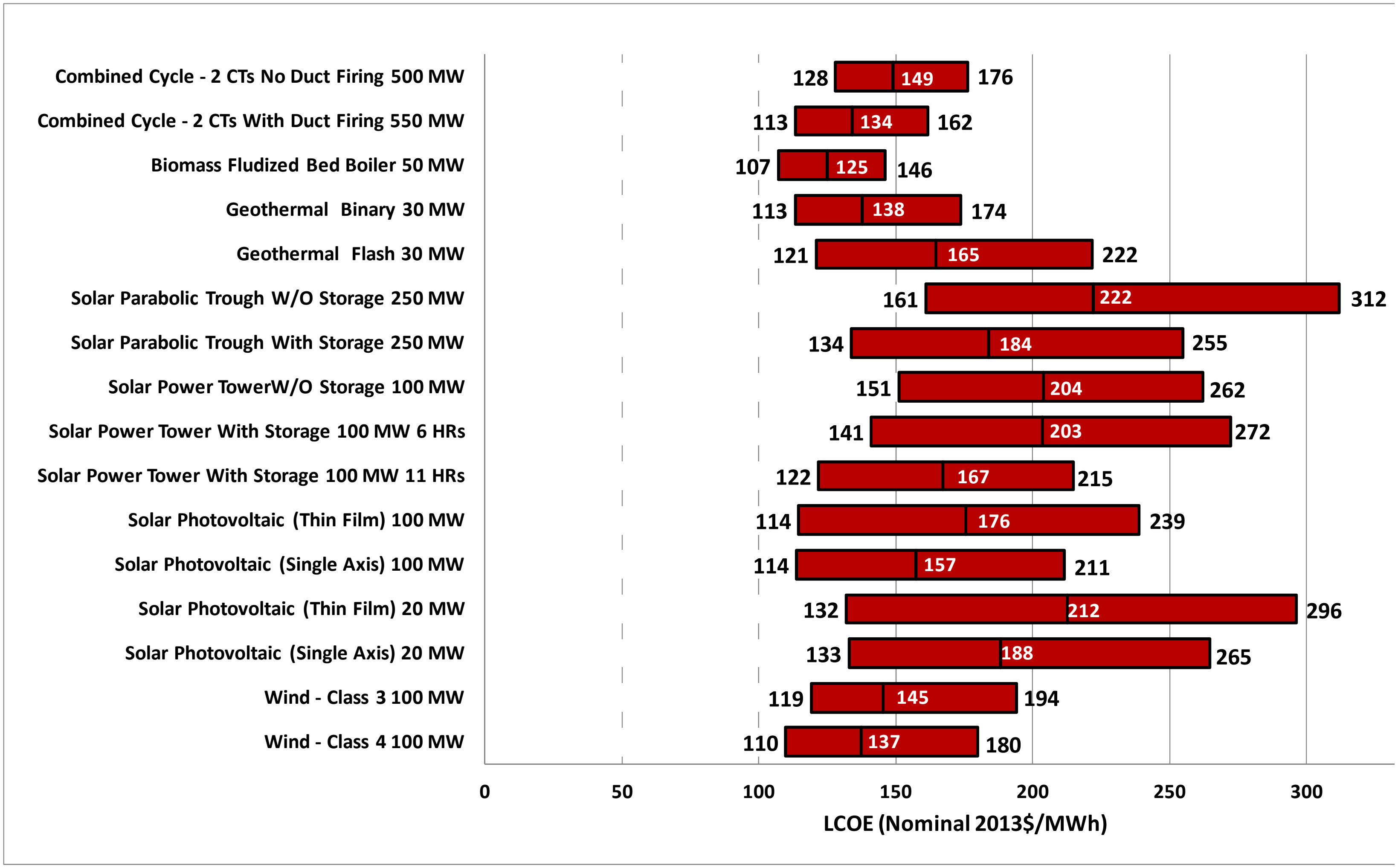
This, too, is merely a step forward. Although this proposed ACAT range of costs is much more reasonable than those proposed using the deterministic method, it is not perfect in that probabilistic assessment relies on assumed distributions of the cost and plant assumptions. In the majority of cases, there are insufficient data to rigorously develop distributions based on historical data; instead, the ranges must be set subjectively through professional judgment. In fact, developing objective probability distributions are impossible for several of these variables. In addition, there is always the uncertainty of any estimated assumption, which means it is never going to be perfect.

Figure 55: Deterministic Levelized Cost Range—Start Year=2013



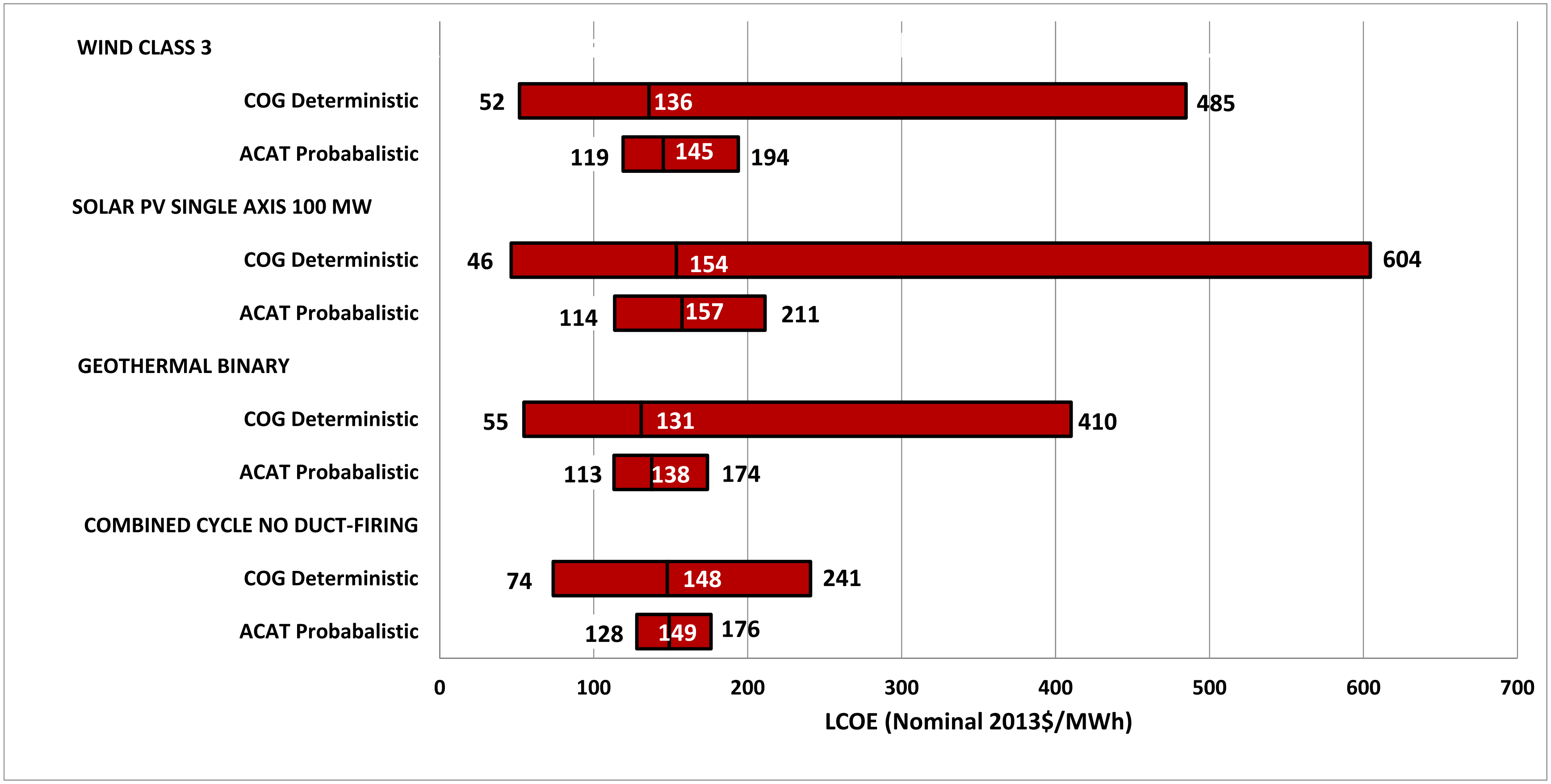
Source: Energy Commission.

Figure 56: Levelized Cost Range Using ACAT Probabilistic Method—Start Year=2013



Source: Energy Commission.

Figure 57: Comparing Levelized Cost of Energy Ranges—ACAT Probabilistic vs. Cost of Generation Deterministic



Source: Energy Commission.

Range of Levelized Costs—Busbar Costs

In the above probabilistic LCOE study—as well as most of this report—LCOE values are reported at the delivery point (the load center). Therefore, the LCOE includes the capital cost of the technology (including interconnection equipment costs and losses) and backbone transmission costs (losses and California ISO charges). This is generally appropriate in that it captures the true total LCOE of a project.

However, many studies report LCOE at the plant busbar level and do not include transmission costs, which produce a significantly lower LCOE. Many do not even include interconnection cost (tie line from the plant to the existing transmission). This lack of specificity makes it extremely difficult to compare against these values and generally causes confusion and compromises other studies.

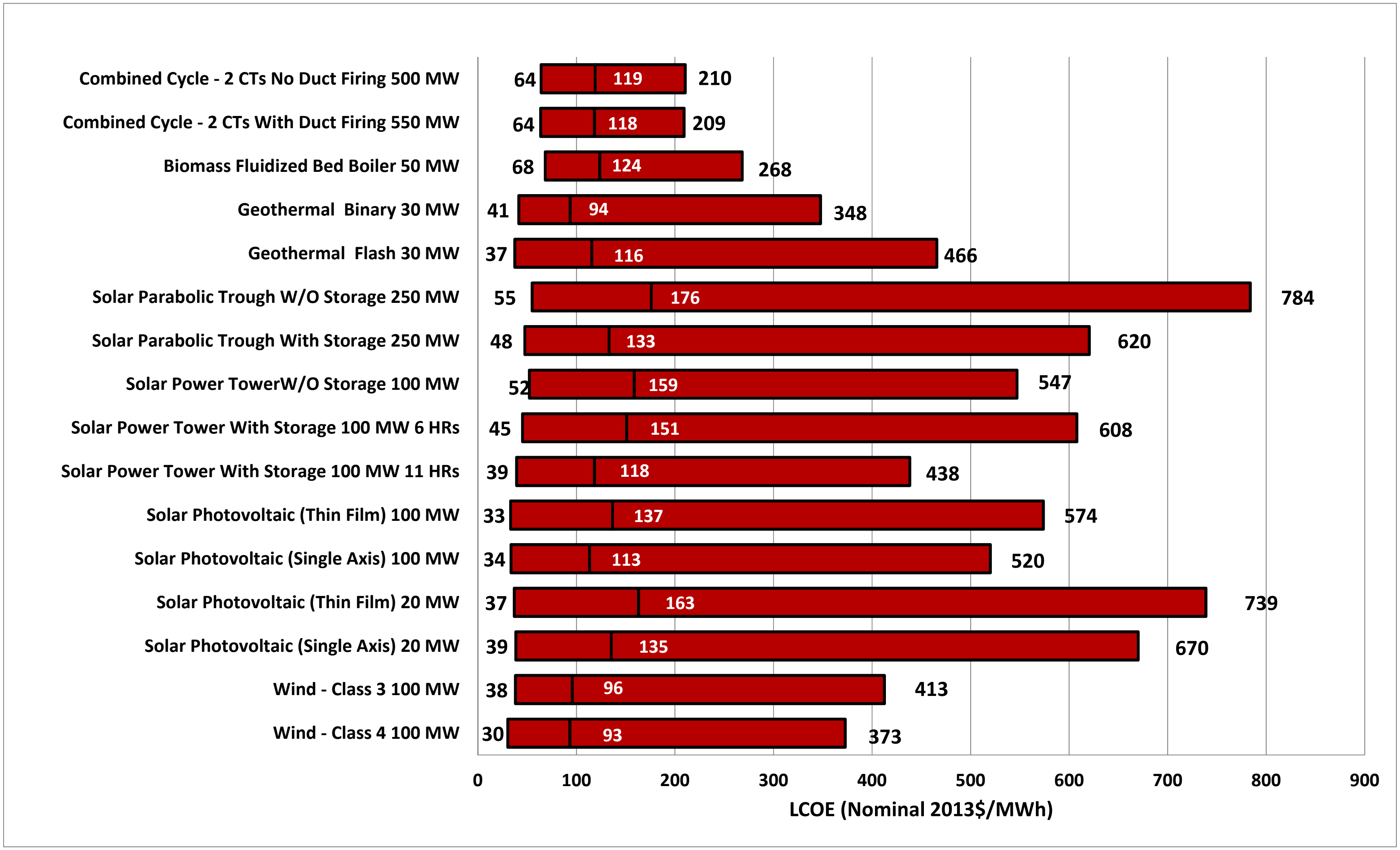
For these reasons, staff is also reporting LCOE probabilistic data at the busbar to compare against these cases in **Figure 56**. Staff's LCOE includes the cost of the interconnection equipment, but not the interconnection losses. This is because it is extremely difficult to break out the interconnection costs in studies, even though staff knows it is included. It should be kept in mind, therefore, that staff values would be significantly lower if staff were able to report LCOE without interconnection costs.

Figure 58 summarizes the deterministic LCOEs at the plant busbar level. **Figure 59** summarizes the corresponding probabilistic LCOEs generated by ACAT at the busbar level.

Figure 60 compares the busbar levelized costs to the previous delivery point LCOEs. Note that these are large differences that in no way can be ignored, as most studies are reporting busbar costs, not delivery point LCOEs. For example, whereas the low end of the delivery point LCOE for solar PV single-axis 100 MW is reported as $114 per MWh, the low busbar LCOE is only $74 per MWh

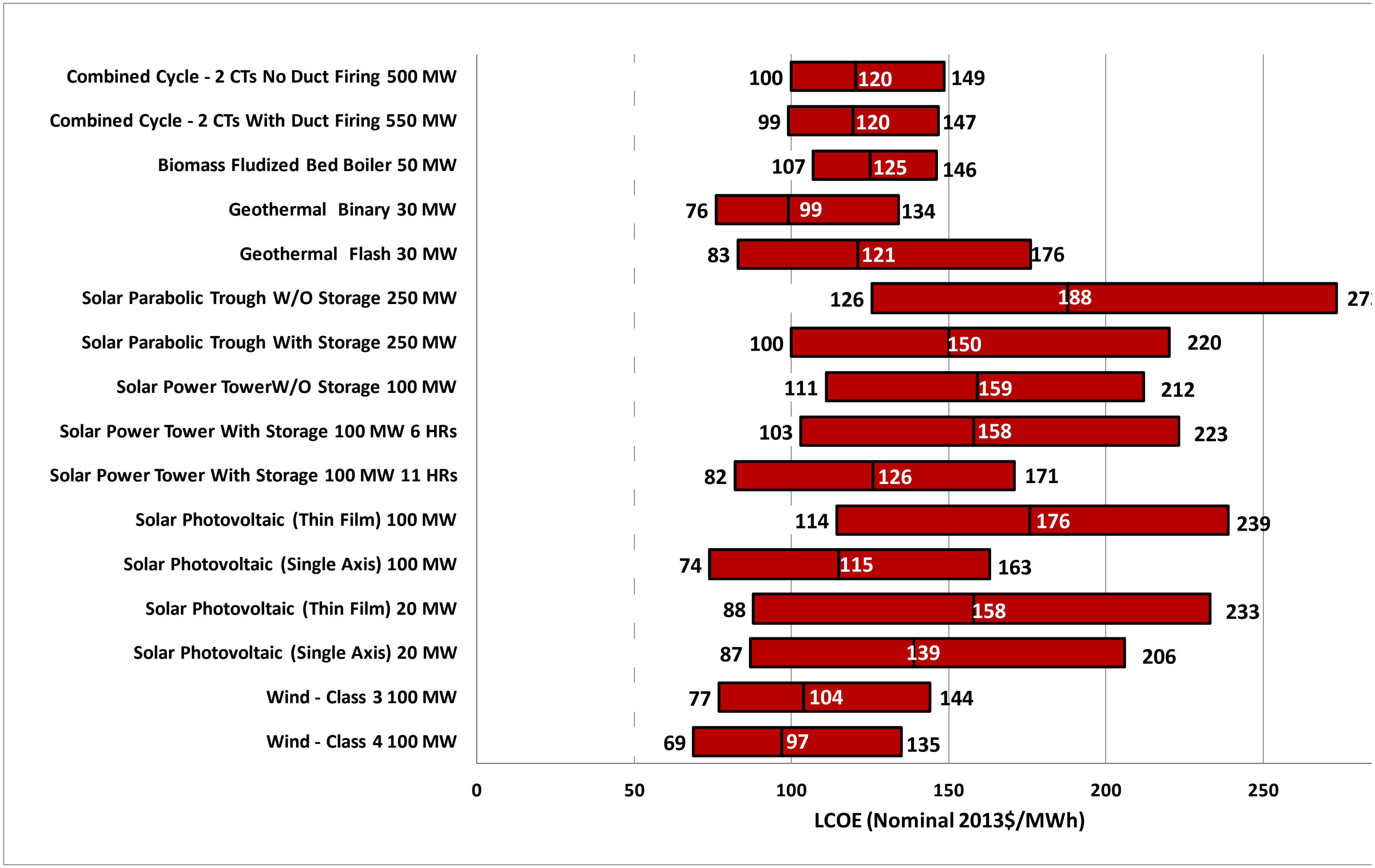
All this points out that levelized costs need to be reported in the context of good documentation if they are to be of any real value. This is not a standard that is always adhered to in the various LCOE studies and the supporting assumptions reported in the literature.

Figure 58: Deterministic Levelized Cost Range—Busbar—Start Year=2013



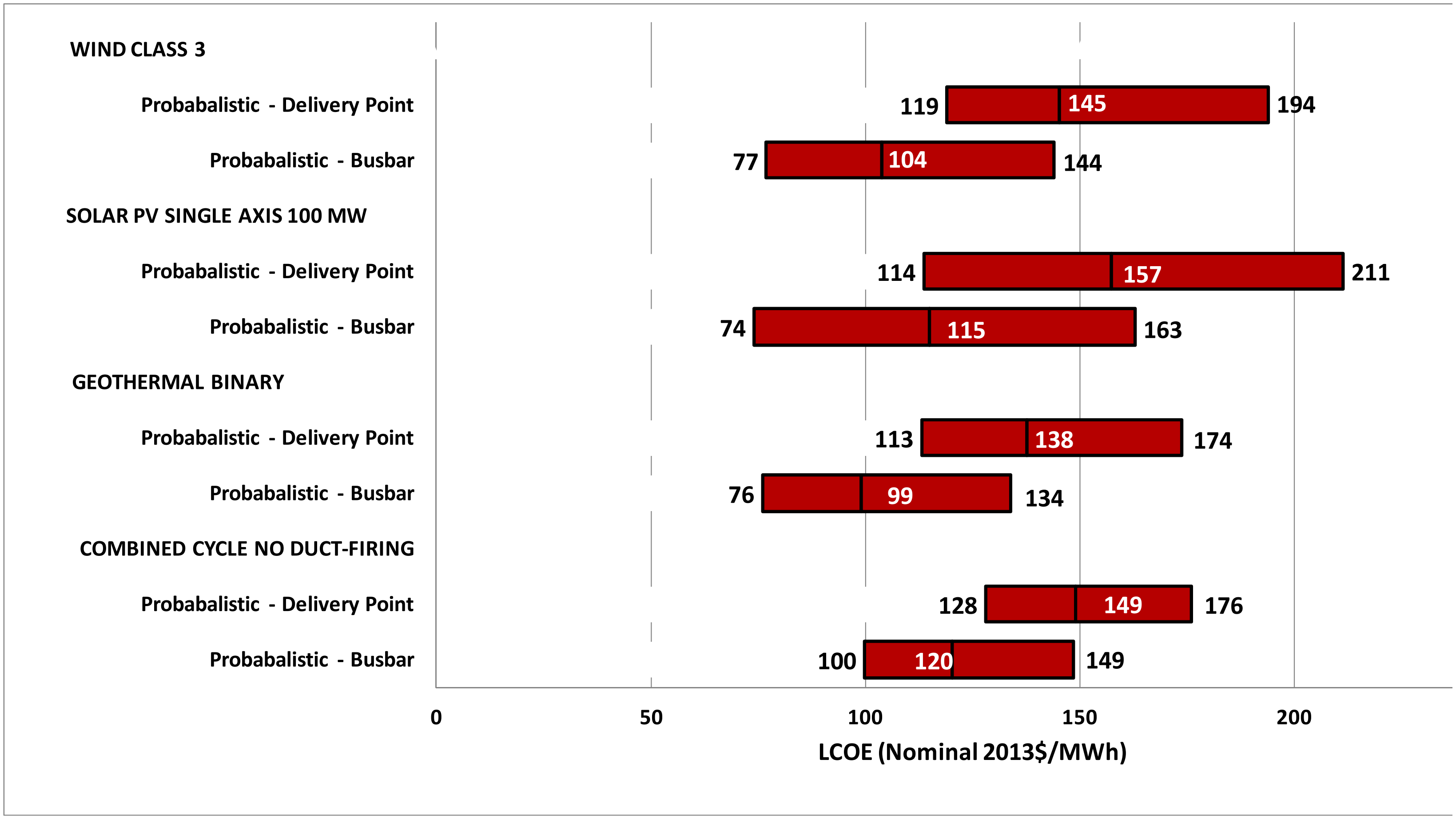
Source: Energy Commission.

Figure 59: Levelized Cost Range Using ACAT Probabilistic Method—Busbar—Start Year=2013



Source: Energy Commission.

Figure 60: Comparison of Busbar Levelized Cost of Energy to Delivery Point Levelized Cost of Energy—Start Year=2013



Source: Energy Commission.

Levelized Cost of Net Qualifying Capacity

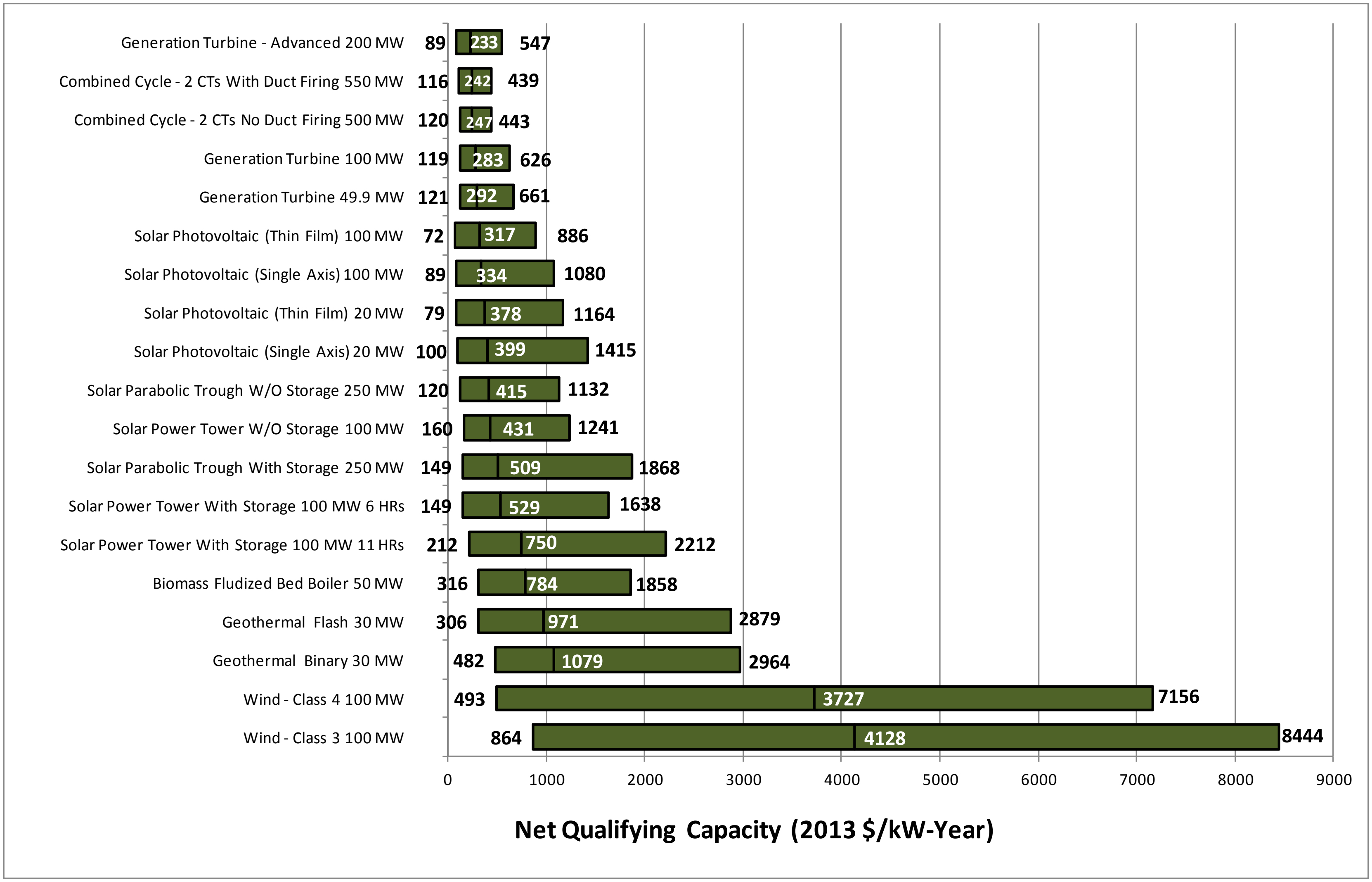
As mentioned earlier in the chapter, LCOE cost is only one factor taken into consideration by utilities and regulators in deciding what types and locations of new generation resources should be built. In fact, it is not the only cost factor. The LCOE values in **Figure 56** are based on the cost per unit of energy produced. This tends to make resources with high energy production look attractive. However, the electricity system in California needs more than energy. The capacity of a generation resource must be considered when electricity system planners attempt to address growth in peak demand. Peak demand is the maximum amount of demand served by the electric grid during an hour of the day.

The capacity value of resources is a key metric in ensuring that the electric system has sufficient resources during those peak hours of the day. The CPUC, working in consultation with the California ISO and the Energy Commission, establishes resource adequacy (RA) under Rulemaking R.08-10-025. As a part of this effort, the CPUC determines the net qualifying capacity (NQC) for California resources serving the California ISO control area. NQC is the amount of capacity for each generation plant that can be relied upon during the typical peak demand hour. This means that resources that are typically generating near full power during 4:00 p.m. to 6:00 p.m. in the summer have a higher percentage of their full capacity designated as NQC.

To illustrate the limitations of using energy as the sole metric when conducting resource planning, **Figure 61** presents estimates of cost /kW-yr. of NQC for the different technologies based on the fixed cost portion of LCOE sorted by mid case values lowest to highest.

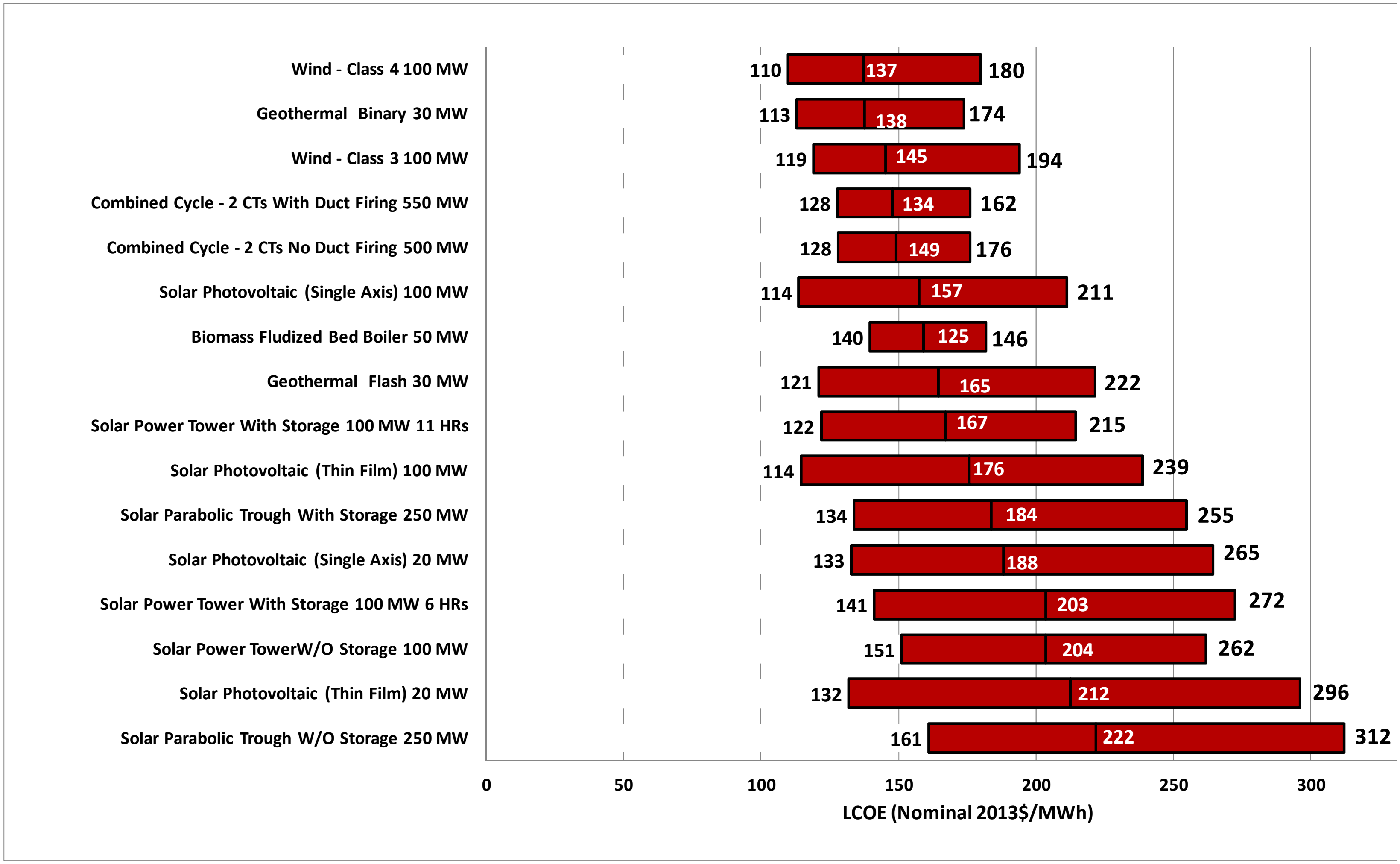
Figure 62 as compared to **Figure 61** shows the differences in relative cost ranking of technologies when the perspective is changed from cost per unit energy to cost per unit capacity. Wind technologies move from being the lowest estimated levelized cost per unit energy to the highest levelized cost per unit of capacity.

Figure 61: Merchant Levelized Cost of Net Qualifying Capacity—Sorted by Mid Case



Source: Energy Commission.

Figure 62: Merchant Levelized Cost of Energy Ranked by Mid Case Probabilistic



Source: Energy Commission.

Conclusion and Next Steps

The primary goal of this project is to produce clear, understandable estimates of the costs associated with building and operating new power plants in California over the next decade. Any attempt to do so faces several challenges and limitations since the marketplace for new generation resources is rapidly evolving through the improvement of renewable technologies and changing relationships between the consumer and energy producer. For example, consumers who have traditionally relied exclusively on the utility for their electricity needs are now installing small on-site generation resources behind the meter. This is dramatically changing the overall electricity consumption patterns seen by the utility and, as a result, changing the operational characteristics that may be of value to the utility or grid operators in the foreseeable future.

Throughout this work, several key insights that may be of interest to stakeholders and policy makers presented themselves. In addition, the limitations of the project were often highlighted as stakeholders raised excellent questions and issues that unfortunately fell outside the bounds of time and resources allocated to this project. This section summarizes both the key insights as well as the areas for further investigation highlighted throughout the process. Stakeholders are invited to weigh in through written comments to this draft report and share their thoughts on how the content might be improved, as well as what new work should be explored next in understanding the cost trends of new generation.

Key Insights

The insights derived from this work are as follows:

- The decline of technology costs associated with solar PV is expected to continue as manufacturers refine production processes and find low-cost solutions to problems.
- Improved quality of data led to an upward revision of the costs of all nonsolar renewable technologies from those reported in 2009, with geothermal flash being dramatically higher. This represents a calibration of data rather than a real-world jump in costs. The revision confirms the need for skepticism about how accurate any single-point cost estimate is. Ranges of costs are a far more realistic approach to understanding what may be seen in the marketplace.
- Long-term expectations of low natural gas prices are likely to make gas-fired power technologies, such as CTs and CCs, attractive to investors in the near term. This same trend may challenge the ability of renewable technologies to compete on a cost basis with fossil technologies.
- Despite their higher levelized costs, CT power plants, based on aeroderivative designs, are being built almost exclusively in California due to operational profiles that are better suited to the highly variable load produced by large amount of renewable resources.

- The cost of GHG emissions credits will likely be a major cost factor in future development of natural gas-fired resources.
- The steadily increasing wheeling access charges the California ISO expects to put in place over the next decade represent a growing, significant cost to renewable developers who find their best renewable resources in locations that are distant from demand.

Areas for Further Investigation

The project scope was ambitious. However, the list of questions of interest to stakeholders and policy makers is far larger than could be encompassed in this report. The following areas related to the cost of new generation in California were identified as being important and/or interesting to investigate in the future:

- Renewable resources can present challenges to utilities that must meet demand regardless of the availability of any individual response. An estimate of the cost of integration from the utility perspective was proposed by several stakeholders.
- As the renewable resource fleet in California ages, some of it will have to be upgraded or replaced. How might the replacement of aging renewable resources with newer technologies affect the expected costs of those projects?
- Many areas of California are constrained with regard to the suitable land available to host a gas-fired power plant. What is the levelized cost of a repower project for a CC or CT on an existing site compared to the same development on a new (or "greenfield") site?
- The developer of a new power plant is not strictly reliant on a single contract to provide the stream of income necessary to recover their costs. Markets such as those for ancillary services and resource adequacy can provide additional streams, changing the amount a developer might be willing to accept for a project. A study laying out these options and how they might affect the market for contracts could be of value to policy makers.
- How should the cost of storage technologies be calculated given their reliance on external generation sources for power? How might storage be most cost-effectively bundled with renewable generation to serve load in California?
- At what stage of market development should developing technologies be included in future iterations of this report?
- Would the stakeholders interests be better served by producing several smaller technology-specific reports rather than a single integrated volume?
- Differences exist in the reported capacity factors between CTs owned and operated by POUs, IOUs, and merchant operators. These differences result in significant cost implications among the three classes. The reason for the empirical difference is not clear and bears further investigation.

Stakeholders are invited and encouraged to pose their own responses to these questions as well as pose additional questions that should be explored in the future. All input will be reviewed and addressed in the final version of this report.

ACRONYMS

ACRONYM	DEFINITION
$/kWh	Dollars per kilowatt hour
$/kW-yr	Dollars per kilowatt year
$/MWh	Dollars per megawatt hour
$/MWh	Dollars per megawatt hour
/kW-year	Per kilowatt year
˚C	Celsius
˚F	Fahrenheit
AB 32	Assembly Bill 32
AC	Alternating current
ACAT	Analytica Cost of Generation Analysis Tool
AFUDC	Allowance for funds used during construction
APCD	San Joaquin Unified Air Pollution District
ARB	California Air Resources Board
ARRA	American Recovery and Reinvestment Act
BAA	Balancing authority area
BETC	Business Energy Tax Credits
BFB	Bubbling fluidized bed
BLM	Bureau of Land Management
BOE	Board of Equalization
Btu/kWh	British thermal units per kilowatt hour
Btu/scf	British thermal units per standard cubic foot
California Energy Commission	Energy Commission
California ISO	California Independent System Operator
CC	Combined cycle
CCTP	California Cap and Trade Program
CF	Capacity factor
CFB	Circulating fluidized bed
CO_{2e}	Carbon dioxide equivalent
COG	Cost of Generation
COG Model	Cost of Generation Model
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CREST	Cost of Renewable Spreadsheet Tool
CSP	Concentrated solar power
CT	Combustion turbine
DC	Direct current
DG	Distributed generation
DSCR	Debt service recovery ratios
DSM	Demand-side management
EERE	Energy efficiency and renewable energy
EFOR	Equivalent forced outage rates
EFORd	Equivalent forced outage rates demand
EMAC	Emission Market Assessment Committee
EPAct	Federal Energy Policy Acts
EPIA	European Photovoltaic Industry Association

ACRONYM	DEFINITION
EPRI	Electric Power Research Institute
ERC	Emission Reduction Credit
FERC	Federal Energy Regulatory Commission
FOR	Forced outage rates
GADS	Generating Availability Data System
GETEM	Geothermal Electricity Technology Evaluation Model
GHG	Greenhouse gas
HHV	Higher heating value
HRSG	Heat recovery steam generator
IEPR	*Integrated Energy Policy Report*
IOU	Investor-owned utility
IPP	Independent power producer
ITC	Investment Tax Credit
kW	Kilowatt
LADWP	Los Angeles Department of Water & Power
LBNL	Lawrence Berkeley National Laboratory
Lbs/MMBtu	Pounds per million British thermal units
Lbs/MWh	Pounds per megawatt hour
LCOE	Levelized cost of energy
LIBOR	London Interbank Overnight Rate
LTPP	Long-Term Procurement Proceeding
MRW	MRW Consulting
MSG	Market Simulation Group
MW	Megawatt
MWh	Megawatt hour
NAMGas	North American Gas-Trade Model
NCF	Net capacity factor
NO_x	Oxides of nitrogen
NQC	Net qualifying capacity
NREL	National Renewable Energy Laboratory
NSPS	New source performance standards
NSR	New Source Review
O&M	Operations and maintenance
ODC	Other direct costs
PIER	Public Interest Energy Research
PM	Particulate matter
PPA	Power purchase agreement
PTC	Production tax credit
PURPA	Public Utility Regulatory Policy Act
PV	Photovoltaic
QFER	*Quarterly Fuels and Energy Report*
RA	Resource adequacy
RAM	Renewable Auction Mechanism
RECLAIM	Regional Clean Air Incentives Market
REPI	Renewable Energy Production Incentives
REPTC	Renewable Energy Production Tax Credits
ROG	Reactive organic gases

ACRONYM	DEFINITION
RPS	Renewables Portfolio Standard
RTC	RECLAIM Trading Credits
SC	Simple cycle
SCE	Southern California Edison
SCQAMD	South Coast Air Management District
SEGS	Solar energy generating systems
SOF	Scheduled outage factor
SONGS	San Onofre Nuclear Generating Station
SO_X	Oxides of sulphur
TDMA	Tax deduction for manufacturing activities
TES	Thermal energy storage
U.S. DOE	United States Department of Energy
U.S. EIA	United States Energy Information Administration
VOC	Volatile organic compound
WACC	Weighted average cost of capital
WECC	Western Electricity Coordinating Council

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APPENDIX A: Effect of Tax Benefits

This attachment quantifies the effect of the tax benefits described in Chapter 2 on LCOE. All values are for merchant developers and the mid cost case. These are all point of delivery LCOEs, not busbar costs.

Figure A-1 shows the merchant mid cost LCOEs as reported throughout this report. These are the LCOE costs as borne by the developer, and are for technologies going online in the year 2013 presented in nominal 2013 $/MWh.

Figure A-2 shows the merchant mid cost LCOEs with the tax benefits included. The tax deduction for manufacturing activities (TDMA) is not shown as a separate entity because it too small in magnitude to be visible on the graph.

Figure A-3 shows the same data as **Figure A-2**, except that tax benefits have been collapsed into two categories:

- Tax Deductions: Accelerated depreciation, solar exemption from ad valorem, and TDMA
- Tax Credits: Business Energy Investment Tax Credit (ITC) and Renewable Energy Production Tax Credit (PTC).

Figure A-4 shows the same data as **Figure A-3** except that the gas-fired technologies have been removed in order to expand the figure and better identify the magnitudes of the renewable technologies.

Figure A-5 is the same as **Figure A-4** except that all the tax benefits have been collapsed into one value.

Figure A-6 is the comparable data to **Figure A-5** for the year 2024. Note that the tax benefits are much smaller because most tax benefits are assumed to have expired leaving only accelerated depreciation and TDMA.

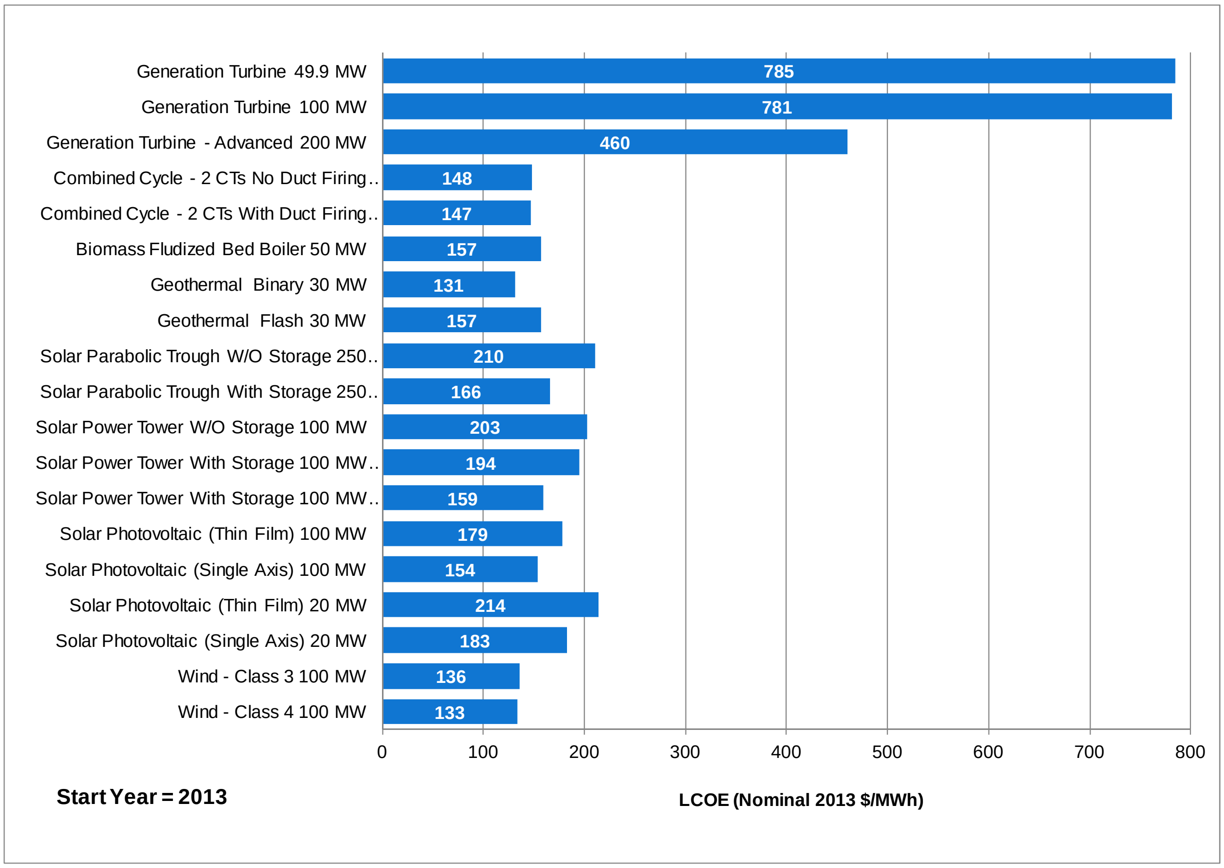
Figure A-7 is comparable to **Figure A-5** except that the gas-fired technologies have been included and the graph is sorted by total cost.

Although these are interesting and useful snap-shots in time, the LCOEs also need to be looked at in the longer time perspective. The remaining figures show the effect of tax benefits through the 2013 – 2024 time horizon. **Figure A-8** shows tax benefits for solar PV Single axis 100 MW technology, the lowest cost LCOE solar technology, and compares it to the 500 MW CC technology[70] as a reference point; it shows the solar technology with its present tax benefits[71] and then what it would be without any tax benefits whatsoever. Looking at the solar with benefits, you can see the see the property tax exclusion expiring in 2016, and then the tax credits expiring the following year. In the early years it depends on the many tax benefits to be competitive with the CC technology. Over the years, it becomes increasingly competitive until the end of the study period, when it passes the CC.

Figure A-9 shows the 20 MW solar PV thin-film technology, the solar technology with the highest LCOE. It shows similar characteristics to the 100 MW solar PV single-axis.

Figure A-10 – Figure A-14 show similar data for other technologies.

Figure A-1: Merchant Levelized Cost of Energy Values

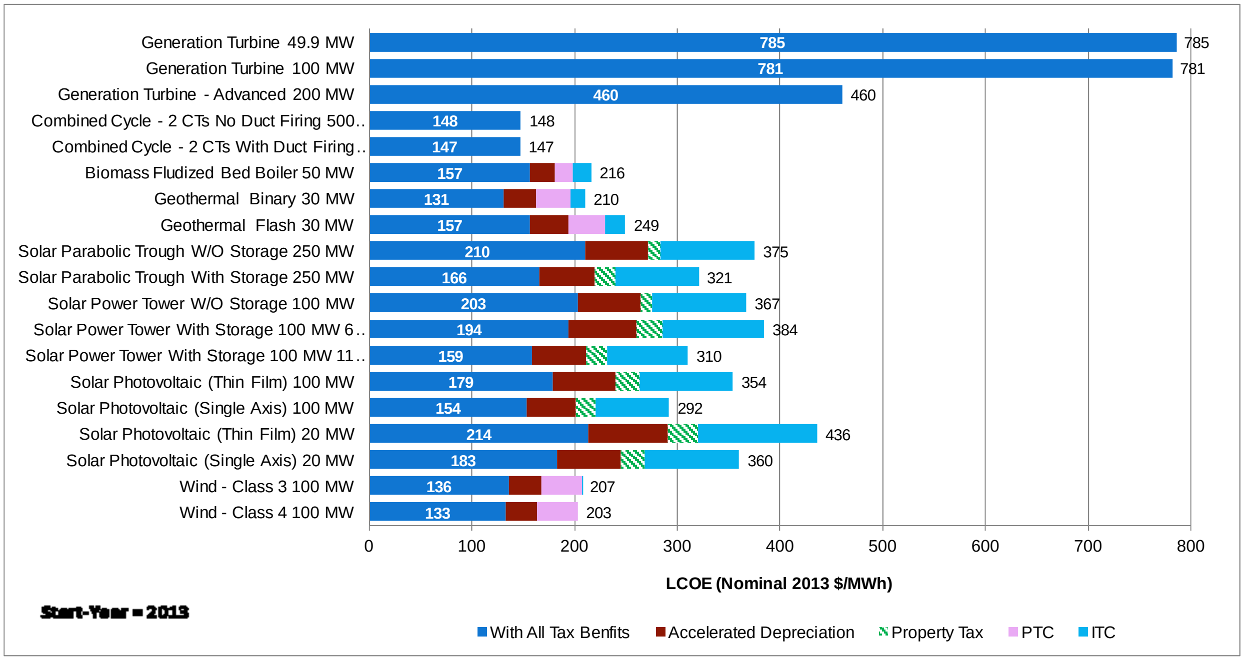


Source: Energy Commission.

70 The CC unit has only the miniscule TDMA tax benefit and would not be visible as a variation on this graph.

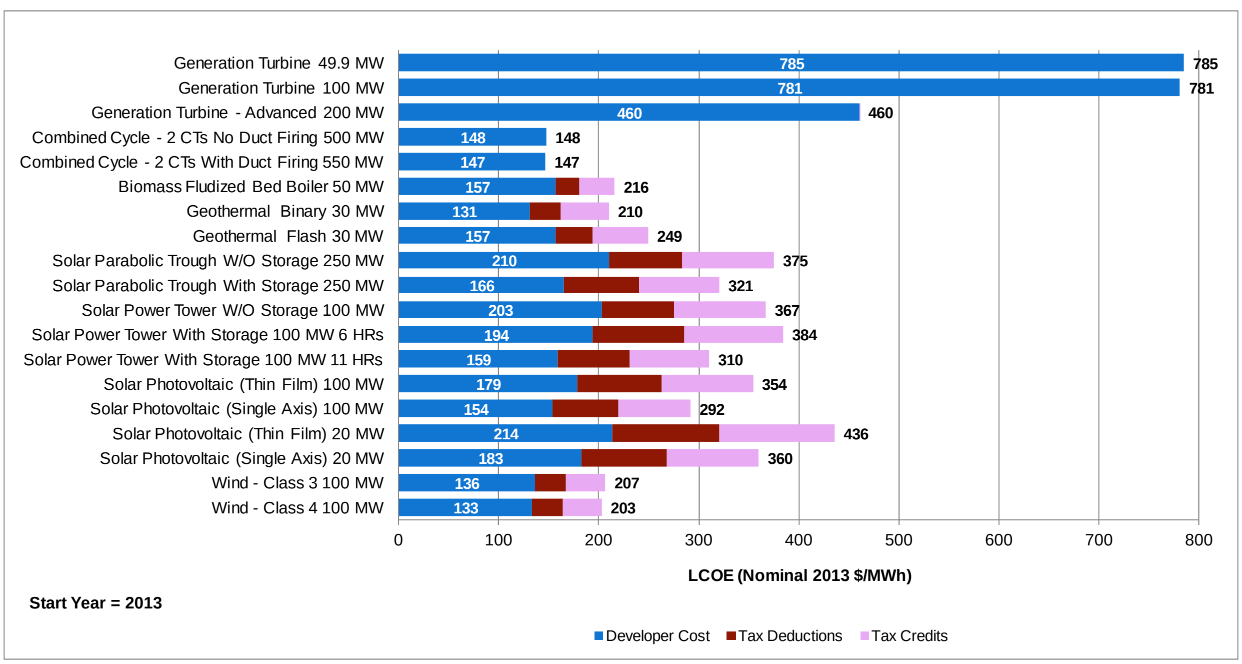
71 In 2017 it loses the ad valorem has expired, and in 2018 the ITC tax credit has expired; only accelerated depreciation and the miniscule TDMA continue.

Figure A-2: Merchant Levelized Cost of Energy Showing Both Developer Costs and Tax Benefits



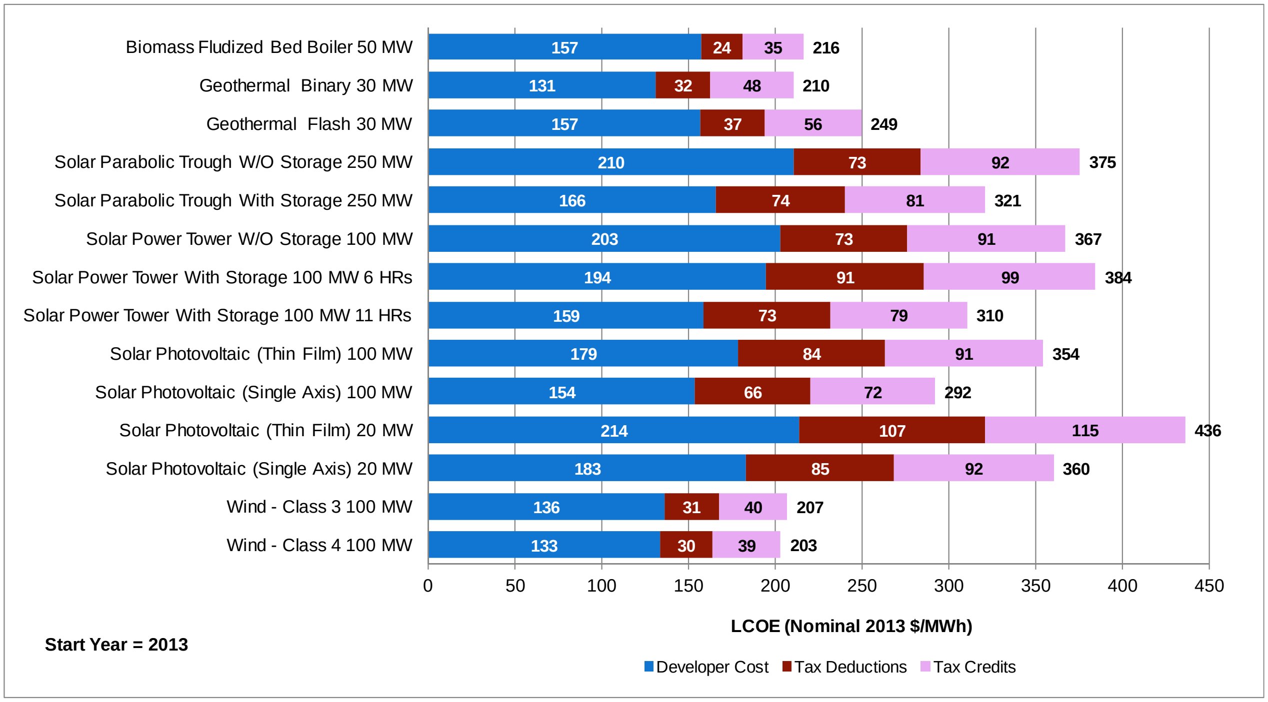
Source: Energy Commission.

Figure A-3: Merchant Tax Benefits Grouped Into the Two Main Categories: Tax Deductions and Tax Credits



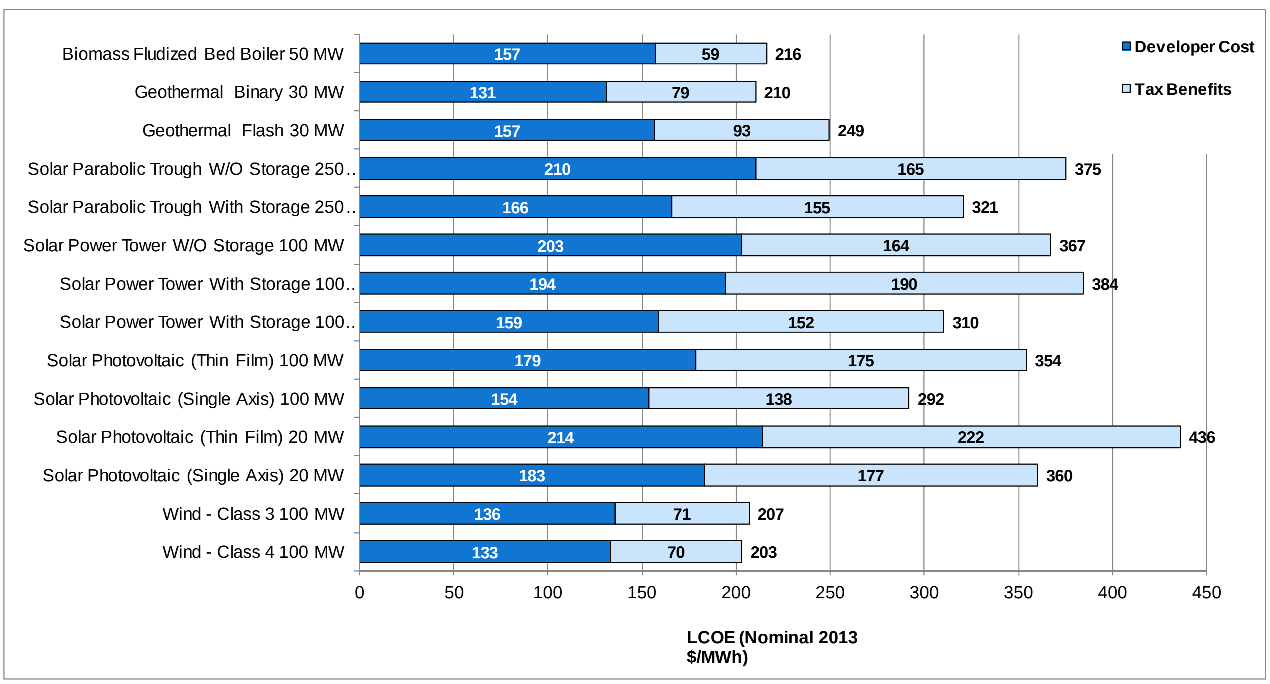
Source: Energy Commission.

Figure A-4: Same as Figure A-3 With Gas-Fired Units Removed



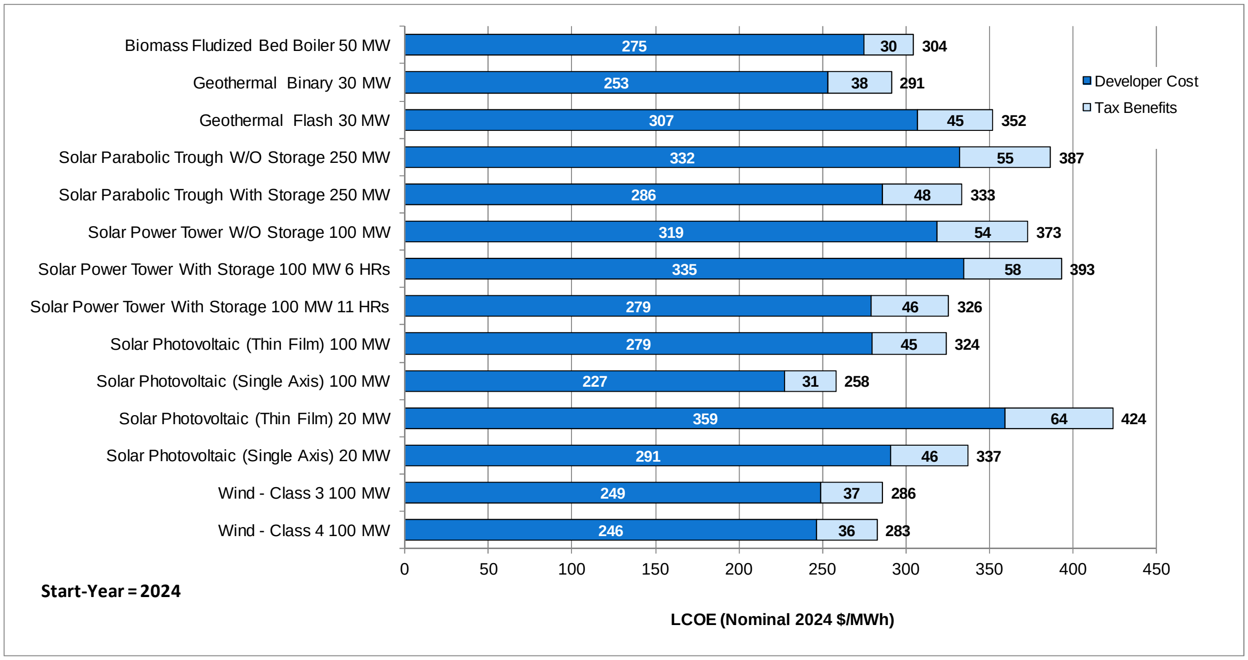
Source: Energy Commission.

Figure A-5: Developer Costs With Tax Benefit Costs Combined as One Value



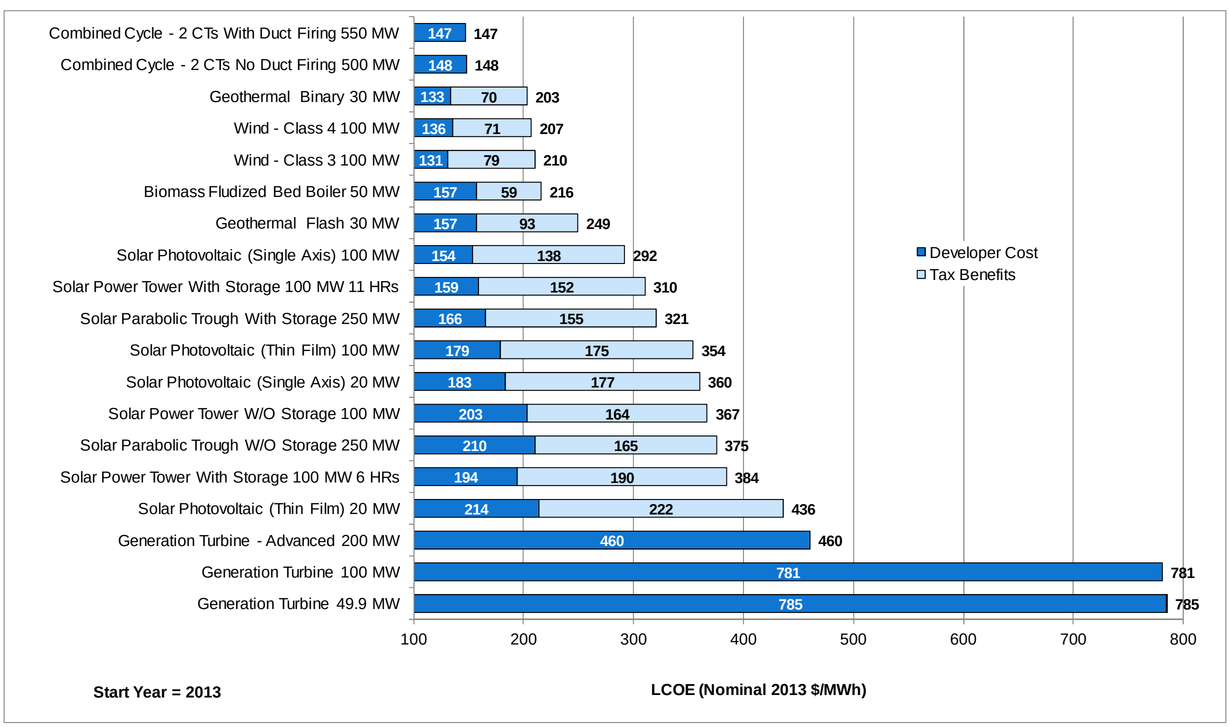
Source: Energy Commission.

Figure A-6: Merchant Developer Costs and Tax Benefit Costs Combined as One Value Start Year=2024



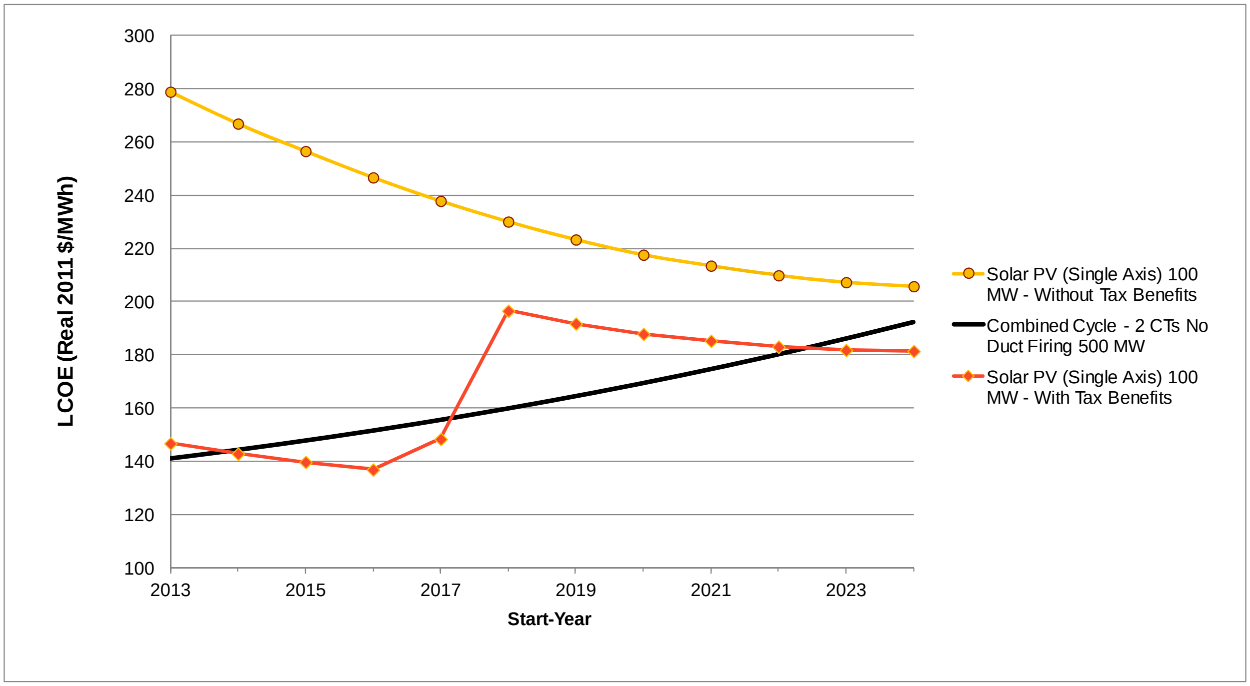
Source: Energy Commission.

Figure A-7: Sorting Costs Based on Total Cost



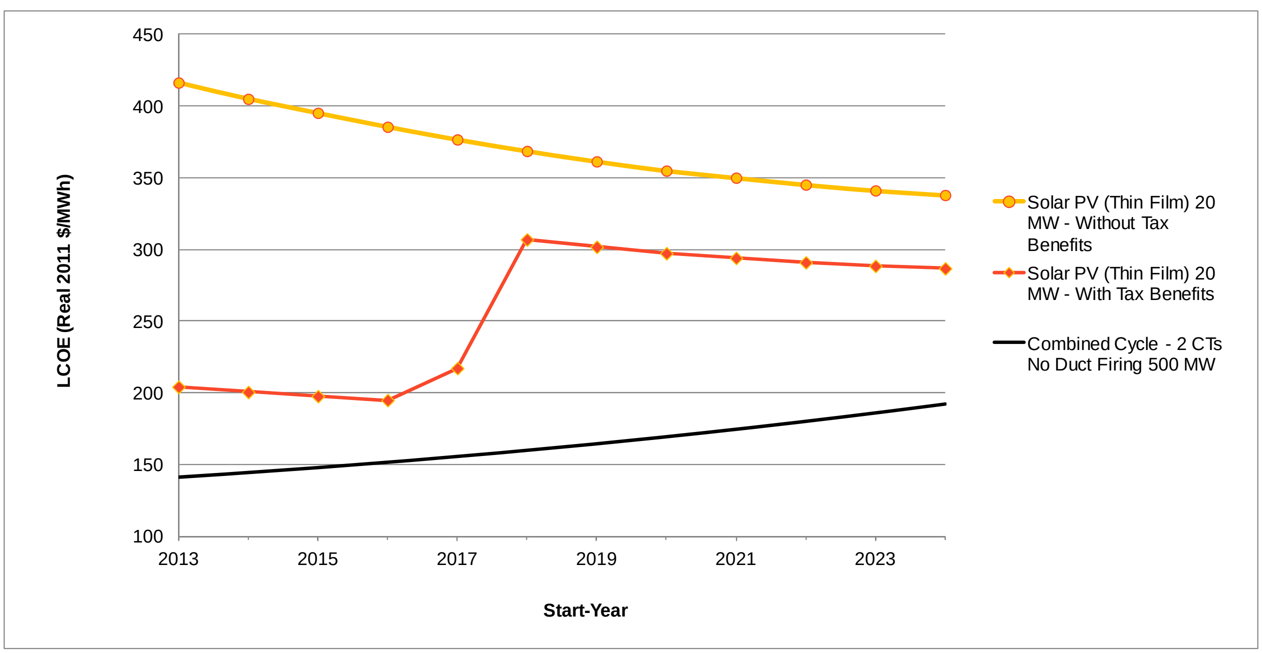
Source: Energy Commission.

Figure A-8: Effect of Tax Credits on Solar Photovoltaic Single Axis 100 MW vs. Combined Cycle



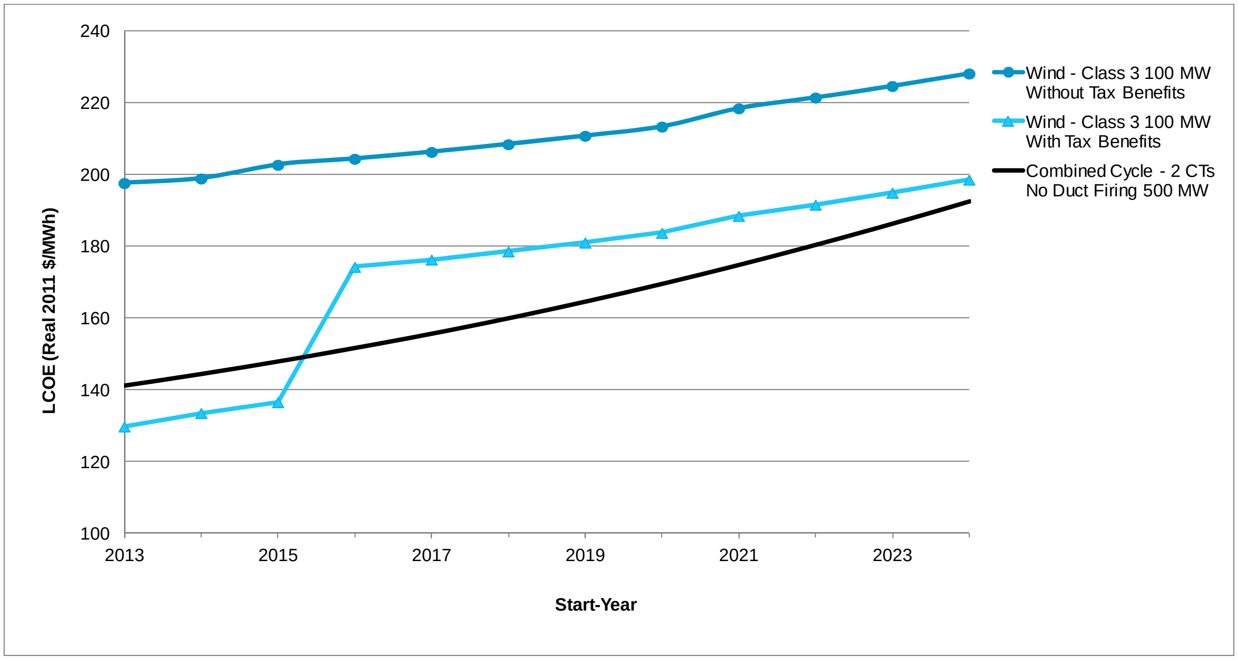
Source: Energy Commission.

Figure A-9: Effect of Tax Credits on Solar Photovoltaic Thin Film 20 Megawatt vs. Combined-Cycle



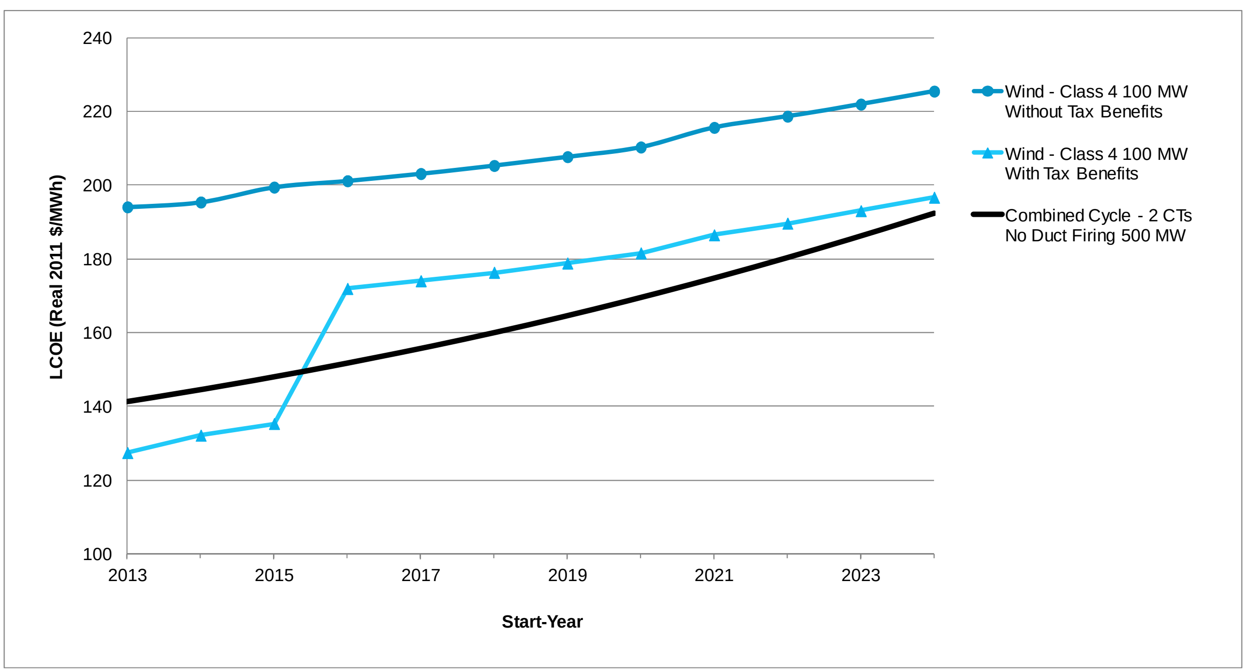
Source: Energy Commission.

Figure A-10: Effect of Tax Credits on Wind Class 3 vs. Combined Cycle



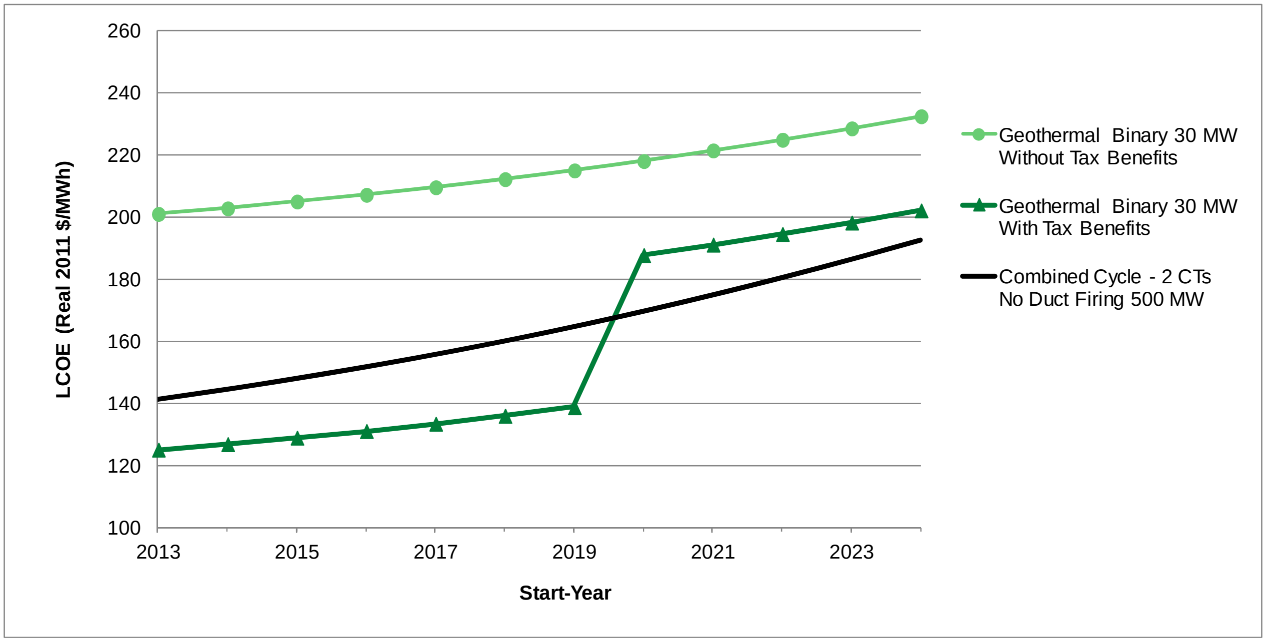
Source: Energy Commission.

Figure A-11: Effect of Tax Credits on Wind Class 4 vs. Combined Cycle



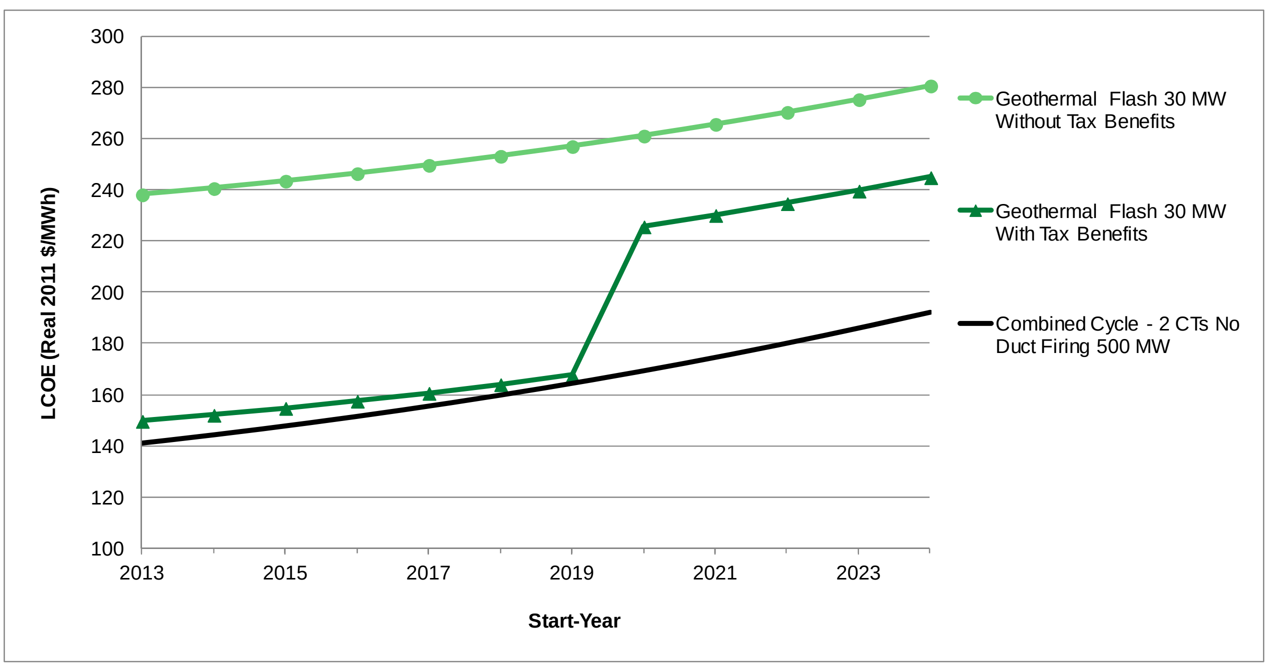
Source: Energy Commission.

Figure A-12: Effect of Tax Credits on Geothermal Binary vs. Combined Cycle



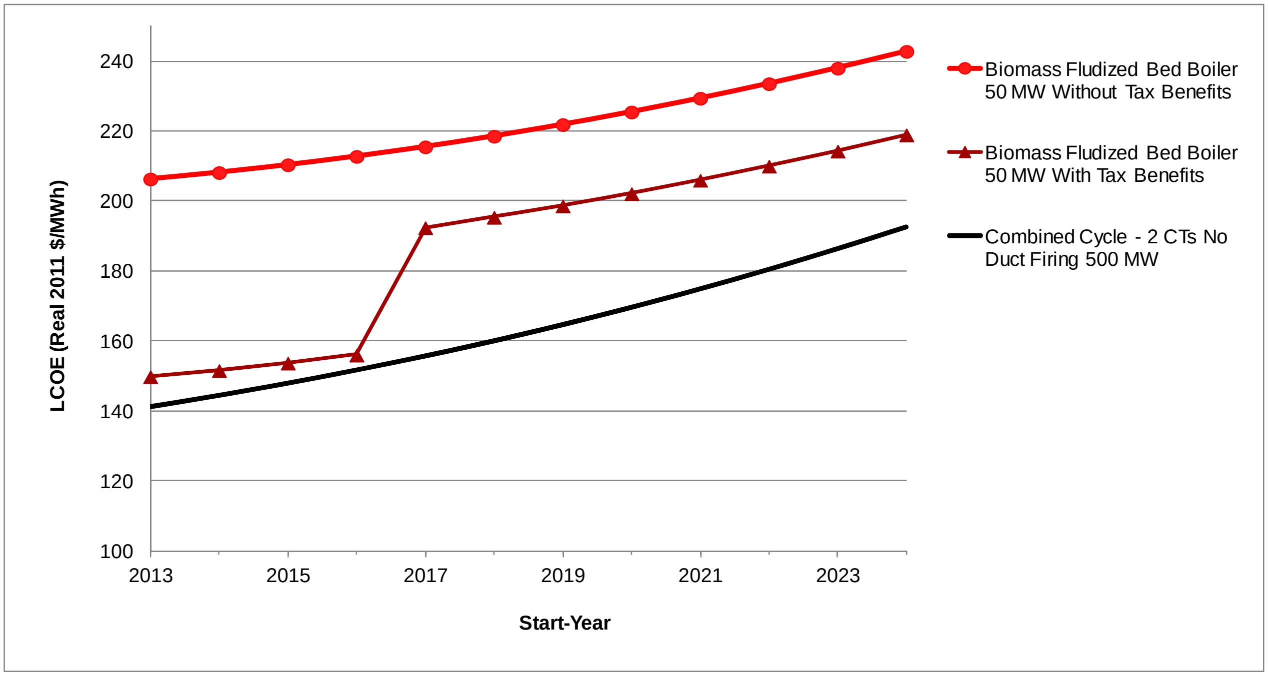
Source: Energy Commission.

Figure A-13: Effect of Tax Credits on Geothermal Flash vs. Combined Cycle



Source: Energy Commission.

Figure A-14: Effect of Tax Credits on Biomass vs. Combined Cycle



Source: Energy Commission.

APPENDIX B:
Gas-Fired Plants Technology Data

This appendix provides supporting information for the conventional and advanced gas-fired generation technology data assumptions provided in the *Cost of Generation Report*.

Plant Data

Plant data are the plant characteristics of the selected conventional gas-fired technologies selected for implementation in the COG Model. These data generally have been collected by Commission staff and consultants for the *IEPR*. Other sources are noted, where relevant.

Selection and Description of Technologies

Two categories of gas-fired technologies are included: CT and CC. The six gas turbine technology cases selected for inclusion in the COG Model have the following basic designs:

- Conventional CT—One LM6000 Gas Turbine
- Conventional CT—Two LM6000 Gas Turbines
- Advanced CT—Two LMS100 Gas Turbines
- Conventional CC—Two F-Class Turbines
- Conventional CC with Duct Burners—Two F-Class Turbines
- High-Efficiency CC—Two H Class Turbines

In each conventional case, staff has provided the most common gas turbine technologies currently used or proposed for use California, and these conventional technologies are likely to be proposed and built in California into the near future. The configuration/size for the conventional technology power plants was selected based on the general prevalence in the existing power plant fleet.

Gross Capacity (MW)

The gross capacity assumed for six gas turbine technologies selected for implementation into the COG Model are provided in **Table B-1**.

Table B-1: Gross Capacity Ratings for Typical Configurations

Technology Case	Gross Capacity
Conventional CT – One LM6000 Turbine	49.9 MW
Conventional CT – One LM6000 Turbine	100 MW
Advanced CT – Two LMS100 Turbines	200 MW
Conventional CC (no duct burners) – Two F-Class Turbines	500 MW
Conventional CC (duct burners) – Two F-Class Turbines	550 MW
High Efficiency CC – Two H-Class Turbines	800 MW

Source: Energy Commission.

The selected gross capacities assume that some form of air preconditioning is used to increase/stabilize the generating capacity while operating at high temperature and that the turbines are not significantly derated by operating at high elevation.

Combined-Cycle and Simple-Cycle Data Collection

The *2007 IEPR* analysis was the starting point for the analysis presented here. That analysis was updated to reflect either changed underlying costs (for example, inflation), or reanalysis of the original survey data to reflect further understanding gained since 2007. These costs were then supplemented with recent data obtained for the *2012 Integrated Energy Policy Report (2012 IEPR).* Fuel use and operational data for California facilities were updated as well from the Commission's *QFER* database.

For the *2012 IEPR*, as with preparing the *2007 IEPR*, staff again submitted to power plant developers/owners a data request for all the combined-2 cycle (but not cogeneration) and CT power plants that were certified by the Energy Commission starting in 1999 and on-line since 2001 (47 total power plants). These plants are summarized in **Table B-2**, together with the in-service year and county location. This table includes all surveyed power plants, including the seven power plants that did not respond to the 2012 data requests.

Table B-2: Surveyed Power Plants[1]

Combined Cycle Plants (25)			Simple Cycle Plants (22)		
Plant Name	**County**	**Operating**	**Plant Name**	**County**	**Operating**
Los Medanos	Contra Costa	2001	Wildflower Larkspur[3]	San Diego	2001
Sutter	Sutter	2001	Wildflower Indigo[3]	Riverside	2001
Delta	Contra Costa	2002	Drews Alliance[3]	San Bernardino	2001
Moss Landing	Monterey	2002	Century Alliance[3]	San Bernardino	2001
La Paloma	Kern	2003	Hanford[3]	Kings	2001
High Desert	San Bernardino	2003	Calpeak Escondido[3]	San Diego	2001
MID Woodland[2,3]	Stanislaus	2003	Calpeak Border[3]	San Diego	2001
Sunrise	Kern	2003	Gilroy[3]	Santa Clara	2002
Blythe I	Riverside	2003	King City[3]	Monterey	2002
Elk Hills	Kern	2003	Henrietta	Kings	2002
Von Raesfeld[2]	Santa Clara	2005	Los Esteros	Santa Clara	2003
Metcalf	Santa Clara	2005	Tracy Peaker	San Joaquin	2003
Magnolia[2]	Los Angeles	2005	Kings River Peaker[2,3]	Fresno	2005
Malburg[2]	Los Angeles	2005	Ripon[2]	San Joaquin	2006
Pastoria	Kern	2005	Riverside[2]	Riverside	2006/11
Mountainview[4]	San Bernardino	2006	Niland[2]	Imperial	2007
Palomar[4]	San Diego	2006	Panoche	Fresno	2009
Cosumnes	Sacramento	2006	Starwood-Midway	Fresno	2009
Walnut[2]	Stanislaus	2006	Orange Grove	San Diego	2010
Roseville[2]	Placer	2007	Canyon[2]	Orange	2011
Gateway[4]	Contra Costa	2009	Mariposa	Alameda	2012
Otay Mesa	San Diego	2009	Almond[2]	Stanislaus	2012
Inland Empire	Riverside	2009/10			
Colusa[4]	Colusa	2010			
Lodi[2]	San Joaquin	2012			

Source: Energy Commission.

Notes:

1 – Not all plants surveyed responded.

2 – Muni-owned facility

3 – Emergency Siting or SPPE Cases

4 – IOU-owned facility

Capital cost information was requested from all 47 plants, while operating costs were requested from plants that began regular operations on January 1, 2011 or earlier. The data requests for the combined cycle and CT units were divided into capital costs and operating and maintenance costs, as summarized in **Table B-3**.

Table B-3: Summary of Requested Data by Category

Capital Cost Parameters	Operating & Maintenance Cost Parameters
Gas Turbine and Combustor Make/Models	Total Annual Operating Costs
Steam Turbine Make/Model	Operating Hours
Total Capital Cost of Facility	Startup/Shutdown Hours
Gas Turbine Cost	Natural Gas Sources
Steam Turbine Cost	Duct Burner Natural Gas Use
Air Inlet Treatment Type and Cost	Natural Gas Average Annual Price Data
Cooling Tower/Air Cooled Condenser Cost	Water Supply Source/Cost/Consumption
Water Treatment Facilities Cost (ZLD?)	Labor (Staffing and Cost)
Site Footprint and Land Cost	Non-Fuel Annual Operating Costs (Consumables, regulatory etc.)
Total Construction Costs (Labor/Equipment/etc.)	Normal Annual Maintenance Costs, including Major Scheduled Overhaul Frequency/Cost
Cost of Site Preparation	Fixed versus Variable O&M Costs Definitions
Cost of Pipeline Linear Construction (natural gas, water, sewer)	
Cost of Transmission Linear Construction	
Cost of Licensing/Permitting Project	
Air Pollution Control Costs	
Cost of Air Quality Offsets	

Source: Energy Commission.

The information request for each power plant was tailored according to the design of that plant. For example, CT facilities did not include questions about steam turbines and duct burners. After receipt of the information requests responses, they were reviewed, and additional data or clarification of data was requested, as appropriate for each power plant, to complete and validate the information to the extent possible. As much of these data were gathered under confidentiality agreements, the details can be presented and discussed only in general, collective terms. Through spreadsheet analysis and comparison of relative costs as a function of various variables, it was possible to determine a suitable base cost plus adders to atypical configurations for the six categories described under Outage Rates.

Outage Rates

Outages are divided into two categories, those that are foreseen or scheduled, and those that are unforeseen or forced. Outages differ from curtailments in that curtailments are considered to be caused by either discretionary choices (for example, responses to economic signals) or by resource shortages (for example, lack of fuel or renewable energy sources). Curtailments are represented in different ways elsewhere in the model.

The SOF was derived from NERC GADS data for California generation resources:

- NERC GADS Vintage 2002 – 2007 California CCs 500 – 900 MW: 6.02 percent
- NERC GADS 2002 – 2007 California CTs 45 – 99 MW: 2.72 percent
- NERC GADS 2002 – 2007 California CTs 100 and greater: 3.18 percent

Likewise, effective forced outage rates (EFOR and EFORd) were collected for California Generation Resources. The EFOR is measured against the period when the unit is operating, that is, it excludes non-operational hours due to curtailments when developing the rate. This is particularly important for low capacity factor resources such as CT units. The EFORd values are used in the model.

- NERC GADS Vintage 2002 – 2007 California CCs 500 – 900 MW EFORd: 3.5 percent (2.24 percent)
- NERC GADS 2002 – 2007 California CTs 45 – 99 MW EFORd: 19.19 percent (5.65 percent)
- NERC GADS 2002 – 2007 California CTs 100 and greater: EFORd: 11.60 percent (4.13 percent)

Capacity Factor (Percentage)

The actual capacity factors (CFs) were determined for the existing California conventional LM6000 CT power plants and F-Class combined cycle power plants, based on the monthly QFER data from 2001 to 2011 for 25 CT facilities and 15 combined cycle facilities, and are provided in **Table B-4** and **Table B-5**. The capacity factors were derived using the following simple equation:

QFER net generation (MWh) /(facility generation capacity(MW) x hrs/year) = Capacity Factor

The combustion turbine units Anaheim, Glenarm, Grayson, Malaga, MID Ripon, Niland, and Riverside are POUs; and Barre, Center, Etiwanda, and Mira Loma are IOUs. The other power plants are all merchant facilities.

The CFs for the CC units are based on the annual average duct-fired capacity for each facility. Magnolia and Cosumnes are POUs, and Palomar and Mountainview are IOUs. The other power plants are all merchant facilities. The staff recommended CFs were determined by examination of historical capacity factor data in the Energy Commission's *QFER* database, as summarized in **Table B-4** and **Table B-5** as well as an examination of production cost simulations. **Table B-6** provides the mid case, high cost, and low cost capacity factors that were recommended for use in the COG Model.

Table B-4: Historical Capacity Factors for Simple-Cycle Turbines—2001 – 2011

		Capacity Factors											
Power Plant Name	**MW**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**Avg**
Windflower Larkspur	90		1.2%	4.0%	4.7%	3.8%	2.9%	6.0%	8.0%	7.6%	6.1%	4.3%	**4.4%**
Windflower Indigo	135		0.3%	5.9%	6.3%	4.7%	4.4%	6.9%	9.9%	5.7%	5.4%	3.4%	**4.8%**
Hanford	92	3.2%	4.9%	2.2%	1.2%	4.0%	2.6%	4.4%	5.7%	7.5%	2.4%	1.3%	**3.6%**
Calpeak Enterprise	50									3.8%	3.9%	9.5%	**5.7%**
Calpeak Border	50									4.2%	2.8%	6.6%	**4.5%**
Gilroy	141.9		4.9%	5.4%	5.6%	4.1%	4.2%	7.2%	7.8%	4.8%	2.5%	2.6%	**4.9%**
King City	47.3		3.9%	4.0%	5.0%	3.7%	3.8%	5.4%	5.8%	4.0%	1.8%	1.2%	**3.9%**
Henrietta	98		3.4%	2.3%	1.3%	1.5%	2.2%	2.4%	5.6%	6.4%	1.8%	1.9%	**2.9%**
Los Esteros	192			9.4%	16.1%	15.9%	4.6%	3.9%	4.8%	4.3%	2.4%	4.0%	**6.5%**
Kings River Peaker	97									19.2%	4.3%	7.5%	**10.4%**
Starwood-Midway	120									3.2%	3.8%	7.1%	**4.7%**
Niland Peaker	93								9.2%	5.6%	3.7%	4.7%	**5.8%**
MID Ripon	100						2.0%	3.1%	3.9%	4.9%	2.5%	4.2%	**3.4%**
Orange Grove	95										7.7%	4.7%	**6.2%**
Anaheim	49.27	21.9%	29.9%	25.4%	13.1%	12.3%	12.8%	11.4%	12.0%	15.8%	9.6%	6.3%	**15.5%**
Barre	49							2.1%	1.1%	0.7%	1.5%	1.5%	**1.4%**
Center	49							1.9%	1.1%	0.8%	1.3%	1.6%	**1.3%**
Creed	48.1			3.3%	2.4%	2.2%	2.7%	3.1%	3.8%	2.9%	1.8%	1.2%	**2.6%**
Etiwanda	49							1.6%	0.9%	0.3%	1.0%	0.6%	**0.9%**
Feather	48.1			3.7%	3.9%	3.0%	3.7%	6.1%	6.5%	6.5%	3.2%	3.1%	**4.4%**
Goose Haven	48.1			3.1%	2.6%	2.5%	2.8%	3.4%	3.7%	2.8%	1.7%	1.4%	**2.7%**
Lambie	48.1			3.2%	3.7%	3.6%	2.8%	3.5%	3.5%	3.3%	0.3%	1.3%	**2.8%**
Riverview	47.3			3.7%	4.1%	4.9%	4.3%	6.4%	7.1%	4.5%	2.0%	2.7%	**4.4%**
Wolfskill	48.1			3.8%	5.0%	3.7%	4.0%	4.9%	6.1%	4.6%	1.8%	2.3%	**4.0%**
Glenarm	94.6				5.4%	2.8%	5.0%	4.5%	4.1%	12.1%	9.5%	10.2%	**6.7%**
Malaga	98						7.6%	15.5%	17.6%	19.0%	4.3%	7.5%	**11.9%**
Mira Loma	49							1.7%	1.0%	0.5%	1.1%	1.2%	**1.1%**
Yuba City	48.1			4.3%	4.2%	8.2%	5.2%	5.9%	8.3%	7.4%	6.7%	3.5%	**6.0%**
Panoche Energy Center	400									4.5%	5.9%	9.0%	**6.5%**

Source: Energy Commission.

Table B-5: Historical Capacity Factors for Combined-Cycle Plants: 2001 – 2011

		Capacity Factors											
Power Plant Name	**MW**	**2001**	**2002**	**2003**	**2004**	**2005**	***2006***	***2007***	***2008***	**2009**	**2010**	**2011**	**Avg**
Moss Landing Power Plant	1060		30.1%	61.4%	58.8%	55.7%	61.2%	74.5%	65.9%	50.1%	40.0%	22.8%	52.0%
High Desert Power Project	830			35.3%	57.5%	55.6%	59.8%	67.6%	70.1%	63.4%	49.9%	28.4%	54.2%
Sutter	578	37.1%	84.1%	72.7%	77.8%	55.4%	48.0%	60.7%	66.0%	52.9%	41.4%	21.8%	56.2%
Los Medanos	540	25.2%	82.5%	74.9%	82.5%	82.9%	67.8%	80.4%	71.7%	77.5%	75.9%	61.5%	71.2%
La Paloma Generating	1124			34.6%	57.2%	46.4%	57.0%	62.6%	62.6%	64.4%	53.7%	13.3%	50.2%
Delta Energy Center	840		46.0%	80.1%	85.1%	81.6%	73.6%	80.2%	73.3%	76.3%	60.8%	63.4%	72.0%
Sunrise Power	585			37.8%	72.7%	76.9%	82.1%	83.6%	82.1%	81.8%	74.3%	31.0%	69.1%
Blythe Energy LLC	520				27.9%	20.4%	24.2%	27.1%	31.3%	31.5%	28.9%	28.3%	27.4%
Elk Hills Power, LLC	550				90.9%	81.8%	78.9%	85.2%	81.1%	78.8%	85.7%	73.9%	82.0%
Metcalf Energy Center	605					44.0%	54.3%	67.0%	74.3%	64.8%	59.1%	36.2%	57.1%
Pastoria	750					38.3%	70.6%	73.5%	74.6%	75.8%	66.0%	44.3%	63.3%
Otay Mesa	590									17.8%	49.3%	47.1%	38.1%
Mountainview	1056					1.7%	55.6%	72.0%	76.4%	65.7%	69.1%	52.8%	56.2%
Palomar	546						56.4%	76.3%	82.0%	75.2%	73.0%	49.2%	68.7%
Magnolia	328					14.2%	40.9%	64.8%	71.5%	71.4%	75.8%	46.2%	55.0%
Colusa	660										1.6%	45.2%	23.4%
Cosumnes	500						57.8%	85.0%	87.6%	78.5%	85.4%	76.9%	78.5%
Gateway	619									56.9%	70.8%	60.5%	62.7%
Inland Empire Energy Center	800									50.7%	77.0%	44.5%	57.4%

Source: Energy Commission.

Table B-6: Estimated Capacity Factors

Technology Case	Owner	Estimated Capacity Factor		
		Mid	High	Low
Conventional CT (both sizes)	Merchant	5.0%	2.5%	7.5%
	POU	7.5%	4.0%	14.%
	IOU	1.0%	1.0%	1.0%
Advanced CT	Merchant	7.5%	3.8%	11.3%
	POU	11.3%	6.0%	21.0%
	IOU	1.5%	1.5%	1.5%
Conventional CC	All Owners	57%	40%	71%
Conventional CC With Duct Burners	All Owners	57%	40%	71%
Advanced CC	All Owners	75%	55%	90%

Source: Energy Commission.

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

The increase in both CT and CC CF seen in the 2009 report in both the *QFER* and California ISO *Annual Report on Market Issues and Performance* has reversed in recent years. The recommended CFs for both types of plants are now lower than those used in the previous version of the COG Model. The advanced CT CFs were increased 50 percent above the assumed conventional CT CFs due to an assumption of increased use due to higher efficiency and the experience of the CTs in the database. The high-efficiency CC CFs are the same as in the 2009 report as that the experience of the High Desert plant has too many unique factors.

Plant-Side Losses (Percentage)

The plant-side losses were estimated by analyzing the *QFER* data for the same facilities analyzed for capacity factor and heat rate. The plant-side losses, determined through the difference in the reported gross vs. reported net generation, for the existing California conventional LM6000 CT power plants and F-Class CC power plants, based on the monthly *QFER* data from 2001 to 2008 for 25 CT facilities and 15 CC facilities. Based on this data, staff recommends the average cost, high cost, and low cost plant-side losses shown in **Table B-7**. Staff does not have data to suggest significantly different plant side loss factors for high–efficiency, combined-cycle facilities. The advanced CT facilities may have increased plant-side losses due to the power required for the turbine inter-cooling auxiliary facilities; however, staff has no specific information to obtain values different from those determined for the LM6000 gas turbine facilities, so the same range is recommended.

Table B-7: Summary of Recommended Plant-Side Losses (%)

Technology	Average	High	Low
All CC	2.9%	4.0%	2.0%
All CT	3.4%	4.2%	2.3%

Source: Energy Commission.

Heat Rate (Btu/kWh)

The actual heat rates, reported as HHV, determined for the existing California conventional LM6000 CT power plants and F-Class CC power plants , based on the monthly QFER data from 2001 to 2011 for 25 CT facilities and 15 CC facilities, are provided in
Table B-8 and **Table B-9.** The heat rates were derived using the following simple equation:

QFER heat input (MMBTU)/QFER net generation (kWh) = heat rate (Btu/kWh)

Table B-8: Simple-Cycle Facility Heat Rates (Btu/kWh, HHV)

		Heat Rates														
Power Plant Name	MW	2001	2002	2003	2004	2005	2006	2007	2008	2006	2007	2008	2009	2010	2011	Avg.
Windflower Larkspur	90		9,972	10,065	10,011	10,236	10,208	10,047	10,019	10,208	9,603	10,019	10,587	10,617	10,906	10,267
Windflower Indigo	135		10,091	10,236	10,061	10,137	10,154	9,934	10,000	10,154	9,934	10,000	10,459	10,628	10,803	10,250
Hanford	92	10,295	10,263	10,279	10,127	10,675	10,220	10,798	10,137	10,220	10,798	10,216	10,571	11,049	11,377	10,526
Calpeak Enterprise	50									10,901	10,780	10,743	10,847	10,894	10,874	10,872
Calpeak Border	50									10,916	10,844	10,772	10,973	10,841	10,768	10,861
Gilroy	141.9		10,187	10,341	10,029	9,970	10,102	10,073	10,125	10,102	11,681	10,022	10,329	10,717	11,609	10,348
King City	47.3		10,109	10,075	10,191	10,259	10,156	9,749	9,862	10,178	9,749	9,862	10,174	10,584	11,908	10,307
Henrietta	98		10,177	10,263	10,419	10,582	10,291	10,491	10,434	10,291	10,491	10,351	10,467	10,559	11,445	10,513
Los Esteros	192			10,345	10,275	10,404	10,480	10,309	10,346	10,480	10,309	10,346	10,197	10,599	10,121	10,342
Kings River Peaker	97									*	9,999	9,957	9,875	*	*	9,875
Starwood-Midway	120												10,775	10,879	10,842	10,832
Niland Peaker	93								10,257			10,031	10,040	10,034	10,263	10,149
MID Ripon	100						12,749	12,494	11,629	12,749	12,494	11,908	11,438	11,746	11,526	11,930
Orange Grove	95													9,775	10,781	10,278
Anaheim	49.27	9,178	9,208	9,325	9,744	10,170	10,213	9,499	9,424	10,213	9,499	9,424	9,358	9,486	9,534	9,558
Barre	49							11,744	12,057		11,744	12,059	12,618	11,590	11,366	11,875
Center	49							10,640	10,587		10,640	10,587	12,392	12,090	11,282	11,398
Creed	48.1			10,124	10,075	10,170	10,749	10,251	10,247	10,749	10,280	10,247	10,211	10,355	11,870	10,450
Etiwanda	49							11,051	12,062		10,760	12,105	14,643	12,254	12,829	12,568
Feather	48.1			9,578	9,748	9,448	9,487	10,308	10,258	9,487	10,349	10,258	10,433	10,930	11,271	10,162
Goose Haven	48.1			10,095	10,156	10,175	10,101	10,358	10,304	10,101	10,213	10,304	10,408	10,479	12,082	10,462
Lambie	48.1			9,953	10,089	10,169	10,317	10,145	10,152	10,317	10,139	8,949	10,468	10,185	11,941	10,380
Riverview	47.3			10,235	10,015	10,069	11,585	10,101	10,217	11,585	10,109	10,217	10,162	10,532	11,720	10,515
Wolfskill	48.1			9,942	10,150	10,297	10,154	10,319	10,208	10,154	10,331	10,208	10,284	10,364	11,635	10,373
Glenarm	94.6				11,969	12,434	10,226	10,439	10,604	8,956	10,500	10,679	11,760	11,293	11,843	11,321
Malaga	98						9,470	9,999	9,957	8,395	9,999	9,957	9,875	9,388	9,685	9,729
Mira Loma	49							11,138	11,992		11,138	11,992	13,560	12,120	11,743	12,111
Yuba City	48.1			9,710	9,549	9,452	9,338	10,071	10,051	9,338	10,088	10,051	10,482	10,492	11,103	10,028
Panoche Energy Center	400												10,189	9,863	9,602	9,884

Source: Energy Commission.

Table B-9: Combined-Cycle Facility Heat Rates (Btu/kWh, HHV)

		Heat Rates														
Power Plant Name	MW	2001	2002	2003	2004	2005	2006	2007	2008	2006	2007	2008	2009	2010	2011	Average
Moss Landing	1060		7,136	7,081	7,069	7,099	7,052	7,084	7,127	7,520	7,437	8,061	7,715	7,478	7,685	7,253
High Desert Power Project	830			7,321	7,348	7,356	7,343	7,047	7,055	7,343	7,083	7,055	7,232	6,837	7,438	7,220
Sutter	578	6,982	7,089	7,156	7,193	7,458	7,451	7,406	7,430	7,451	7,406	7,430	7,454	7,569	7,745	7,357
Los Medanos	540	6,947	7,090	7,239	7,191	7,290	7,337	7,210	7,218	7,337	7,210	7,288	7,184	7,168	7,256	7,194
La Paloma Generating	1124			7,198	7,133	7,234	7,167	7,166	7,172	7,167	7,165	7,172	7,184	7,213	7,272	7,193
Delta Energy Center	840		7,295	7,310	7,289	7,288	7,324	7,317	7,321	7,334	7,313	7,630	7,308	7,381	7,374	7,321
Sunrise Power	585			7,524	7,213	7,206	7,295	7,274	7,266	7,295	7,262	7,266	*	7,205	7,785	7,346
Blythe Energy LLC	520				7,416	7,419	7,436	7,825	7,808	7,436	7,825	7,833	7,399	7,329	7,397	7,504
Elk Hills Power, LLC	550				6,855	6,990	7,051	7,050	7,063	7,051	7,050	7,048	7,001	7,008	7,187	7,025
Metcalf Energy Center	605					7,028	7,048	7,042	6,884	7,048	7,040	6,893	7,172	7,304	7,478	7,137
Pastoria	750					7,230	7,050	7,062	7,032	7,050	7,187	7,025	6,951	7,026	7,206	7,079
Otay Mesa	590												6,968	6,960	7,290	7,072
Mountainview	1056					12,056	7,252	7,063	7,141	7,252	7,063	7,141	7,213	7,144	7,209	7,868
Palomar	546						7,069	7,038	6,959	7,069	7,042	6,959	7,016	6,973	7,135	7,032
Magnolia	328					7,614	7,340	7,456	7,233	7,340	7,456	7,233	7,200	7,199	7,115	7,308
Colusa	660													7,812	7,141	7,476
Cosumnes	500						7,198	7,042	7,047	7,198	7,042	7,047	7,026	6,952	7,027	7,049
Gateway	619												7,123	7,011	7,128	7,087
Inland Empire Energy Center	800												7,040	6,802	6,902	6,915

Source: Energy Commission.

Table B-10 provides the mid-cost, high-cost, and low-cost heat rates that were recommended for use in the COG Model. These values are higher (in other words, less efficient) than those reported by manufacturers and often used in other studies because these values include real-world operations, such as start-ups and load following.

Table B-10: Summary of Recommended Heat Rates (Btu/kWh, HHV)

Technology	Mid[a]	High[a]	Low[b]
Conventional CT[c]	10,586	11,892	9,982
Advanced CT	9,880	10200	9600
Conventional CC	7,250	7,480	7,030
Conventional CC W/ Duct Firing	7,250	7,480	7,030
High Efficiency CC	6,915	7,140	6,705

Source: Energy Commission.

Notes:

[a] Average and High cost recommended values are based on an analysis of average and high QFER heat rates and current turbine technology (for example the average heat rate for the conventional CT is based on new projects installing the next generation of LM6000 gas turbine). [b] Low cost recommended values are based on new and clean heat rates from turbine manufacturers. Average heat rates in COG 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.

Plant Cost Data

The plant costs data were obtained from the surveys as described in *Combined and Simple Cycle Data Collection* previously. In addition, costs are adjusted for the physical performance parameters and the instant costs are converted to installed costs using the financial parameters described in this report. The plant cost data are now identified for average, high-, and low-cost cases; therefore, the specificity of the design has been simplified. All projects are assumed to have SCR for control NO_x emissions and an oxidation catalyst for control of carbon monoxide emissions. Plant costs also include acquisition of ERCs, both for criteria pollutants in the capital costs, and for GHGs in the annual operational costs.

Combined-Cycle Capital Costs

Table B-11 provides the assumed design configuration of the three CC cases**.** The projects with announced instant or as-built installed cost data that were evaluated to determine the recommended average, high, and low capital cost values for the three CC cases are shown in **Table B-11**. Only one high-efficiency H-frame turbine project has been constructed and is in operation in California—Inland Empire. However, the project experienced unusual construction issues, and the owner did not provide capital cost estimates. Thus, the cost estimates are based on the analysis prepared for the *2009 Cost of Generation Report*.

Table B-11: Base Case Configurations—Combined-Cycle

500 MW Combined-Cycle Base Configuration
1) 500 MW Plant W/O Duct Firing
2) Two F-Frame Turbines W/One Steam Generator
550 MW Combined-Cycle Base Configuration
1) 500 MW Plant W/Duct Firing
2) Two F-Frame Turbines W/One Steam Generator
3) 50 MW of Duct Firing
800 MW High–Efficiency, Combined-Cycle Base Configuration
1) 800 MW Plant W/O Duct Firing
2) Two H-Frame Turbines W/Single Shaft Generators

Source: Energy Commission.

Table B-12 shows the recommended instant costs for the three CC cases in the COG Model. These costs estimates exclude land acquisition, environmental permitting and air emission reductions credit acquisition. Those costs are incorporated separately into the COG Model as those costs usually vary for local and jurisdictional circumstances. The high-efficiency CC case cost is based on very limited data for a different advanced gas turbine type. However, it is reasonable to have an economy of scale reduction in cost that is, somewhat muted for the high efficiency CC case, based on increased project generation capacity.

Table B-12: Total Instant Costs for Combined-Cycle Cases

Combined Cycle Case (Nominal 2011$)	Mid ($kW)	High ($kW)	Low ($kW)
Conventional 500 MW CC Without Duct Firing	$902	$992	$738
Conventional 550 MW CC With Duct Firing	$880	$980	$707
High Efficiency 800 MW CC Without Duct Firing	$957	$1,218	$759

Source: Energy Commission.

Note: The high and low values are based on the 10 percentile and 90 percentile values for the evaluated projects.

Simple-Cycle Capital Costs

Table B-13 provides the assumed design configuration of the three CT cases**.** The projects with announced instant or as-built installed cost data that were evaluated to determine the recommended average, high, and low capital cost values for the three CT cases are shown in **Table B-13**.

Table B-13: Base Case Configurations—Simple-Cycle

49.9 MW Simple-Cycle Base Configuration
1) 49.9 MW Plant
2) One LM6000 Gas Turbine With Chiller Air Pretreatment
100 MW Simple-Cycle Base Configuration
1) 100 MW Plant
2) Two LM6000 Gas Turbines With Chiller Air Pretreatment
200 MW Advanced Simple-Cycle Base Configuration
1) 200 MW Plant
2) Two LMS100 Gas Turbines With Evaporative Cooler Air Pretreatment

Source: Energy Commission.

Table B-14 shows the recommended instant costs for the three combined cycle cases in the Model. As with the combined-cycle data, these costs estimates exclude land acquisition, environmental permitting, and air emission reductions credit acquisition. Those costs are incorporated separately into the COG Model as those costs usually vary for local and jurisdictional circumstances. The advanced CT case cost is based on very limited data for a different advanced gas turbine type. The significantly lower cost for the advanced CT case seems to overstate the potential for economy of scale reduction in cost, particularly since the LMS100 technology requires an increase in auxiliary equipment costs. Therefore, there is a low level of confidence with the advanced CT costs.

Table B-14: Total Instant Costs for Simple-Cycle Cases

Simple Cycle Case (Nominal 2009$)	Mid ($/kW)	High ($/kW)	Low ($/kW)
Conventional 49.9 MW CT	$1,080	$1,503	$716
Conventional 100 MW CT	$1,080	$1,503	$716
Advanced 200 MW CT	$891	$1,313	$527

Source: Energy Commission.

Note: The high and low values are based on the 10 percentile and 90 percentile values for the evaluated projects.

Construction Periods

The staff-recommended construction periods for use in the model are based on an analysis of the facilities surveyed for the *2007 IEPR* and other known project construction periods. **Table B-15** provides the average-cost, high-cost, and low-cost heat rates that were recommended for use in the COG Model.

Construction periods can be influenced by many factors, including greenfield or brownfield sites, the overall complexity of the design of the facility, the constraints due to site size or location, and a myriad of other factors. The recommended values assume a "normal" range of factors and do not include extraordinary circumstances.

Table B-15: Summary of Recommended Construction Periods (months)

Technology	Average	High	Low
Conventional CC	26	36	20
Conventional CC With Duct Firing	26	36	20
High efficiency CC	26	36	20
Conventional CT[a]	9	16	4
Advanced CT[b]	15	20	12

Source: Energy Commission.

Note:

[a] The conventional CT values are recommended for both the single turbine (49.9 MW) and two turbine (100 MW) cases.

[b] Engineering estimate using the anticipated 18-month Panoche case construction duration as slightly higher than average value due to it being a four-turbine project rather than a two- turbine project.

Fixed and Variable Operating and Maintenance Costs

Combined-Cycle Operating Costs

The operating costs consist of three components: fixed O&M, variable O&M, and fuel.

Fixed O&M is composed of two components: staffing costs and nonstaffing costs. Nonstaffing costs are composed of equipment, regulatory filings, and ODCs.

Variable O&M is composed of the following components:

- Outage Maintenance—Annual maintenance and overhauls and forced outages.
- Consumables Maintenance
- Water Supply Costs

Simple-Cycle Operating Costs

The operating costs consist of two components: fixed O&M and variable O&M. **Table B-16** and **Table B-17** summarize the fixed and variable O&M components, respectively. Fixed O&M is composed of two components: staffing costs and non-staffing costs. Nonstaffing costs are composed of equipment, regulatory filings, and ODCs. As with the CC fixed costs, staffing costs for CT units, and thus total fixed O&M, were found to vary with plant size. In this case, outage costs were found to vary little with the historical generation. This may be because these costs are driven more by starts than by hours of operation. For this reason, these costs were placed in fixed costs instead. This practice appears to be more consistent with the cost estimates developed by other agencies and analysts.

Variable O&M is composed of the following components:

- Consumables Maintenance
- Water Supply Costs

However, the variable costs for the CC plants exclude the water supply costs because the underlying water rates vary by locality or region and are computed within the model. For the CT plants, the water costs are so insignificant that they do not have an appreciable effect on the variable O&M costs.

Table B-16: Fixed Operations and Maintenance

Technology	Average	High	Low
Small CT	$18.55	$57.22	$6.68
Conventional CT	$18.55	$57.22	$6.68
Advanced CT	$18.55	$57.22	$6.68
Conventional CC	$32.69	$77.96	$8.87
Conventional CC With Duct Firing	$32.69	$77.96	$8.87
High-Efficiency CC	$32.69	$77.96	$8.87

Source: Energy Commission.

Table B-17: Variable Operations and Maintenance

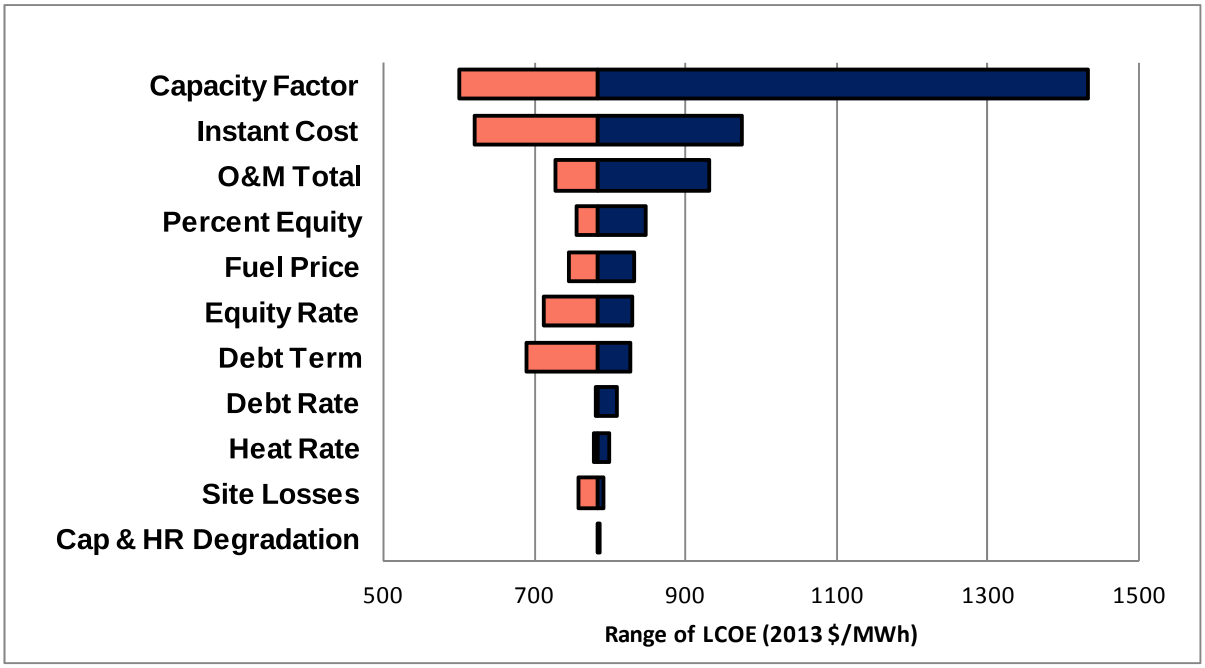
Technology	Average	High	Low
Small CT	$0.43	$1.41	$0.13
Conventional CT	$0.43	$1.41	$0.13
Advanced CT	$0.43	$1.41	$0.13
Conventional CC	$0.58	$1.79	$0.18
Conventional CC With Duct Firing	$0.58	$1.79	$0.18
High-Efficiency CC	$0.58	$1.79	$0.18

Source: Energy Commission.

APPENDIX C:
Tornado Diagrams

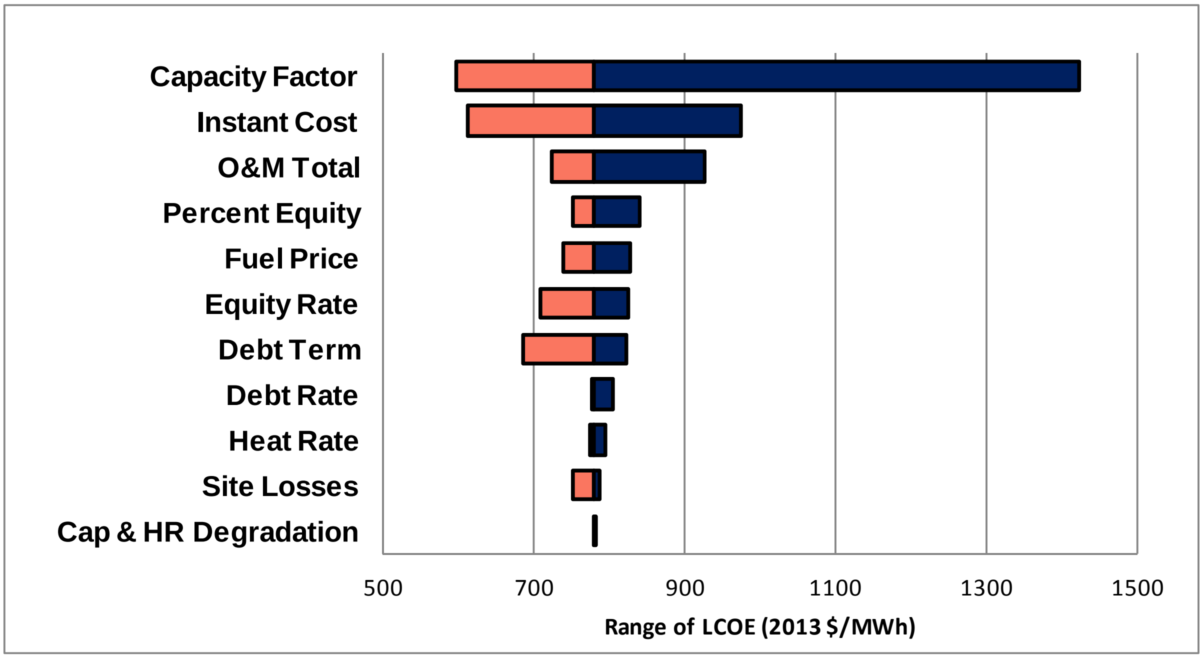
This appendix provides a complete set of tornado diagrams for a start year of 2013.

Figure C-1: Tornado Diagram—Generator Turbine 49.9 MW



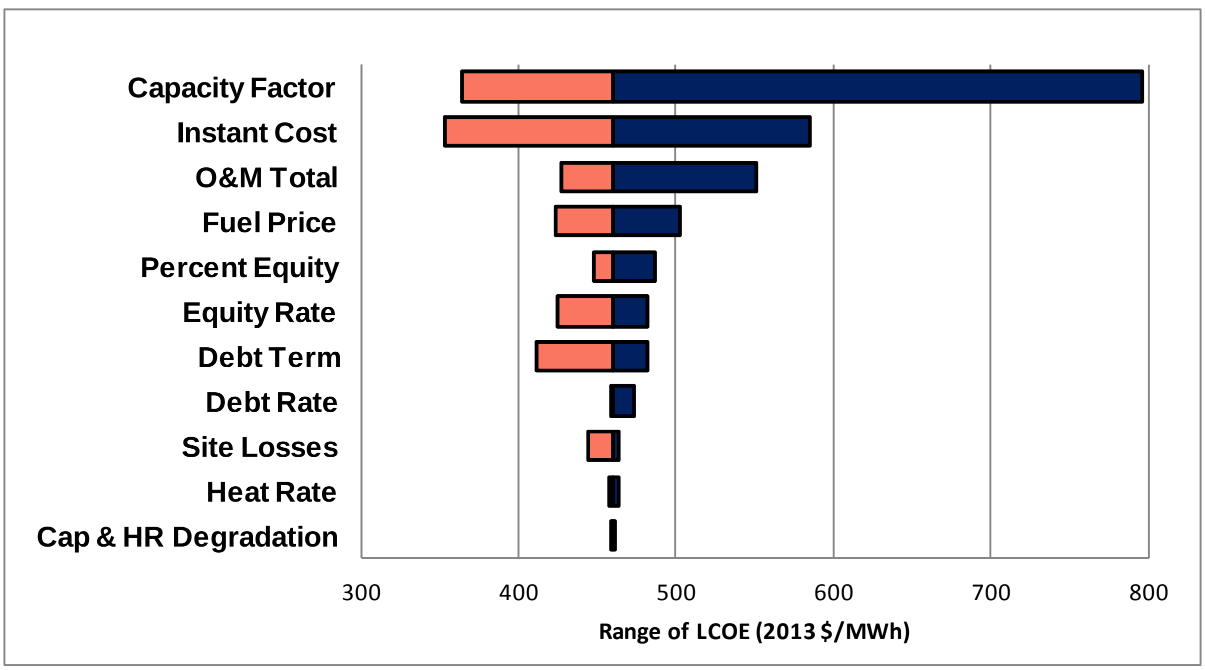
Source: Energy Commission.

Figure C-2: Tornado Diagram—Generator Turbine 100 MW



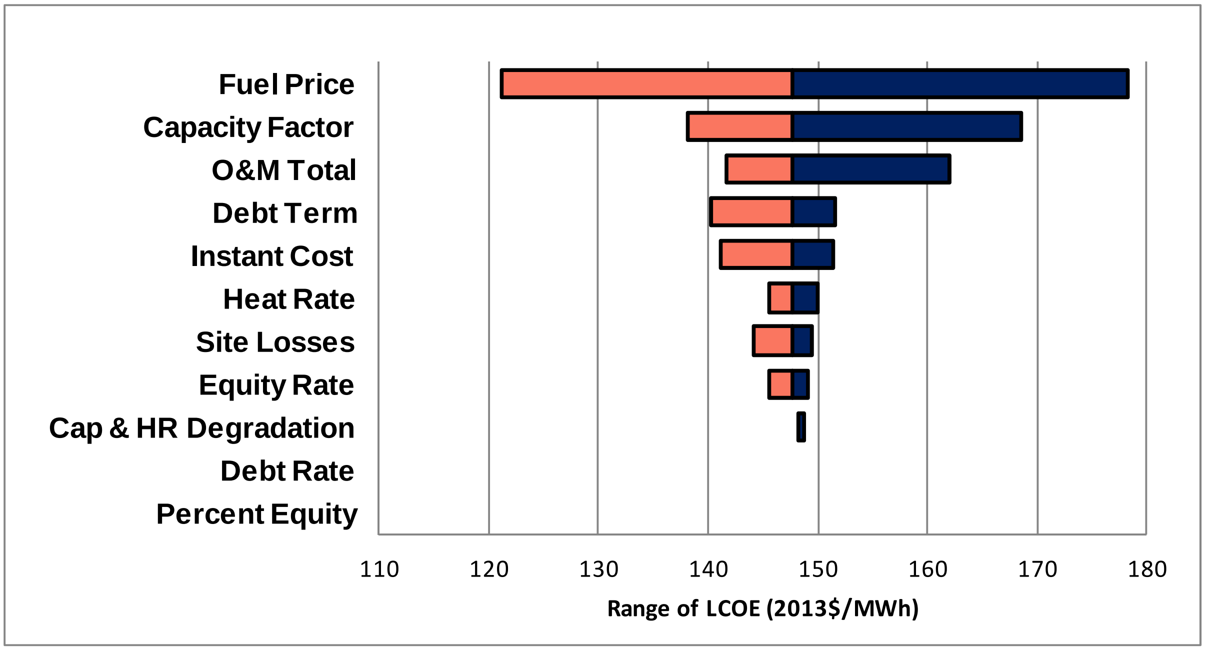
Source: Energy Commission.

Figure C-3: Tornado Diagram—Advanced Generation Turbine



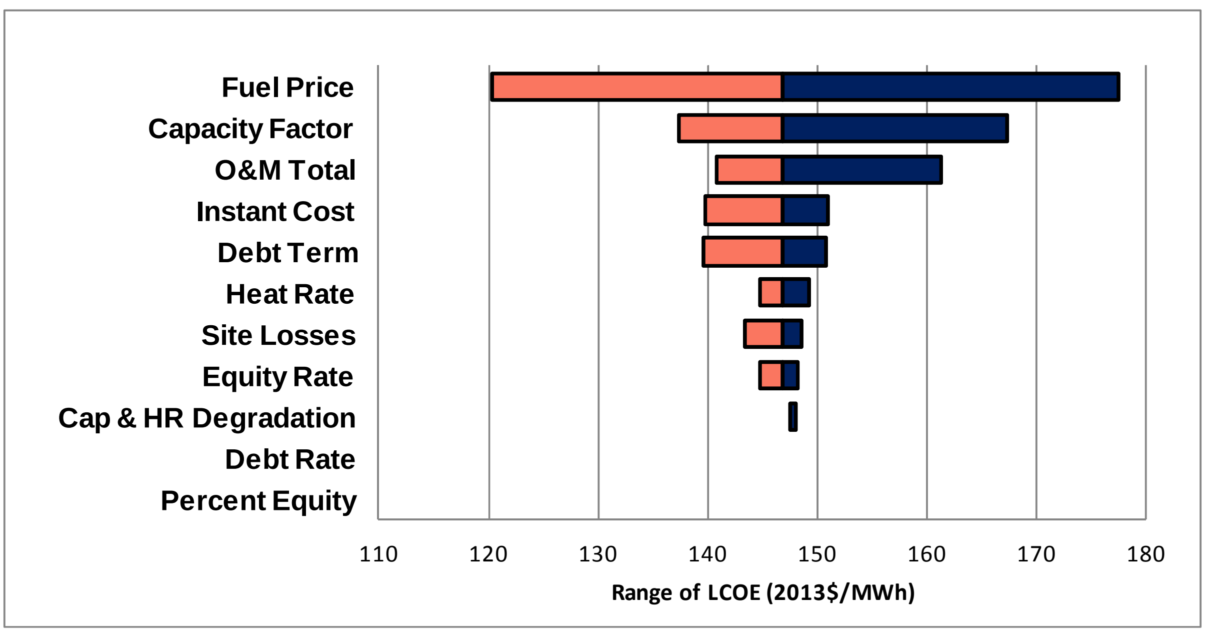
Source: Energy Commission.

Figure C-4: Tornado Diagram—Combined-Cycle 500 MW



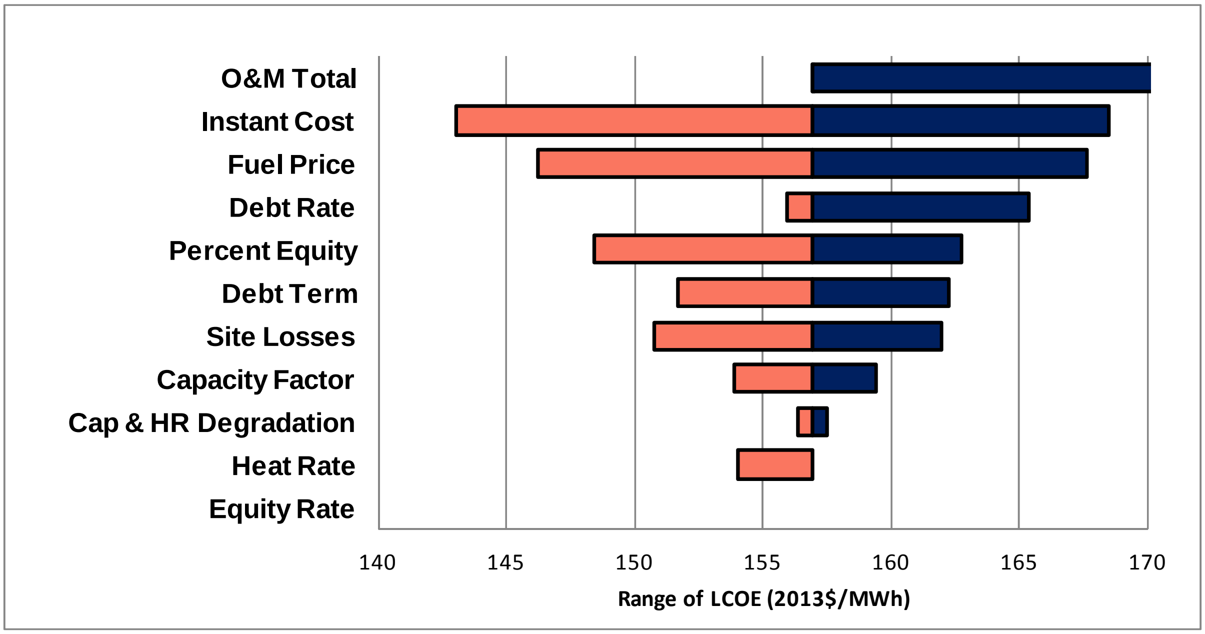
Source: Energy Commission.

Figure C-5: Tornado Diagram—Combined-Cycle With Duct Firing 550 MW



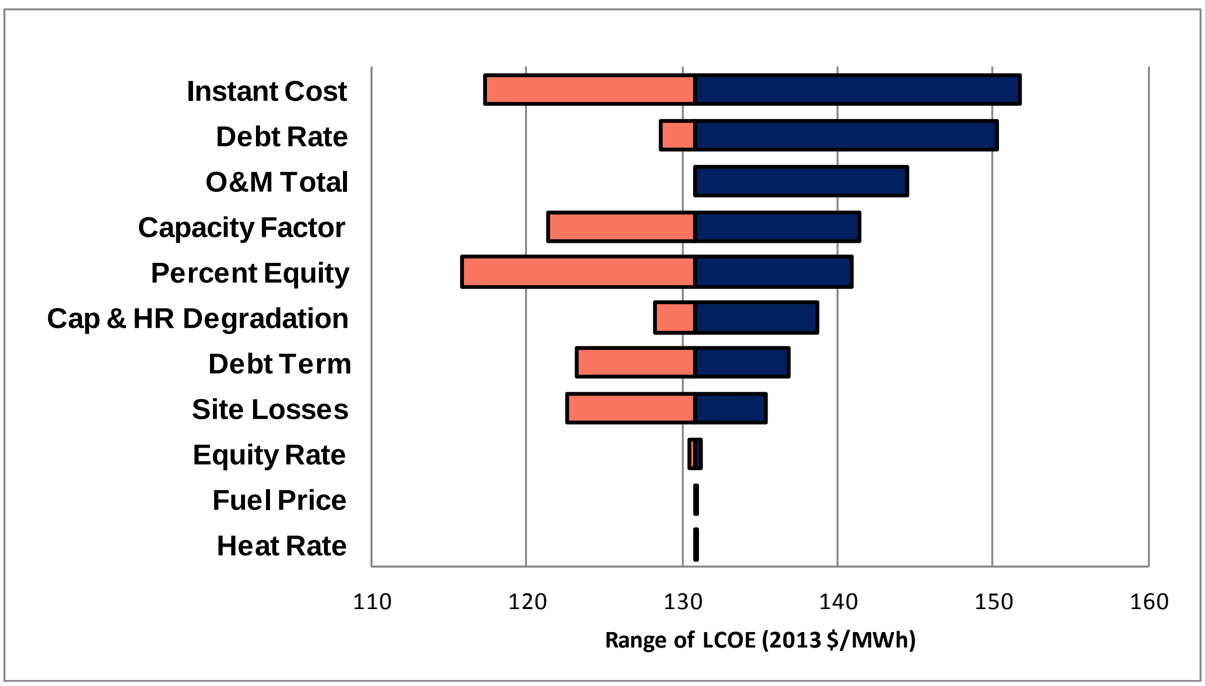
Source: Energy Commission.

Figure C-6: Tornado Diagram—Biomass Fluidized Bed 50 MW



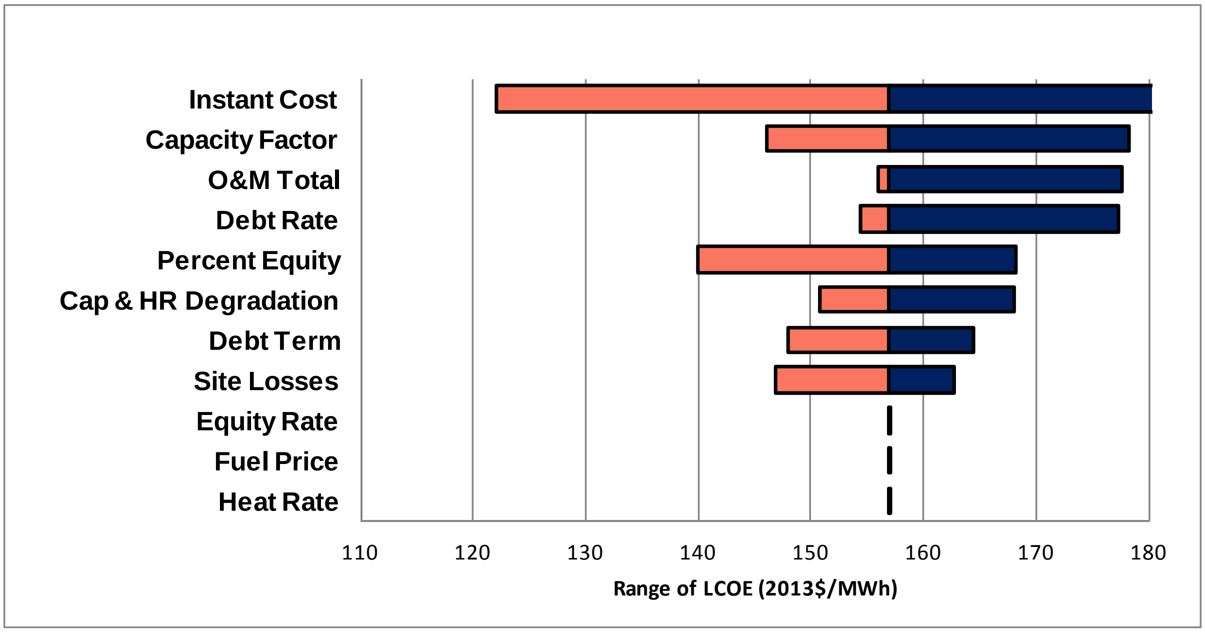
Source: Energy Commission.

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



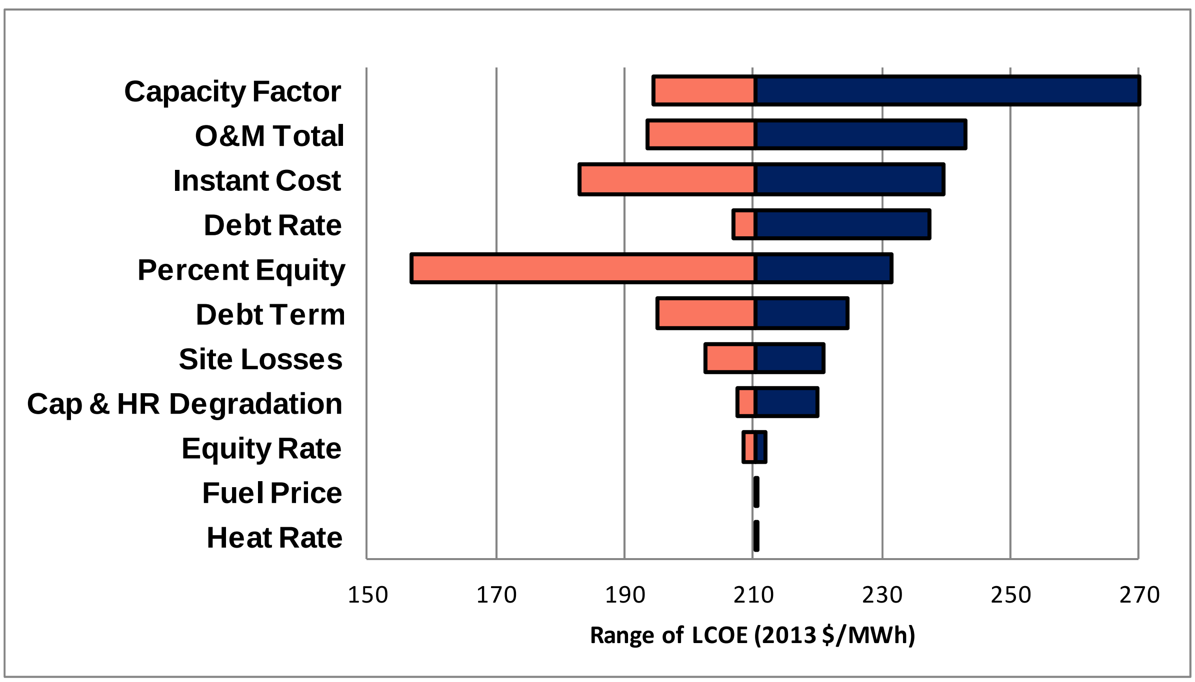
Source: Energy Commission.

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



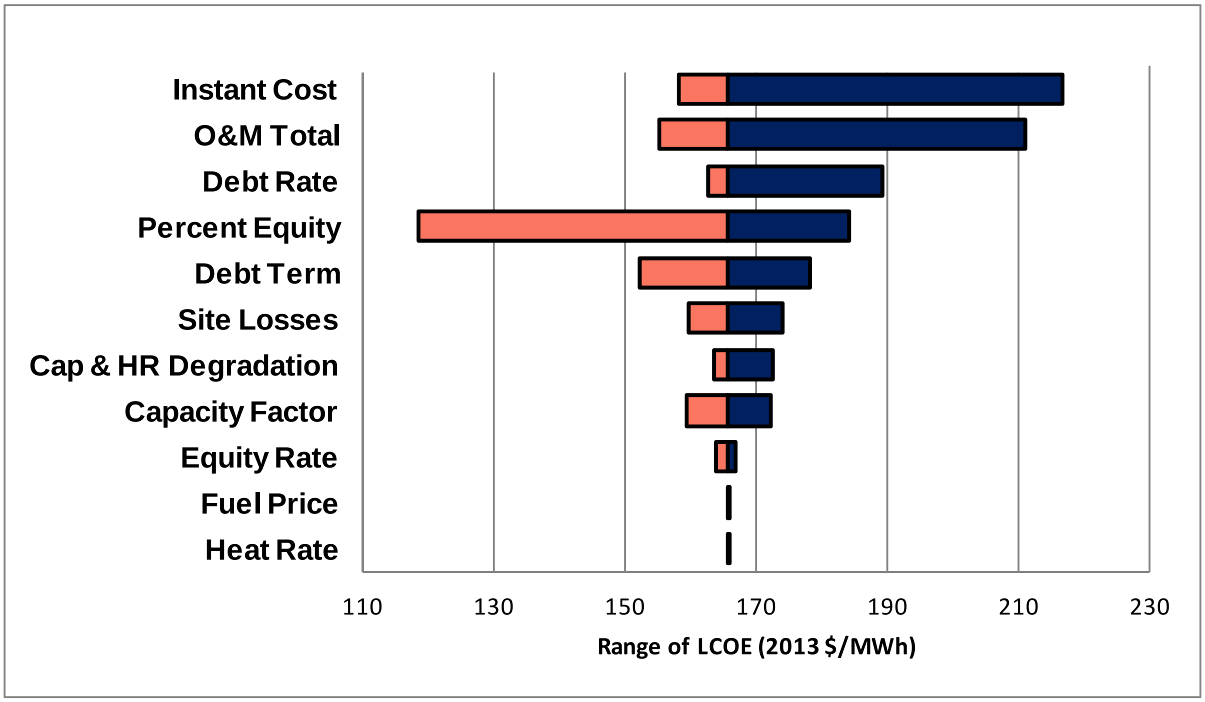
Source: Energy Commission.

Figure C-9: Tornado Diagram—Solar Parabolic Trough Without Storage 250 MW



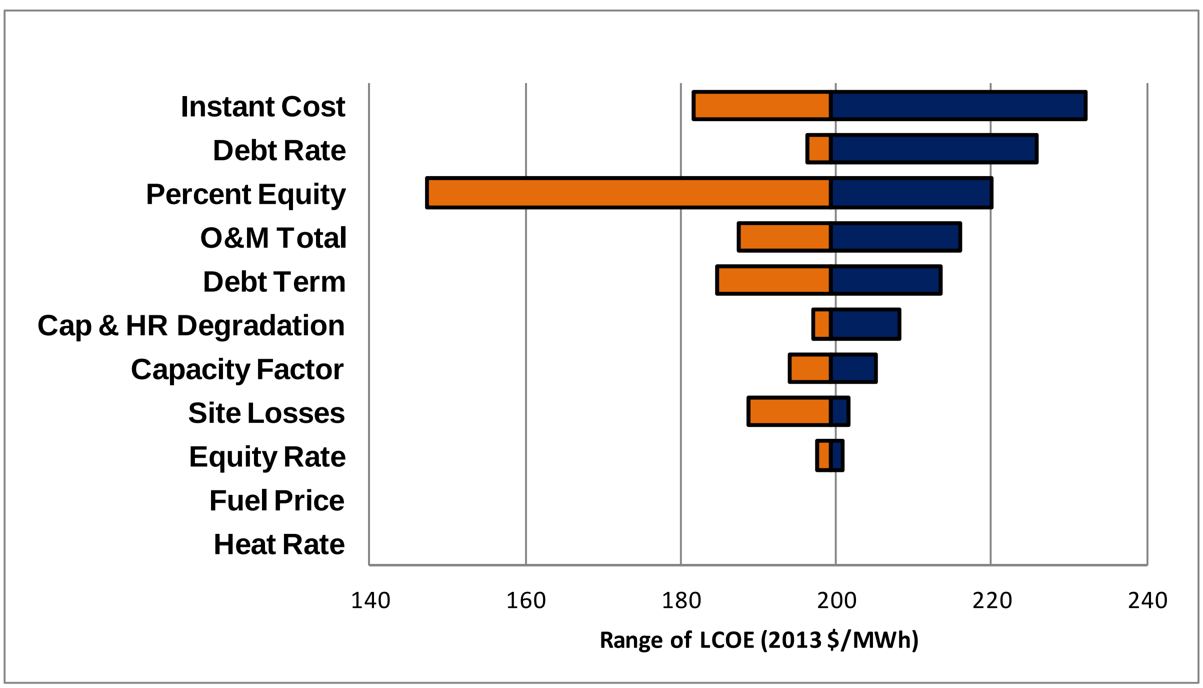
Source: Energy Commission.

Figure C-10: Tornado Diagram—Solar Parabolic Trough With Storage 250 MW



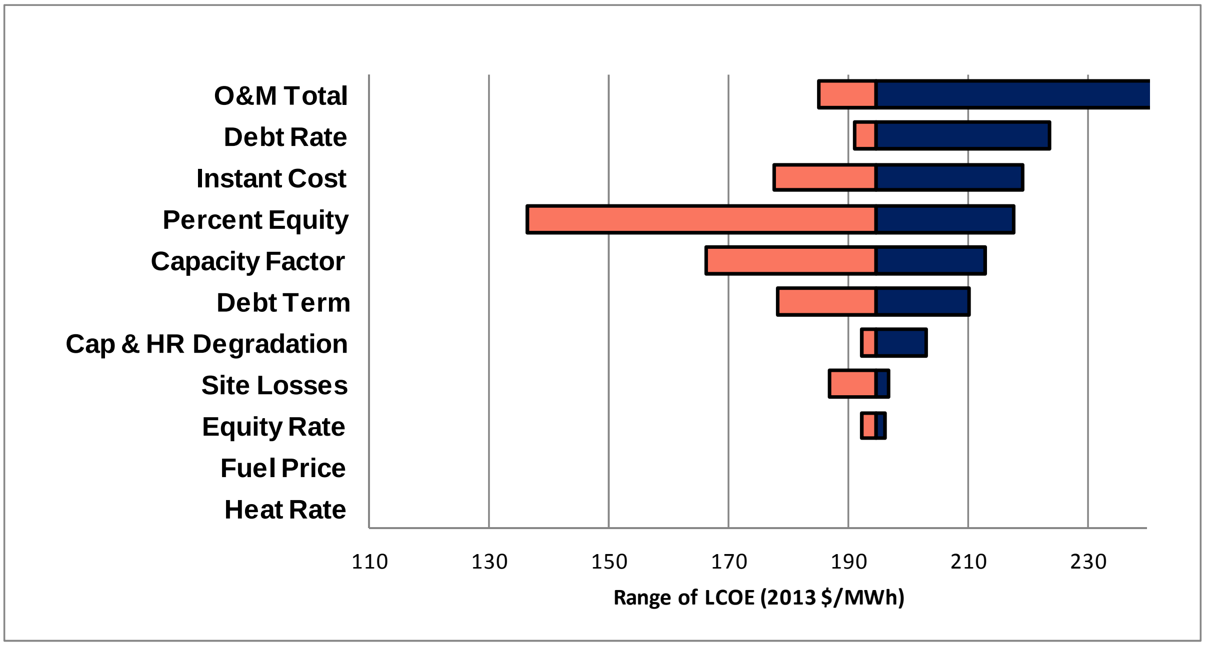
Source: Energy Commission.

Figure C-11: Tornado Diagram—Solar Tower Without Storage 100 MW



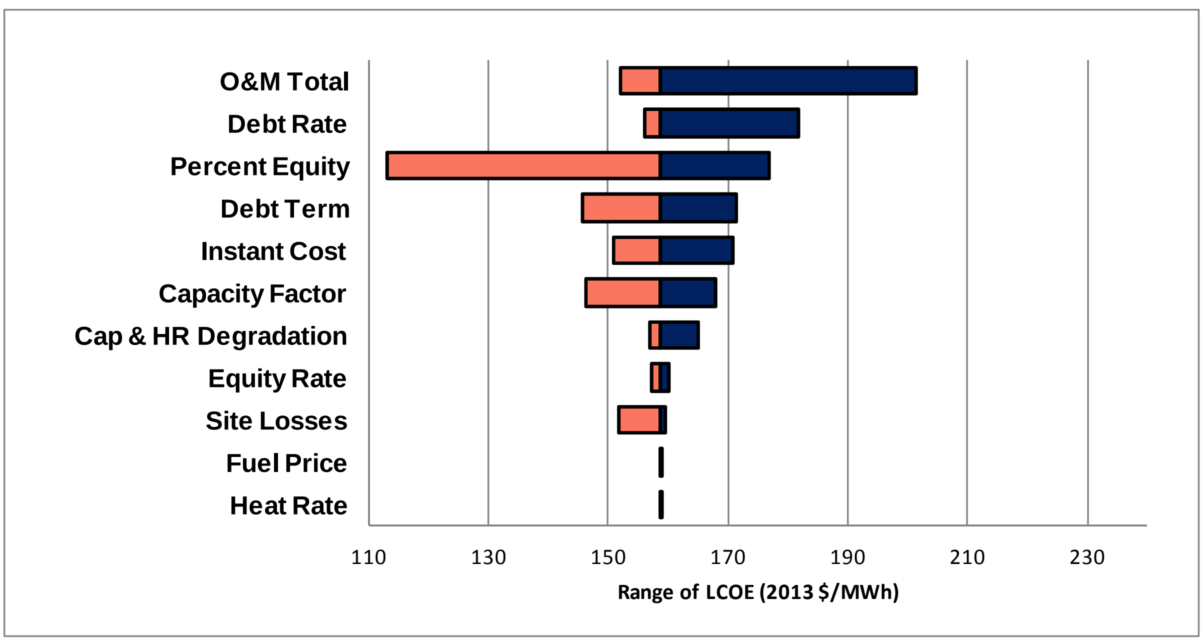
Source: Energy Commission.

Figure C-12: Tornado Diagram—Solar Tower Six Hours Storage 100 MW



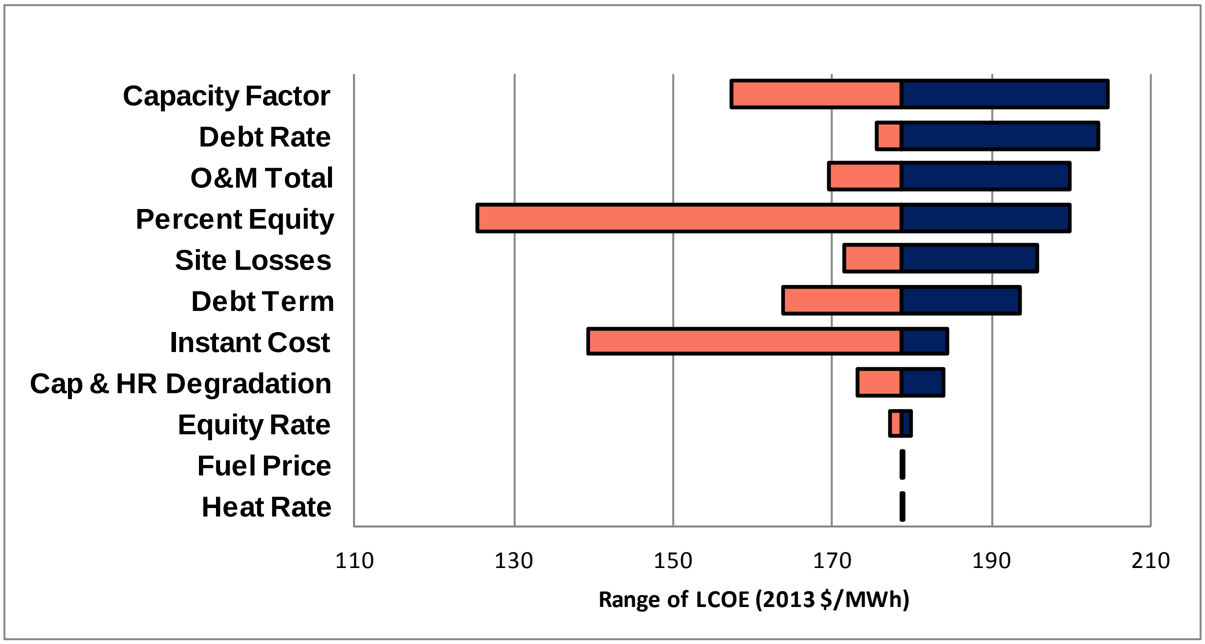
Source: Energy Commission.

Figure C-13: Tornado Diagram—Solar Tower 11 Hours Storage 100 MW



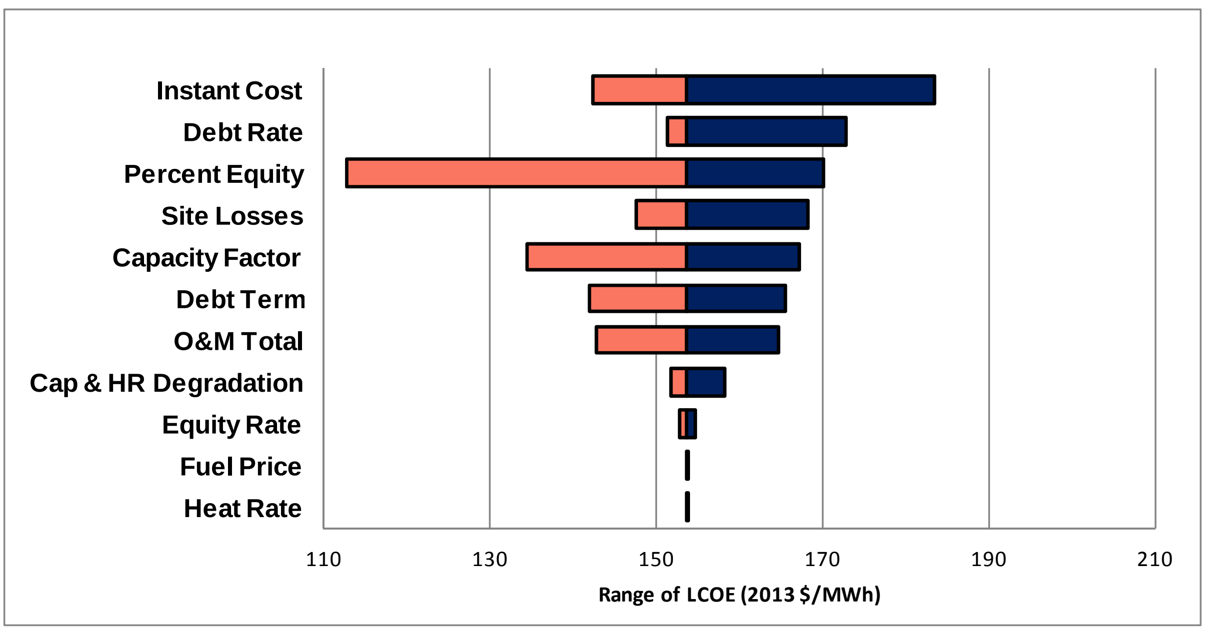
Source: Energy Commission.

Figure C-14: Tornado Diagram—Solar Photovoltaic Thin-Film 100 MW



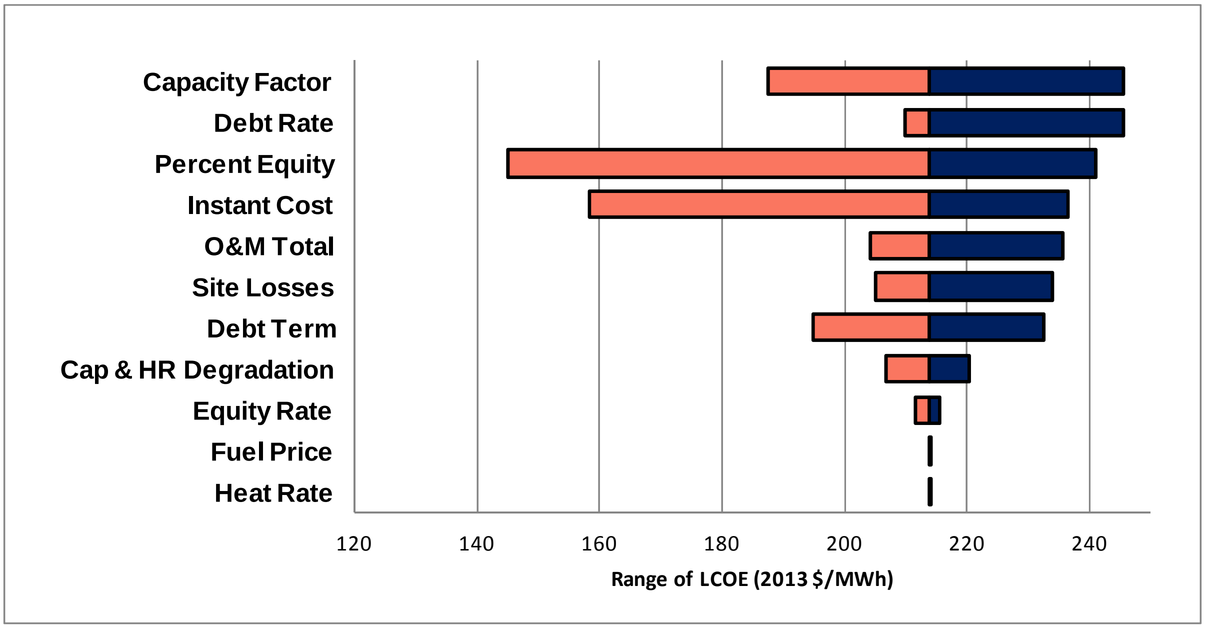
Source: Energy Commission.

Figure C-15: Tornado Diagram—Solar Photovoltaic Single-Axis 100 MW



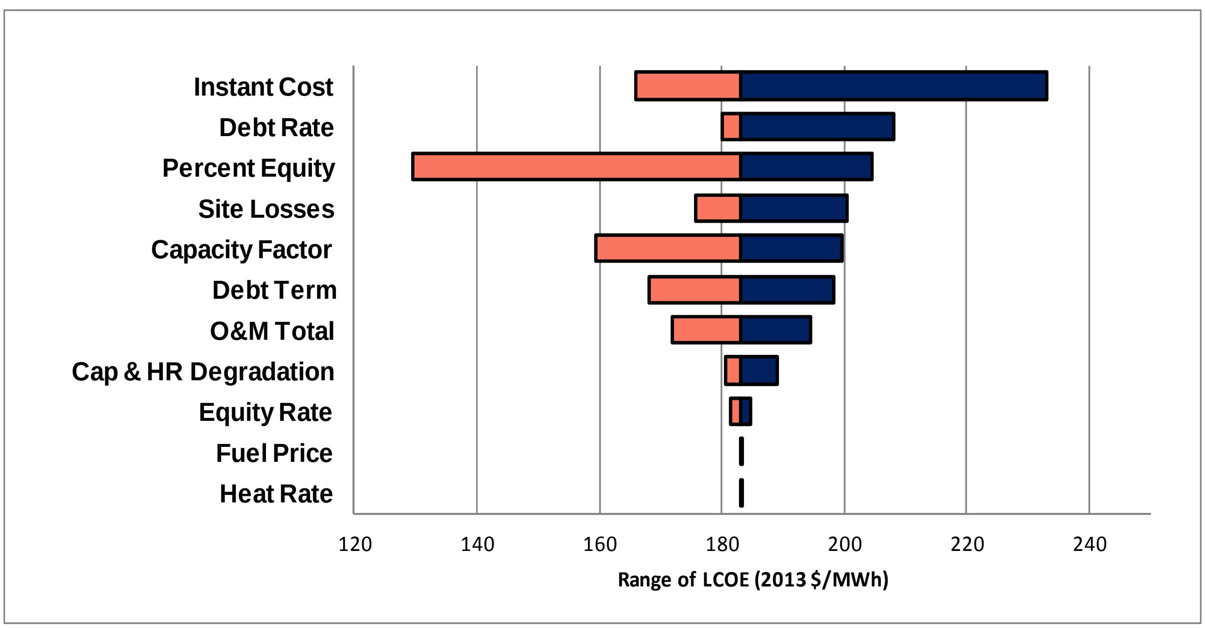
Source: Energy Commission.

Figure C-16: Tornado Diagram—Solar Photovoltaic Thin-Film 20 MW



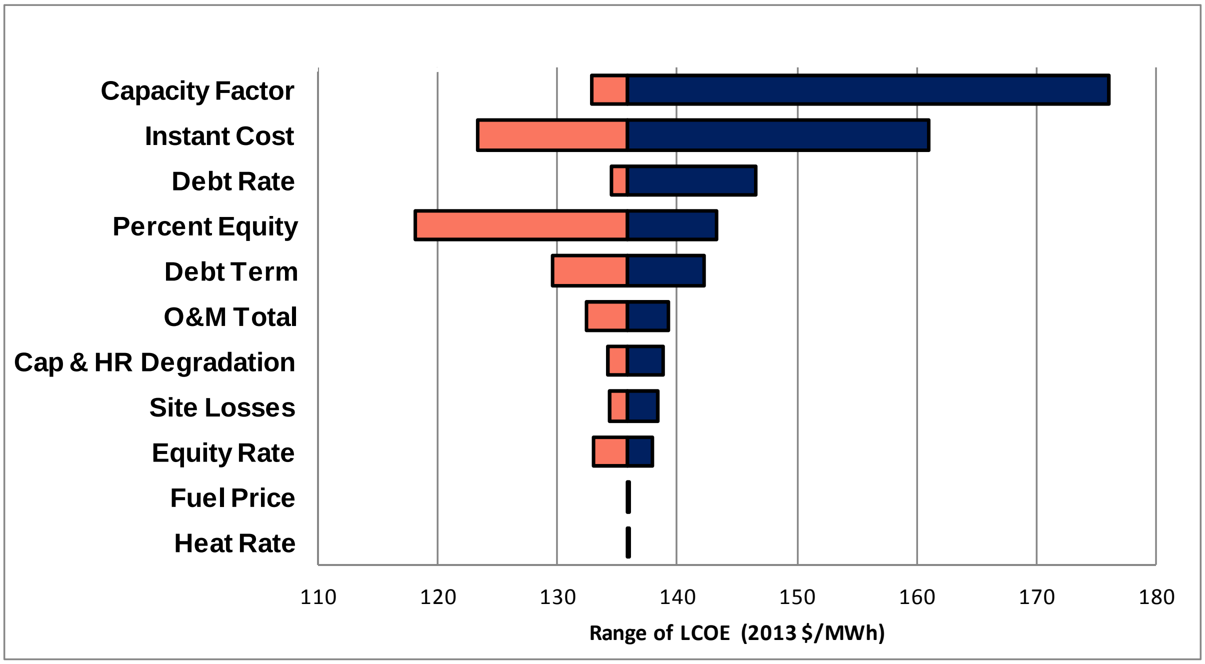
Source: Energy Commission.

Figure C-17: Tornado Diagram—Solar Photovoltaic SingleAxis 20 MW



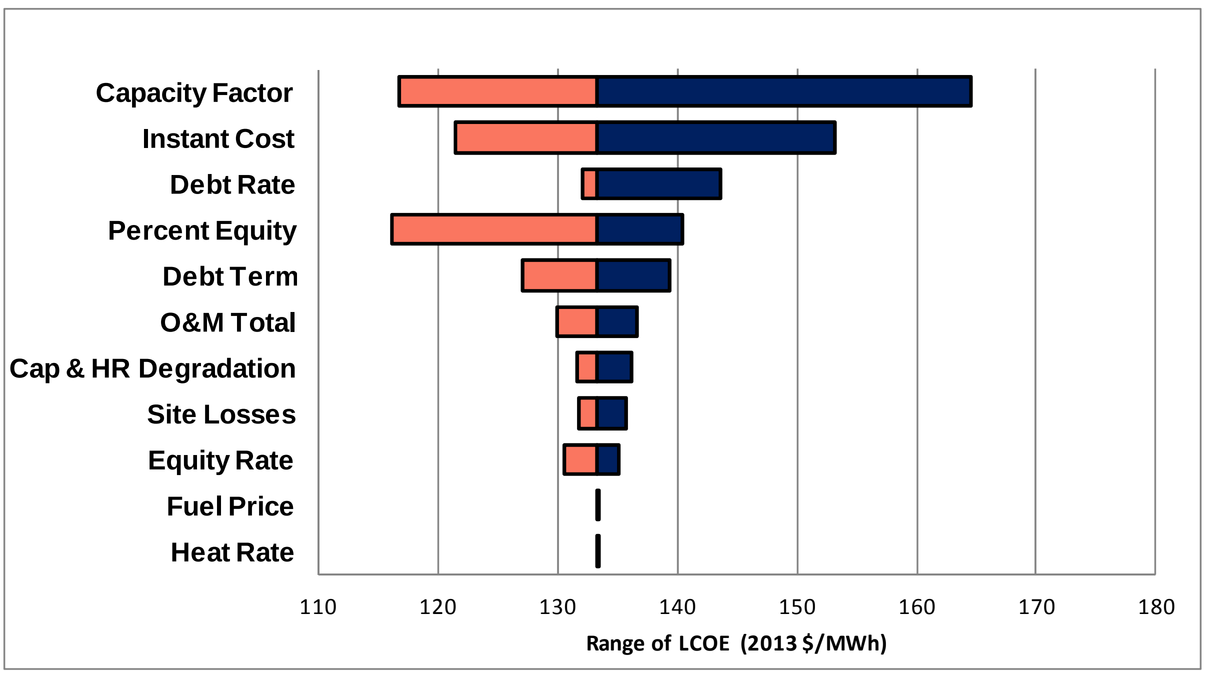
Source: Energy Commission.

Figure C-18: Tornado Diagram—Wind Class 3 100 MW



Source: Energy Commission.

Figure C-19: Tornado Diagram—Wind Class 4 100 MW



Source: Energy Commission.

APPENDIX D:
Description of Models

Three models were used to calculate the instant, installed, and levelized costs in this report:

- The Energy Commission's COG Model
- Lumina's Analytica Model
- Analytica ACAT

Cost of Generation Model

The COG Model is used to develop three values used in the report:

- Instant Cost
- Installed Cost
- Levelized Cost

The first two costs are developed as a part of the logic that develops levelized cost.

Instant Cost

The capital cost component of instant cost is entered into the COG Model based on exogenously calculated values. It can be a single value reflecting the base year costs—this is presently 2011. Or it can be entered as a formula to capture the changing costs over the study period—most commonly for renewables such as solar which are, in general, expected to have declining costs.

The COG Model will then add ancillary costs as necessary, such a land costs and licensing costs, to get the complete instant cost. These costs are shown on the construction costs worksheet and brought forward to the input-output worksheet.

Installed Cost

Installed costs are then developed from the instant costs in the same construction costs worksheet by adding the cost of the construction loan, the sales tax, and fees.

Levelized Cost

A simplified flow chart of the COG Model's inputs and outputs is shown in **Figure D-1**.

Using the inputs on the left side of the flow chart, which is described in detail later in this appendix, the COG Model can produce the outputs shown on the right side of the flow chart. The top set of output boxes show the levelized costs:

- Levelized fixed costs
  - Capital & Financing
  - Ad Valorem
  - Insurance
  - Fixed O&M
- Levelized variable costs
  - Fuel Cost
  - Variable O&M
  - Transmission Costs
- Total levelized costs (Fixed + Variable)

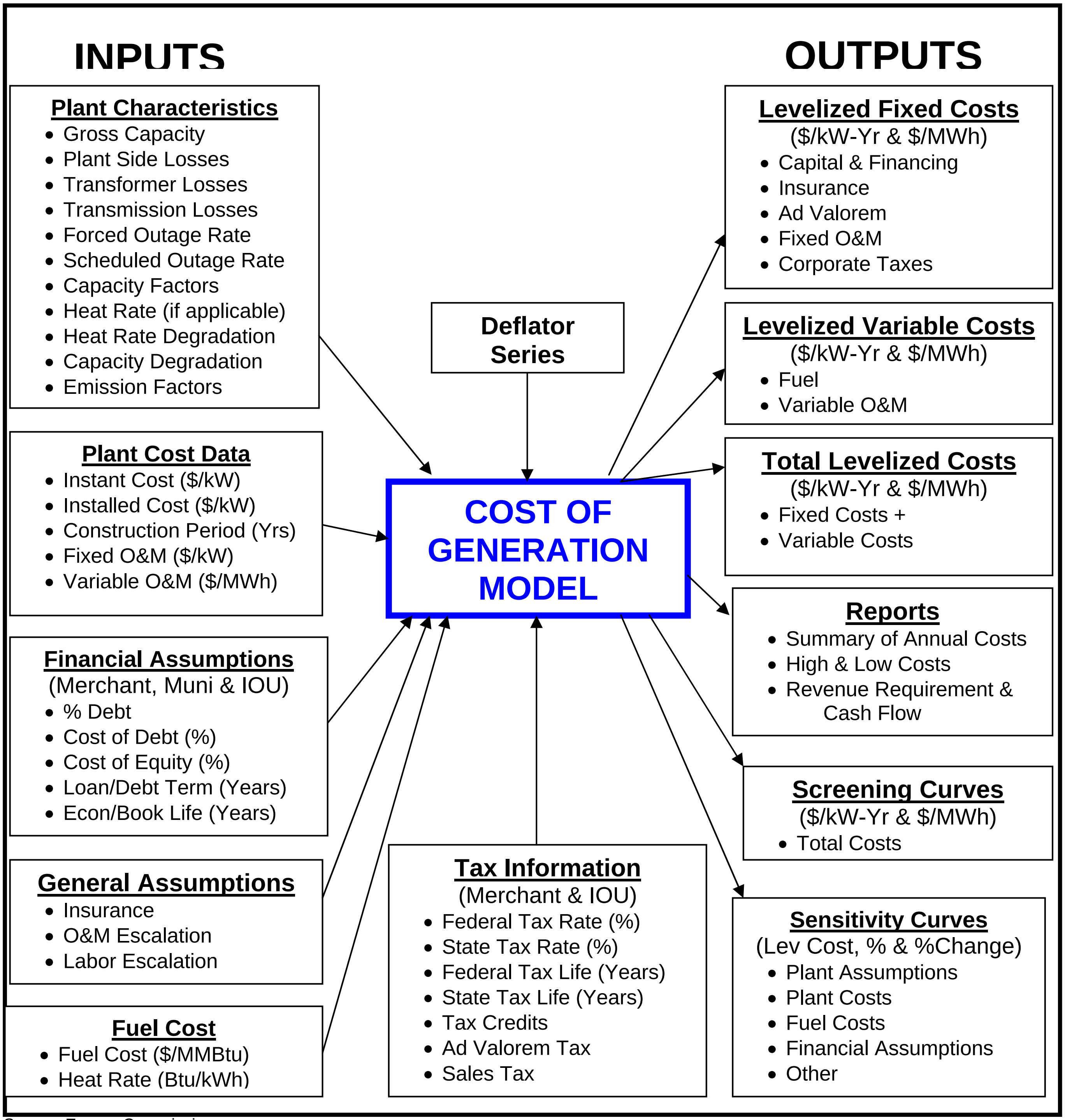
These categories are typical of most cost of generation models. These results and supporting data are used in almost any study that involves the cost of generation technologies. They can be used to evaluate the cost of a generation technology as a part of a feasibility study or to compare the differences between generation technologies. They also can be used for system generation or transmission studies.

This COG Model is more useful than the typical model since it also provides high and low levelized costs. It also differs from than the traditional model since it can create three other outputs that are useful, but not commonly provided in the models:

- Annual costs, which are not traditionally displayed in both a table and a graph.
- Screening curves, which show the relationship between levelized cost and capacity factor—an addition that makes the COG Model much more useful in evaluating cost of generation costs and comparing different technologies.
- Sensitivity curves, which show the percentage change in outputs (levelized cost) as various input variables are changed.

In addition, the COG Model can also be used to forecast the cost of wholesale electricity, which is explained later in the chapter.

Figure D-1: Cost of Generation Model Inputs and Outputs



Source: Energy Commission.

Cost of Generation Model Structure

The COG Model is contained in a single Excel workbook (spreadsheet model) that presently calculates levelized costs for 19 technologies. The COG Model is designed to accommodate an almost unlimited number of additional technologies. It also includes a function for storing and recalling user-defined scenarios. This workbook consists of 30 spreadsheets (worksheets), but 2 of these are informational and do not contribute to the calculations. A summary of these worksheets is illustrated in **Figure D-2**. A flow sheet description of the COG Model can be found on the instructions worksheet of the COG Model.

One way to better understand the COG Model is to visualize the "Income Revenue" and "Income Cash-Flow" worksheets as a model, the "Input-Output" worksheet as the control module, which also summarizes the results, and the remaining worksheets as data inputs that also provide preprocessing as necessary.

Input-Output Worksheet

This is where the user selects the generation technology, its type of financing and the start year, and reads the results. **Figure D-3** shows the input selection box. Through the use of drop-down windows, the user selects the type of financing, start year of project the technology, and tax loss treatment. For a gas-fired technology the user also selects carbon price, gas price, and region. If the technology is a CC unit, then the user selects the number of combustion turbines. Once all of these selections have been made, the user presses the red execute button to activate the levelized cost macro.

Based on these selections, the macro collects the relevant data and delivers it to the data worksheets. The income statement then uses the data worksheets to calculate the levelized costs and reports those costs back to the input-output worksheet to the table shown in **Table D-1**. The reported high-cost and low-cost LCOEs assume all high or low assumptions occur simultaneously. This deterministic case would occur with such small probabilities that they are only useful for perspective—which explains why staff has gone to probabilistic LCOEs derived from ACAT.

Table D-2 shows the associated data assumptions that have been used. These high and low assumptions are useful from any perspective, deterministic or probabilistic. They are important to the user and should be scrutinized to make sure that they are consistent with the project for which they are being used. At the bottom of these data, there is a DSCR check to ensure that financing is realistic.

Figure D-2: Summary of Worksheets

Instructions	General Instructions & Model Description
Input-Output	User selects Assumptions - Levelized Costs are reported along with some key data values.
Annual Cost Chart	Reports annual fixed, variable and total O&M costs for selected scenario as well as the NPV for each cost stream
Screening Curve	Contains a GUI and macro that graphs the levelized cost as a function of capacity factor for any of the plant technologies.
Sensitivity Curve	Contains a GUI and macro that graph the levelized cost as a function of a percent change in various base values so as to examine the sensitivity of the output to the specified variables.
Print Tables	Presents and compares costs for all technologies and developers for up to two scenarios
Yearly Costs	User selects technologies, developers and cost cases and annual costs are presented for each selection
Changes	Tracks Model modifications using version numbers
Physical Data	plant physical data is summarized - User can override data for unique scenarios.
Financial Data	Financial & Tax Data are summarized - User can override data for unique scenarios
Construction Costs	Construction Costs are calculated in base year dollars
O&M Costs	O&M Costs are calculated in base year dollars
Income Cash -Flow	Calculates Annual Costs and Levelizes those Costs – Using Cash-Flow accounting
Income Rev Req	Calculates Annual Costs and Levelizes those Costs – Using Revenue Requirement accounting
Inflation	Calculates Historical & Forward Inflation Rates based on GDP Price Deflator Series - Used by Income Worksheets.
Financial Assumptions	Data Assumptions summary of all Financial Data.
Renewables	Equity return calculations for renewables (wind and non-wind)
Tax Incentives	Presents information on tax incentives by technology
Transmission	Reports transmission line losses and rates
Fuel Price Forecasts	Fuel Price Forecast - Used by the Income Worksheets.
Air & Water Data	Regional Air Emissions & Water Costs - Used by Data 2 Worksheet.
ERC Forecasts	General Assumptions summary such as Inflation Rates & Tax Rates.
SCAQMD Fees	Presents SCAQMD Rule 1304.1 In-lieu ERC Fees
Plant Type Assumptions	Summary of Data Assumptions summary for each Plant Type.
PTA - Average	Average Plant Type Assumptions
PTA - High	High Plant Type Assumptions
PTA - Low	Low Plant Type Assumptions
General Assumptions	General Assumptions summary such as Inflation Rates & Tax Rates.
Labor Table	Calculates the Labor Cost components.
Overhaul Calcs	Calculates Overhaul & Equipment Replacement Costs - Used by Data 2 Worksheet.
CC HeatRate	Shows the regression and provides the Heat Rate factors.
WEP Forecast	Contains Wholesale Electricity Price Forecast

Source: Energy Commission.

Figure D-3: Technology Assumptions Selection Box

INPUT SELECTION

Step 1: Select Developer and Financing	Merchant Fossil
Step 2: Select Start-Year	2013
Step 3: Select Technology	Combined Cycle - 2 CTs No Duct Firing 500 MW
Step 4: Select Tax Loss Treatment	Tax Equity Financing

FOR GAS-FIRED UNITS ONLY

Step 5: Select Carbon Price	Carbon Price Mid
Step 6: Select Natural Gas Price	CA Average
Step 7: Select Plant Site Region	CA - Avg.
Step 8: Turbine Configuration	2

Step 9: Click the Execute Button → **Execute**

Source: Energy Commission.

Table D-1: Illustrative Levelized Cost Output

OUTPUT RESULTS - Summary of Levelized Costs

Combined Cycle - 2 CTs No Duct Firing 500 MW

Merchant Fossil	Mid-Cost Case		High-Cost Case		Low-Cost Case	
Start Year = 2013 (2013 Dollars)	**$/kW-Yr**	**$/MWh**	**$/kW-Yr**	**$/MWh**	**$/kW-Yr**	**$/MWh**
Capital & Financing - Construction	$122.53	$26.49	$210.98	$65.02	$67.32	$11.69
Insurance	$8.26	$1.79	$9.70	$2.99	$6.44	$1.12
Ad Valorem Costs	$11.98	$2.59	$13.18	$4.06	$9.03	$1.57
Fixed O&M	$43.23	$9.35	$94.65	$29.17	$17.69	$3.07
Corporate Taxes (w/Credits)	$40.49	$8.75	$79.89	$24.62	$9.11	$1.58
Fixed Costs	**$226.49**	**$48.97**	**$408.40**	**$125.85**	**$109.60**	**$19.02**
Fuel & GHG Emissions Costs	$333.39	$72.09	$283.59	$87.39	$267.60	$46.45
Variable O&M	$3.75	$0.81	$7.56	$2.33	$1.47	$0.26
Variable Costs	**$337.14**	**$72.90**	**$291.15**	**$89.72**	**$269.07**	**$46.70**
Total Levelized Costs To Delivery Point	**$563.64**	**$121.87**	**$699.55**	**$215.57**	**$378.67**	**$65.73**
Transmission Service Costs	$119.62	$25.87	$81.91	$25.24	$45.73	$7.94
Total Levelized Costs w/Transmission	**$683.26**	**$147.74**	**$781.46**	**$240.81**	**$424.40**	**$73.67**

Source: Energy Commission.

Table D-2: Illustrative Data Assumptions

Cost Case Assumptions	Mid Cost Case		High Cost Case		Low Cost Case	
Capital and Operating Costs	**Base Yr 2011**	**Start Yr 2013**	**Base Yr 2011**	**Start Yr 2013**	**Base Yr 2011**	**Start Yr 2013**
Instant Cost ($/kW)	$979	$1,025	$1,155	$1,209	$787	$824
Installed Cost ($/kW)	$1,113	$1,166	$1,392	$1,457	$852	$892
Ratio of Installed Cost to Instant Cost		1.137		1.205		1.082
Ratio of Installed Cost to Component Cost		1.2348		1.403		1.1547
Fixed O&M Cost ($/kW-Yr)	$32.69	$34.56	$77.96	$82.42	$13.04	$13.79
Variable O&M Cost ($/MWh)	$0.58	$0.61	$1.79	$1.89	$0.18	$0.19
Total O&M ($/MWh)	$7.13	$7.54	$24.04	$25.42	$2.28	$2.41
Total O&M ($/kW-Yr)	$35.59	$37.62	$84.23	$89.06	$14.16	$14.97
Insurance ($/kW-Yr)	$6.68	$6.99	$8.35	$8.74	$5.11	$5.35
Ad Valorem ($/kW-Yr)	$12.10	$12.67	$14.82	$15.52	$9.26	$9.69
Operational Performance	**Factor**	**Hours**	**Factor**	**Hours**	**Factor**	**Hours**
Scheduled Outage Factor (SOF)	6.02%	527.4	6.02%	527.4	6.02%	527.4
Forced Outage Rate (FOR)	2.24%	114.4	2.24%	80.3	2.24%	142.5
Operational (Service) Hours Per Year		4993.2		3,504.0		6,219.6
Equivalent Availability Factor	91.87%		91.87%		91.87%	
Capacity Factor	57.00%		40.00%		71.00%	
Fuel Use Summary	**2013**	**Levelized**	**2013**	**Levelized**	**2013**	**Levelized**
Average Heat Rate (Btu/kWh)	7,250	7383	7,480	7,531	7,030	7,224
Fuel Use (MMBtu)	18,100,350	18,100,350	13,104,960	13,104,960	21,861,894	21,861,894
Fuel Price ($/MMBtu)	$4.56	$7.11	$6.67	$9.32	$2.79	$3.83
Financial Information	**Cap Structure**	**Cost of Capital**	**Cap Structure**	**Cost of Capital**	**Cap Structure**	**Cost of Capital**
Weighted Avg. Equity		13.25%		15.00%		10.41%
Equity	33.0%	13.25%	60.0%	15.00%	20.0%	10.41%
Tax Equity	0.0%	0.00%	0.0%	0.00%	0.0%	0.00%
Debt Financed	67.0%	4.52%	40.0%	6.63%	80.0%	4.64%
Discount Rate (WACC)	6.17%	4.53%	10.57%	8.84%	4.28%	2.68%
Inflation Rate from Base Yr. to Start Yr.	2.31%		2.31%		2.31%	
Inflation Rate from Start Year Forward	1.56%		1.59%		1.56%	
Loan/Debt Term (Years)	10		7		20	
Equipment Life (Years)	30	12/31/2042	20	12/31/2032	30	12/31/2042
Economic/Book Life (Years)	30		20		30	
Federal Tax Life (Years)	20		20		20	
State Tax Life (Years	20		20		20	
Capacity and Energy	**Effective MW**	**Energy GWh**	**Effective MW**	**Energy GWh**	**Effective MW**	**Energy GWh**
Gross (Dependable)	500.0	2451.7	500.0	1740.0	500.0	3026.1
Net Capacity – Plant Side	485.5	2380.6	480.0	1670.4	490.0	2965.6
Net Capacity – Transmission Side	483.1	2368.7	477.6	1662.1	487.6	2950.7
To Delivery Point	471.6	2312.4	466.2	1622.5	476.0	2880.5

Source: Energy Commission.

Other COG Model Features

Besides the LCOE described above, the COG Model has two other functions:

- Screening Curves—Plots LCOE as a function of capacity factor.
- Sensitivity Curves—While the screening curve function addresses only the effect of capacity factor, the screening curve function addresses a wide range of variables.

Lumina's Analytica Model

Analytica is a visual software package developed by Lumina Decision Systems for creating, analyzing and communicating quantitative decision models (Lumina, 2013). As a modeling environment, it is interesting in the way it combines hierarchical influence diagrams for visual creation and view of models, intelligent arrays for working with multidimensional data, Monte Carlo simulation for analyzing risk and uncertainty and optimization, including linear and nonlinear programming. Its design, especially its influence diagrams and treatment of uncertainty, is based on ideas from the field of decision analysis. As a computer language, it is notable in combining a declarative (nonprocedural) structure for referential transparency, array abstraction, and automatic dependency maintenance for efficient sequencing of computation.

The Analytica Cost of Generation Analysis Tool

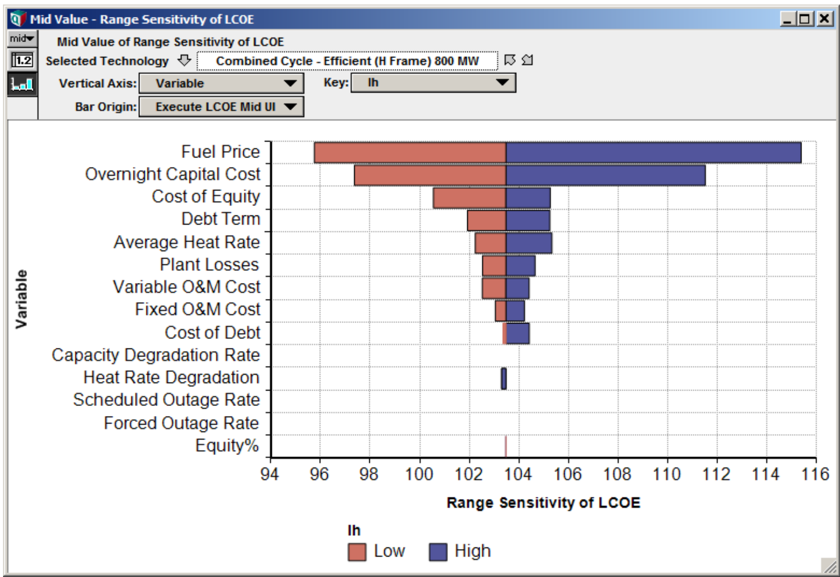
The ***ACAT*** (Sherwin and Henrion, 2013) combines the Analytica Model with the COG Model to provide probabilistic high and low LCOEs, using Monte Carlo analysis. ACAT does this by changing input cells in the COG spreadsheet to vary key input assumptions and saving the corresponding results. ACAT can perform such sensitivity analysis or Monte Carlo analysis for one, all, or a selected subset of the electricity generation technologies represented in COG.

For range sensitivity analysis, it varies each parameter from its specified low to high value while keeping the values of all the other input parameters at their mid values. It uses COG to calculate the corresponding result (LCOE) for each technology. In this way, it lets you compare the direction and magnitude of the change in the output caused the change in each input. **Figure D-4** illustrates the ACAT tornado diagram that displays the resulting range sensitivities for each parameter arranged one above the other.

For Monte Carlo analysis, ACAT fits a probability distribution to each uncertain input parameter, treating the specified low, mid, and high values as 10th, 50th, and 90th percentiles—as illustrated in **Figure D-5.** It extrapolates a minimum (0th percentile) and maximum (100th percentile) to enclose the specified low to high values, subject to specified bounds on each quantity. For example, most parameters are bounded below by zero. It then fits cubic spline distributions (see below) to the specified percentiles. ACAT then performs

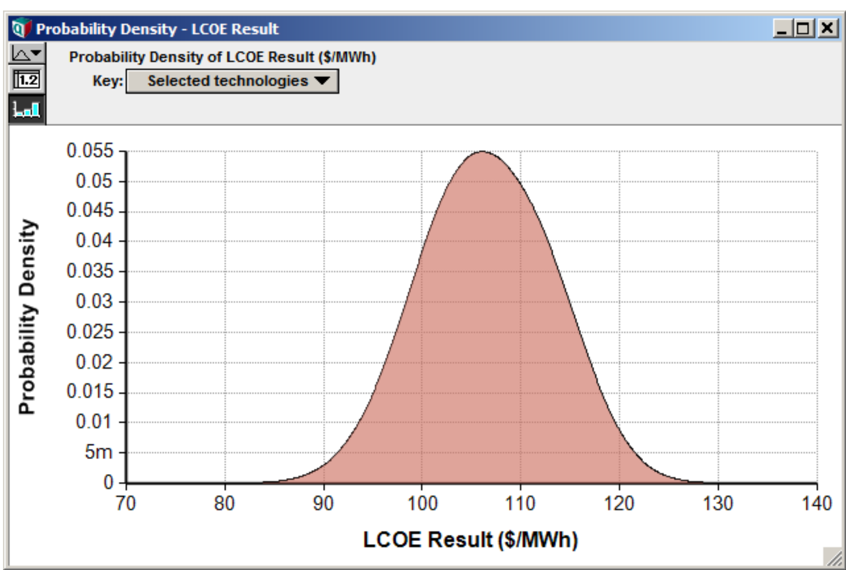
Monte Carlo by selecting values at random from each parameter distribution and setting those as inputs into COG. It obtains and stores the corresponding result for LCOE. It repeats this process a specified number of times, usually between 100 to 10,000, to generate a random sample of values from the output distribution. It then lets you display the resulting distribution as a probability density function, cumulative distribution function, or other forms.

Figure D-4: An Example Range Sensitivity Analysis (Tornado Chart) Generated by ACAT



Source: Energy Commission.

Figure D-5: An Example Probability Distribution Generated by ACAT



Source: Energy Commission.

Cubic Spline Distributions

ACAT lets you fit a uniform, triangular, or cubic spline distribution to the specified low, mid, and high values of each uncertain quantity. For the current purpose, the cubic spline distribution was found to give the best result.

ACAT treats the low, mid, and high values respectively as the 10th, 50th, and 90th percentiles of the distribution (also x10, x50, and x90). By default it estimates lower and upper bounds, x0 and x100, for each quantity such that:

$$x100 - x90 = w\ (x90 - x50)$$

$$x10 - x0 = w\ (x50 - x10)$$

These calculations use a width factor w set by default to 2.0. ACAT also lets you specify a minimum and maximum value on the possible values. For most quantities, the minimum is zero. For percentages, the maximum is at most 100 percent. The minimum and maximum override the x0 and x100 respectively if x0<minimum or x100>maximum.

The ***cubic spline distribution*** fits a piecewise cubic distribution to the five specified percentiles on the cumulative probability distribution. This usually gives rise to a bell-shaped curve as long as the percentiles are spaced apart, but with finite bounds unlike a normal or lognormal distribution.

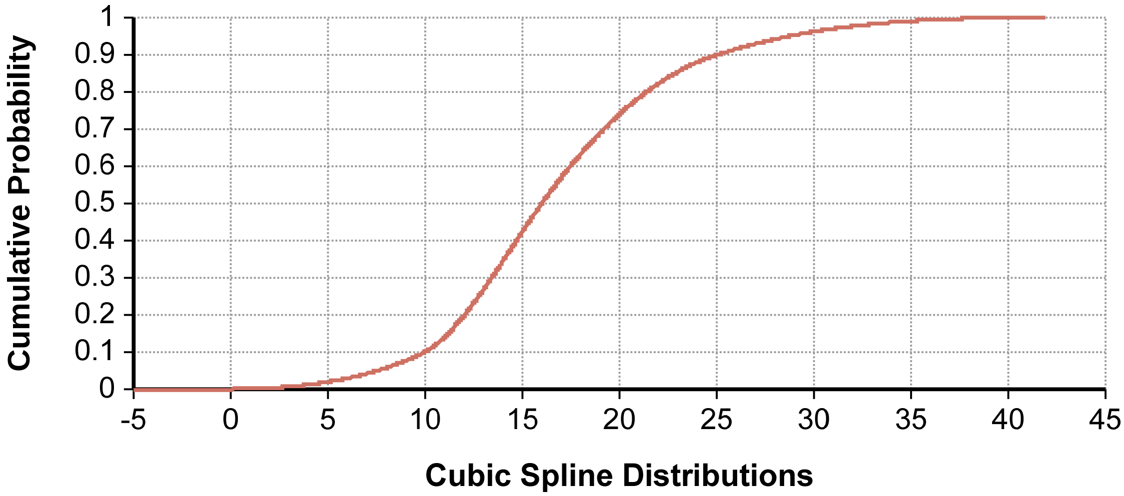
Figure D-6 and **Figure D-7** show an example cubic spline distribution fitted to the five percentiles with probabilities and values given in **Table D-3**. Note that the cumulative probability **Figure D-6** matches all the values in **Table D-3** except the 50 percent value—a good match with smooth looking curve.

Table D-3: Shows the Cumulative Probability and Corresponding Values (Percentiles) for the Specified Min, Low, Mid, High, and Maximum Values

	Probability	Value
Min	0%	0
Low	10%	10
Mid	50%	15
High	90%	25
Max	100%	45

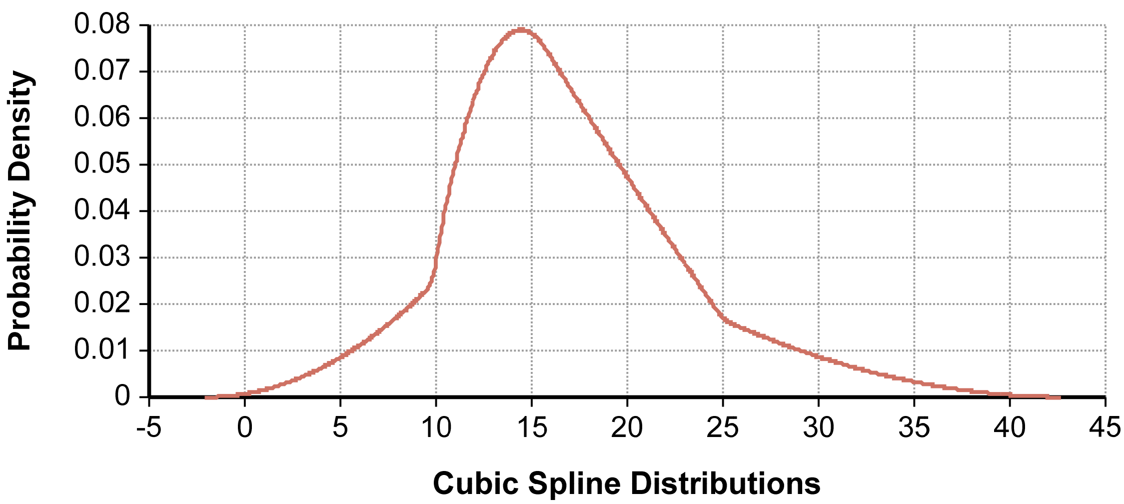
Source: Energy Commission.

Figure D-6: Cubic Spline Distribution Fitted to Points on the Cumulative Probability Distribution With Probabilities and Values Given in Table D-3



Source: Energy Commission.

Figure D-7: Cubic Spline Distribution From Table D-3 Shown as the Corresponding Probability Density Distribution

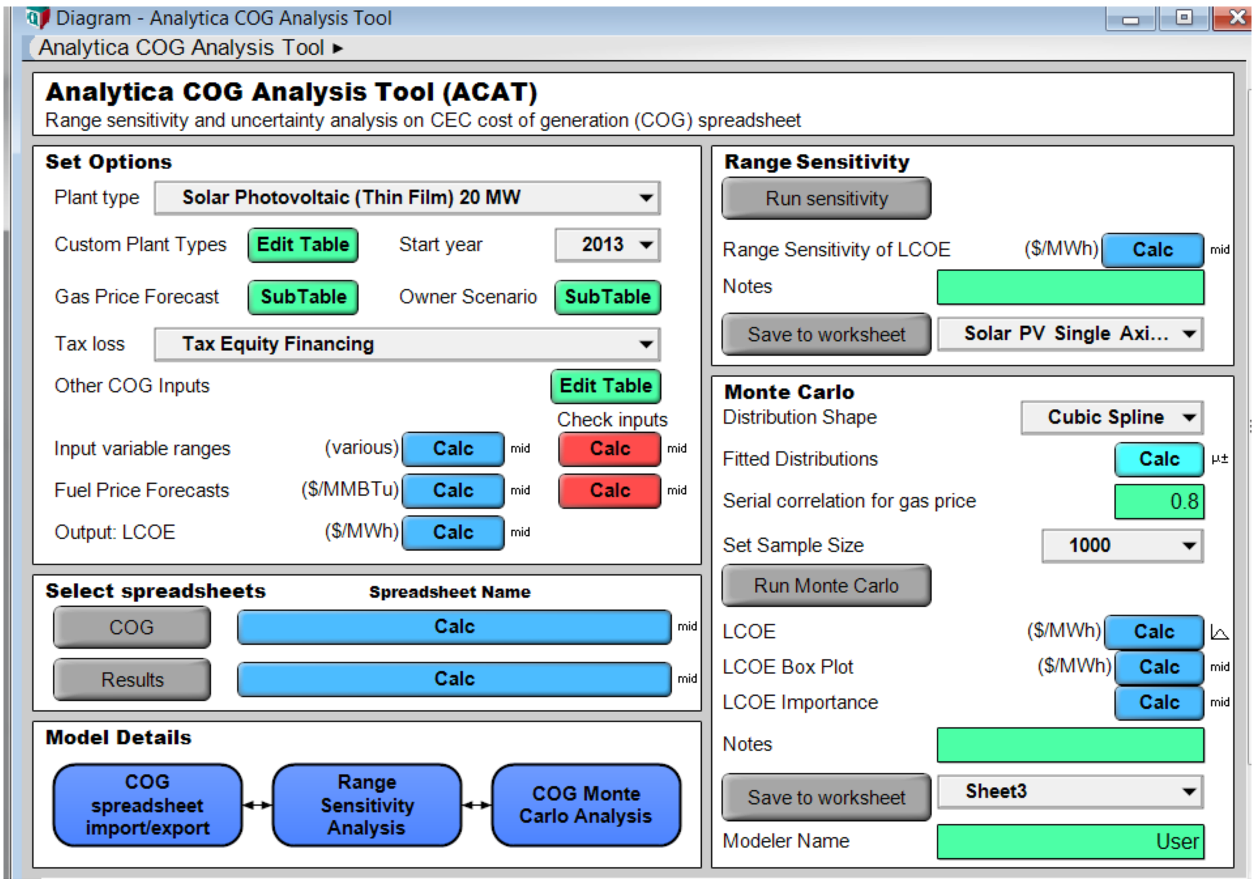


Source: Energy Commission.

If two or more of the percentiles have the same value (for example, if x10 = x50), it has a vertical step in the cumulative distribution and corresponding delta function in the density function. The shape is symmetrical if the specified percentiles are symmetrical. The spline assures a smooth slope on the cumulative distribution, but may have a discontinuous slope on the density function.

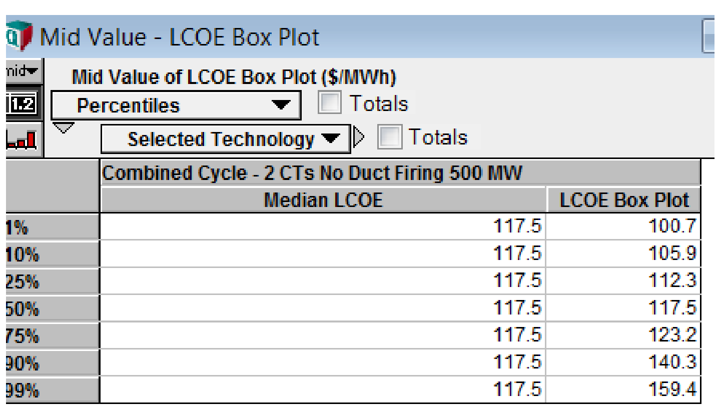
Figure D-8 shows the interface for the ACAT Model. Key features are selecting the plant type, running Monte Carlo, and reading the results from the LCOE box plot, as shown in **Figure D-9.**

Figure D-8: ACAT Interface



Source: Energy Commission.

Figure D-9: ACAT LCOE Box Plot


Mid Value - LCOE Box Plot

Mid Value of LCOE Box Plot ($/MWh)

Percentiles | Totals

Selected Technology | Totals

	Combined Cycle - 2 CTs No Duct Firing 500 MW	
	Median LCOE	LCOE Box Plot
1%	117.5	100.7
10%	117.5	105.9
25%	117.5	112.3
50%	117.5	117.5
75%	117.5	123.2
90%	117.5	140.3
99%	117.5	159.4

Source: Energy Commission.