IER INSTITUTE FOR ENERGY RESEARCH

The Levelized Cost of Electricity from Existing Generation Resources

JULY 2016 | THOMAS F. STACY | GEORGE S. TAYLOR, PH.D.

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Introduction

In this paper, we analyze publicly available data to establish the average levelized cost of electricity from existing generation sources, or "LCOE-E." This new measure is a crucial piece of information that has been missing from the electricity policy discussion. The LCOE-E data and framework we introduce in this report offer policymakers a powerful tool as they make decisions that affect the cost of electricity in the U.S.

What is the levelized cost of electricity? The approach taken by the federal Energy Information Administration (EIA) to answer that question ignores the cost of electricity from all of our existing resources and publishes LCOE calculations for new generation resources only. If no existing generation sources were closed before the end of their economic life, EIA's approach would provide sufficient information to policymakers on the costs of different electricity policies.

However, in the current context of sweeping environmental regulations on conventional generators—coupled with mandates and subsidies for intermittent resources—policies are indeed forcing existing generation sources to close early. Federal policies alone threaten to shutter 110 gigawatts of coal and nuclear generation capacity.[1] The LCOE-E we introduce in this paper allows for much-needed cost comparisons between existing resources that face early closure and the new resources favored by current policy to replace them.

First, our findings show the sharp contrast between the high cost of electricity from new generation resources and the average low cost from the existing fleet. Existing coal-fired power plants, for example, generate reliable electricity at an LCOE-E of $39.9 per megawatt-hour on average. Compare that to the LCOE of a new coal plant, which is $95.1 per megawatt-hour according to EIA estimates. This analysis also shows that, on average, continuing to operate existing natural gas, nuclear, and hydroelectric resources is far less costly than building and operating new plants to replace them. Existing generating facilities produce electricity at a substantially lower levelized cost than new plants of the same type. This analysis uses forward-looking LCOE based on estimates by EIA to compare with our estimates of LCOE from existing facilities.

Second, we adjust the LCOE estimates provided by EIA to reflect the average real-world capacity factors of different generation resources on the power grid. We find that EIA's estimates of the LCOE for new generation resources are low, because EIA provides these estimates at high levels of utilization relative to historical levels. For our LCOE estimates, we use the most recent delivered fuel price data instead of EIA estimates of future fuel prices.

Third, we estimate the amount intermittent resources increase the LCOE for conventional resources by reducing their utilization rates without reducing their fixed costs. We refer to these as "imposed costs," and we estimate them to be as high as $25.9 per megawatt-hour of intermittent generation when we model combined cycle natural gas energy displaced by wind, and as high as $40.6 per megawatt-hour of intermittent generation when we model combined cycle and combustion turbine natural gas energy displaced by PV solar.[2]

The LCOE-E framework allows for cost comparisons that are relevant for today's energy policymakers. For example, when all known costs are accurately included in the LCOE calculations, we find that existing coal ($39.9), nuclear ($29.1), and hydroelectric resources ($35.4) are about one-third of the cost of new wind resources ($107.4) on average and one-fourth of the cost of new PV solar resources ($140.3).[3] By increasing the transparency of the costs associated with policies favoring new resources over existing conventional resources, we hope to inform policymakers with the best available data and raise the level of the electricity policy debate.

About the Authors

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Tom Stacy has dedicated the past eight years to education and research in electricity generation, wholesale market design and public policy with a focus on the dynamics of grid-scale wind electricity; has served on the ASME Energy Policy Committee; has testified before Ohio energy policy related legislative committees numerous times, many by invitation from their chairpersons. He continues to help state lawmakers come to terms with the electricity system's complex economic and technical issues and base the state's electricity related laws and regulations on conservative economic, sound engineering, and prudent land use principles. He holds a B.A. in Industrial Marketing from the Ohio State University's Fisher College of Business.

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Executive Summary

The purpose of this report is to compare the cost of electricity from existing generation resources with the cost from new generation resources that might be constructed to replace them. To date, the Levelized Cost of Electricity from new generation resources (LCOE) has been the primary focus of "cost of electricity" comparison studies and debates. Our calculation of levelized cost from existing resources (LCOE-E) offers policymakers a more accurate depiction of the tradeoffs involved in decisions affecting the electricity industry. LCOE-E is based on data from two government sources – Federal Energy Regulatory Commission (FERC) Form 1 and Energy Information Administration (EIA) Form 860.

Decision-makers often compare levelized cost of electricity from various types of new power plants that might be built to serve society in the future. One such comparison, a part of the EIA's Annual Energy Outlook (AEO) includes a projection for the LCOE from new generation facilities that could be brought online in the future. EIA defines LCOE as "the per-megawatt-hour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle."[4] EIA's estimates of LCOE are the most widely accepted and commonly used version of the LCOE methodology.

LCOE comparisons can be quite useful if they encompass a wide range of likely alternatives. However, one of the clear deficiencies of most LCOE reports has been the absence of any information about the cost of electricity from existing generation resources, even though those resources supply all of our electricity today and most of them could continue to supply reliable electricity at the lowest cost for years – even decades to come.

On the other hand, if regulators or lawmakers force power plants to retire earlier than they would have otherwise, the price of electricity must increase to pay for the incremental cost of replacement capacity. Because electricity is an essential input to nearly all goods and services, the cost of replacing operationally sound, least cost electricity-producing power plants with new ones that produce electricity at a higher levelized cost ripples throughout the domestic economy.

This report provides a baseline from which policymakers can assess the cost of replacing existing plants with new ones.

Our analysis is based on data reported to federal government agencies, EIA and FERC. The data suggest that on average each resource category's existing power plants have lower fixed costs and similar variable costs compared to their most likely replacements. The primary reason new power plants have higher LCOE is because they begin their operational lives with a full burden of construction debt and equity investment to repay. Since existing power plants have already repaid some or all of those obligations, their fixed costs going forward are lower. To the extent power plants of the same type outlive their "mortgages," they enjoy far lower fixed costs of operation, and thus are likely to be capable of supplying electricity at a lower cost overall.

Data sources mined for this report indicate that for all major generation resources, the fleet-average cost of electricity from existing power plants is less than the fleet-average cost of electricity from new power plants of the same type. We also examine a best-case scenario for new plants using a hypothetically achievable capacity factor that, in most cases, is higher than observed data.

Table 1A Table 1A

EXISTING VS. NEW (2013 $/MWh)

GENERATOR TYPE	LCOE of Existing Generation (at actual 2015 Capacity Factors and Fuel Costs)	LCOE of New Generation (at actual 2015 Capacity Factors and Fuel Costs)
DISPATCHABLE FULL-TIME-CAPABLE RESOURCES		
Conventional Coal	39.9	N/A[4]
Conventional Combined Cycle Gas (CC gas)[1]	34.4	55.3
Nuclear	29.1	90.1
Hydro	35.4	122.2
DISPATCHABLE PEAKING RESOURCES		
Conventional Combustion Turbine Gas (CT gas)	88.2	263.0
INTERMITTENT RESOURCES - AS USED IN PRACTICE	N/A[3]	
Wind including cost imposed on CC gas	N/A[3]	107.4 +other costs[5]
PV Solar including cost imposed on CC and CT gas[2]		140.3 +other costs[5]

Table 1B Table 1B

NEW VS. NEW (2013 $/MWh)

GENERATOR TYPE	LCOE of New Generation (at actual 2015 Capacity Factors and Fuel Costs)	LCOE of New Generation (at EIA-Assumed Capacity Factors and Fuel Costs)
DISPATCHABLE FULL-TIME-CAPABLE RESOURCES		
Conventional Coal	N/A[4]	95.1
Conventional Combined Cycle Gas (CC gas)[1]	55.3	75.2
Nuclear	90.1	95.2
Hydro	122.2	83.5
DISPATCHABLE PEAKING RESOURCES		
Conventional Combustion Turbine Gas (CT gas)	263.0	141.5
INTERMITTENT RESOURCES - AS USED IN PRACTICE	N/A[3]	
Wind including cost imposed on CC gas	107.4 +other costs[5]	73.6 +other costs[5]
PV Solar including cost imposed on CC and CT gas[2]	140.3 +other costs[5]	125.3 +other costs[5]

[1] Fuel costs derived using most recent (2015) delivered fuel price and heat rate data from EIA.

[2] PV solar LCOE based on EIA 860 reported capacity factor of 25.9% and adding back imposed costs of 3rd % PV market share

[3] Lack of sufficient FERC Form 1 data prevented us from producing estimates of LCOE-E for wind and PV Solar.

[4] Regulations from the Environmental Protection Agency currently prevent new construction of coal-fired power plants. Specifically, the EPA's New Source Performance Standards for CO2 are a de facto mandate for carbon capture and sequestration (CSS) for coal plants, and CCS is not a commercially viable technology.

[5] "Other Costs" could add $25 - $50 per MWh and include transmission costs and subsidies not considered by EIA in their calculation of LCOE. Further, EIA makes no distinction between the 20-25 year expected lifespans of win and solar facilities vs. the 50+ year lifespans of most other technologies. See the following publications: *http://www.nrel.gov/docs/fy11osti/47078.pdf* , *http://eelegal.org/?page_id=1734*

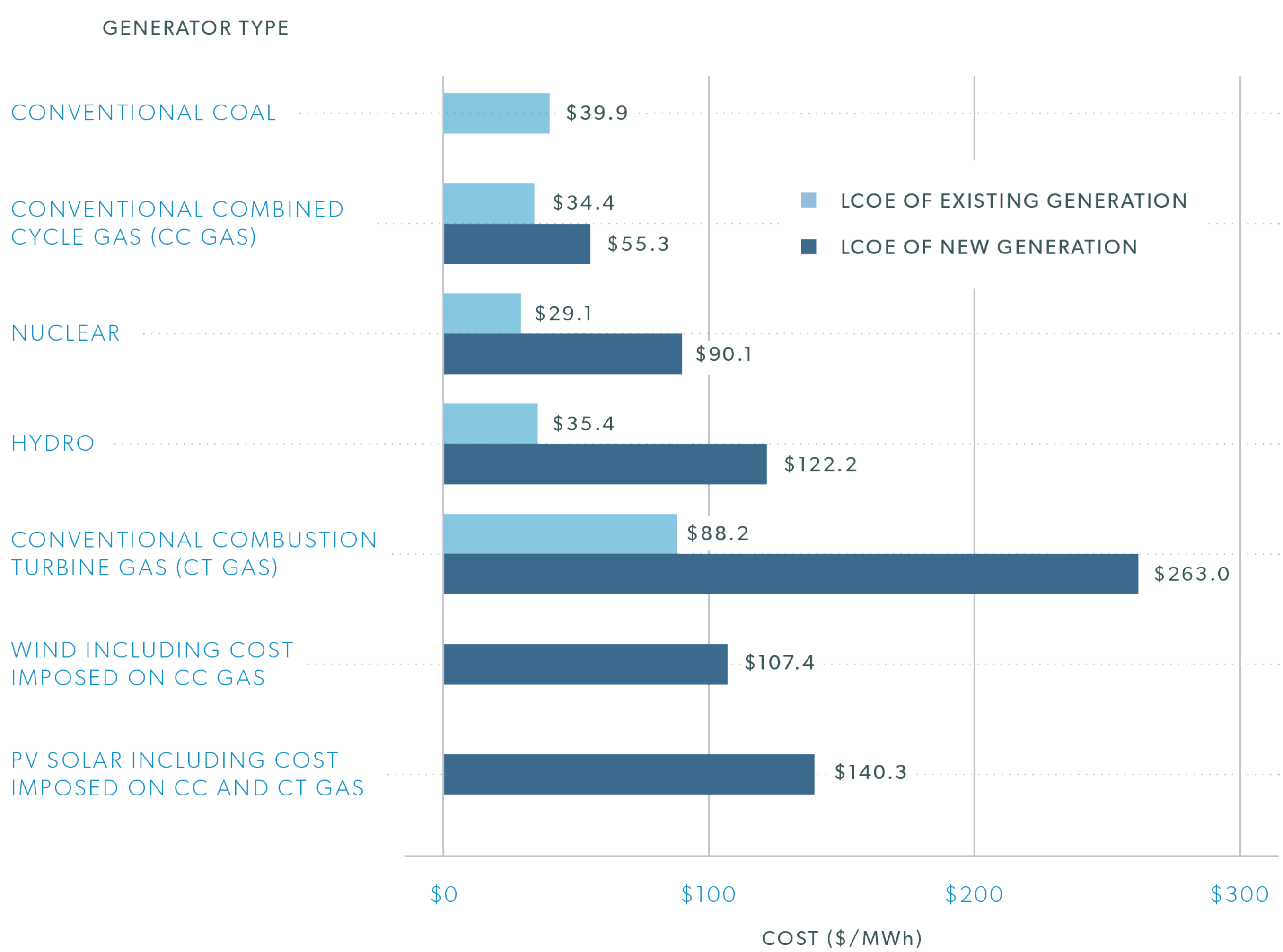
Table 1A shows the levelized cost of electricity (LCOE) for existing resources--as derived using the FERC Form 1 database--and compares that to the LCOE for new resources. As Table 1A makes clear, the cost advantage of existing resources over new sources is pronounced. For both columns in Table 1A, we use 2015 fuel cost and capacity factor data from the Energy Information Administration (EIA). This allows us to make the most direct, apples-to-apples comparison between the LCOE of existing and new resources.

Table 1B highlights our adjustments to EIA's methodology in reporting the LCOE of new resources. Two key adjustments have substantial impacts on LCOE: 1) replacing EIA's fuel cost projections with 2015 data significantly lowers the LCOE of natural gas-fueled generation resources (CC gas and CT gas), and 2) using actual capacity factor data from 2015 (as opposed to EIA's "best-case" capacity factor assumption) affects all resources, but in different directions.[5] For example, it raises the LCOE for CC gas, CT gas, hydro, and wind while it lowers the LCOE for nuclear and solar.

Environmental Regulations + Subsidies and Mandates for Renewables are Driving Most New Generating Capacity Construction, Not New Electricity Demand

The reason the cost of generation from existing sources is so important is that government mandates, regulations and subsidies (not additional demand) are driving the construction of new generation resources.

LEVELIZED COST OF ELECTRICITY



FERC Form 1 and EIA 860 show that, in the absence of mandates, subsidies and regulatory compliance costs, the cost of electricity from almost all existing generation resources will remain less than the cost of electricity from their likely replacements for at least the next 10 to 20 years.

In fact, in their 2014 State of the Market report to FERC, grid operator PJM's Independent Market Monitor stated that: "Subsidies in the form of additional out of market revenue is not consistent with the PJM market design. The result would be to artificially depress prices in the PJM capacity market. This would negatively affect the incentives to build new generation and would likely result in a situation where only subsidized units would ever be built."[6]

From 2004 through 2014, electricity demand in the United States increased by an average of 0.3% percent per year.[7] Absent mandates for new generation and the onset of new federal environmental regulations forcing some coal fired generating capacity to retire, almost no new generation capacity would have been necessary over that ten-year period.

Longevity of the Existing Fleet

Forms 1 and 860 data indicate that most existing power plants could remain economically viable for years or decades beyond their current age. While existing resources remain our lowest cost option, regulatory compliance costs and artificial "wholesale price suppression" brought about by subsidizing and mandating higher cost and lower value technologies (for example, through the wind production tax credit, solar investment tax credit, and renewable energy mandates) combined with wholesale price caps cause low-cost existing dispatchable resources to operate at a financial loss. These external influences are not consistent with cost-minimizing market design. The result is that some existing resources may be operating at a net financial loss even while their likely replacements would produce electricity at a substantially higher cost.[8] The lowest possible electricity rates will only be achieved by keeping existing generating resources in operation until their product becomes uneconomic– not relative to suppressed wholesale market clearing prices, but rather *relative to the levelized cost of electricity from new sources that would replace them.*[9]

Conclusion

Most existing coal, natural gas, nuclear, and hydroelectric generation resources could continue producing electricity for decades at a far lower cost than could any potential new generation resources. At a typical coal-fired power plant, for example, when a component wears out, only the component must be replaced, not the entire plant. The same is true for nuclear plants, until they reach their regulatory end of life, which is currently defined to be 60 years, but could be extended to 80 years.[10] Under current laws, rules, and regulations, large amounts of generating capacity are slated to retire and will be replaced with new generating capacity, which will produce electricity at a far higher average levelized cost. The Institute for Energy Research identified more than 110 gigawatts of coal and nuclear generation capacity set to close as a direct result of federal regulations.[11]

When electricity from an existing electric generating plant costs less to produce than the electricity from the new plant technology expected to be constructed to replace it—and yet we retire and replace the existing plant despite the higher costs—ratepayers must expect the cost of future electricity to rise faster than it would have if we had instead kept the existing power plants in service.

An unprecedented amount of generating capacity is set to close due to ongoing renewable policies, undervalued capacity markets, currently low natural gas prices, and additional environmental regulations. In the absence of even some of these factors, most existing power plants would remain operational, helping keep electricity costs low for many years or decades into the future.

[1] *This estimate was made before finalization of the Clean Power Plan, which will increase the amount of coal-fired power plants shuttered by federal policy tremendously.*

[2] *At six percent PV solar energy market share modeled vs. CAISO load profile and sunlight profiles.*

[3] *At three percent energy market share for PV solar and capacity factor adjusted US average PV solar LCOE, based on CAISO load and solar resource availability profiles.*

[4] *Energy Information Administration, Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2014, Apr. 17, 2014.*

[5] *Capacity factor is the average output of a plant or fleet over time divided by the theoretical maximum output of that plant or fleet, and is listed as a percentage. For example, EIA's best-case capacity factor for CC gas used in its LCOE estimates is 87 percent, and the actual capacity factor observed for the CC gas fleet in 2015 was 56.3 percent.*

[6] *Testimony of Monitoring Analytics, Dr. Joe Bowring, to the Ohio Electricity Mandate Costs Legislative Study Committee, April 16th, 2015 available through the office of the committee chairman, 131st Ohio General Assembly Senator Troy Balderson.*

[7] *Energy Information Administration, www.eia.gov/electricity/monthly Monthly Energy Review, Table 7.2a Electricity Net Generation: Total (All Sectors), February 2015, http://www.eia.gov/totalenergy/data/monthly/pdf/sec7_5.pdf*

[8] *http://www.monitoringanalytics.com/reports/Reports/2011/IMM_Comments_to_MDPSC_Case_No_9214_20110128.pdf Section 1 B, page 5*

[9] *Low-cost natural gas is another factor influencing the retirement of coal (and even some nuclear) capacity. Competitive marginal prices for CC gas energy place downward pressure on clearing prices, which in turn reduce the revenues accruing to all technologies. A properly valued and functioning capacity market should result in capacity market clearing prices sufficient to carry existing capacity contributors (in this case coal and nuclear) through any short-term reduction in gross margin and/or capacity factor.*

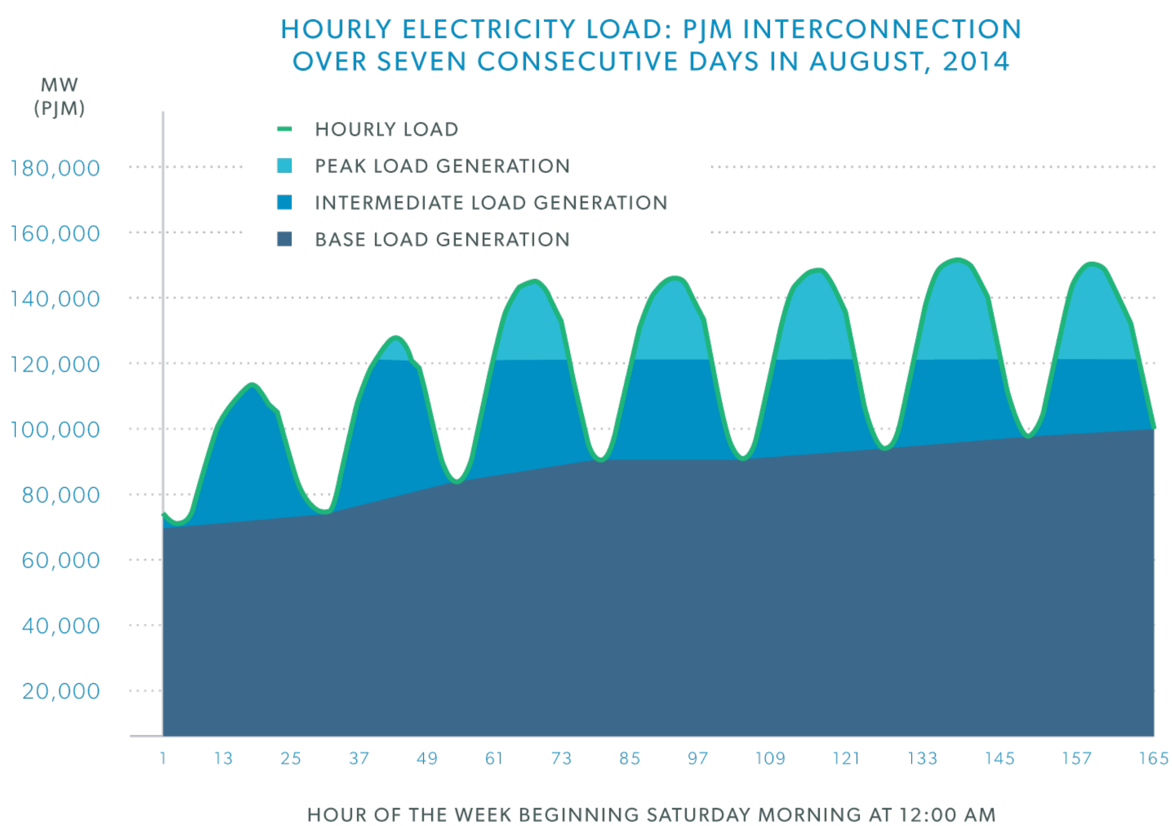
[10] *Katherine Tweed, APS Argues to Extend Lifespan of Nuclear Reactors to 80 Years, IEEE Spectrum, Dec. 12, 2013, http://spectrum.ieee.org/energywise/energy/nuclear/aps-argues-to-extend-lifespan-of-nuclear-reactors-to-80-years . The American Physical Society argues that there are no technical barriers to run nuclear power plants for up to 80 years—20 years beyond the current maximum 60-year life of nuclear power plants.*

[11] *Travis Fisher, Assessing Emerging Policy Threats to the U.S. Power Grid, Institute for Energy Research, Feb. 24, 2015, http://instituteforenergyresearch.org/wp-content/uploads/2015/02/Threats-to-U.S.-Power-Grid.compressed.pdf . The estimate was made based on federal policies, not including EPA's Clean Power Plan, which was not finalized at the time of the study.*

I. IDENTIFYING VALUE-COMPARABLE GENERATION RESOURCE CATEGORIES

Valid LCOE Comparison Must Be Limited to Generation Resources with Similar Performance Capabilities/Characteristics

One of the most commonly overlooked aspects of comparing the cost of electricity from different sources is that different generating resources play different roles in keeping the electricity grid in balance. Some are designed to run almost all the time at a fairly steady level (base load) while others run part of the time (load following). Still others are designed to run only a few hours per day or year, and must adapt quickly to changes in demand or supply (peaking resources). For this reason, peaking resources should not be electricity-cost compared with nuclear designed for base load operation, or with coal or CC gas units designed for base load and load following. That is why this report lists peaking resources in a separate section from base load generators; in the same way, EIA lists non-dispatchable resources in a separate section of its LCOE Table 1.



It would be convenient for cost comparison purposes if all types of electricity generators could serve the entire demand market, but that is not realistic. Electricity has no shelf life. It is instantaneously perishable, so it cannot be produced now and used several hours, days, weeks or months later without large scale "batteries" or other mass electricity storage devices that convert the electricity to some other form of energy (such as chemical or kinetic potential), store it, and then convert it back into consumable electricity.

Because most bulk electricity storage options add more cost than the potential savings, fuel storage (where possible) remains the most prudent choice. For technologies whose fuel cannot be stored and will not always be available in accordance with electricity demand, the cost of necessary storage capacity to bring it to the same dispatchability standards as conventional generators must be counted as part of the cost of those technologies.

Another option is to force dispatchable generators to "back down" relative to their previous levels whenever non-dispatchable generators produce electricity. As with electricity storage, there are both potential costs and savings in doing so. The savings are in the form of lower variable costs (including some fuel savings) of the dispatchable fleet. The costs are more complicated and stem from the unchanged fixed costs of dispatchable generators having to be recovered through the sale of less electricity long-term (because the dispatchable generators are backing down to accommodate non-dispatchable resources). In this report, we refer to these costs as "imposed costs."

If we could build fewer dispatchable resources as we add non-dispatchables, these imposed costs would not exist. Unfortunately the "replacement value" of some nondispatchable resources for dispatchable resources is very low–close to zero–as measured by their guaranteed performance across the hours of the year society requires the greatest amount of electricity.

We are fortunate to have the means to store electricity-generating fuels and deliver them to the generators in the amounts and at the times electricity is needed. These fuels—primarily coal, natural gas and uranium—provide prompt and consistent generation of electricity in accordance with electricity demand, which is integral to electricity's value proposition. For that reason, LCOE comparisons are valid only between resources with similar performance characteristics: that is, between technologies that are able to consistently and reliably serve the same segments of electricity demand. EIA partially represents this by listing non-dispatchable technologies such as wind and solar in a separate section of its LCOE Table 1, making special note just prior to its summary tables: "The duty cycle for intermittent renewable resources, wind and solar, is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset) and so will not necessarily correspond to operator dispatched duty cycles. As a result, their LCOE values are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar) and therefore are shown in separate sections within each of the tables."[12]

Table 1 of EIA's LCOE lists the high end of achievable annual capacity factors for each technology for dispatchable resources and a simple estimate of average capacity factors expected for the next non-dispatchable resources to be built in each region of the United States. The latter may be optimistic for wind, given that some U.S. regions have extraordinarily weak wind resources. An exploration of estimated capacity factors for marginal wind and solar resources is beyond the scope of this report, but merits further study. Nevertheless, these high end and estimated-marginal-average capacity factors may have been displayed in EIA Table 1 to assist readers in further distinguishing between the capabilities of different dispatchable technologies in order to avoid an invalid LCOE comparison between full-time-capable and part-time-capable dispatchable resources which serve different market segments. EIA says: "In Table 1 and Table 2, the LCOE for each technology is evaluated based on the capacity factor indicated, which generally corresponds to the high end of its likely utilization range."

But natural gas and coal resources tend to operate at capacity factors significantly lower than "the high end of their utilization range" as shown in Table 2 of this report.[13] Capacity factors directly impact levelized cost calculations because the present value of fixed costs over a unit's cost recovery period is converted to a fixed cost per MWh when calculating LCOE. In other words, a lower capacity factor means fewer operating hours and hence a higher fixed cost per MWh and higher overall LCOE.

Therefore, EIA's LCOE estimate is biased in favor of those technologies for which EIA's assumed capacity factor is higher than the actual capacity factor. As discussed, this report makes a further distinction within EIA's category "Dispatchable Technologies," dividing them into two separate categories: "Dispatchable Full Time Capable Resources," and "Dispatchable Peaking Resource," Combustion Turbine (CT) gas, which is expected to be called on and to run reliably, primarily at times of high electricity demand.

Base Load (Full-Time-Capable) Resources

Nuclear, coal, and CC gas electricity are commonly deployed through facilities designed to produce:

- at or near full nameplate capability
- for sustained periods of time from several days to several months

Many hydroelectric resources operate the same way, although their capacity may vary from one time of the year to another. These operating characteristics promote the highest fuel efficiencies and lowest variable costs, as well as the lowest emissions intensities.

Peak Demand Resources

CT gas facilities are designed to minimize fixed costs in anticipation of the low utilization rate associated with serving peak demand. The trade-off is lower fuel efficiency, higher variable costs and higher emissions intensity. Because CT gas units produce relatively small amounts of energy on an annual basis, low fixed costs take precedence over low fuel cost and emissions. While EIA lists a possible 30 percent capacity factor for CT gas, FERC Form 1 and EIA 923 data indicates that CT gas units typically have capacity factors in the mid to high single digits. A report prepared under contract to EIA assumes a 10 percent capacity factor for CT gas units in its calculation of fixed costs per MWh, while Electric Power Monthly shows real world capacity factors for CT gas units average 6.7 percent.[14] Since CTs were not intended to be full time resources, they are not direct replacements for nuclear, coal or CC gas units.

Intermittent Fuel Resources

EIA refers to hydroelectric, wind and solar as "Non-Dispatchable Resources" because they consume fuels whose availability is not under human command. Such units can be turned down or off, ("downward dispatchable") but they cannot produce more electricity than their fuel streams permit. Wind generation is particularly problematic, because across most of the United States its season of lowest production corresponds with the season of highest demand (summer).

Solar photovoltaic (PV) has the advantage of producing during daytime hours when demand is high. However, electricity demand remains high for several hours after solar radiation has declined in late afternoon. Therefore, even though solar generation's correlation with demand is higher than wind generation's, solar still has limited value as a replacement for "peaker" power plants whose fuel can be consumed precisely and only at peak demand times. Because combustion turbines (peaker plants) are less fuel-efficient than other dispatchables, solar PV saves more fuel per MWh of generation than wind. Neither solar PV nor wind, however, are good substitutes for base or intermediate load power plants.

The range of different hydroelectric facility capabilities means hydro does not fit neatly in any particular segment of a LCOE table. "Run of river" hydroelectric power could be shown in the intermittent or dispatchable category depending on the water resource feeding any given hydroelectric facility. Many current hydro facility locations and designs offer some fuel supply certainty over time (or "storage") in the form of regular precipitation, melting snow pack and/or ground saturation over a facility's feedstock watershed, or through impoundment capability (deep water stored behind tall dams), which allows them to operate much like dispatchable generators for weeks or even months at a time. Periodic shortages of water for hydro develop gradually and are far more foreseeable than shortages in wind velocity.

Due to untimely changes and low availability of their fuels during hours of peak demand, wind and solar resources are not direct or complete substitutes for dispatchable resources. They are instead "supplemental" options that reduce the fuel consumption and utilization rates of "dispatchable" units without replacing the need to build and maintain those units. Wind and solar therefore can be thought of as "energy only" resources that save a portion of the variable costs (fuel and variable operations and maintenance or O&M), but little or no fixed costs.

To make it possible for policymakers to compare the cost of electricity from all available technologies, the body of this report examines each intermittent resource as part of a fulltime-capable "combination" of resources composed of the intermittent resource and a full-time-capable dispatchable resource, the combination of which can deliver approximately the same levels of capacity and energy as the dispatchable resource by itself. Namely, we examine two hybrid sources of firm capacity: 1) CC gas plus wind, and 2) CC and CT gas plus PV solar. The LCOE of these two combinations is derived from the costs of the two components.

FOOTNOTES: IDENTIFYING VALUE-COMPARABLE GENERATION RESOURCE CATEGORIES

[12] *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm*

[13] *http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a* ***and*** *http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_b*

[14] *"..assumed 10 percent annual capacity factor and an operating profile of approximately 8 hours of operation per CT start." http://www.eia.gov/oiaf/beck_plantcosts/pdf/updatedplantcosts.pdf (8-5) Actual class average CT capacity factor across the system in 2015 was 6.7% http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_a*

II. LCOE-E DATA SOURCES AND METHODOLOGY

Determination of LCOE from Existing Resources

This report uses data from two federal databases to calculate the levelized cost of electricity from existing power plants (LCOE-E). The first is the Federal Energy Regulatory Commission's (FERC's) Form 1 database.[15] Form 1 filings include annual fuel consumption, electricity generation and cost data from all non-government-owned power plants. Data for the past twenty years' filings are available to the public with some exceptions. The second data source is EIA's Form 860. Form 860 contains much of the same information as Form 1 (except cost and generation data), but also identifies the technology employed at each power plant, the types of fuel consumed, and unit capacity ratings.

All commercial electricity generators are required to file Form 1 annually. This form is "a comprehensive financial and operating report submitted for Electric Rate regulation and financial audits."[16] To produce this report, we collected, sorted and evaluated data from each of the 20 years of FERC Form 1 filings available on line. Specifically, nameplate capacity (MW), annual generation (KWh/yr.), ongoing capital expense (nominal $ since inception), annual operating expense including fuel (nominal $/YR) and fuel expense (nominal $/YR).

EIA Form 860 "collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants with 1 megawatt or greater of combined nameplate capacity."[17] While Form 1 is the only public source of financial data from commercial power plants, it allows open text responses in some fields such as unit name, generator technology and fuel type. Form 860 limits respondents' entries regarding plant name, unit name, fuel type and generator technology (prime mover) to specific ID numbers and codes, restrictions which facilitate sorting and disambiguation. Form 860 also serves as a cross reference for other generator attributes and facts such as physical address, nameplate capacity, grid control region and RTO/ISO interconnection.

Most wind and solar facilities have either not submitted Form 1, have been permitted to complete the form only partially, or have requested their entries be redacted from the public record. Of those that did report, more than half were incomplete or unusable. This resulted in a sample that could not be used to estimate levelized cost. As a result, the cost of existing sources of wind and solar versus the other sources of electricity generation could not be calculated using a consistent methodology. For these reasons, this report does not estimate LCOE-E for wind or solar.

FERC Form 1 Data

FERC Form 1 is maintained as 20 databases--one for each of the past twenty years. For this report we collected data for each plant for all twenty years. All thermal sources (Coal, CT Gas, CC Gas, nuclear and dual fuel and dual output plants) report as steam plants. Hydro plants report on a separate page. The fields used to calculate LCOE from existing sources are highlighted in the following figure.

Name of Respondent	This Report Is: (1) ☐ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report End of ________

STEAM-ELECTRIC GENERATING PLANT STATISTICS (LARGE PLANTS)

1. Report data for plant in Service only.
2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants.
3. Indicate by a footnote any plant leased or operated as a joint facility
4. If net peak demand for 60 minutes is not available, give data which is available, specify period.
5. If any employees attend more than one plant, report on line11 the approximate average number of employees assignable to each plant.
6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct.
7. Quantities of fuel burned (Line38) and average cost per unit of fuel burned (Line41) must be consistent with charges to expense accounts 501/507 (Line42) as shown on Line 20.
8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)						
6	Net Peak Demand on Plant - MW (60 Minutes)						
7	Plant Hours Connected to Load						
8	Net Continuous Plant Capability (Megawatts)						
9	When Not Limited by Condenser Water						
10	When Limited by Condenser Water						
11	Average Number of Employees						
12	Net Generation, Exclusive of Plant Use - KWh						
13	Cost of Plant: Land and Land Rights						
14	Structures and Improvements						
15	Equipment Costs						
16	Asset Retirement Costs						
17	Total Cost *Reported as an aggregate figure since inception						
18	Cost per KW of Installed Capacity (line 17/5) Including						
19	Production Expenses: Oper, Supv & Engr						
20	Fuel * Reported as an annual expense						
21	Coolants and Water (Nuclear Plants Only)						
22	Steam Expenses						
23	Steam From Other Sources						
24	Steam Transferred (Cr)						
25	Electric Expenses						
26	Misc Steam (or Nuclear) Power Expenses						
27	Rents						
28	Allowances						
29	Maintenance Supervision and Engineering						
30	Maintenance of Structures						
31	Maintenance of Boiler (or reactor) Plant						
32	Maintenance of Electric Plant						
33	Maintenance of Misc Steam (or Nuclear) Plant						
34	Total Production Expenses * Annual						
35	Expenses per Net KWh						
36	Fuel: Kind (Coal, Gas, Oil or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned * Annual						
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)						
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year						
41	Average Cost of Fuel per Unit Burned						
42	Average Cost of Fuel Burned per Million BTU						
43	Average Cost of Fuel Burned per KWh Net Gen						
44	Average BTU Per KWh Net Generation						

FERC Form 1 Field Name Visual FoxPro Databases	Reason Field Collected
RESPONDENT_ID	Sorting field used to aggregate each plant's 20 years of data
REPORT_YEAR	Sorting field for chronological arrangement of values for each plant. To establish each plant's sample vintage and number of contiguous years in final sample.
PLANT_NAME	Name of plant. Used to sort polled database by plant. used to cross reference Form 1 data with EIA Form 860
PLANT_KIND	Used to preliminarily distinguish between nuclear, coal, and other types of primary units at each plant
YR_CONST	Used to track the age of the plant
YR_INSTALLED	Indicates the most recent year units were added
TOT_CAPACITY	Nameplate capacity of reported unit or entire plant. Used to calculate plant capacity factor.
PEAK_DEMAND	Not used in this report
PLNT_CAPABILITY	Not used in this report
NET_GENERATION	Annual generation figure. Used to convert annual expenses figures to $/MWh for each year for each round
COST_OF_PLANT_TO	Cumulative Capital Cost since inception reported annually. Includes construction cost. Subtracting each year's figure from the following year's reported figure yields annual capital expense.
EXPNS_FUEL	Annual fuel expense. Used to calculate the cost of fuel per MWh for each year in a plant record. Subtracting this from the tot_prdctn_expns yields Fixed + Variable O&M excluding fuel.
TOT_PRDCTN_EXPNS	Annual production expenses (includes fuel)(includes both fixed & variable operations expense)

Eliminating Plants and/or Years with Flawed or Incomplete Fields

The Form 1 database included some records in which fields were missing or contained erratic values. Records with data missing in fields required to calculate LCOE were discarded, as were records with erratic or unintelligible numbers and records where the plant name or specific unit in the plant could not be reconciled with the 2012 EIA 860 database.

For example, if a plant reported cumulative production expense figures that implied large negative values for some specific years, these might represent the correction of a previous error, but it is impossible to know which previous year or years were corrected. In this case, calculation of capital expense per MWh for any year would not be reliable. So for the plant in question, all years of and prior to any negative result(s) were omitted from the chronological plant record.

Discrimination of Useful from Incomplete/Invalid Form 1 Records

In cases of missing data: if at least three consecutive years of complete data were available in the years prior to or following the missing data, we included as many consecutive years with complete data as possible—and in some cases, included more than one (but not more than two), sample windows for the same plant. Dual windows for the same plant were treated as two separate samples.

When a plant record reported a change in nameplate capacity of 5% or more, we divided the chronological data for the plant into two independent samples where three or more years of data were available before and after the nameplate capacity change. Because such uprates were optional, and historical learning might incorporate such uprates for new plants, the year(s) of the uprate were omitted from the former and latter samples for that plant. In that sense we calculate LCOE-E under the assumption no additional downtime and capital expense will occur over the remaining lifespan of that plant.

The year of a plant's retirement was often marked by a steep reduction in annual capacity factor. Where these reductions were significant, we omitted the final year from a plant's sample window. Assuming a thirty year lifespan, omitting the final year of operations created at most a 3.3% opportunity for error and on average about half that. Since very few plants retired during the Form 1 data window, the average error due to omitting the final year of operation over our entire sample was even less.

Furthermore, since the final year could have been a partial year of operation, but the month of retirement was not often reported, inclusion of the final year also represented an opportunity for error. The same reasoning applies to omission of initial year data for plants which began operation within the 20-year span of the database.

Form 1 suggests categories and names for respondents to use in the "plant_kind" field found on page 402, but then allows respondents to enter open-ended text responses in the field. As a result, our confidence in the accuracy of data was low. Misspellings, multiple names for the same technology, and inaccurate information were entered into this field. Inconsistencies appeared not only from one plant to another, but sometimes from year to year at the same plant. This lack of data certainty and sortability necessitated cross referencing Form 1 "plant_kind" data for each plant with the more reliable EIA 860 generator level and plant level databases, as explained in the EIA 860 section below.

EIA 860 Data

As indicated above, in the Form 1 filings FERC allowed open ended text for the "plant_kind" field. We found that in the EIA 860 generator level database, the fields "prime mover" and "fuel type" were consistently filled out. The public database contained complete, reliable annual records for all power plant facilities, and for the generators or units within those facilities.

The following table shows fields collected from the 2012 plant level and generator level EIA 860 databases.

Once data were collected from both plant level and generator level 860 data sets, each facility's data were sorted and merged into a single row/record, similar to the procedure used with the Form 1 data.

Field Retrieved	EIA Plant Data	EIA Generator Data	FERC Form 1 Data
Utility ID	X	X	
Utility Name	X	X	
Plant Code	X	X	
Plant Name	X	X	INCS
Plant/Unit Ownership			X
County	X		
State	X	X	X
ISO RTO	X		
Prime Mover (generator technology)		X	INCS
Energy Source 1		X	INCS
Energy Source 2		X	
Operational Status		X	X
Nameplate Capacity	X	X	X
Summer Capacity	X	X	X
Unit Initial Operating Year	X		X
Annual Generation			RDCT
Annual Fuel Expense			RDCT
Annual Total Operations Expense			X
Annual Aggregated Plant Capital Spending			X

X	Reported Consistently	INCS	Reported Inconsistently	RDCT	Partially Redacted

Cross-Referencing Form 1 and 860 Records

Form 1 records for each plant were cross-referenced with 2012 EIA 860 plant and unit records, ascertaining/verifying the generating technology and fuel used at each plant. Plants and units we could not cross reference between Form 1 and 860 data sets were searched individually on the internet for utility industry and general news stories in an effort to create as complete and fully cross referenced Form 1 / EIA 860 data set as possible. Plants whose prime mover and/or fuel were still ambiguous were omitted from the sample.

Applying a Uniform Fuel Price to LCOE-E and LCOE-New

EIA publishes average delivered fuel prices by state for each month and year and a weighted average national annual figure for each fuel. In our calculations, we applied 2015 delivered fuel prices for natural gas and coal to both existing and new generation resources. Because future fuel price fluctuations will impact LCOE from both new and existing plants similarly, 2015 fuel prices were applied to both. We also note that fuel prices for natural gas were at historic lows in 2015 and have fluctuated considerably in the past decade. Hence the current very low LCOE for new and existing CC gas hinges critically on fuel price.

FOOTNOTES: LCOE-E DATA SOURCES AND METHODOLOGY

[15] *Federal Energy Regulatory Commission, Form 1 – Electric Utility Annual Report, Dec. 18, 2014,* http://www.ferc.gov/docs-filing/forms/form-1/data.asp

[16] *Federal Energy Regulatory Commission, Form 1 – Electric Utility Annual Report, Dec. 18, 2014,* http://www.ferc.gov/docs-filing/forms/form-1/data.asp

[17] *Energy Information Administration, Form EIA-860 detailed data, Feb. 17, 2015,* http://www.eia.gov/electricity/data/eia860/

III. DATA ANALYSIS

According to EIA, LCOE is "- the per-megawatt-hour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle."[18] Components of LCOE include:

- **Construction cost, typically paid using a blend of debt and owner equity with a repayment term for all technologies over the first 30 years of operation.**
- **Ongoing capital expenditures for upgrades and major overhauls**
- **Operations and maintenance expenses, which have fixed and variable components**
- **Fuel**
- **New transmission investment. Note that EIA's number for transmission investment does not take into account the likely physical location of any of the technologies examined in their report. Instead, EIA treats all technologies the same with regard to transmission investment.**

Because of the running total reported for cost of plant, construction cost is not independently reported in Form 1 records, except where the facility was constructed within the past 20 years. For the younger plants, we used the reported costs. For older plants, we used EIA's capital cost value for new plants of the same or similar technology, deflated to the year of the existing plant's construction as a proxy for actual construction cost.

Ongoing capital cost is reported as "Cost of Plant Total" in Form 1. This is a cumulative figure beginning with the year construction was commenced. For plants older than 20 years, the first year of available data for cost of plant total is a blended value of construction cost and ongoing annual capital expenditures through 1994.

An estimated adder for taxes, insurance and real cost of borrowing of 34 percent has been added to all capital costs per tables received from particular power plant financial officers.

Form 1 records show a total figure for operations and maintenance in each year's forms, showing both fixed and variable operations and maintenance expense and fuel. Fuel expense is reported in a separate field, allowing the derivation of total O&M excluding fuel. Fuel expense is then added back using 2015 delivered fuel prices. This was done because current fuel price is a better indicator of future fuel price than its historical fuel price.

Initial transmission costs for existing power plants were excluded because these costs are either fully repaid (in the case of older facilities) or are likely to be recovered through the rate base—even if the associated power plant retires prematurely.[19]

Next we converted historical year annual capital and O&M figures to 2013 dollars for every record[20] in the sample. We then divided annual capital and operations spending by annual net generation for each plant for each year to convert the figures into $/MWh.

U.S. average delivered cost of fuel per MWh was added at an assumed standard heat rate for each technology.

The remaining construction debt was calculated based on 30-year term from date of construction over the coming 30 years. Remaining debt and expected return on equity obligations make up a small fraction of levelized cost for existing resources.

The average of the coming thirty years' capital, O&M and fuel costs per MWh sum to the final levelized cost figure.

Present Value and Other Cost Adjustments

We applied an annual average rate of inflation to historical year reported data for O&M, construction cost and ongoing capital spending.[21] Only real rate of interest is implicit in the addition to capital cost described in the following section.

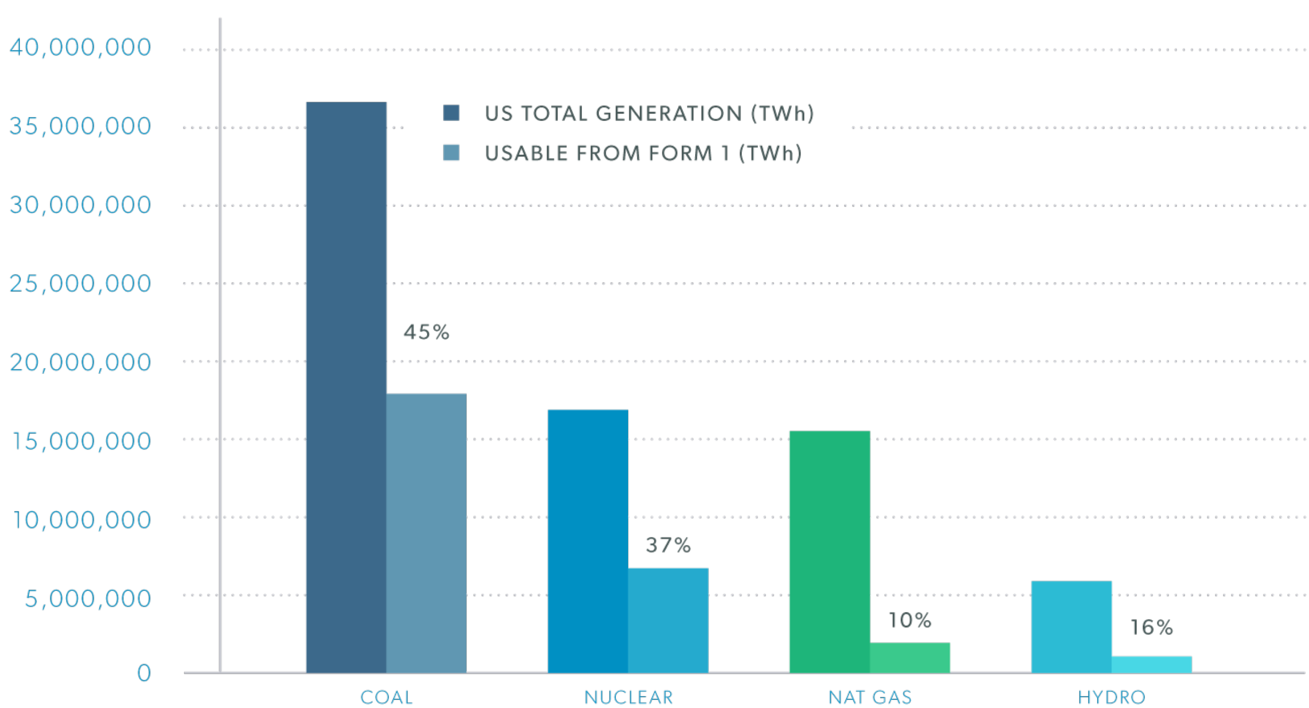
Applying Cost of Capital Adjustment to Ongoing Capital Expense per MWh

In the initial calculations of LCOE, we applied several factors:

- Inflation/present value factor: Using a table of historical inflation rates, we applied a present value calculation based on the mean age of each plant's sampled time window to bring all the figures to 2012 equivalent dollars.
- Real Cost of Capital, Insurance and Property Tax Multiplier: Based on recommendations from industry officials, we applied a fixed 34 percent adder to reported annual capital expense. While this may not be accurate for all plants or across technologies, using this average figure does not represent a significant error in the final results.

LCOE-E Form 1 Sample Size

The FERC Form 1 public database includes only data from non-government owned power plants. This represents a considerable limitation of our sample size compared to the entire grid-connected power plant fleet in the entire United States. The Form 1 database allows respondents open text entry of the name of the type of generating unit or units the respondents refer to in each form. For this reason, this report cross-referenced Form 1 records with the most recently available EIA Form 860 records.[22] The Form 860 records require respondents to choose from a specific list of fuel and prime mover (technology) codes. The EIA maintains Form 860 data for facilities generating units in separate files, with common fields across files so merging can be automated. Additionally, the 860 records make clear the nameplate capacity and age of each unit within each facility as well as the physical address, FERC market region and ISO/RTO (where applicable) of each plant. While the Form 1 data provided the necessary financial and electricity generation data, the 860 data provided a well-organized crosscheck as to what was actually being reported in FERC Form 1. The following figure shows the usable sample size in the Form 1 database over the years 1994 – 2013 vs. the installed capacity in the U.S. by generating technology.

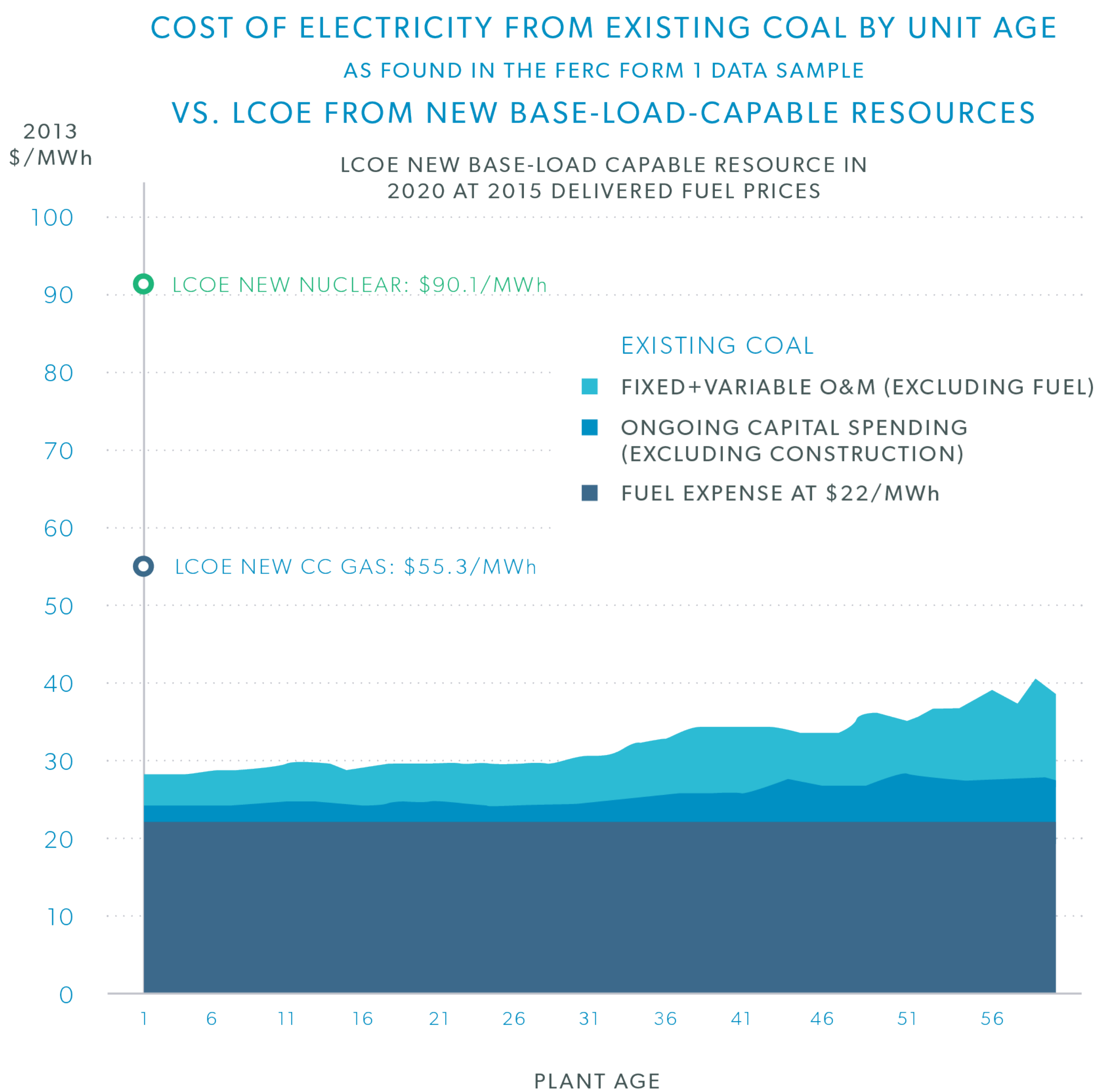


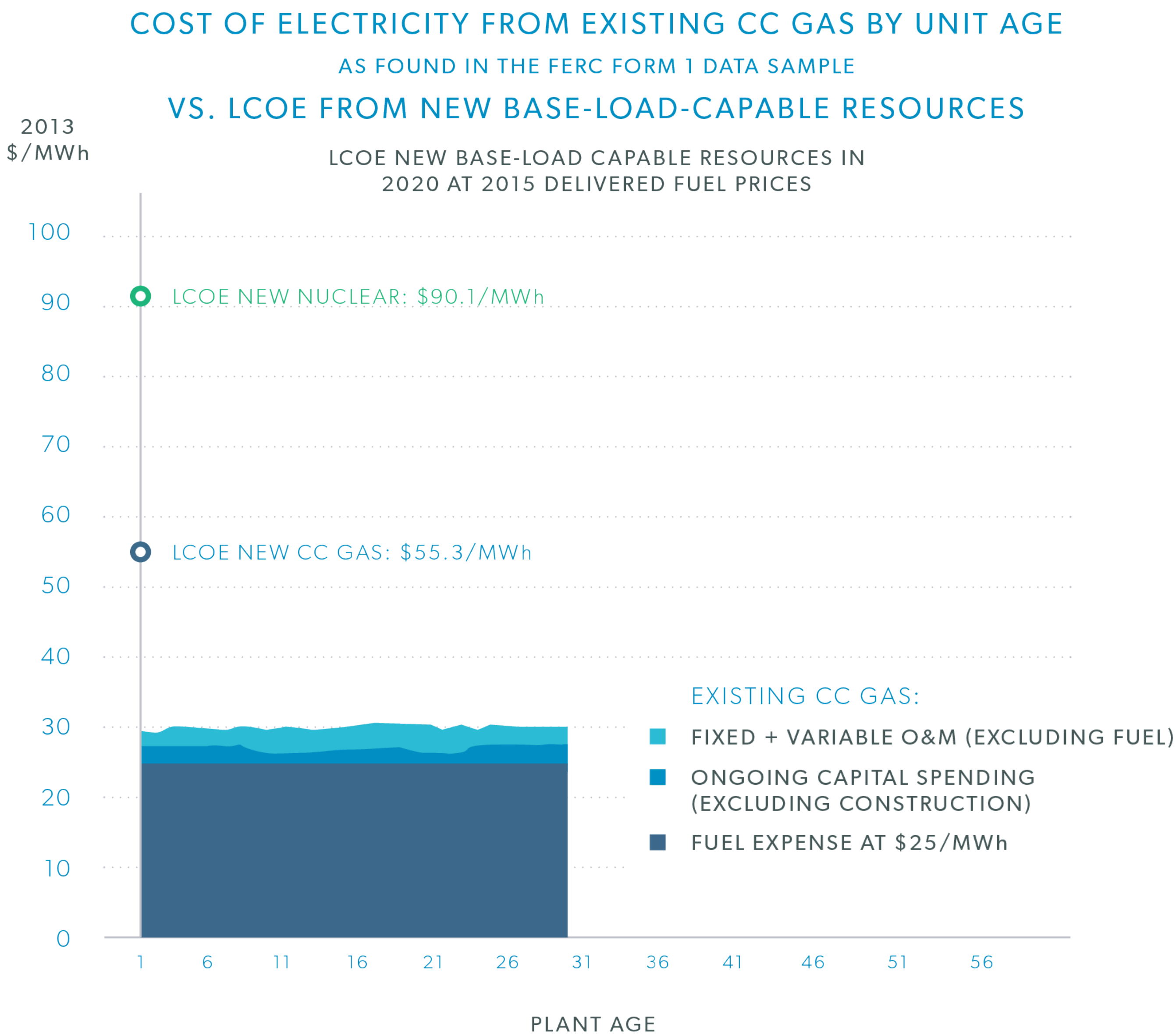
Capital Reinvestment and Operations Expense Trends by Technology by Plant Age

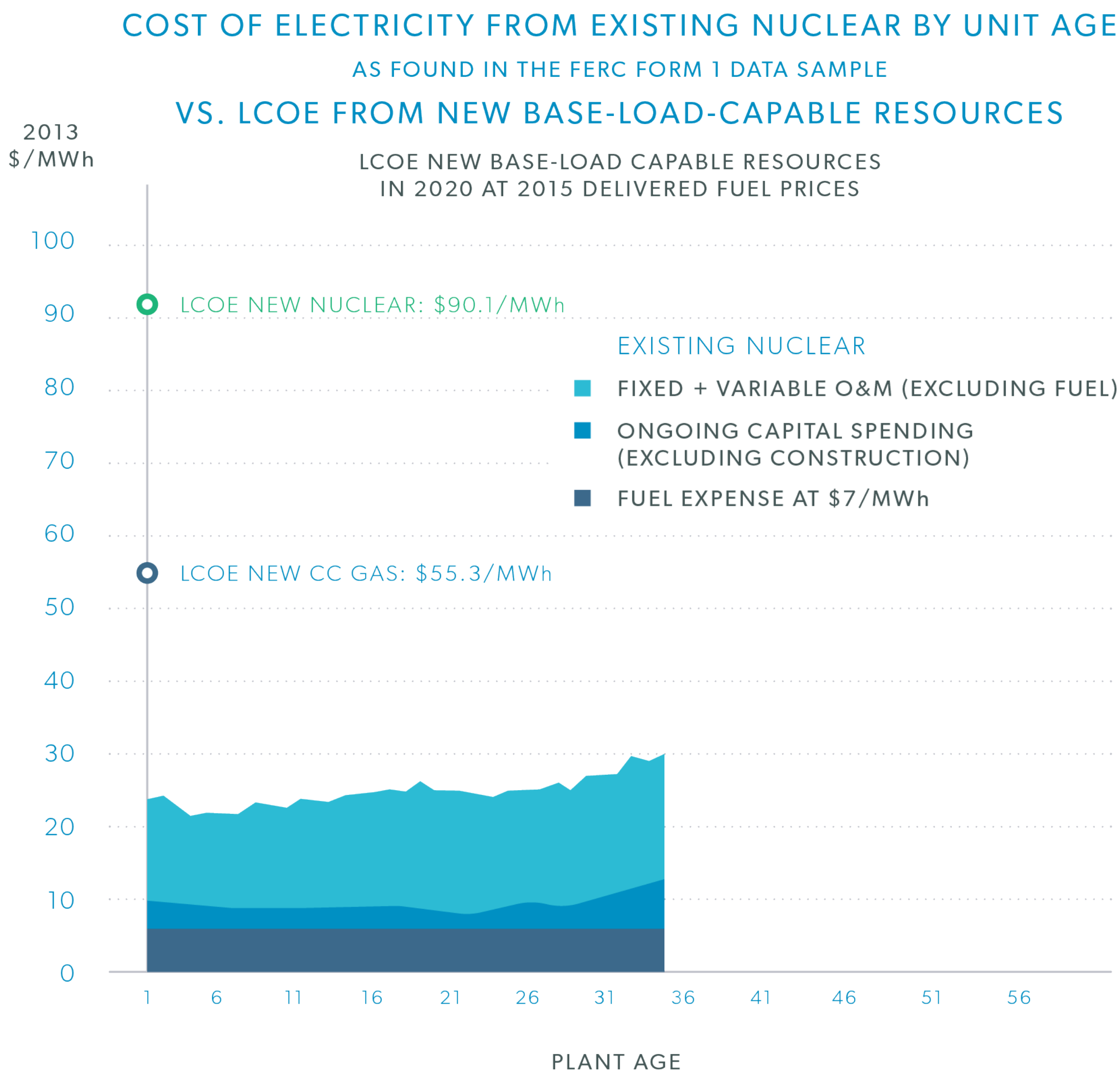
In addition to the "static" cost comparisons between various electricity resource choices, it is helpful to illustrate trends by plant age. The FERC Form 1 sample offers a cross section of plants by plant age in two ways:

1. **It considers each plant's annual generation costs for up to the past twenty years.**
2. **It considers operating plants constructed over the entire history of the electricity sector.**

We illustrate these plant age trends by unit age within each major technology below. The shaded areas of the three graphs illustrate the average levelized cost of electricity from existing full-time-capable resources by generating technology by plant age, excluding outstanding construction debt repayment obligation and at 2014 delivered fuel prices. These values are derived from the usable FERC Form 1 sample. The stripes above each shaded area represent LCOE from new resources, at the same delivered fuel price used for existing resources. The vertical distance between the shaded area and the stripe above represents the opportunity cost of replacing the existing resource with the corresponding new resource.




COST OF ELECTRICITY FROM EXISTING CC GAS BY UNIT AGE
AS FOUND IN THE FERC FORM 1 DATA SAMPLE
VS. LCOE FROM NEW BASE-LOAD-CAPABLE RESOURCES
2013 $/MWh
LCOE NEW BASE-LOAD CAPABLE RESOURCES IN 2020 AT 2015 DELIVERED FUEL PRICES
100
90
80
70
60
50
40
30
20
10
0
LCOE NEW NUCLEAR: $90.1/MWh
LCOE NEW CC GAS: $55.3/MWh
EXISTING CC GAS:
FIXED + VARIABLE O&M (EXCLUDING FUEL)
ONGOING CAPITAL SPENDING (EXCLUDING CONSTRUCTION)
FUEL EXPENSE AT $25/MWh
1
6
11
16
21
26
31
36
41
46
51
56
PLANT AGE

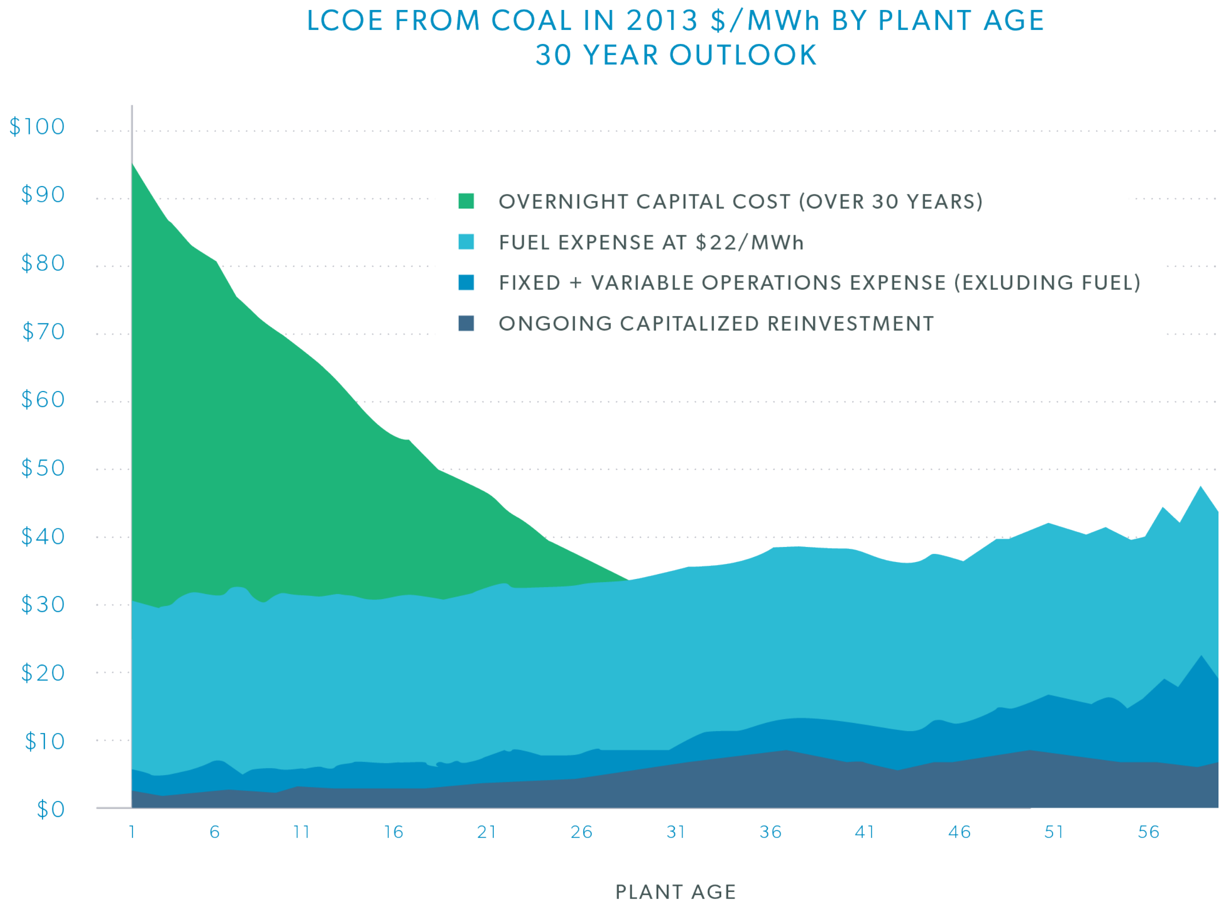


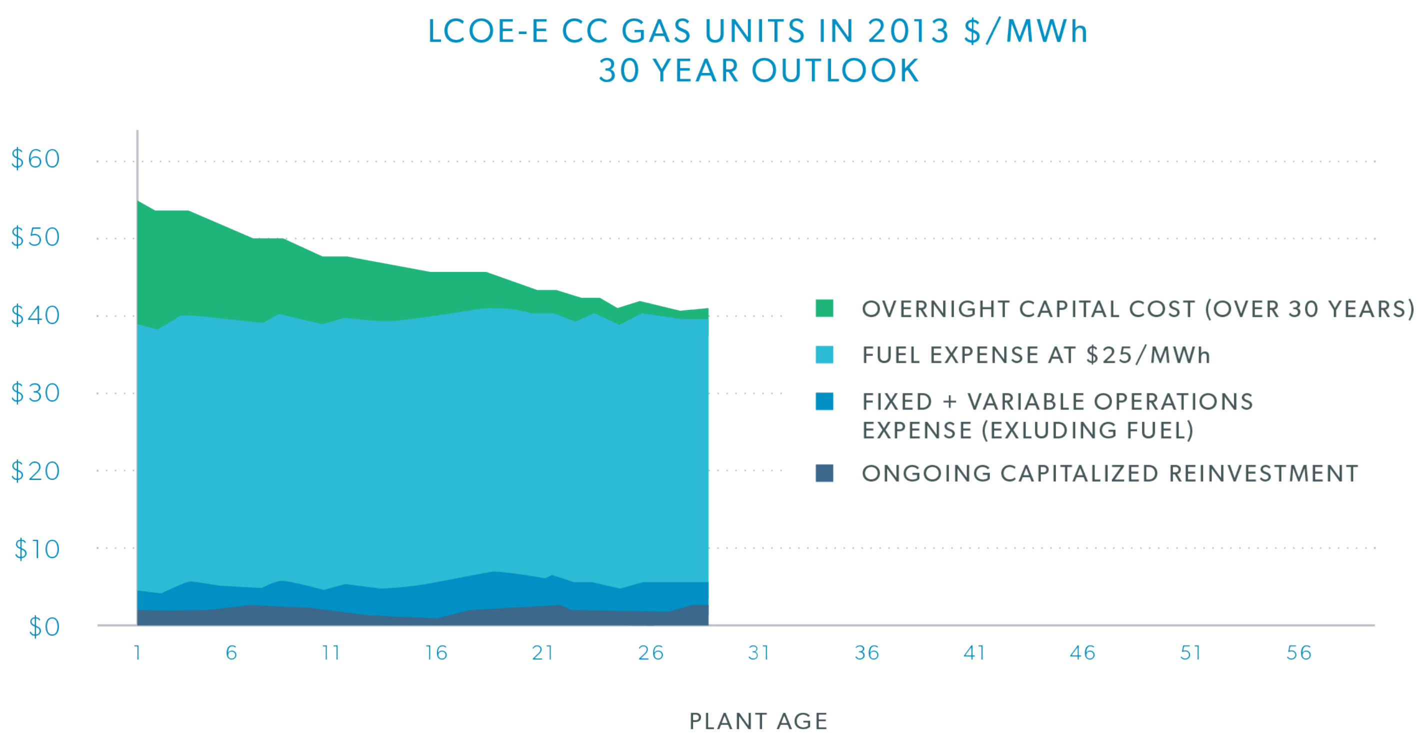
The shaded blocks for new full-time-capable technologies in the previous graphs show the range of expected LCOE based on the range of fleet-average capacity factors between actual (as reported by EIA in Electric Power Monthly) and "best case" (which were used by EIA to calculate LCOE).

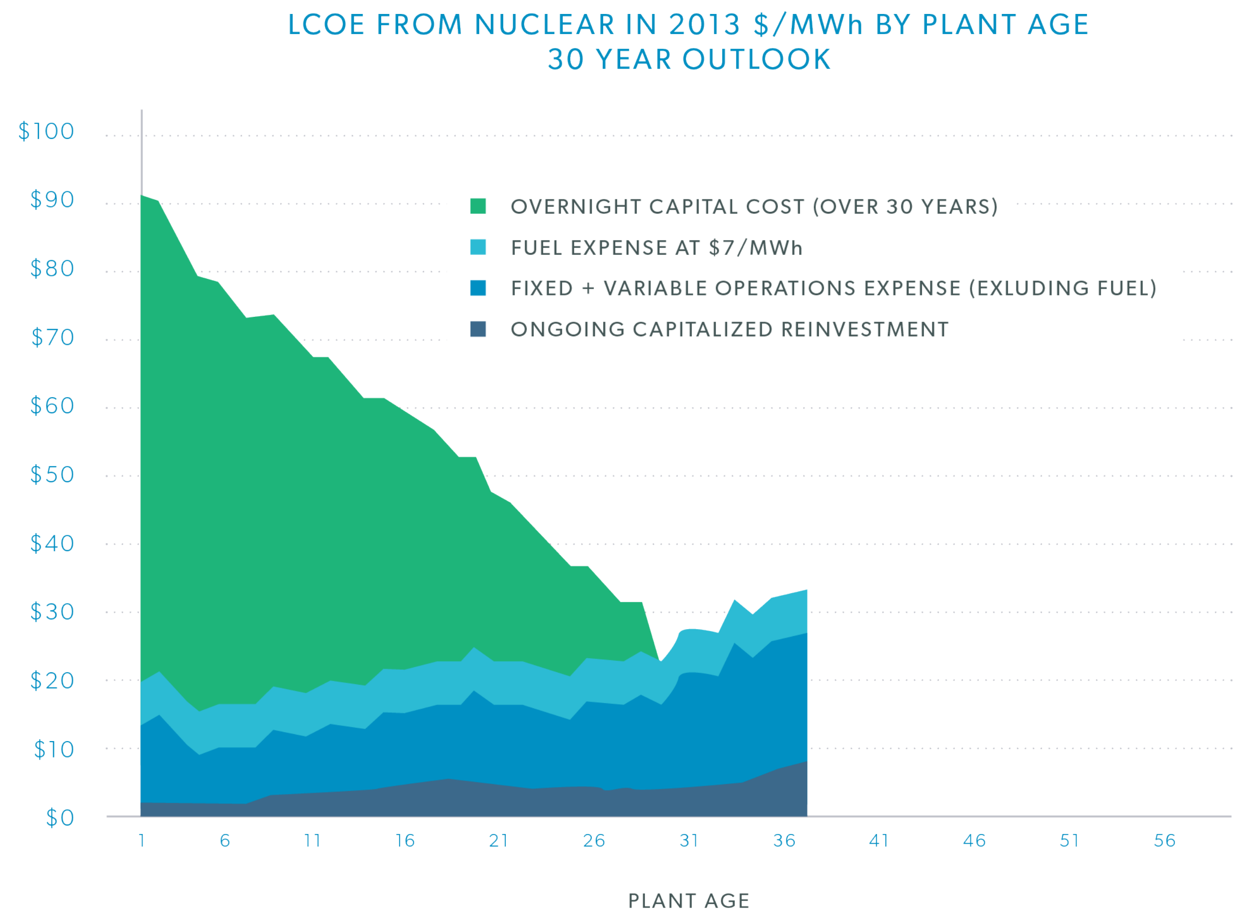
These graphs indicate that, on average, existing full-time capable plants of any age will have a lower LCOE than their likely replacements for the foreseeable future—even at "best case" capacity factors. Of course, some existing units do not achieve their same-age technology's average LCOE. Some of those may be approaching or have reached the end of their competitive lifespans.

Reinvestment and Operations Expense by Unit Age vs. Remaining Fixed Costs Recovery for Base Load Capable Resources

Data from Form 1 show ongoing expenses rise gradually over time as plants age. From a second perspective similar to that shown in the graphs above, some outstanding debt repayment and return on equity obligations do exist for all new and some existing units, but decline over an assumed 30-year financial repayment term. The purple shaded areas on the following charts represent the decline of remaining construction cost repayment obligation and the rising operations expense across their current lifespans. The height of the entire shaded area at any year represents the "going forward" LCOE for the next 30 years.


LCOE FROM COAL IN 2013 $/MWh BY PLANT AGE
30 YEAR OUTLOOK
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
OVERNIGHT CAPITAL COST (OVER 30 YEARS)
FUEL EXPENSE AT $22/MWh
FIXED + VARIABLE OPERATIONS EXPENSE (EXLUDING FUEL)
ONGOING CAPITALIZED REINVESTMENT
1
6
11
16
21
26
31
36
41
46
51
56
PLANT AGE


LCOE-E CC GAS UNITS IN 2013 $/MWh
30 YEAR OUTLOOK
$60
$50
$40
$30
$20
$10
$0
OVERNIGHT CAPITAL COST (OVER 30 YEARS)
FUEL EXPENSE AT $25/MWh
FIXED + VARIABLE OPERATIONS EXPENSE (EXLUDING FUEL)
ONGOING CAPITALIZED REINVESTMENT
1
6
11
16
21
26
31
36
41
46
51
56
PLANT AGE



Observation: Going forward LCOE is at its lowest for plants which have just retired construction debt and equity obligations (at 30 years of age).

Observation: For plants within any generation resource category, per-MWh operations expenses rise gradually over their lifespans, but do not exceed the rate of decline in construction repayment obligations over a 30-year repayment term. On average, therefore, going-forward LCOE-E falls steadily until plants reach age 30, then rises gradually as operations and capital expenditures accrue due to facility and component age. Regulatory changes imposed on existing generators after they are constructed and in operation also force new capital expenditures.

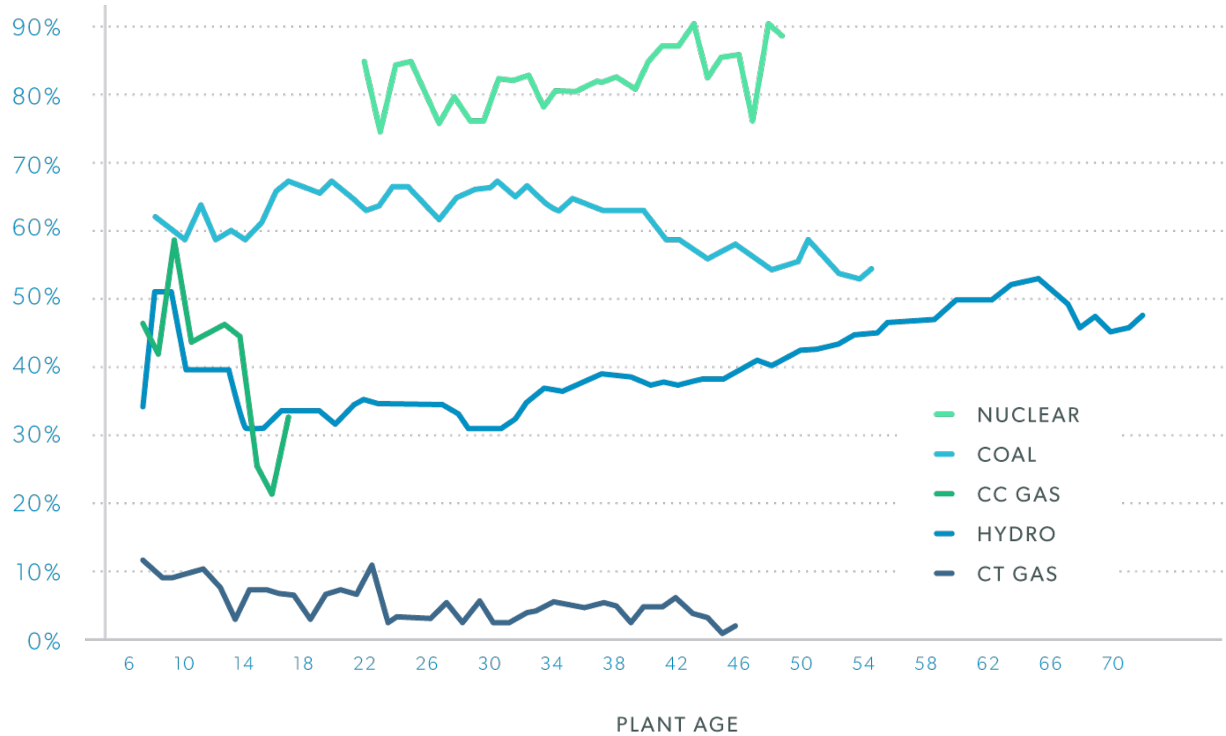
On average, even for the oldest plants of each generation resource category sampled, rising operations capital reinvestment expenses do not appear to force LCOE-E to the level of LCOE from new resources for several years to several decades. This suggests the US could enjoy lower cost electricity for the foreseeable future by continuing to operate existing power plants with levelized costs lower than their possible replacements.

Observation: Older power plants with lower fixed costs and lower LCOE are of the highest value to electricity consumers.

Capacity Factor by Generating Technology by Plant Age

Capacity factor, listed as a percent, is the measured historical (or assumed future) utilization rate of a unit or technology over an average calendar year relative to theoretical maximum (running at nameplate capacity for all hours). The following graph indicates that capacity factors for older plants are not markedly lower than those for younger plants of the same type (except for hydroelectric).

HISTORICAL CAPACITY FACTOR BY PLANT AGE IN 2019
FROM 1994 - 2013 FERC FROM-1 DATA SET



Applying Real-World Capacity Factors to EIA LCOE-New

For new resources, EIA lists "best case scenario" capacity factors for each technology, based on an absence of market competition throughout a year. Capacity factors are de-rated based only on manufacturer suggested maintenance down time (all resources) seasonal fuel efficiency derates (nuclear and combustion technologies) and estimated average annual fuel source unavailability (wind, solar and hydro).

Historical capacity factors for fossil fueled resources are considerably lower than best case scenario levels for most technologies. As such, EIA's calculation of fixed costs per MWh likely underestimates actual fixed costs per MWh in competitive markets and fluctuating load conditions from day to night, weekday to weekend and season to season.

Table 2 lists real capacity factor ranges vs. the capacity factors used by EIA to calculate LCOE for new resources. The product of the sum of fixed cost components of LCOE-New and the adjustment multiplier for each resource yields LCOE-New under the assumption that average utilization rates for new resources would match average utilization rates of existing generators in the real world.

Table 2

Table 02 Generator Type	2015 Real World Capacity Factors	EIA LCOE 2020 Capacity Factor Assumptions	Fixed Cost Adjustment Factor
DISPATCHABLE FULL-TIME-CAPABLE RESOURCES			
Conventional Coal[1]	54.6%	85%	1.56
Conventional Combined Cycle Gas (CC Gas)	56.3%	87%	1.55
Nuclear	92.2%	90%	0.98
Hydro	35.9%	54%	1.50
DISPATCHABLE PEAKING RESOURCE			
Conventional Combustion Turbine Gas (CT Gas)	6.7%	30%	4.48
INTERMITTENT RESOURCES			
Wind[3]	32.5%	36%	1.11
PV Solar[3]	28.6%	25%	0.87

Table 3

Table 03 New Generator Type	Sum of Fixed Costs of LCOE-New as reported by EIA LCOE 2020 (2013 $/MWh) ×	Adjustment Factor =	Adjusted Fixed Cost per MWh +	Variable Costs inlcuding fuel at 2015 delivered price =	EIA LCOE-New 2020 at Real-World Capacity Factors (2013 $/MWh)
Dispatchable Full-Time-Capable Resources					
Conventional Coal[1]	N/A	N/A	N/A	N/A	N/A
Conventional Combined Cycle Gas (CC Gas)	17.3	1.55	26.7	28.6	55.3
Nuclear	83.0	0.98	81.0	9.1	90.1
Hydro	76.6	1.50	115.2	7.0	122.2
Dispatchable Peaking Resource					
Conventional Combustion Turbine Gas (CT Gas)	47.0	4.48	210.4	52.5	263.0
Intermittent Resources – as used in practice					
Wind including cost imposed on CC gas[3]	73.6	1.11	81.5	+ $25.9 Imposed cost on new CC gas	107.4
PV Solar including cost imposed on CC and CT gas[3]	125.3	0.87	109.5	+ $30.8 Imposed cost on new CT and CC gas	140.3

Table 3 shows the sum of per-MWh fixed cost components of LCOE and applies the real world adjustment multiplier. The right hand column shows LCOE at real world capacity factors.

Table 4

Table 04 Generator Type	LCOE Existing at 2015 Real World Capacity Factors (2013 $/MWh)	EIA LCOE New at Real World Capacity Factors (2013 $/MWh)	Premium for Replacing Existing with Same Resource New
DISPATCHABLE FULL-TIME-CAPABLE RESOURCES			
Conventional Coal[1]	39.9	N/A	N/A
Conventional Combined Cycle Gas (CC Gas)	34.4	55.3	61%
Nuclear	29.1	90.1	210%
Hydro	35.4	122.2	245%
DISPATCHABLE PEAKING RESOURCE			
Conventional Combustion Turbine Gas (CT Gas)	88.2	263.0	198%
INTERMITTENT RESOURCES – AS USED IN PRACTICE			
Wind including cost imposed on CC gas[3]	--	107.4	--
PV Solar including cost imposed on CC and CT gas[3]	--	140.3	--

Table 4 compares LCOE-E to LCOE at equivalent capacity factors.

Calculation of Cost Imposed by Wind on Base Load Capable Resources

As we discussed on page 9 above, non-dispatchable resources impose costs on dispatchable resources by causing them to run fewer hours without substantially reducing their fixed costs.

Thus, with an increase in non-dispatchable generation, the fixed costs of dispatchable resources are levelized over fewer units of production. Below, we provide the methodology for calculating the cost wind imposes on CC gas. The result of the calculation is that each additional MWh of wind imposes a cost of $25.9 per MWh under real-world capacity factors in 2013 dollars and based on EIA's Annual Energy Outlook 2015 levelized costs. Appendix A provides examples of this methodology based on 2012 dollars and EIA's Annual Energy Outlook 2014 levelized costs. We leave the example in Appendix A unchanged from the original report but note that the imposed cost of wind fell slightly due to the higher capacity factor for CC gas in 2015.

Intermittent resources do not always displace natural gas generation. In practice, they also displace generation from coal and perhaps nuclear power plants, among others. But for simplicity and the purposes of this report, we make the following assumptions about how intermittent resources are integrated onto the electric grid:

- We compare two scenarios in a snapshot in time (load growth and fuel prices are held constant).
- The base line scenario assumes no intermittent generation. In this simple baseline scenario, CC gas provides all needed electricity.
- The alternate scenario includes an intermittent resource (wind) combined with CC gas, where the two resources combine to produce the same constant output as in the baseline scenario.
- CC gas as a fleet offers 87% of its nameplate capacity as summer peak demand capacity credit[23] regardless of capacity factor.
- CC gas as a fleet offers base load capacity. That is, at whatever capacity factor it operates, it operates at the same level all the time.

- Intermittent resources (wind) are "paired" with CC gas to create the same flat generation profile, capacity factor and capacity value in the pairing as achieved by CC gas alone in the base line scenario.

- Capacity values for intermittent resources are determined using the "mean of lowest quartile output across summer peak hours" method recommended by Midcontinent ISO's market monitor, Potomac Economics[24] and using hourly wind data from MISO and PJM for calendar year 2013.

- Installed capacity of CC gas in the hybrid pairing with wind is equal to capacity value of CC gas in the baseline scenario minus the capacity value of the intermittent resource (wind) in the pairing divided by the capacity value of CC gas (0.87).

- Installed capacity of the intermittent resource is equal to the nameplate of the CC gas prior to the addition of the intermittent resource times the CC gas capacity factor prior to the pairing.

- The annual energy from the new CC gas capacity in the pairing is the remainder of CC gas energy prior to the intermittent resource minus the energy that can be produced at the best-case capacity factor of the installed capacity of the intermittent resource.

- The new capacity factor of the new installed capacity of CC gas in the pairing is the new CC gas energy divided by the new CC gas capacity required to meet the capacity and energy levels of CC gas prior to the pairing.

- Fixed costs per MWh of CC gas are altered by multiplying the prior fixed costs per MWh by the prior capacity factor of CC gas divided by the new capacity factor of CC gas.

- The imposed cost per MWh of the intermittent resource is the increase in fixed cost per MWh of CC gas times the percentage of CC gas in the pairing divided by the percentage of the intermittent energy in the pairing.

Calculation of Cost Imposed by PV Solar on Base Load Capable and Peaking Resources

The methodology for determining wind's imposed cost assumes uncurtailed wind is part of a full time base load hybrid with CC gas. We cannot assume that PV solar is part of a base load hybrid because it does not produce at night and it does produce some energy across many of the peak hours of the daytime, especially in summer, when CT gas is often the marginal resource. PV also produces electricity during "shoulder" load hours when CC gas is often on the margin. Instead of using the same methodology we applied to wind, we developed a scenario that assumes solar displaces two resources: CC gas and CT gas, and that it reduces their capacity factors at equal rates. That is, we assume that if the capacity factor of CC gas started at 50% without PV solar and falls by 10% to 45% with PV solar, then if CT gas started at 5% it would drop to 4.5% (also 10%). We do not know the exact ratio in each electricity market because grid operators do not release recent-year hourly and monthly marginal fuel reports due to the competitively sensitive nature of that data. The ratio does have an impact on imposed cost because CT gas starts at a relatively low capacity factor and corresponding high fixed cost per MWh. As its utilization rate falls to zero, its fixed cost per MWh goes up exponentially. As a result, if we assume CT gas is displaced more than CC gas, then the imposed cost is larger. If we assume solar primarily displaces CC gas and very little CT gas, then the imposed cost is lower.

Under this set of assumptions, we estimate the capacity value of PV solar at incremental capacity additions. After a few percentage points of energy market share gain, the residual peak load hours shift from late afternoon to mid-evening. At mid-evening solar is not producing, so its ability to further reduce the required system capacity falls to zero. For this reason, solar PV's capacity value falls as its market share rises, creating a "diminishing returns" scenario that drives up imposed cost at each incremental addition of solar capacity. The same is not necessarily true for wind, because wind produces across a full spectrum of hours of the year and those generating hours can shift substantially from day to day, season to season and year to year. That is why we believe wind's capacity value stays about the same as more capacity is added to the system.

The analysis is based on real world hourly PV generation and hourly system electricity demand (load) data reported by California Independent System Operator (CAISO) for calendar year 2014. Six percent PV energy market share is expected to be achieved in California in 2015 or 2016. From the CAISO analysis, and using additional information provided by the U.S. Department of Energy's Energy Information Administration (EIA), we estimate the U.S. average levelized cost of electricity from PV for the entire United States in 2020.

The CAISO hourly data allow estimation of the replacement value of PV capacity for dispatchable capacity, or PV's relative "capacity value" (CV). Because the CV of PV is lower than the CV of the resources from which it gains market share, dispatchable resources cannot "retire" at the same rate as PV capacity is added, assuming CAISO will (or must) maintain its current level of system peak demand reserve capacity. Instead, more generating resources must remain operational in the system to achieve the same system peak reserve margin.[26] It is elementary, then, that on average, generators must achieve a lower market share and utilization rate (capacity factor [CF]) than prior to the PV capacity additions. At a lower average CF, the breakeven fixed cost per MWh of the system generator fleet necessarily rises. We term this effect "imposed cost" of PV energy.

The analysis shows that as PV gains energy market share beyond the first few percent, its CV falls to zero.[26] As capacity value falls, imposed cost rises. We believe imposed costs are not recognized or represented in EIA's LCOE forecast.[27]

We adjust EIA's US LCOE 2020 in two ways:

- For real world US average capacity factor in 2015 of 28.6% of nameplate (vs. EIA LCOE 2020 estimate of 25%),
- For an estimated imposed cost (based on capacity factors, capacity value and energy market share achieved)

According to data gathered from the CAISO web site, in 2014, PV attained 4.48% energy market share across the CAISO control region, with enough new PV capacity added across the year to ensure more than 5% energy market share in 2015.[28] For this reason, we report the LCOE from new PV capacity capturing its sixth percentage point of energy market share:

California ISO / NERC Region 20

EIA LCOE 2020 Regional Estimate (at 31% CF) $111.1

Imposed Cost From 6th Percent Market Share $35.8

Total Estimated Cost of New PV $146.9

PV installed capacity at the beginning of 2014 and monthly capacity additions across the year could not be verified because data from EIA and CAISO sources does not match. Therefore, it was impossible to determine the annual CF of PV in CAISO for 2014. We assume the CF for new PV capacity in 2020 assigned for NERC region 20 in the EIA's National Electricity Modeling System (NEMS) is 31%.

We note here that CF, when used to estimate total PV nameplate capacity on the system from known generation data, affects total PV CV (in MW) on the system. CF and CV therefore have an inverse relationship, as do CF and imposed cost.

Applying Model Results to National Average LCOE from PV

According to industry growth estimates released by the solar trade group Solar Energy Industries Association, PV will have captured more than 2% energy market share in the US in 2020.[29] Consistent with our reasoning for evaluating the next (sixth) percentage market share gain for PV on the CAISO system, we utilize imposed cost of the next percent of energy market share for PV for the national imposed cost estimate in our LCOE estimate for the United States. For the U.S., the estimated CV of the capacity sufficient to capture a three percent energy market share for PV would be 16.2% of nameplate and would impose a cost of $30.8 (2013 $/MWh) of PV generation onto new combined cycle and combustion turbine generators, as shown here.

US Average

EIA LCOE 2020 (at 28.6% CF) (2013 $/MWh)[30] $109.5

US Estimated Imposed Cost From 3% Mkt. Share $30.8

Total Estimated Cost of New PV[31] $140.3

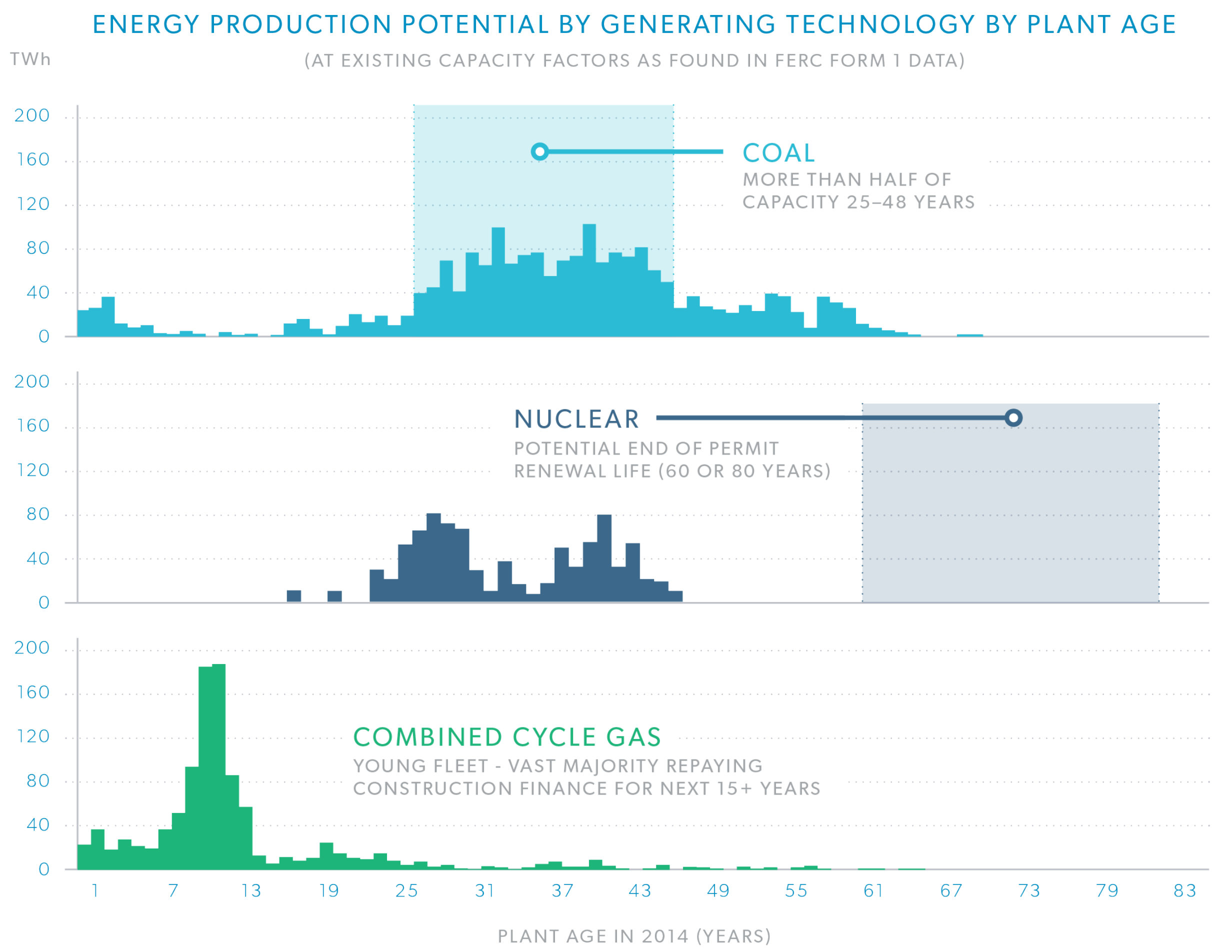
Appendix B provides the methodology for determining solar PV's imposed cost on CC gas and CT gas in more detail and provides examples of the calculation.

U.S. Generating Capability by Generating Technology by Unit Age

The following bar chart shows installed capacity times 8,760 hours (the number of hours in one year) times the highest capacity factors achievable for each respective technology as reported in EIA LCOE Table 1, herein referred to as "generating capability." The figure is shown for all US plants from newly commissioned through 83 years of age, as reported in EIA Form 860.

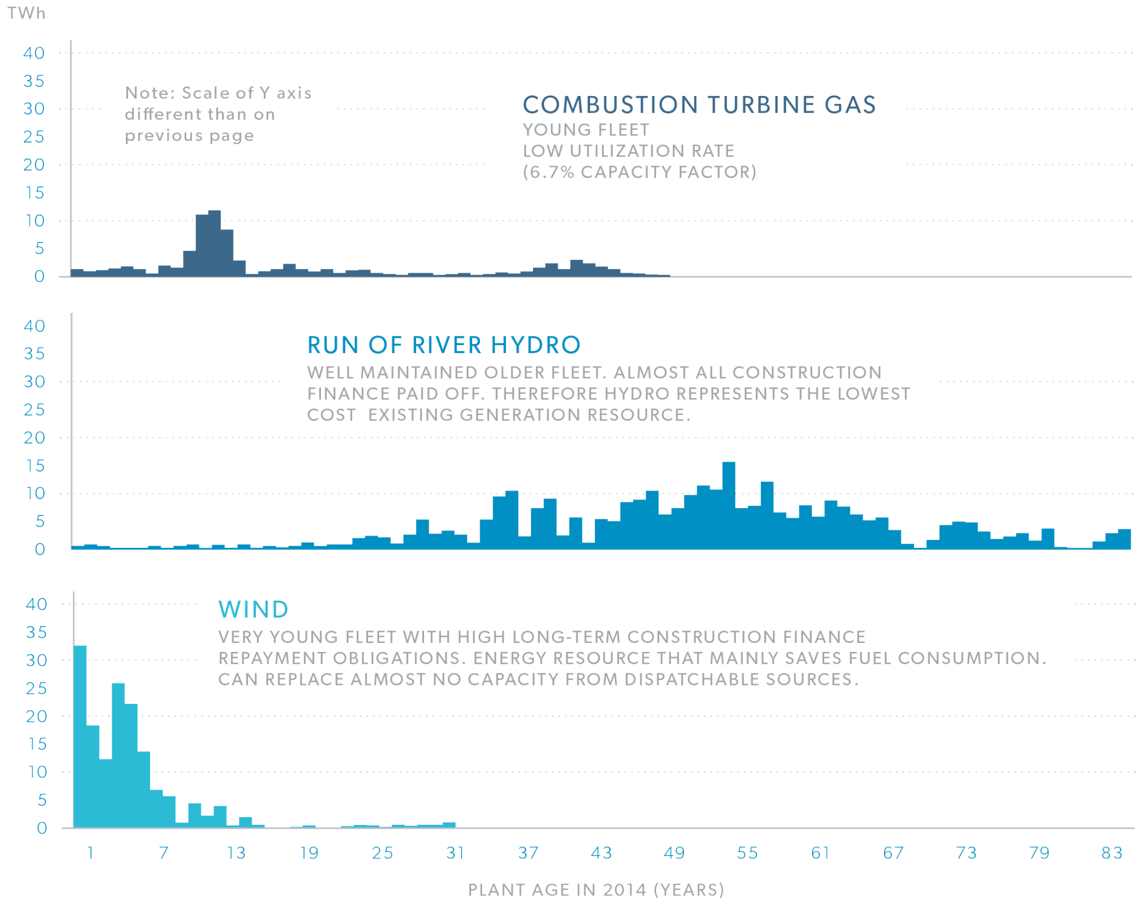
The three technologies shown in the first chart are full-time-capable resources that make them reasonable substitutes for each other. The technologies shown in the second group of three charts include sources that are not substitutes for one another or for any of the full-time-capable resources.

The vertical scale is different between the first and second set of charts—specifically, the scale is five times greater for the first compared with the second.



ENERGY PRODUCTION POTENTIAL BY GENERATING TECHNOLOGY BY PLANT AGE

(AT EXISTING CAPACITY FACTORS AS FOUND IN FERC FORM 1 DATA)



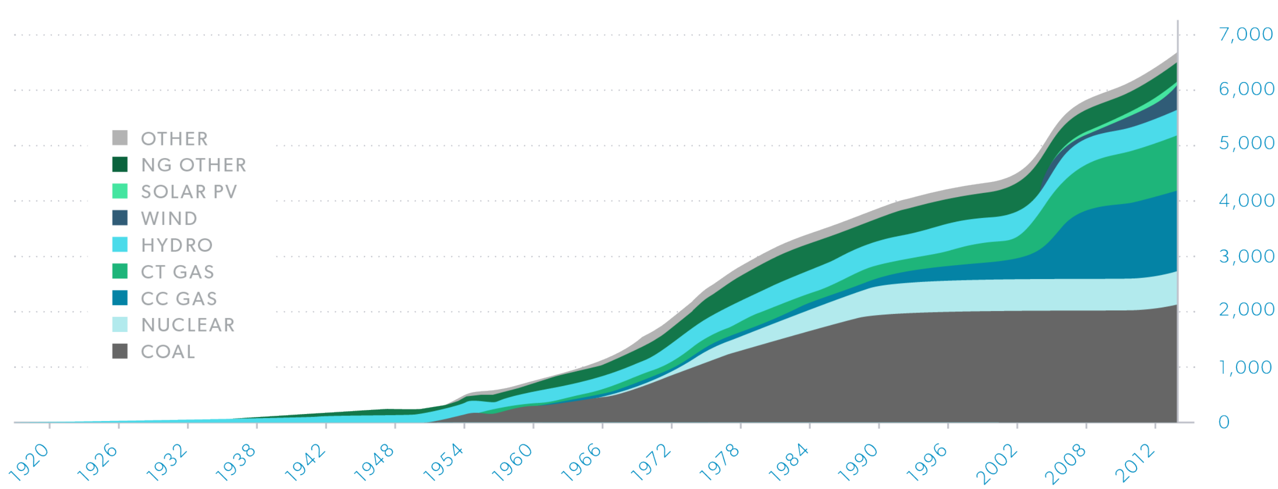
The histograms above indicate that almost the entire existing fleet would have a decade or more of remaining economic life relative to their likely replacements if not for the impacts imposed by new existing source environmental regulations, coupled with the profit and market share erosion associated with subsidies and mandates for non-dispatchable (renewable) generation.

The following illustration shows the generating capability of the existing fleet by year at best-case capacity factors. Generating capability exceeds total demand by almost 65%, and capacity was sufficient to meet peak demand (peak demand and summer capacity not shown).

Source Data for Graph Below: EIA 860, 2013[32] and AEO 2015[33]

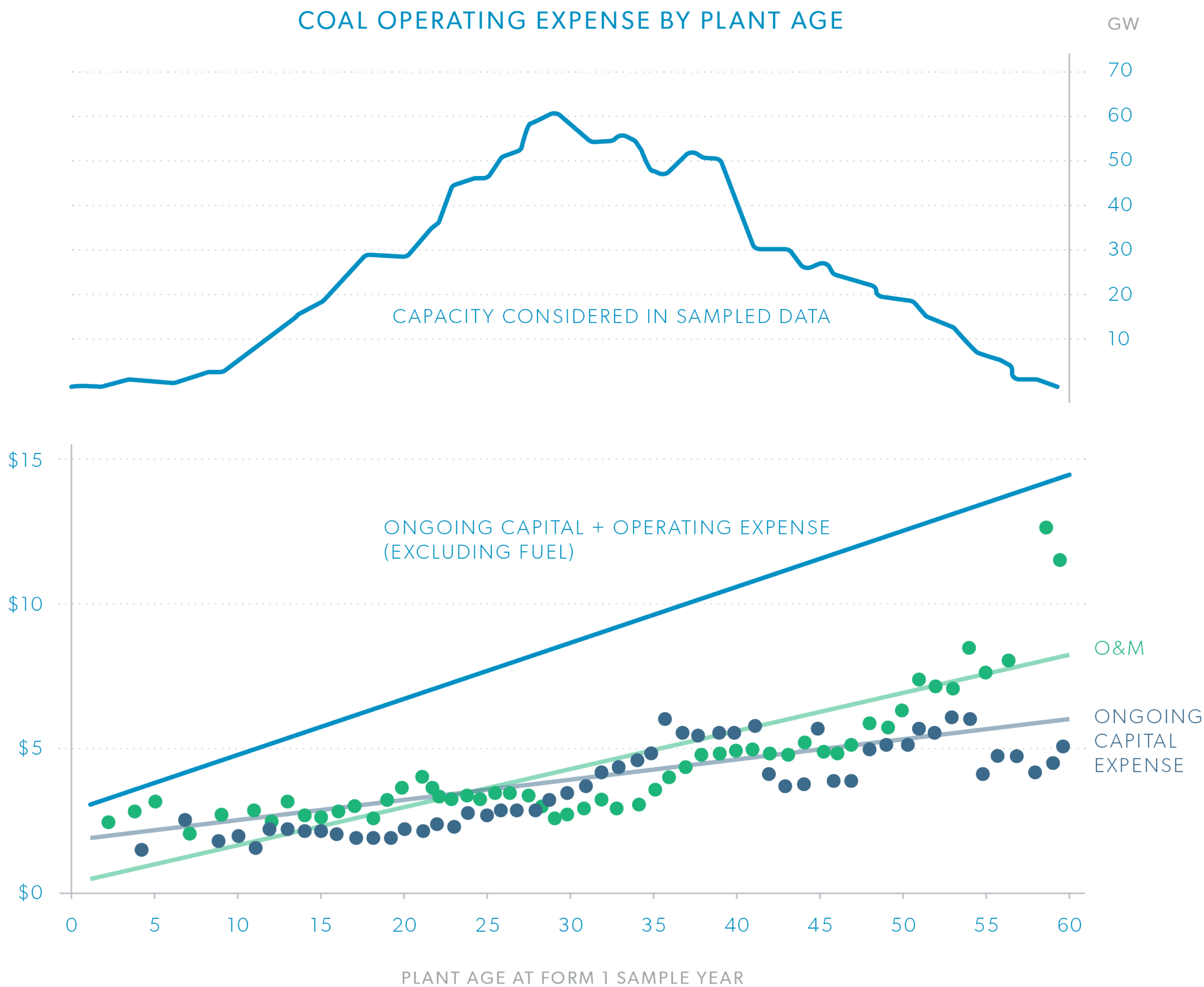
CUMULATIVE OPERATIONAL GENERATING CAPABILITY BY YEAR BY FUEL TYPE AT EIA FORECAST CAPACITY FACTORS (TWh/YEAR)

ANNUAL ELECTRICITY DEMAND 2014: 4,089 TWh

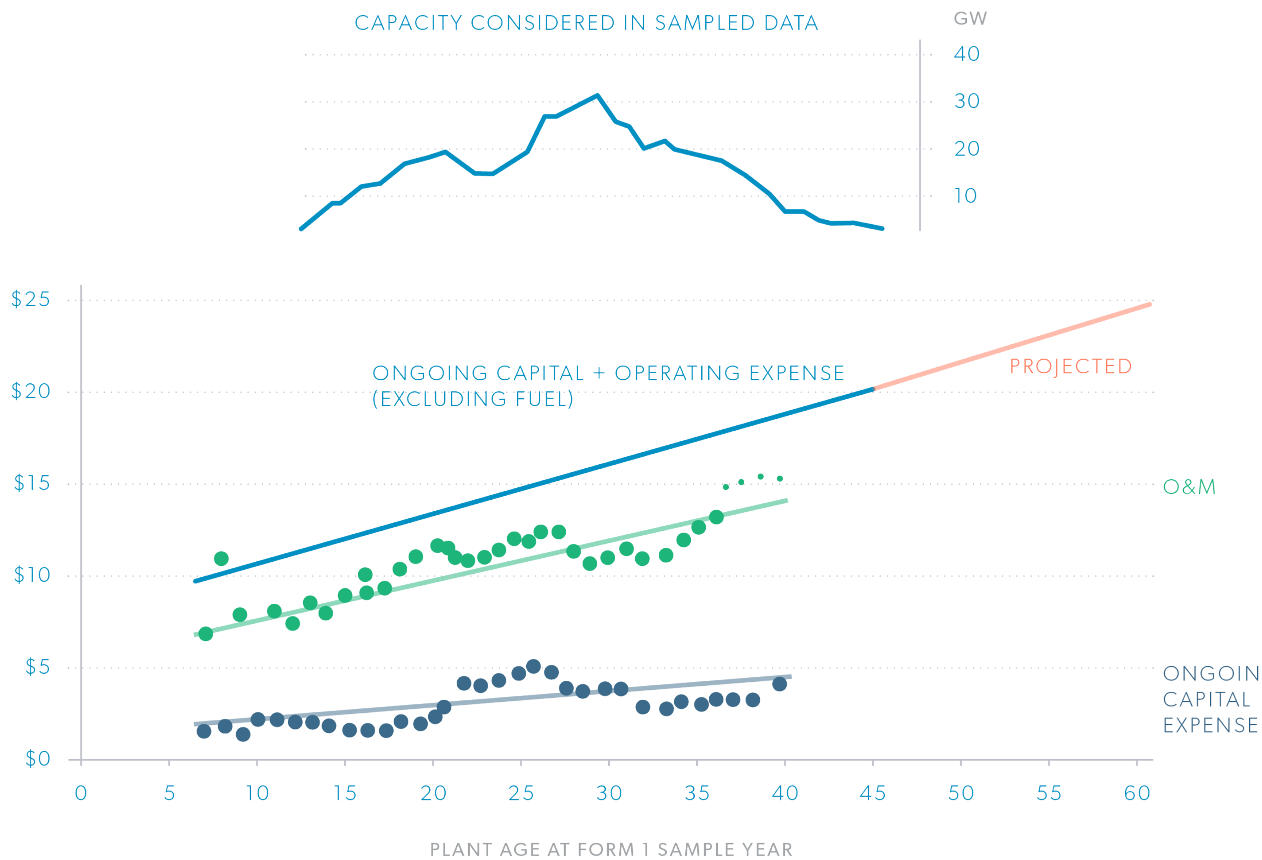


Sample Size by Plant Age by Major Generating Technology

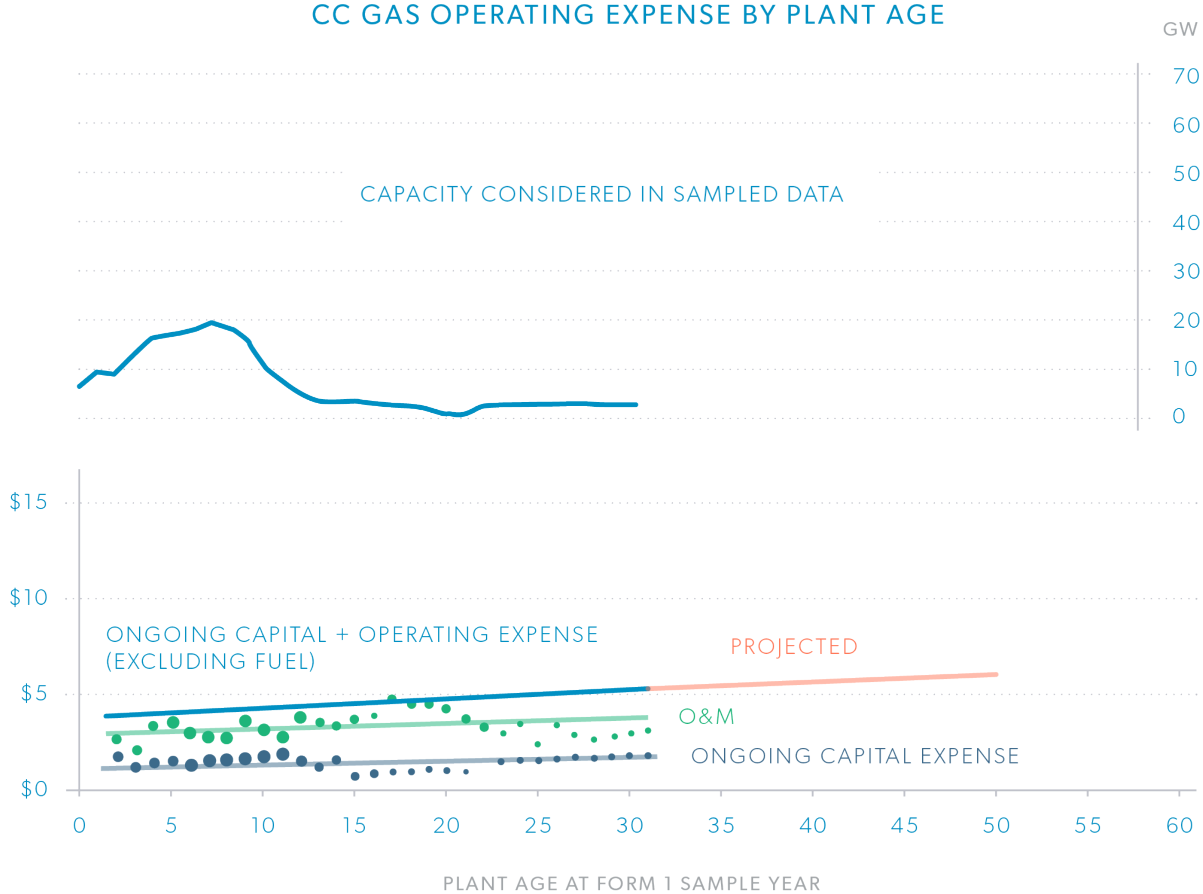
The following bubble charts show fleet-average operations and ongoing capital reinvestment expenses by plant age for each considered technology. Bubble size as well as the line graph above each bubble chart represent the FERC Form 1 sample size by technology by plant age.



NUCLEAR OPERATING EXPENSE (2013 $/MWh) BY PLANT AGE



CC GAS OPERATING EXPENSE BY PLANT AGE



EIA's Calculation of the Components of LCOE

There are important limitations to the application of EIA's LCOE figures when evaluating the costs of electricity from and between new resources:

- EIA applies "best case" (high end) capacity factors in calculating fixed cost per MWh. As a result fixed costs per MWh and LCOE are understated for technologies whose capacity factors in real world application fall short of "best case." For example, EIA applies a 30% capacity factor to fixed costs of combustion turbines, while those resources realize only a 6.7% capacity factor in application today. This means fixed costs per MWh for CT are underestimated by nearly five fold.

- EIA assumes a 30-year lifespan for all technologies in their LCOE report for new generation resources, giving no credit to the value of the electricity produced by new units surviving beyond that age, and applying no penalty for technologies with operational lives of less than 30 years.

- EIA transmission investment figures do not recognize the additional cost of transmission associated with onshore wind, which must be sited near the best fuel availability locations. These locations are many hundreds of miles from primary load centers of the continental US. Therefore EIA either sharply underestimates transmission expense for wind or grossly overstates its achievable capacity factor. In either case, LCOE for new onshore wind is underestimated by EIA.

- Special accelerated depreciation available to wind and solar is not considered a "cost" in EIA's calculation of those technologies' LCOEs. It should be, however, because it represents advanced cash flows to wind developers and postponed cash flows to the treasury, which is funded primarily by all taxpayers.

- EIA divides its LCOE Table 1 into two sections attempting to separate resources which are not performance (and cost) comparable. In practice, combustion turbines are not performance comparable to full-time-equivalent resources and should be separated into their own section of the table to avoid confusion.

- Graph above each bubble chart represent the FERC Form 1 sample size by technology by plant age.

[18] *Energy Information Administration, Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2015, June 3, 2015,* http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

[19] *However, when an existing power plant is induced to retire and is replaced with a new one constructed at a a different site, the existing transmission serving the retiring generation unit may become underutilized, while new transmission must be constructed for the new generator. These circumstances add additional cost to the system that would otherwise be unnecessary. That would clearly be the case when wind energy capacity is added to the system because of the remote siting requirement for that technology. But in addition, some new natural gas fired power plants would also require either new gas or electricity transmission. While we maintain EIA's direct transmission cost estimates for new generation resources, estimates of imposed transmission cost are beyond the scope of this report.*

[20] *The number of records in the sample is equal to the number of "plant years" collected. This is the number of power plants reporting to Form 1 times the average number of years of complete data across all power plants. Due to some missing data and significant nameplate capacity changes at some plants, the average sample period was approximately 11 years.*

[21] http://data.bls.gov/pdq/SurveyOutputServlet

[22] *At the time of original publication, June, 2015*

[23] *At the time of original publication, June, 2015*

[24] https://www.potomaceconomics.com/uploads/reports/2012_SOM_Report_final_6-10-13.pdf *Section II C, page 16*

[25] ftp://ftp.pjm.com/operations/wind-web-posting/2013-hourly-wind.xls & https://www.misoenergy.org/Library/Repository/Market%20Reports/20131231_hwd_HIST.csv

[26] *We determine capacity through a calculation that considers the technology's stand-alone capability to meet peak loads in a recent historical year.*

[27] *We do not adjust EIA's PV LCOE to account for the difference between the 30-year financial lifespan EIA assumed and the actual lifespan of PV facilities, the cost of long-distance transmission, accelerated depreciation subsidies or regulatory costs. However, we note that EIA did not fully consider these costs, which are likely in the range of $25 to $40 per megawatt-hour. The basis is physical lifespan, long distance transmission costs (infrastructure and losses) and "subsidies" recognized but not counted as costs in EIA's "fixed charge factor* http://www.eia.gov/renewable/workshop/gencosts/ *and other subsidies such as state mandates, loan programs and other incentives, and impact of net metering laws.*

[28] http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf

[29] http://www.seia.org/research-resources/us-solar-market-insight *(Estimated based on SEIA projected installed capacity at 25% CF)*

[30] *EIA forecast LCOE for PV is 125.3 (2013 $/MWh) at a 25% CF. US Average real world CF for PV in 2014 was 25.9%.* http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_6_07_b *We adjust the LCOE estimate to reflect a 25.9% CF: 125.3 x 25% / 25.9% = 120.9.*

[31] *EIA published a national average figure of 125.3 (2013 $/MWh) for LCOE from PV in 2020, but does not offer the methodology or regional weightings by which the average is calculated. This report uses the LCOE for NERC region 20, CASIO (received in email from EIA, ibid), from EIA's Annual Energy Outlook 2015, calculates the imposed cost for that region using data from CASIO, and then applies that methodology to the average LCOE for the nation from EIA's report found at* http://www.eia.gov/forecasts/aeo/electricity_generation.cfm

[32] http://www.eia.gov/electricity/data/eia860/ *(Generator/Unit level data set)*

[33] http://www.eia.gov/forecasts/aeo/MT_electric.cfm

IV. SUMMARY & RECOMMENDATIONS

Electricity from the existing generating fleet is less expensive than from its available new replacements, and existing generators whose construction costs repayment and recovery obligations have been substantially or entirely met are often the least-cost producers in their resource fleet. Cost trends extracted from Form 1 indicate the fleet average cost of electricity from existing resources is on track to remain a lower cost option than new generation resources for at least a decade—and possibly far longer.

However, wholesale energy and capacity market price suppression caused by external subsidies can drive lowest-cost generators toward earlier retirement than otherwise. This negative incentive is compounded as units face capital reinvestment decisions to comply with additional environmental or other regulations.

When low-cost electricity generators retire, they must be replaced with capacity sources whose electricity may be substantially more expensive. Recognizing these costs now could help avert poor policy and regulatory decisions in the near term.

A combination of current public policies drive the current retire/replace, trend including:

- **Subsidies; making the construction and operation of energy-only "renewable" generation resources the least-cost entry even though they may offer a significantly lower capacity value than the sources they displace.**
- **Mandates; requiring significant increases in the market share of renewable electricity over several years. Increases in market share for renewable energy erodes the market share and capacity factor of marginal high capacity value resources.**
- **Environmental and other regulations, both pending and finalized, add new fixed costs to existing units.**

The levelized cost of electricity from existing resources (LCOE-E) is a vital piece of information that has been missing from the public policy discussion. The framework we introduce in this report offers policymakers a powerful tool as they make decisions that affect not only the cost structure of the U.S. electricity industry but, by extension, a large sector of the domestic economy and a fundamental part of Americans' well-being.

Appendix A: Levelized Cost of Electricity from Wind

This appendix uses the methodology explained in Section III of this report to provide examples of the calculation for determining wind's imposed cost on CC gas. These examples are based on EIA's levelized cost from its Annual Energy Outlook (AEO) 2014 and are quoted in 2012 dollars. As such, the numbers will not match those provided in the main body of this report which are based on EIA's levelized costs from AEO 2015 and quoted in 2013 dollars. These examples are for illustrative purposes.

Example 1: Base Load CC Gas + Wind at Best-Case Capacity Factors

In this example, the CC gas fleet runs at an 87% annual capacity factor. For simplicity, we assume the CC gas fleet runs at a steady state 24/7/365.

1 MW of CC gas on the system works to provide 0.870 MWs of constant power 24/7/365. Its capacity factor is: 0.870MW / 1MW= 87%. 0.870 MW of wind is then "installed" and operates at a 35% capacity factor with no curtailment. Its output ranges from a minimum of 2.7% of nameplate (using the mean of lowest quartile output across peak hour calculation method) to 100% of nameplate.[34]

To create the identical generation and capacity profile as the 1 MW of CC gas, we will require slightly less CC gas summer capacity by the amount of summer capacity offered by the 0.870 MW of wind. Specifically: 0.870 MW x 2.7% = 23.49 KW. 0.870 MW CC gas summer capacity – 0.02349 MW = 0.84651 MW of CC Gas summer capacity required. To achieve that level of summer capacity we must divide by the capacity value of the CC Gas facility: 0.84651 / 87% = 0.973 MW.

We have now established that the pairing includes 0.870 MW of wind nameplate capacity and 0.973 MW of CC gas nameplate capacity.

The CC gas system will back down in synchronously as wind generation increases so that the pairing produces 0.870 MWs continuously throughout the year.

The wind energy produces an average of 0.870 MWs x 35% capacity factor = 0.3045 average MWs of power. The CC gas produces 0.8700 MW – 0.3045MW = 0.5655 MWs from its installed 9,730MWs.

The new CC gas capacity factor in the pairing is: 5,655MW / 9,730MW = 58.1%

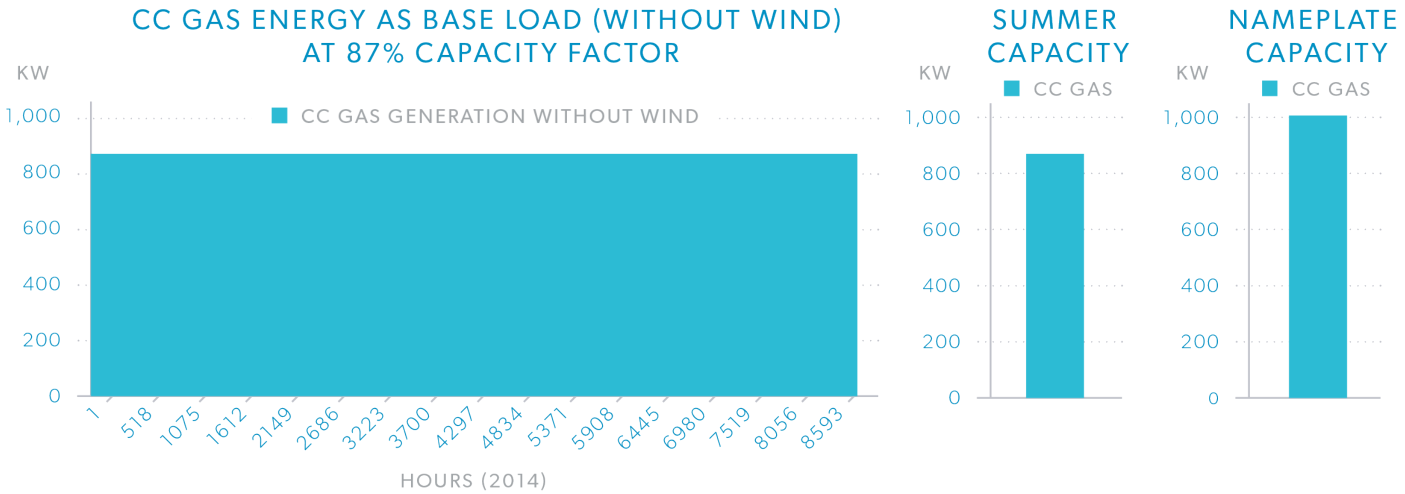
The fixed cost per MWh from the CC gas was $17.20/MWh at an 87% capacity factor. The new fixed cost per MWh is $17.20 x 87%/58.1% = $25.75/MWh.

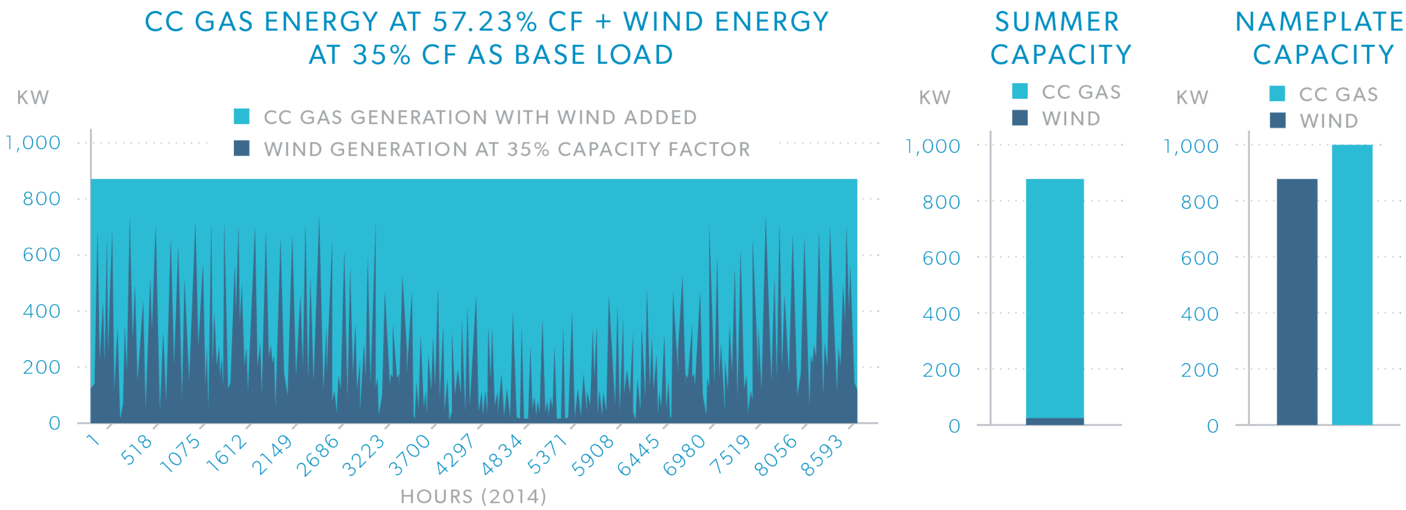
Each unit of gas in the pairing costs $25.75 - $17.20 = $8.55/MWh more than it used to.

Every MWh of wind energy in the pairing requires: 65% / 35% = 1.86 units of CC gas energy.

The imposed cost of wind on CC gas in the pairing is $8.55 x 65%/35% = $15.87 per MWh of wind in the pairing. The natural gas fuel and capital cost savings in the pairing are integral to these figures. The figures in the following spreadsheet table reflect the example above. All Excel worksheets are available on request.[35]

Model to serve a full time slice of 870KW demand and 870KW of UCAP	
CC GAS SERVING MODEL REQUEST BY ITSELF	
Fixed Cost ($/MWh) of CC Gas at 87% CF	$17.2
Variable Cost ($/MWh) of CC Gas	$42.1
Capacity Factor of CC Gas	87.0%
Capacity Value (UCAP) of CC Gas	87.0%
ADD MAXIMUM WIND CAPACITY TO REPLICATE MODEL SCENARIO (WITHOUT CURTAILMENT)	
KIND OF INTERMITTENT	WIND
Nameplate Capacity of wind to build (MW)	0.870
Summer Capacity From wind (KW)	23.49
Average energy from 0.87MW of wind at 35% CP (KW)	304.50
Residual energy to be generated from CC Gas (KW)	565.50
Residual Summer Capacity Required from CC Gas (KW)	845.51
Nameplate Capacity of CC Gas required to meet new summer capacity requirement (KW)	973.00
Fixed Cost ($/MWh) of Intermittent	$80.3
Variable Cost ($/MWh) of Intermittent	$ --
Capacity Factor of Intermittent	35.0%
Capacity Value of Intermittent	2.7%
RESULTING RATIOS AND COSTS WHEN PAIRING WIND WITH CC GAS	
LCOE CC Gas Alone	$59.3
LCOE Intermittent Alone (Invalid Choice)	$80.3
CC Gas nameplate required to meet 870KW of summer capacity and 870KW of energy (KW)	1,000.0
Gas nameplate required to meet 0.65% of PREVIOUS energy and 846.51KW of summer capacity	973.0
Energy from 973 KW of CC gas in combination with wind	565.50
Old CC Gas capacity factor	87.0%
New CC Gas Capacity Factor After Backing Down for Intermittent	58.1%
Fixed Cost ($/MWh) of CC Gas in Combination with Intermittent	$25.75
LCOE CC Gas in Combination with Intermittent	$67.85
Percent of Energy from CC Gas	65.0%
Percent of Energy from Wind	35.0%
LCOE of combination new CC Gas + new wind	$72.21
Imposed cost on new CC Gas per unit of new wind	$15.87
LCOE new wind including imposed cost	$96.17
Imposed cost on CC Gas per unit of CC Gas in Pairing	$8.55





Example 2: "Base Load" CC Gas + Wind at Real-World Capacity Factors:

In this example the CC gas fleet runs at a 47.8% annual capacity factor. For simplicity, we assume the CC gas fleet runs at a steady state 24/7/365.

1 MW of CC gas on the system works to provide 0.478 MWs of constant power 24/7/365. Its capacity factor is: 0.478MW / 1MW= 47.8%.

0.478 MW of wind is then "installed" and operates at a 33.9% capacity factor with no curtailment. Its output ranges from a minimum of 2.7% of nameplate (using the mean of lowest quartile output across peak hour calculation method) to 100% of nameplate.

To create the identical generation and capacity profile as the 1 MW of CC gas, we will require slightly less CC gas summer capacity by the amount of summer capacity offered by the 1 MW of wind. Specifically: 0.478 MW wind nameplate x 2.7% = 12.91 KW of summer capacity from wind. 0.870 MW CC gas summer capacity – 0.01291 MW = 0.85709 MW of CC Gas summer capacity required. To achieve that level of summer capacity we must divide by the capacity value of the CC Gas facility: 0.85709 / 87% = 0.98517 MW.

We have now established that the pairing includes 0.478 MW of wind nameplate capacity and 0.98517 MW of CC gas nameplate capacity.

We assume the CC gas system will back down synchronously as wind generation increases so that the pairing produces 0.478 MWs continuously throughout the year.

The wind energy produces an average of 0.478 MWs x 33.9% capacity factor = 0.16204 average MWs of power. The CC gas is left to produce 0.478 MW – 0.16204MW = 0.31596 MWs from its installed 0.98517 MWs.

The new CC gas capacity factor in the pairing is: 0.31596 MW / 0.98517 MW = 32.07%

The fixed cost per MWh from the CC gas was $31.12/MWh at a 47.8% capacity factor. The new fixed cost per MWh is $31.12 x 47.8%/32.07% = $46.39/MWh.

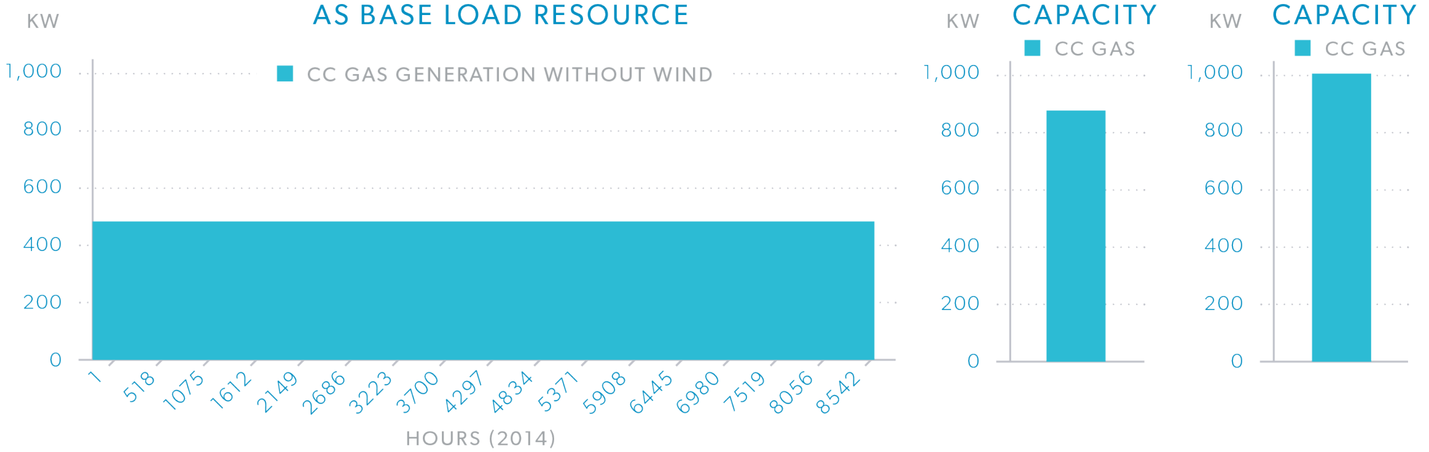
Each unit of gas in the pairing costs $46.39 - $31.31 = $15.26/ MWh more than it used to.

Every MWh of wind energy in the pairing requires: 66.1% / 33.9% = 1.95 units of CC gas energy.

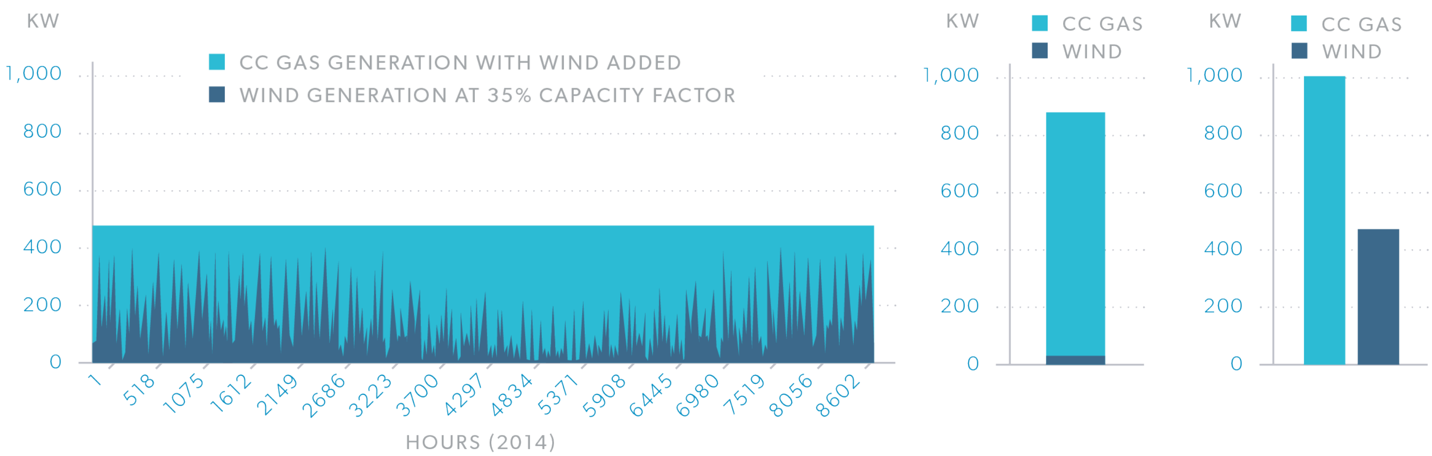
The imposed cost of wind on CC gas in the pairing is $15.26 x 66.1%/33.9% = $29.76 per MWh of wind in the pairing. The natural gas fuel and capital cost savings in the pairing are integral to these figures. The figures in the following spreadsheet table reflect the example above. All Excel worksheets are available on request.[36]

Model to serve a full time slice of 478KW demand and 870KW of UCAP	
CC GAS SERVING MODEL REQUEST BY ITSELF	
Fixed Cost ($/MWh) of CC Gas at 47.8% CF	$31.12
Variable Cost ($/MWh) of CC Gas	$42.10
Capacity Factor of CC Gas	47.8%
Capacity Value (UCAP) of CC Gas	87.0%
ADD MAXIMUM WIND CAPACITY TO REPLICATE MODEL SCENARIO (WITHOUT CURTAILMENT)	
KIND OF INTERMITTENT	WIND
Nameplate Capacity of wind to build (MW)	0.478
Summer Capacity From wind (KW)	12.91
Average energy from 0.498MW of wind at 33.9% CF (KW)	162.04
Residual energy to be generated from CC Gas (KW)	315.96
Residual Summer Capacity Required from CC Gas (KW)	857.09
Nameplate Capacity of CC Gas required to meet new summer capacity requirement (KW)	985.17
Fixed Cost ($/MWh) of Intermittent	$78.16
Variable Cost ($/MWh) of Intermittent	$ --
Capacity Factor of Intermittent	33.9%
Capacity Value of Intermittent	2.7%
RESULTING RATIOS AND COSTS WHEN PAIRING WIND WITH CC GAS	
LCOE CC Gas Alone	$73.22
LCOE Intermittent Alone (Invalid Choice)	$78.16
CC Gas nameplate required to meet 870KW of summer capacity and 478KW of energy (KW)	1,000.0
Gas nameplate required to meet 0.661% of PREVIOUS energy and 857.09KW of summer capacity	985.17
Energy from 985.2 KW of CC gas in combination with wind	315.96
Old CC Gas capacity factor	47.8%
New CC Gas Capacity Factor After Backing Down for Intermittent	32.1%
Fixed Cost ($/MWh) of CC Gas in Combination with Intermittent	$46.4
LCOE CC Gas in Combination with Intermittent	$88.5
Percent of Energy from CC Gas	66.1%
Percent of Energy from Wind	33.9%
LCOE of combination new CC Gas + new wind	$84.99
Imposed cost on new CC Gas per unit of new wind	$29.76
LCOE new wind including imposed cost	$107.92
Imposed cost on CC Gas per unit of CC Gas in Pairing	$15.26

CC GAS GENERATION AT 47.8% CAPACITY FACTOR AS BASE LOAD RESOURCE | SUMMER CAPACITY | NAMEPLATE CAPACITY



CC GAS AT 32.1% CF + WIND AT 33.9% CF AS BASE LOAD RESOURCE | SUMMER CAPACITY | NAMEPLATE CAPACITY



FOOTNOTES: APPENDIX A

[34] *https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/BOD/Markets%20Committee/2013/20130724/20130724%20Markets%20 Committee%20of%20the%20BOD%20Item%2005%202012%20SOM%20Report.pdf (Page 16)*

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Appendix B: Levelized Cost of Electricity from PV Solar

This appendix estimates the levelized cost of electricity (LCOE) from new photovoltaic solar power (PV). Imposed cost (defined later) rises as the PV energy market share increases. We examine LCOE at one percent increments of energy market share in a regional grid system from zero percent through fifteen percent.

Methodology for Calculating Imposed Cost of Solar PV

Refer back to pages 27-28 for our discussion regarding PV solar. The calculations in Appendix B are intended to be illustrative. The final figures below do not match the figures on page 28 of the report because we used EIA 2014 real world capacity factors for all applicable resources in Appendix B. The figures above rely on the more recently released 2015 national average capacity factors. Further, one data set underlying the imposed cost figures above and in Appendix B is the set of solar generation data published by CAISO, which was difficult to compile. Due to the format of the CAISO data, it was impractical to regather and recalculate load, solar generation, and residual peak load for 2015 in the course of finalizing this report. Hence all calculations in Appendix B reflect 2014 data.

We estimate the US average LCOE of PV in 2020 at 153.7 and the LCOE of PV in the California region at 151.7 (2013 $/MWh) including imposed cost for the next one percent energy market share gain in their respective jurisdictions. This is higher than estimated by EIA in their LCOE 2020 forecast,[37] and indicates PV solar electricity is four to five times more expensive than electricity from most existing dispatchable resources.

CCGT and CT as Proxy for Actual Marginal Resources Displaced by PV

Because hourly marginal resource reports for CAISO were not found in the public domain, we are not able to verify which generating technologies PV generation displaces or in what ratio. We therefore estimate imposed cost under a model case where only new combustion turbine (CT) and combined cycle (CCGT) units experience reductions from their previous annual generation totals as PV capacity is added, and experience them at an equal percentage reduction from their previous capacity factors.[38] This assumption does not consider the likely increase in upward ramping requirements placed on gas generators due to rapidly declining PV generation across hours of fairly steady, near peak demand. That circumstance has been widely reported to require an increase in the use of CT (or CCGT in heat recovery steam generator (HRSG) bypass mode) capacity as PV capacity increases.

Real world circumstances certainly vary by region of the country and by local transmission constraints. Even though our displaced resource and ratio assumption may not hold true in specific regions of the country, we argue that all capacity-bearing generator technologies carry fixed costs, and operate at some CF prior to PV capacity being added to the system, and that resources displaced will achieve lower capacity factors once PV energy gains market share. Imposed costs are therefore present at some level even if our best assumption cannot rely on actual marginal resource data. The calculations used for this report yield a marginal fixed cost per unit of energy curve (i.e. change in $/MWh) as a result of incremental one percent PV energy market share gains.

Imposed Cost Should be Allocated to its Source

Imposed cost increases as more and more PV capacity is added to a system. This is because energy produced by early PV installations reduces original gross peak demand at late afternoon hours to levels below demand levels occurring at evening hours. Once that happens, no amount of additional PV capacity can reduce the new daily peaks in the residual load curve (net of solar energy already being produced by previously installed PV capacity) which now occur after PV stops producing in the evening. This is illustrated in Figures 1A and 1B later in this report. Therefore, PV's value as a capacity resource falls away as market share increases and residual daily load peaks shift to evening hours.

Because "imposed cost" does not accrue directly to intermittent generators in wholesale energy markets or through the value of renewable energy credits (RECs), most lawmakers, regulators and electricity consumers do not recognize its existence, let alone allocate it correctly, even though imposed cost is very real in a "conservation of matter" sense. We believe imposed cost should be considered and shown as an expense on the policy, LCOE and wholesale market "ledgers" of the intermittent generators which induce them.

Estimating Capacity Value (CV) of PV

This report utilizes hourly PV generation and hourly electricity demand data for 2014 across the CAISO system as reported by CAISO.

We model the minimum availability of PV energy from incremental capacity additions across the highest 900 net electricity demand hours in CAISO (net of PV generation from previously installed capacity) of the year in "1% market share increments" from zero to fifteen percent PV market share. These calculations were made at various confidence levels. That is, a 75% confidence level would return the lowest hourly generation that could be expected from incremental PV capacity across 75% of the 900 highest net load hours of the year. After each 1% energy market share addition of PV generation we re-calculate net load and re-sort the 8,760 hourly net load figures highest to lowest. Of the new ordered net load data we consider the 900 hours of greatest net demand in analyzing the next 1% market share addition of PV contribution to "peak load" fulfillment. Then, for the 900 greatest net load hours, we sort PV generation lowest to highest. The 225th lowest PV generation hour of the 900 highest demand hours is considered the "75% confidence level." In other words, 75% of the time PV is expected to generate at some percent of nameplate capacity or above across the 900 highest net demand hours of the year. This is repeated through 15% PV energy market share.

CV was also estimated using the "mean of lowest quartile generation" method (MLQG). This is the average expected generation of the lowest one fourth of generating hours of the highest 900 electricity net demand hours of the year. The analysis allowed us to calculate the CV and resulting system imposed cost for each successive percentage gain of PV energy market share. Because the 75 percentile method yielded results more favorable to PV CV than the MLQG method, we base our imposed cost estimates on the more generous 75 percentile method. Imposed cost would be higher under the alternative calculation method. All worksheets are available upon request of the author.

The CV determination method in this report differs significantly from the effective load carrying capability (ELCC) convention. This is because we believe a proper long term capacity planning metric must measure each technology's dependability at high demand periods independent of:

- system or regionally constrained area load profile dynamics over time,
- point-in-time system or regional reserve margins, and
- the uncertain future ratio of dispatchable to intermittent fueled generators across a system or within any transmission constrained region on the system.

While ELCC is a valid statistical measure of an intermittent generating technology's capability to address new load under static generating resource blend and load profile assumptions, resource blend is not constant in the real world across capacity planning time horizons, nor are increasing loads of the existing use profile a certainty.

PV's CV is therefore calculated for purposes of this report based on its stand-alone ability to reduce existing peak system demand across the 900 greatest peak demand hours of 2014. We do not, however, assign CV based on the absolute peak load hour of the year. Instead, we measure PV's expected contribution at and above various percentages of the top 900 ordered peak demand hours of the sampled year. Our methodology answers the question, "What minimum percentage of PV's nameplate capacity is that capacity expected to generate across (75%) of the highest peak demand hours of a year?"

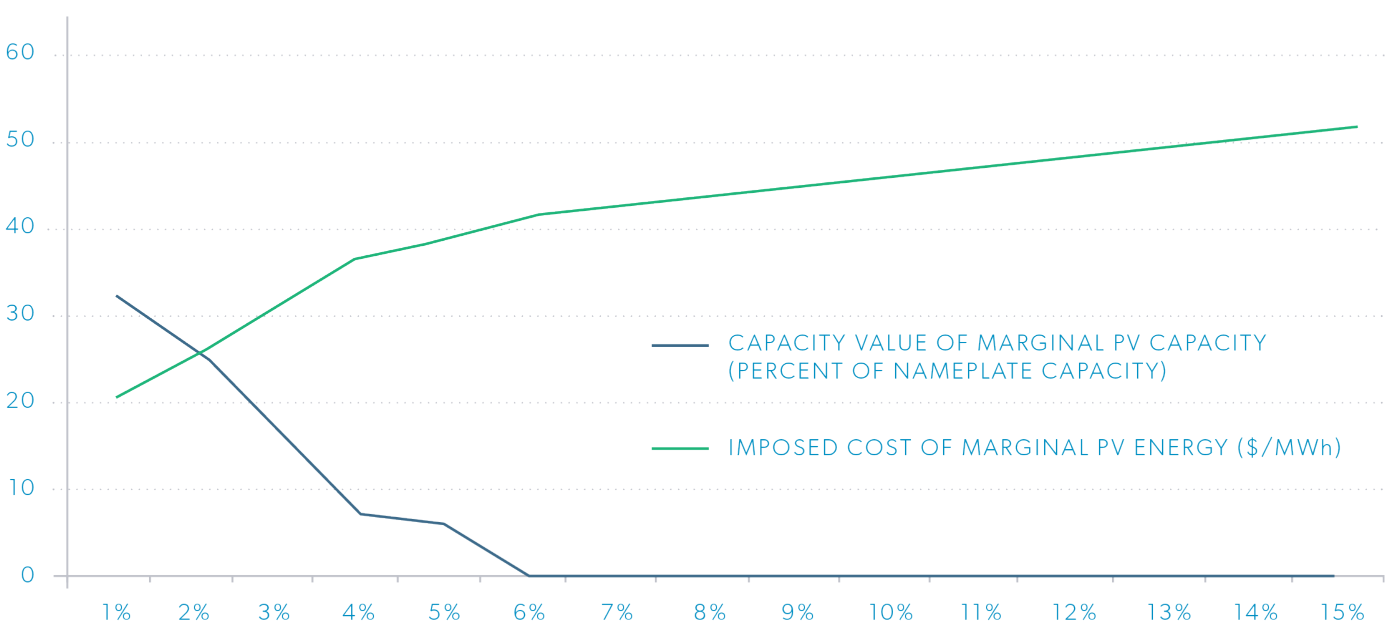
We base our definition of "peak demand hours of the year" on the highest 900 hours, because this is likely to capture most or all of the highest 360 load hours across typical load and weather years--even as PV might achieve very optimistic market share--and because 360 is approximately the number of hours considered in several other RTO/ISO regions in their determination of CV (also termed by some regulators and regional market organizations as "capacity credit").[39] Those regions, however, specify a set of hours they consider to contain most of the highest demand hours of a year (e.g. "2 PM to 6PM across June, July and August") which "misses" a significant number of peak demand hours in CAISO in 2014, and likely in many other years and regions. Furthermore, that set of hours fails to include most of the peak demand hours net of higher market penetrations of PV. For this reason, we chose to evaluate the specific 900 highest demand hours, rather than a set of hours that "might" contain "most" of them.

We calculate net system demand after adding each 1% market share gain for PV for the top 900 demand hours of 2014. We then sort by net demand at each percent market share gain and evaluate the top 900 net load hours of the 8,760 total hours in a calendar year. The highest demand hour in 2014 consumed an average of 44,671 MW and the 900th highest demand hour consumed an average of 33,970 MW, a range of almost 11,000 MW. The highest hourly PV generation at (extrapolated) 15% market share was 10,267 MW, making our inclusion of 900 hours sufficient to minimize skewed results due to an insufficient sample size.

The statistically appropriate confidence level necessary to maintain system reliability at current reserve margin levels is not determined by this report.[40] Peak load hours are defined here as the highest 900 electricity demand hours of a calendar year. That is, the net load hour of the year ranking 225th highest represents the 75% confidence level. The average generation from the lowest 225 generating hours of the highest 900 net load hours is the MLQG confidence level. Our expectation is that the appropriate confidence level falls within the range we consider for this report.

ESTIMATED CAPACITY VALUE AND IMPOSED COST OF PV SOLAR: CAISO AT 31% CF

PV ENERGY MARKET SHARE	CAPACITY VALUE OF MARGINAL PV CAPACITY (PERCENT OF NAMEPLATE CAPACITY)	IMPOSED COST OF MARGINAL PV ENERGY
1%	32.6%	21.0
2%	25.3%	25.1
3%	16.2%	30.2
4%	7.1%	35.3
5%	4.7%	37.4
6%	0.0%	40.6
7%	0.0%	41.6
8%	0.0%	42.7
9%	0.0%	43.8
10%	0.0%	45.0
11%	0.0%	46.2
12%	0.0%	47.6
13%	0.0%	49.0
14%	0.0%	50.4
15%	0.0%	52.0

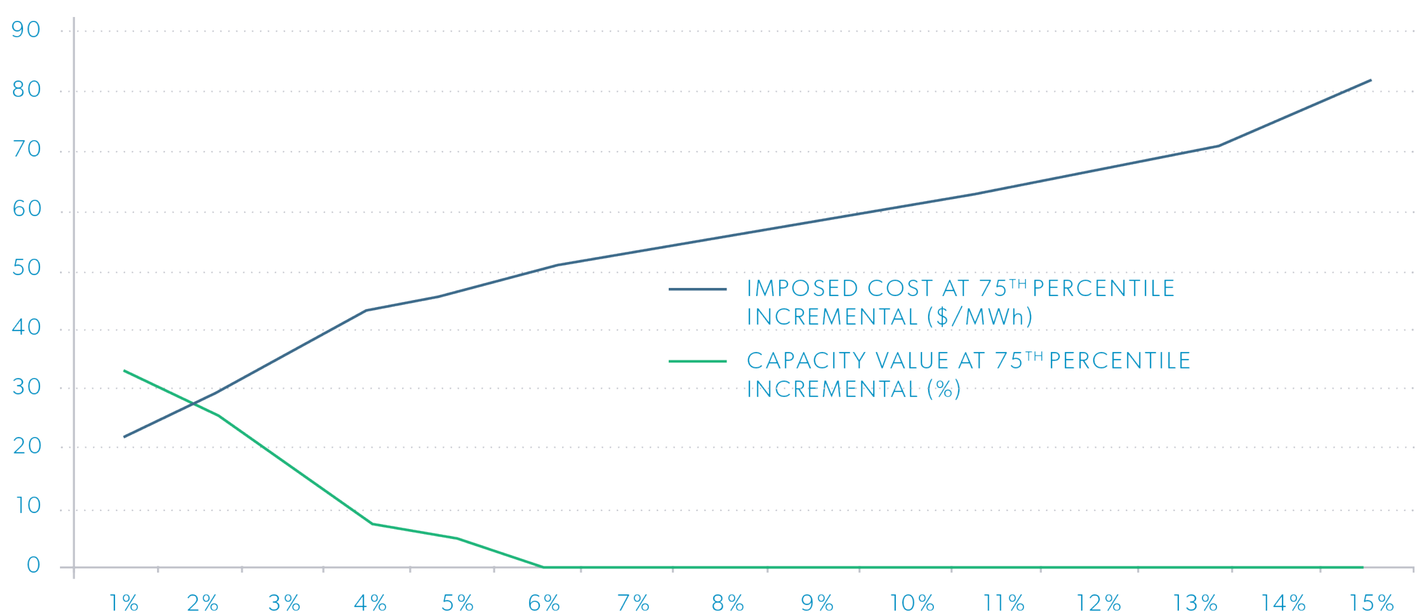


At each incremental market share level, the MLQG confidence level returns the lowest CV, and the 75th percentile confidence level returns the highest CV. The range of CVs for these two confidence levels turns out to be narrow, but the 75th percentile method yields the more generous capacity value result. We present only the 75th percentile figures in this report.

The following pairs of tables and graphs demonstrate how the CV of PV capacity additions fall and imposed costs rise for each successive energy market share gain in CAISO and for the US, respectively. Costs vary slightly between the two, based on differing CF assumptions used in the calculations. CVs are identical in the two cases because they are listed as a percent of nameplate capacity. CVs (in MWs) would vary inversely with CF assumptions.

ESTIMATED CAPACITY VALUE AND IMPOSED COST OF PV SOLAR: US AVG. AT 25.9% CF

PV ENERGY MARKET SHARE	CAPACITY VALUE AT 75TH PERCENTILE INCREMENTAL (%)	IMPOSED COST AT 75TH PERCENTILE INCREMENTAL ($MWh)
1%	32.6%	20.9
2%	25.3%	26.1
3%	16.2%	32.8
4%	7.1%	39.7
5%	4.7%	42.9
6%	0.0%	47.8
7%	0.0%	50.0
8%	0.0%	52.5
9%	0.0%	55.3
10%	0.0%	58.4
11%	0.0%	61.8
12%	0.0%	65.7
13%	0.0%	70.1
14%	0.0%	75.1
15%	0.0%	80.8



What Imposed Cost (as Defined in this Report) Does Not Include

Imposed cost as used in this report does NOT include additional costs borne by dispatchable resources such as lost fuel efficiency from "cycling" and steep "ramping" nor the higher maintenance costs associated with those more demanding operating dynamics.

Imposed cost also does not include higher transmission investment costs for remotely sited PV. It does not include an adjustment for a likely shorter physical lifespan of PV systems relative to the lifespans of conventional generators.

Finally, while imposed cost monetizes the indirect cost of intermittent and "outside operator control" renewable "fuel" resource behavior, we do not intend to imply PV technology on the whole is a direct substitute for any dispatchable resource. Clearly it is not, as dispatchable resources are available to operate 24/7/365 and can be scheduled by the system operators.

The sum of these unconsidered factors could increase the cost of PV significantly. Reliable quantitative data were not readily available and as such, such estimates were not appropriate for this analysis.

Capacity Value (CV) Calculations Using CAISO 2014 Hourly Load

Our analysis suggests that incremental additions of PV capacity offer steeply declining CV. PV fleet-average CV for the first 5% energy market share in CAISO is 17.2% of nameplate capacity and the resulting imposed cost spread across all PV is 28.6 (2013 $/MWh) as shown in Table 3 of this report, while the six percent incremental market share has CV of 0%. It is important to note that PV provides some CV at low market penetration, but as residual peak load hours[41] shift to evening, additional capacity contribution to meeting net peak load falls sharply. We label this effect PV's "capacity value cliff." The imposed cost of energy from the capacity required to attain the six percent incremental market share rises significantly to $40.6, a 42% imposed cost increase over the previously existing 5% average market share bearing installed PV capacity.[42]

In our example we assume the resources displaced by PV are new combined cycle natural gas (CC gas) and new combustion turbine natural gas (CT gas) generators, with their respective forecast levelized fixed costs at real-world CFs.[43]

Fleet average CVs and imposed costs are simply an averaging function of preceding incremental CVs as shown below:

CAISO MARGINAL AND FLEET AVERAGE CAPACITY VALUES (%) AND IMPOSED COSTS ($/MWh)

CAPACITY VALUE OF MARGINAL CAPACITY	FOR (NTH % PV ENERGY MARKET SHARE)	IMPOSED COST OF MARGINAL CAPACITY	FLEET AVERAGE CAPACITY VALUE	FLEET AVERAGE IMPOSED COST
32.6%	1%	$21.0	32.6%	21.0
25.3%	2%	$25.1	28.9%	22.8
16.2%	3%	$30.2	24.7%	24.9
7.1%	4%	$35.3	20.3%	27.1
4.7%	5%	$37.4	17.2%	28.6
0.0%	6%	$40.6	14.3%	30.0
0.0%	7%	$41.6	12.3%	31.0
0.0%	8%	$42.7	10.7%	31.8
0.0%	9%	$43.8	9.5%	32.4
0.0%	10%	$45.0	8.6%	32.9
0.0%	11%	$46.2	7.8%	33.2
0.0%	12%	$47.6	7.2%	33.6
0.0%	13%	$49.0	6.6%	33.8
0.0%	14%	$50.4	6.1%	34.1
0.0%	15%	$52.0	5.7%	34.3

Assumptions to the Calculation of PV Imposed Cost

We provide a step by step calculation of estimated capacity value and imposed cost of PV for its first five, and its sixth percent energy market share. The analysis indicates the presence of a fleet average imposed cost of PV for the first five percent PV market share, and a larger incremental imposed cost for the sixth incremental percent of energy market share.

PV often displaces natural gas generation. We chose to model that dynamic in this report.[44] In the following example, we make the following assumptions about how PV resources are integrated onto the electricity grid:

- Hourly PV generation in CAISO totaled 10,435,675 MWh for 2014 against 232,734,274 MWhs of load, equating to a 4.483% energy market share for PV.

- EIA estimates a 31% CF for PV in NERC region 20 (California) in LCOE assumptions for 2020. We assume that same CF for existing California PV. At 31% CF, PV installed capacity for 2014 would have been 3,843 MW (nameplate).[45]

- Example assumes zero load growth.

- CV estimates use the 900 greatest electricity demand hours in CAISO for 2014. We chose 900 hours because several prominent ISO/RTOs estimate CV across a smaller set of approximately 360 hours of the year that do not capture early evening hours. In PJM, for example, CV for intermittent generators is determined using the hours between 2PM and 6PM across the months of June, July and August.[46] However, as PV attains market share, many of the 360 residual peak load hours (net of PV generation) shift from late afternoon when PV is often productive, to twilight hours with little to no PV generation. This causes the fixed window of peak demand hours to miss the mark and over-value additional PV's contribution to meeting future peak demand. We therefore examine a larger and more flexible sample size (the 900 highest net demand hours) which we feel more accurately reflects incremental PV capacity's contribution to meeting peak electricity demand.

- As PV is added, we reduce the annual energy from the remaining CCGT and CT facilities equally, estimated based on the hours of day PV is generating and which technologies are likely "on the margin" at those hours of the year. This is not meant to be a perfect representation of the resources displaced by PV but rather a reasonable facsimile of the fixed costs and CFs of the resources actually displaced. Real world data based on an hourly marginal resource report (which we could not obtain from CAISO) would yield more precise imposed costs.

- PV installed capacity is added in increments sufficient to capture one additional energy market share gain in a system with annual load and load profile held constant.

- System capacity reserve margin is held constant by "retiring" CT gas, CC gas capacity with CV (in MWs) equal to the CV in MWs of PV added. In the real world retirements and capacity additions take time to evolve, which masks the gradually accruing costs. Our calculations and this example shine light on the need to maintain system reserve capacity while adding low CV resources to the generation mix.

- CT gas and CC gas each and as a combined "natural gas fired fleet" offer 87% of their nameplate capacity as net summer capacity[47] regardless of either resource's estimated real-world or "best case" CFs. We use net summer capacity as CV because no other published values for natural gas generator CV by any calculation method could be attained.

- CT gas and CC gas together offer a blend of base load, load following and peak load following at estimated respective CFs of 6.6% and 51.9% in the 0% PV base scenario.[48]

- CVs for PV use the 75th percentile highest net load hour methodology, the most lenient of the confidence levels we considered. The 75th percentile mark means PV is permitted to fall short of its CV 25% (90) of the highest 900 load hours of 2014 (net of generation from modeled previously existing PV capacity). It is the 225th highest PV generation of the highest 900 net load hours of 2014.

- The annual energy from the CT gas and CC gas capacity with the 6th percentage of PV added to them is the remainder of CT gas and CC gas energy prior to the PV energy minus the energy produced by incremental PV capacity.

- The new CF of the residual installed capacity of CT gas and CC gas with the incremental PV is the new CT gas and CC gas energy divided by the new CT gas and CC gas capacity required to meet the capacity and energy levels of CT gas and CC gas prior to the addition of the incremental PV resource.
- Fixed costs per MWh of CT gas and CC gas are then recalculated by multiplying their new fixed costs per MWh in the base line scenario by the ratio of their base line CFs divided by their new CFs.
- The imposed cost per MWh of the incremental PV energy is the increase in fixed cost per MWh of CT gas and CC gas times the percentage of CT gas and CC gas energy in the resulting system divided by the incremental PV energy.

Imposed Cost Calculation Example for CAISO

CAISO 0% PV ENERGY MARKET SHARE CASE

The base case scenario assumes no PV exists on the CAISO system. In this case, we estimate the CT gas fleet, (consisting of approximately 12,000 MWs of nameplate capacity), runs at 6.6% annual CF. Similarly, the CC gas fleet is estimated to consist of approximately 22,000 MWs of installed capacity and achieves a 51.9% annual CF. In this scenario, together CT and CC gas would have generated 46% of CAISO system energy in 2014.[49]

CT gas:
12,000 MW X 6.6% X 8,760 hours per year = 6.98 Million MWhs per year

CC gas:
22,000 MW X 51.9% X 8760 hours per year = 100.08 Million MWhs per year

Total = 107.06 Million MWhs

Absent PV, gas aggregated CF would have been 35.9%:

107.06 Million MWhs / ((22,000 MWs + 12,000 MWs) X 8,760) = 35.9%

CAISO 5% PV ENERGY MARKET SHARE CASE

In 2014, PV actually achieved 4.484% energy market share in CAISO according to published data. (10,435,675 MWhs). We adjust this to 5% (11,639,164 MWhs) for this example. Assuming the PV fleet average CF was 31%, average PV nameplate capacity across 2014 would have been approximately 4,286 MW:

11.639 Million MWhs / (31% X 8,760) = 4,286 MWs

CAISO 2014 TOTAL GENERATION (MWh) = 232,734,000

TECHNOLOGY	CC GAS	CT GAS	NAT GAS TOTAL	NEW PV	EXISTING PV	TOTAL GAS + PV
FLEET AVERAGE PV SOLAR	0%					
CV%	87.0%	87.0%	87.0%	0.0%	N/A	N/A
SUMMER CAP (CV)(MW)	19,140	10,440	29,580	N/A		29,580
ENERGY MKT SHR%	43.0%	3.0%	46.0%	0.0%	0.0%	46.0%
ANNUAL ENERGY (MWh)	100,075,620	6,982,020	107,057,640	N/A	-	107,057,640
CAPACITY FACTOR (%)	51.9%	6.6%	35.9%	N/A	31.0%	N/A
EST. NAMEPLATE CAP (MW)	22,000	12,000	34,000	N/A	0.0	34,000
FIXED COST ($/MWh)	$29.0	$153.57	$37.11	N/A	N/A	N/A

According to our analysis, the fleet average CV of the first 4,286 MWs of PV is 17.2%.[50] Therefore, 736 MW of CV was provided by 5% energy market share for PV:

4,286 MWs X 17.2% = 736 MW

The CV of the gas fleets is 87% of nameplate capacity.[51] The remaining installed gas fired capacity required to maintain the same system capacity reserve margin as prior to PV is 33,154 MWs:

22,000 MWs + 12,000 MWs – (736 MW / 87%) = 34,000 MWs – 846 MWs = 33,154 MW

Energy produced by the remaining gas fleet in the presence of 5% PV was 95.42 Million MWhs:

107.06 Million MWhs – 11.64 Million MWhs = 95,418,476 MWhs

The new CF of the gas fleet is 32.9%:

95.42 Million MWhs / (33,154 MW X 8,760 hours per year) = 32.9%

The new fixed cost per MWh for gas is 40.60 ($/MWh) of gas energy produced. This is calculated by energy market share weighted average for CT and CC gas:

($31.71 x 89,195,532 MWh / 95,418,476 MWh + $168.0 x 6,222,944 MWh / 95,418,476 MWh) = 40.6

Fleet Average imposed cost per unit of gas energy at 5% PV energy market share is 3.49 ($/MWh) of gas energy:

$40.60 - $37.11 = $3.49 per MWh of gas energy

Fleet average imposed cost per unit of PV energy at 5% energy market share is $28.6/MWh of PV energy:

$3.49 X 95.42 Million MWhs / 11.64 Million MWhs = $28.6 / MWh of PV energy

CAISO 2014 TOTAL GENERATION (MWh)	CC GAS	CT GAS	NAT GAS TOTAL	NEW PV	EXISTING PV	TOTAL GAS + PV
232,734,000						
TECHNOLOGY	CC GAS	CT GAS	NAT GAS TOTAL	NEW PV	EXISTING PV	TOTAL GAS + PV
FLEET AVERAGE PV SOLAR	5%					
CV%	87.0%	87.0%	87.0%	N/A	17.2%	0.0%
SUMMER CAP (CV)(MW)	18,664	10,180	28,844	N/A	736	29,580
ENERGY MKT SHR%	38.3%	2.7%	41.0%	N/A	5.0%	43.0%
ANNUAL ENERGY (MWh)	89,195,532	6,222,944	95,418,476	N/A	11,639,164	107,057,640
CAPACITY FACTOR (%)	47.5%	6.1%	32.9%	N/A	31.0%	N/A
EST. NAMEPLATE CAP (MW)	21,453	11,701	33,154	N/A	4,286	37,440
FIXED COST ($/MWh)	$31.71	$168.0	$40.6	N/A	N/A	N/A

CAISO CASE OF INCREASING PV ENERGY MARKET SHARE FROM 5% to 6%

Beginning with the ratios, CFs and fixed costs per MWh figures for CT and CC gas at 5% market penetration, we add an additional 857 MWs of PV capacity – enough to capture a six percent energy market share at 31% CF based on 2014 CAISO load conditions. The annual energy yield of the added PV capacity would be 2.33 Million MWhs under these assumptions.

The six percent market share for PV reduces gas energy to 93.09 Million MWhs:

95.42 Million MWhs – 2.33 Million MWhs = 93.09 Million MWhs

The CV of the marginal PV capacity offers no CV.

Gas CV required to maintain the same reserve margin does not change:

33,154 MW – 0 MW / 87% = 33,154 MW

This yields a lower CF for gas of 32.1%:

93.09 MM MWhs / (33,154 MW * 8760) = 32.1%

The fixed cost per MWh impact on the gas fleet of the incremental 1% PV market share gain is therefore $1.0/MWh of gas energy:

$41.6 - $40.6 = $1.0/MWh of gas.

The estimated imposed cost per incremental unit of PV is therefore $40.6/MWh of incremental PV:

$1.0/MWh of gas X (93.09 Million MWhs gas energy / 2.33 Million MWhs of incremental PV energy) = $40.6[52]

CAISO 2014 TOTAL GENERATION (MWh)	CC GAS	CT GAS	NAT GAS TOTAL	NEW PV	EXISTING PV	TOTAL GAS + PV
232,734,000						
TECHNOLOGY	CC GAS	CT GAS	NAT GAS TOTAL	NEW PV	EXISTING PV	TOTAL GAS + PV
FLEET AVERAGE PV SOLAR	5%					
CV%	87.0%	87.0%	87.0%	N/A	17.2%	0.0%
SUMMER CAP (CV)(MW)	18,664	10,180	28,844	N/A	736	29,580
ENERGY MKT SHR%	38.3%	2.7%	41.0%	N/A	5.0%	43.0%
ANNUAL ENERGY (MWh)	89,195,532	6,222,944	95,418,476	N/A	11,639,164	107,057,640
CAPACITY FACTOR (%)	47.5%	6.1%	32.9%	N/A	31.0%	N/A
EST. NAMEPLATE CAP (MW)	21,453	11,701	33,154	N/A	4,286	37,440
FIXED COST ($/MWh)	$31.71	$168.0	$40.6	N/A	N/A	N/A

TECHNOLOGY	CC GAS	CT GAS	NAT GAS TOTAL	NEW PV	EXISTING PV	TOTAL GAS + PV
MARGINAL PV SOLAR ADDED	6%					
CV%	87.0%	87.0%	87.0%	0.0%		
SUMMER CAP (CV)(MW)	18,664	10,180	28,844	-	736	29,580
ENERGY MKT SHR%	37.4%	2.6%	40.0%	1.0%	5.0%	46.0%
ANNUAL ENERGY (MWh)	87,019,514	6,071,129	93,090,643	2,327,833	11,639,164	107,057,640
CAPACITY FACTOR (%)	46.3%	5.9%	32.1%	31.0%	31.0%	N/A
EST. NAMEPLATE CAP (MW)	21,453	11,701	33,154	857	4,286	38,297
FIXED COST ($/MWh)	$32.5	$172.2	$41.6	N/A	N/A	N/A
PERCENT OF GAS CAPACITY	64.7%	35.3%				
PERCENT OF GAS ENERGY	93.5%	6.5%				
MARGINAL PV SUMMARY						
NAMEPLATE CHANGE (MW)	-	-	-	857	N/A	857
IMPOSED COST PER UNIT OF GAS ($/MWh)	$0.8	$4.2	$1.0	N/A	N/A	N/A
IMPOSED COST PER UNIT OF PV ($/MWh)	$29.6	$11.0	$40.6	N/A	N/A	$40.6

IMPOSED COST CALCULATION EXAMPLE FOR US TOTAL

For this example, we estimate installed capacity and energy market share for CC and CT gas resources nationally using EIA Forms 860 and 923 data (2014) and other sources. EIA's reported U.S. total net electricity generation in 2014 is used for annual system load. While exact input figures can be debated, the example output is not significantly altered.

Table 4 shows the marginal and fleet average capacity values and imposed costs of PV at one percent increments of energy market share for the United States, at EIA LCOE 2020 estimated PV capacity factor in 2020 of 25%.

US TOTAL MARGINAL AND FLEET AVERAGE CAPACITY VALUES (%) AND IMPOSED COSTS ($/MWh)

CAPACITY VALUE OF MARGINAL CAPACITY	FOR (NTH % PV ENERGY MARKET SHARE)	IMPOSED COST OF MARGINAL CAPACITY	FLEET AVERAGE CAPACITY VALUE	FLEET AVERAGE IMPOSED COST
32.6%	1%	$20.9	32.6%	20.9
25.3%	2%	$26.1	28.9%	23.1
16.2%	3%	$32.8	24.7%	25.7
7.1%	4%	$39.7	20.3%	28.4
4.7%	5%	$42.9	17.2%	30.3
0.0%	6%	$47.8	14.3%	32.1
0.0%	7%	$50.0	12.3%	33.4
0.0%	8%	$52.5	10.7%	34.3
0.0%	9%	$55.3	9.5%	35.0
0.0%	10%	$58.4	8.6%	35.6
0.0%	11%	$61.8	7.8%	36.1
0.0%	12%	$65.7	7.2%	36.5
0.0%	13%	$70.1	6.6%	36.8
0.0%	14%	$75.1	6.1%	37.1
0.0%	15%	$80.8	5.7%	37.4

0% PV ENERGY MARKET SHARE CASE

In this case, we scale our example to the entire US. We change the levelized costs of CT and CC gas using a capacity factor adjustment from the LCOE 2015 report released by IER in June, 2015, which concluded that the CT fleet achieved a capacity factor of 4.8%, down from the 6.6% CF assumption in CAISO, and that the CC fleet achieved a capacity factor of 47.8%, down from the 51.9% assumed for CAISO. This adjustment raises the levelized fixed costs of those resources to 212.5 and 31.5 $/MWh, respectively.

We estimate the US average energy market share for CT to be 1.4% and for CC to be 25.6% based on EIA summary statistics[53] and the ratio of CT to CC energy estimated for CAISO using EIA 860 data. We note that energy market share does not affect imposed cost calculations.

US average PV capacity factor is set at 25%: the level estimated by EIA in its LCOE 2020 forecast. This increases the installed capacity of PV per percent energy market share for the US to 18,566 MW.[54] We do not decrease PV CV with the decrease in CF so the increased installed capacity per MWh increases effective CV (in MWs), lowering imposed cost (per MWh).

CT gas

135,377 MW X 4.8% X 8,760 hours per year = 56,923,496 MWhs per year

CC gas:

248,583 MW X 47.8% X 8760 hours per year = 1,040,886,784 MWhs per year

Total = 1,097,810,280 MWhs per year

Absent PV, gas aggregated CF would have been 32.6%:

1,097,810,280 MWhs / ((248,583 MWs + 135,377 MWs) X 8,760) = 32.6%

TECHNOLOGY	CC GAS	CT GAS	NAT GAS TOTAL	NEW PV	EXISTING PV	TOTAL GAS + PV
FLEET AVERAGE PV SOLAR	0%					
CV%	87.0%	87.0%	87.0%	0.0%	N/A	N/A
SUMMER CAP (CV)(MW)	216,267	117,778	334,046	N/A		334,046
ENERGY MKT SHR%	***25.60%***	***1.4%***	***27.0%***	0.0%	0.0%	27.0%
ANNUAL ENERGY (MWh)	1,040,886,784	56,923,496	1,097,810,280	N/A	-	1,097,820,280
CAPACITY FACTOR (%)	47.8%	4.8%	32.6%	N/A	25.0%	N/A
EST. NAMEPLATE CAP (MW)	248,583	135,377	383,960	N/A	0.0%	383,960
FIXED COST ($/MWh)	$31.5	$212.5	$40.87	N/A	N/A	N/A

US TOTAL 2% PV ENERGY MARKET SHARE CASE

Here we raise US PV solar energy market penetration in the US to 2% (81,319,280 MWhs) in this example. Assuming the PV fleet average CF was 25%, average PV nameplate capacity at 2% energy market share would have been approximately 37,132 MW:

81,319,280 Million MWhs / (25% X 8,760) = 37,132 MWs

From our analysis, the fleet average CV of the first 37,132 MWs of PV is 28.9%[55] of installed nameplate capacity. Therefore, 10,745 MW of CV was provided by 2% energy market share for PV:

37,132 MWs X 28.9% =10,745 MW

The CV of the gas fleets is 87% of nameplate capacity.[56] The remaining installed gas fired capacity required to maintain the same system capacity reserve margin as prior to PV is 371,610 MWs:

248,583 MWs + 135,377 MWs – (10,745 MW / 87%) = 383,960 MWs – 12,350 MWs = 371,610 MW

Energy produced by the remaining gas fleet in the presence of 2% PV was 1,016,491,000 MWhs:

1,097,810,280 MWhs – 81,319,280 MWhs = 1,016,491,000 MWhs

The new CF of the gas fleet is 31.2%:

1,016,491,000 MWhs / (371,610 MW X 8,760 hours per year) = 31.2%

The new fixed cost per MWh for gas is $42.72/MWh of gas energy produced, derived using a weighted average:

($32.9 x 963,784,059 MWh + $222.1 x 52,706,941 MWh) / 1,016,491,000 MWh = $42.72

Imposed cost per unit of gas energy for the first 2% PV energy market share is $1.85 / MWh of gas energy:

$42.72 - $40.87 = $1.85 per MWh of gas energy

40.87 is the levelized fixed cost of gas energy in the zero percent PV base case.

Fleet average imposed cost per unit of PV energy at 2% energy market share is $23.1 / MWh of PV energy as shown in Table 4 above:

$1.85 X 1,016,491,000 MWhs / 81,319,280 MWhs = $23.12 / MWh of PV energy

TECHNOLOGY	CC GAS	CT GAS	NAT GAS TOTAL	NEW PV	EXISTING PV	TOTAL GAS + PV
FLEET AVERAGE PV SOLAR	0%					
CV%	87.0%	87.0%	87.0%	0.0%	N/A	N/A
SUMMER CAP (CV)(MW)	216,267	117,778	334,046	N/A		334,046
ENERGY MKT SHR%	***25.60%***	***1.4%***	***27.0%***	0.0%	0.0%	27.0%
ANNUAL ENERGY (MWh)	1,040,886,784	56,923,496	1,097,810,280	N/A	-	1,097,820,280
CAPACITY FACTOR (%)	47.8%	4.8%	32.6%	N/A	25.0%	N/A
EST. NAMEPLATE CAP (MW)	248,583	135,377	383,960	N/A	0.0%	383,960
FIXED COST ($/MWh)	$31.5	$212.5	$40.87	N/A	N/A	N/A

US TOTAL FUTURE CASE OF INCREASING PV ENERGY MARKET SHARE FROM 2% TO 3%

Beginning with the ratios, CFs and fixed costs per MWh figures for CT and CC gas at 2% market penetration, we add an additional 18,566 MWs of PV capacity – enough to capture three percent energy market share at 25% CF based on 2014 US Total net generation.[57] The annual energy yield of the marginal PV capacity would be 40,659,640 MWhs under these assumptions.

The three percent market share for PV reduces gas generation to 975,831,360 MWhs:

1,016,491,000 – 40,659,640 MWhs = 975,831,360 MWhs

The CV of the marginal PV capacity is 16.2% of marginal PV nameplate capacity, or 3,000 MW.

18,566 MW x 16.2% = 3,000 MW

Total gas nameplate capacity required to maintain the same reserve margin is:

371,610 MW – 3,000 MW / 87% =
371,610 MW – 3,448 MW = 368,162 MW

This yields a lower CF for gas of 30.3%:

975,831,360 MWhs / (368,162 MW * 8760) = 30.3%

The fixed cost per MWh impact on the gas fleet of the incremental 1% PV market share gain is therefore $1.4/MWh of gas energy:

$44.09 - $42.72 = $1.37/MWh of gas.

The estimated imposed cost per incremental unit of PV is therefore $32.8/MWh of incremental PV:

$1.37/MWh of gas X (975,831,360 MWhs gas energy / 40,695,640 MWhs of incremental PV energy) = 32.8 ($/ MWh)

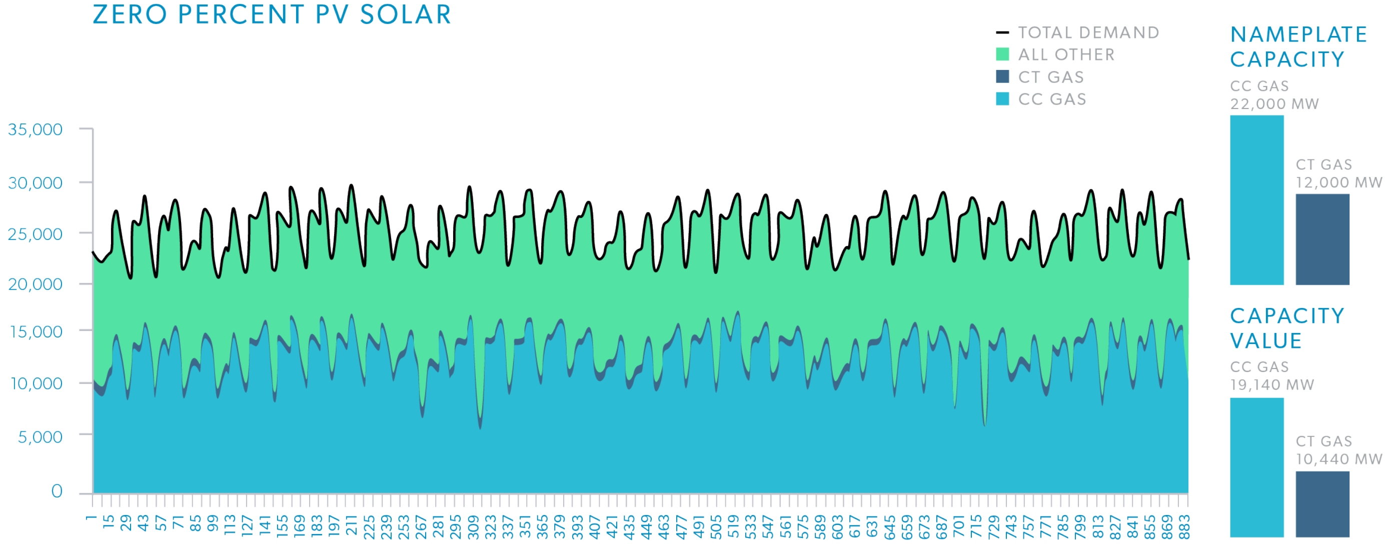
US TOTAL 2014 NET GENERATION (MWh)	2%	2%	2%	2%	2%	2%
4,065,964,000	CC GAS	CT GAS	NAT GAS TOTAL	NEW PV	EXISTING PV	TOTAL GAS + PV
TECHNOLOGY	CC GAS	CT GAS	NAT GAS TOTAL	NEW PV	EXISTING PV	TOTAL GAS + PV
FLEET AVERAGE PV SOLAR	2%					
CV%	87.0%	87.0%	87.0%	N/A	28.9%	0.0%
SUMMER CAP (CV)(MW)	209,311	113,990	323,301	N/A	10,745	334,046
ENERGY MKT SHR%	23.7%	1.3%	25.0%	N/A	1.0%	27.0%
ANNUAL ENERGY (MWh)	968,784,059	52,706,941	1,016,491,000	N/A	81,319,280	1,097,810,280
CAPACITY FACTOR (%)	45.7%	4.6%	31.2%	N/A	25.0%	N/A
EST. NAMEPLATE CAP (MW)	240,587	131,023	371,610	N/A	37,132	408,742
FIXED COST ($/MWh)	$32.9	$222.1	$42.72	N/A	N/A	N/A

TECHNOLOGY	CC GAS	CT GAS	NAT GAS TOTAL	NEW PV	EXISTING PV	TOTAL
MARGINAL PV SOLAR ADDED	3%					
CV%	87.0%	87.0%	87.0%	16.2%		
SUMMER CAP (CV)(MW)	207,368	112,932	320,301	3,000	10,745	334,046
ENERGY MKT SHR%	22.8%	1.2%	24.0%	1.0%	1.0%	26.0%
ANNUAL ENERGY (MWh)	925,232,697	50,598,663	975,831,360	40,659,640	81,319,280	1,097,810,280
CAPACITY FACTOR (%)	44.3%	4.4%	30.3%	25.0%	25.0%	N/A
EST. NAMEPLATE CAP (MW)	238,354.52	129,807.00	368,162	18,566	37,132	423,860
FIXED COST ($/MWh)	$34	$229.2	$44.09	N/A	N/A	N/A
PERCENT OF GAS CAPACITY	64.7%	35.3%				
PERCENT OF GAS ENERGY	94.8%	5.2%				
MARGINAL PV SUMMARY						
NAMEPLATE CHANGE (MW)	(2,333)	(1,216)	(3,449)	18,566	N/A	15,117
IMPOSED COST PER UNIT OF GAS ($/MWh)	$1.1	$7.1	$1.37	N/A	N/A	N/A
IMPOSED COST PER UNIT OF PV ($/MWh)	$24.0	$8.8	$32.8	N/A	N/A	$32.8

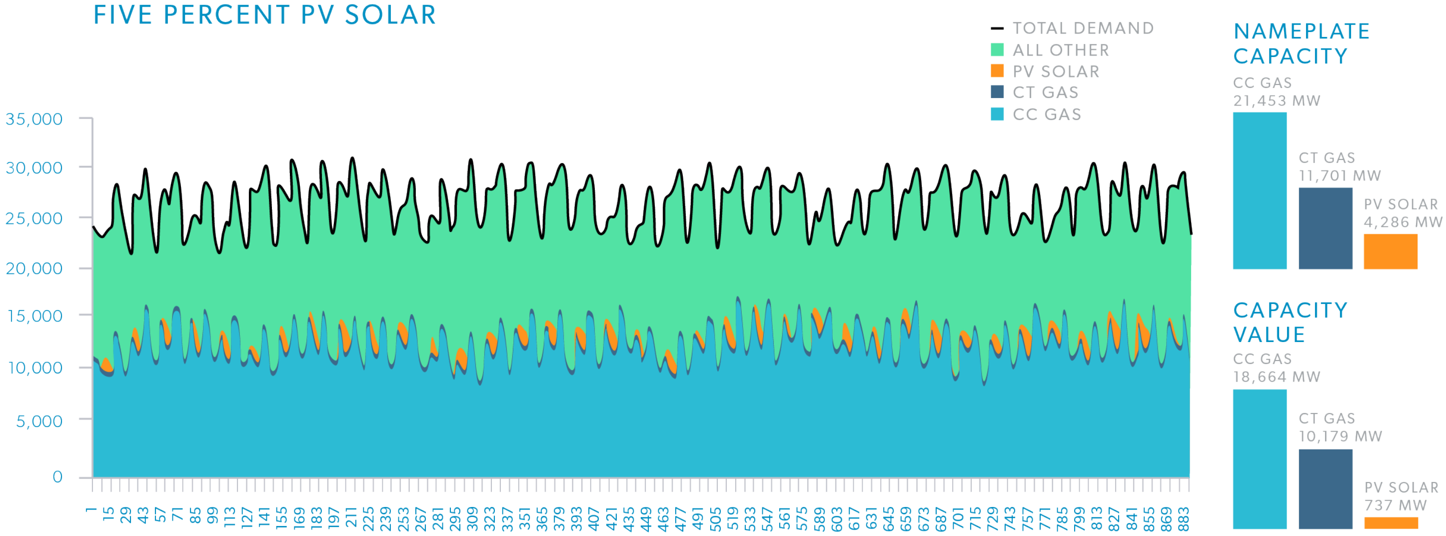
All Excel worksheets with formulas are available on request.[58]

Example Generation and Load Curves for CC and CT Gas With/Without PV Solar

CC AND CT GAS ON REGIONAL SYSTEM WITH ZERO PERCENT PV SOLAR



CC AND CT GAS ON REGIONAL SYSTEM WITH FIVE PERCENT PV SOLAR



The graphic above illustrates the energy, nameplate capacity and capacity value substitute of PV solar for natural gas CC and CT technologies considered in this report. The capacity value of the PV solar installed capacity is shown at 17.2% of nameplate capacity at 5% energy market share using the 75th percentile generation CV calculation methodology.

PV Declining Value as Replacement for Residual Peak Load Generation

We depict hourly electricity demand in CAISO for September 15th, 2014 as the wide blue line in figure 1 below. This was near annual peak demand day of that year. Demand net of several increments of PV capacity is shown in the thinner lines of various colors. The figure illustrates that PV contributes to a reduction of daily peak demand until PV capacity achieves a 5% energy market share. After that, peak demand net of previously operating PV occurs at hour 20 - after useful sunlight is no longer available.

As a result, additional PV capacity beyond 5% market share increasingly forces other dispatchable resources to stand down while it is sunny, without allowing those dispatchable resources to retire, as they are needed for system adequacy at hour 20. This lowers the CFs of the displaced dispatchable fleet technologies, raising their break-even fixed costs per MWh. We label this effect "imposed cost" of PV energy.

Two possibilities exist to avoid imposed cost at higher PV energy market shares. Excess electricity could be produced at hours just preceding peak load hours of the day, and converted to chemical or kinetic/potential energy (battery, compressed air or hydro pumped storage). The stored energy can then be converted back to electricity at hour 20. The other alternative is to force society to use less electricity at hour 20.

The former is prohibitively expensive, and is likely to remain so for most of the US due to infrastructure costs and conversion losses both into and out of the storage form of energy. The latter involves a paradigm shift away from the conventional idea that the electricity system is designed to serve consumers' convenience at whatever time energy consuming needs arise.

Figure 1A

CAISO GROSS SYSTEM LOAD AND
LOAD NET PV SOLAR AT SEVERAL PV SOLAR ENERGY MARKET SHARE LEVELS
SEPTEMBER 15, 2014

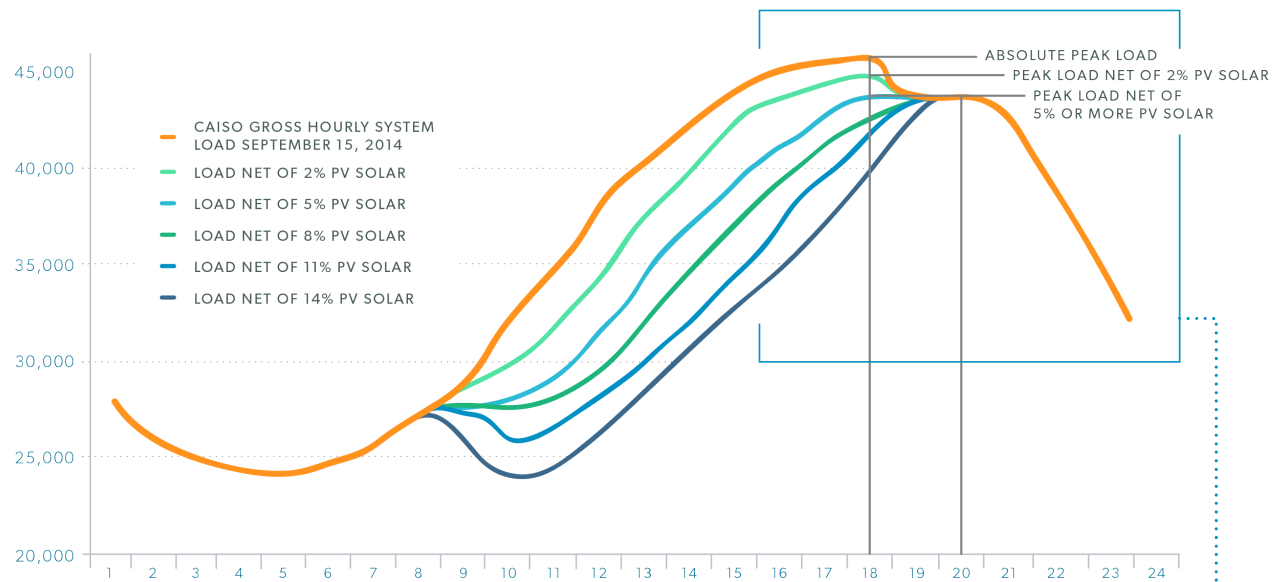


Figure 1B

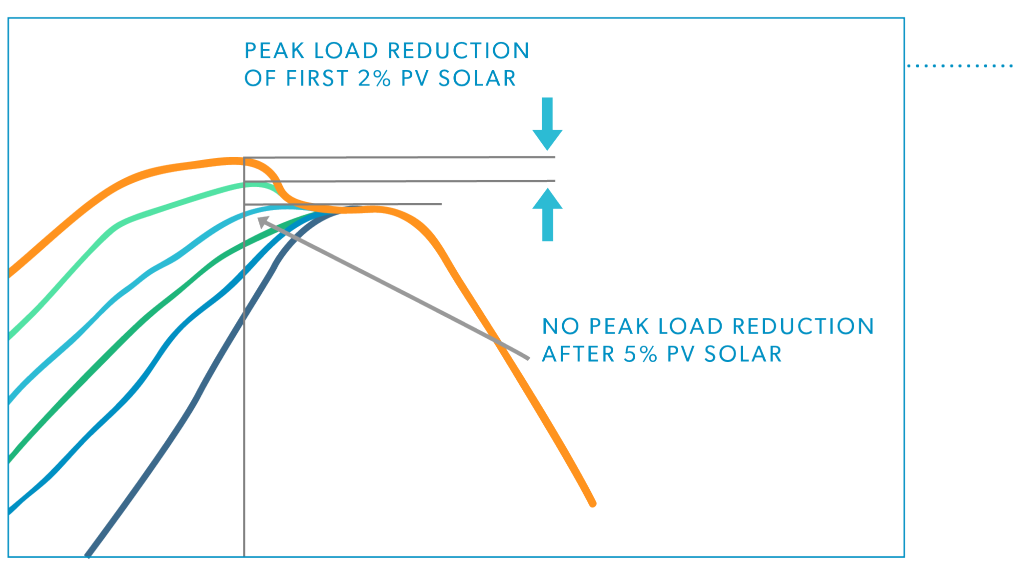


Figure 2

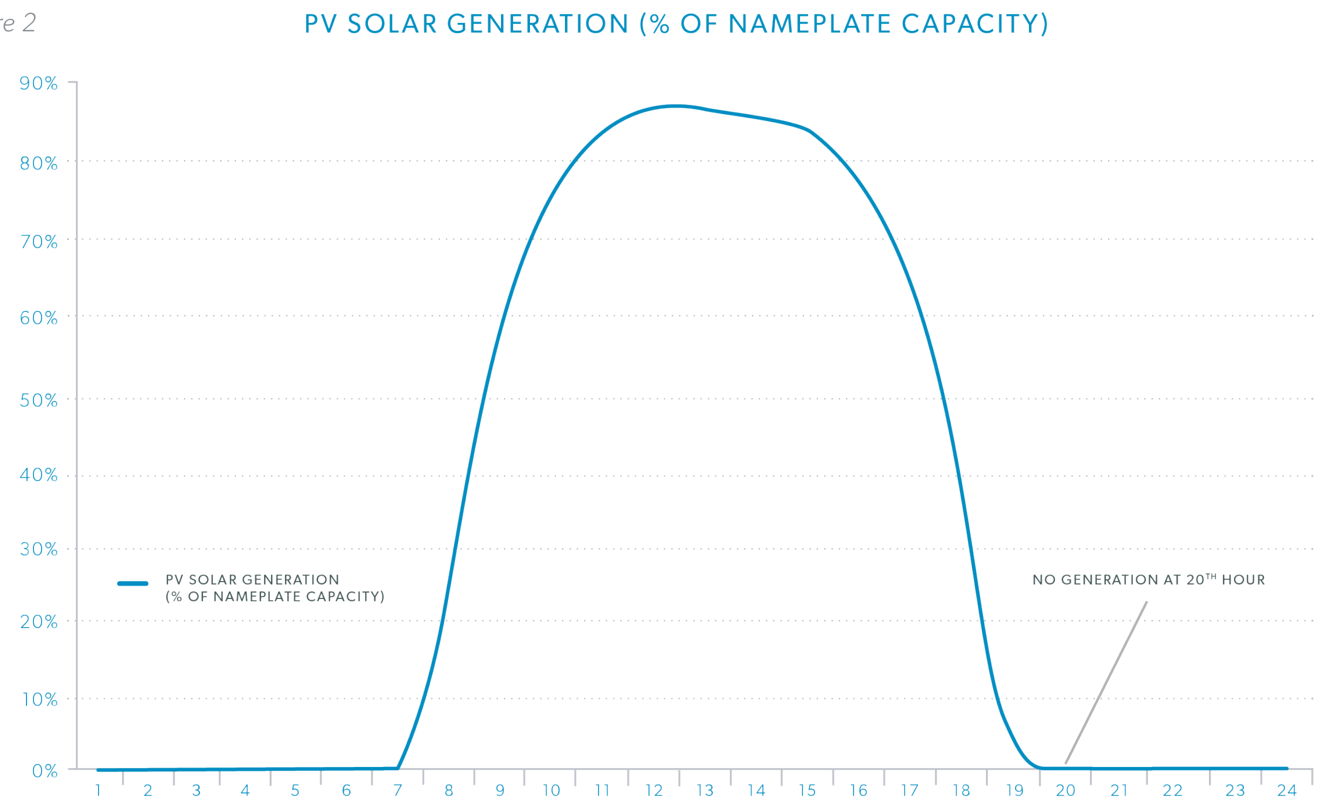


Figure 2 shows reported hourly PV generation in CAISO for September 15th, 2014, corresponding to the net load curves represented in figures 1A and 1B, above.

Figures 3 and 4 illustrate a full week of modeled hourly natural gas generation and PV generation.[59]

Figure 3

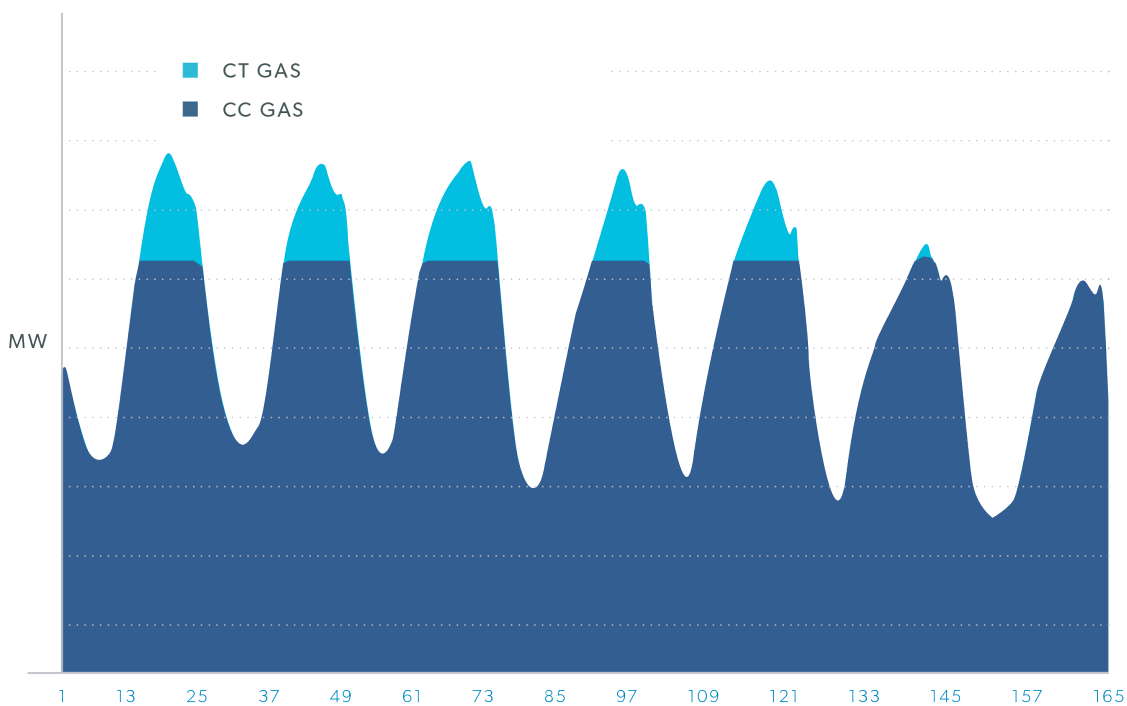
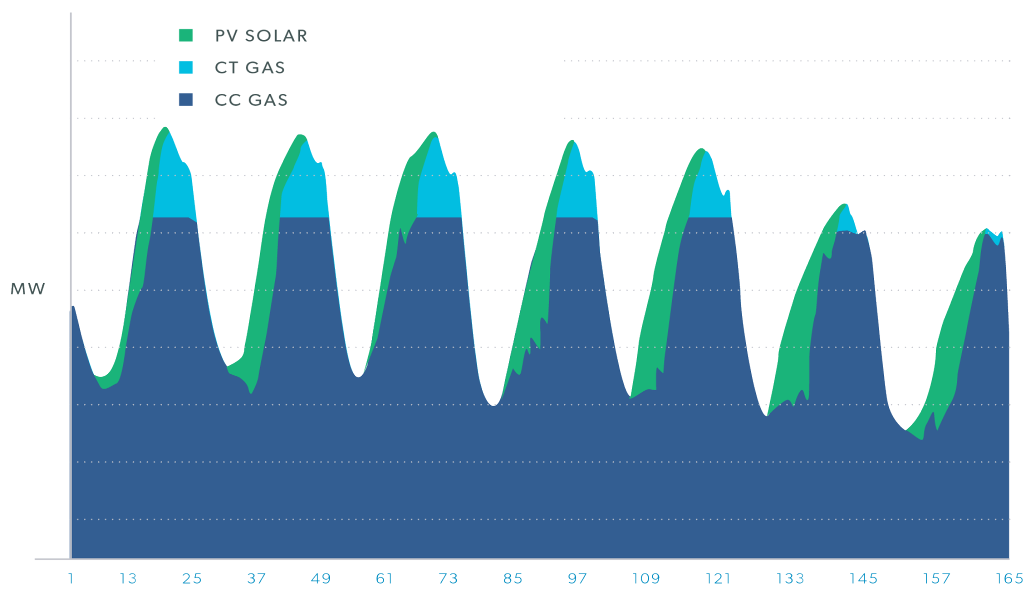


Figure 4

HOURLY LOAD MET BY CC GAS, CT GAS & PV SOLAR



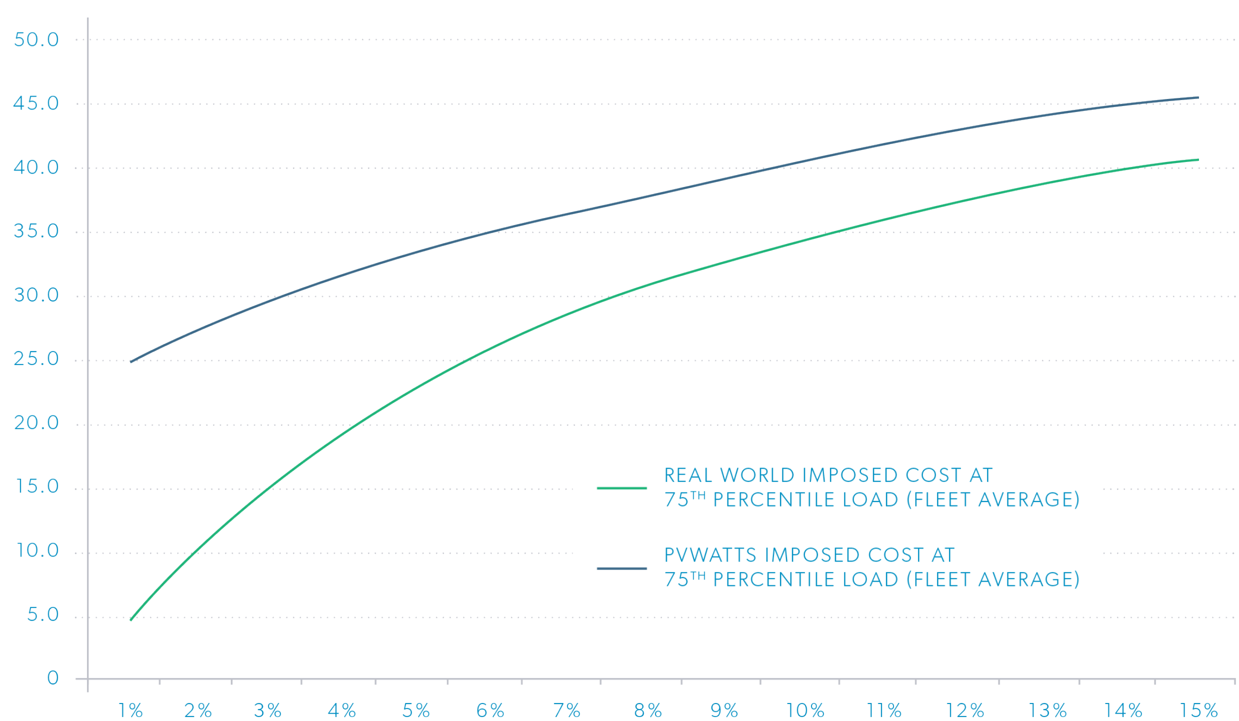
HOUR OF THE WEEK BEGINNING SATURDAY MORNING AT 12:00 AM

Levelized Cost of PV Calculations Using the US DOE's PVWATTS Model

We repeated the calculations of CV and imposed cost of PV using hourly outputs of the National Renewable Energy Laboratory's "PVWATTS" modeling software against CAISO hourly demand.

Calculated CVs using the PVWATTS data started lower and fell more sharply than for CAISO reported hourly PV generation data. This is not surprising, because the PVWATTS data had more uniform and slightly earlier evening decline than the real world data, causing it to miss evening residual peak loads sooner.

As a result, imposed costs were higher with modeled data than for real world data. The following graph expresses the differences in fleet average imposed cost between modeled generation and normalized CAISO published data at both 75% and 95% load confidence levels. Fleet average looks at the entire PV installed fleet rather than incremental capacity additions.



Appendix B Discussion

EIA forecasts new PV to have among the highest levelized cost of electricity of any new resource is 2020. With consideration of imposed cost included LCOE for PV is estimated to be over $150/MWh both in California and for the US. Moreover, new PV comes at an astronomical premium relative to existing dispatchable generators.

The total levelized cost electricity from capacity constructed which increases PV energy market share in CAISO from 5% to 6% is estimated at $151.7 MWh, which includes imposed cost of $40.6MWh at EIA's estimated 31% CF and at EIA's $111.1 LCOE estimate for NERC Region 20.[60]

On a national average basis, we estimate the levelized cost of electricity from PV in 2020 at 153.7 (2013 $/MWh) including imposed cost under the assumption PV solar is capturing three percent of energy market share in 2020. The estimated cost of electricity from new PV in CAISO ($151.7) represents a cost up to five times the average LCOE from least-cost existing dispatchable resources.

In regional systems such as CAISO where incremental additions of PV capacity offer no reduction in system peak loads, the minimum installed capacity of dispatchable generators required to meet peak system load cannot be reduced at all, while additional PV generation continues to drive down their CF while driving up their going-forward levelized costs.

We believe PV has lower than advertised guaranteed contribution to peak load fulfillment at increasing market penetrations when using CV calculations that consider PV's stand-alone capabilities (rather than metrics such as ELCC that "borrow" CV from other resources in the fleet). At 6% energy market share, which PV will achieve in CAISO in 2015, CV falls to zero while imposed costs alone rise above $40 per MWh, nearing recent year national average wholesale energy market clearing prices.

For states and regions where electricity cost is important to manufacturing competitiveness, caution should be exercised in setting renewable energy policies that induce PV capacity growth. Lawmakers and regulators should consider indirect costs such as imposed cost, which are additive to subsidy the costs of other policies that induce PV capacity expansion.

FOOTNOTES: APPENDIX B

[37] *http://www.eia.gov/forecasts/aeo/electricity_generation.cfm*

[38] *There are services available to help determine the causes of generator cycling such as those offered by Renewable Impacts, LLC. http://www.renewableimpacts.com/*

[39] *PJM and MISO both use a range of hours in certain "summer months." MISO staff admitted in a telephone conversation that this set of hours is recognized by MISO as inappropriate for determining accurate CV for PV.*

[40] *We do feel, however, that whatever "confidence level" is chosen for PV should be applied to all generation technologies in a calculation of the appropriate confidence level to maintain system adequacy.*

[41] *Net of generation from previously installed PV capacity*

[42] *Our analysis considers the highest 900 net load hours of 2014 in CAISO (net of existing PV). Of these hours, the 225th lowest PV generation hour equates to a 75% confidence level and the average of the lowest 225 PV generation hours equates to the MLQG confidence level. That is, marginal PV capacity will generate at or above its respective CV 75 percent of those 900 hours, respectively. In hours where PV fails to meet its capacity CV, other generating technologies will be required to achieve system adequacy, intruding into system reserve margin.*

[43] *Eventually all existing resources are replaced with new. Reporting the imposed cost on existing resources would mask the high imposed cost of low CV resources upon that eventuality.*

[44] In practice, PV from time to time may also displace generation from coal and hydro. It is also possible but less likely that PV might reduce the productivity of nuclear power plants. The major impetus for adding PV is to reduce the consumption of fossil fuels and their associated air emissions, so it is important to note that when PV displaces (run of river) hydro or nuclear generation, there is no reduction in fossil fuel consumption or the associated air emissions. For this reason we evaluate PV's impact on natural gas generation only.

[45] (10,435,675 MWhs / 8,760 hours in the year) / 31% CF

[46] We found that in CAISO, annual peak load hours often occurred outside of such a strict pattern of hours. We therefore gathered load and real PV generation data across CAISO for the highest 900 load hours of 2014 for this analysis. From those 900 hours we determined the net peak load hours (net of PV generation) at each 1% energy market share of PV from zero to 15% energy market share. From each result we sorted the 900 hours highest to lowest by load, and then based our evaluation on the highest 360 of 900 net peak load hours. http://www.pjm.com/~/media/documents/manuals/m21.ashx (Appendix B, Section B2, Line Items 7, 8, 9)

[47] http://www.eia.gov/electricity/data/state/plancapacity_annual.xls

[48] This is based in part on data reported by CAISO: http://www.caiso.com/Documents/2014AnnualReport_MarketIssues_Performance.pdf , in part on data from The US Energy Information Administration: http://www.eia.gov/electricity/data/eia860/xls/eia8602014.zip and in part on typical CFs reported for CC and CT gas facilities in other ISO/RTOs such as MISO and PJM. A breakdown of energy market shares and/or CFs for CT and CC gas was not evident on the CAISO public web site.

[49] CAISO reports natural gas held 41% energy market share for 2014 while PV held 5% energy market share for the same year. Because the initial scenario assumes 0% PV that scenario includes 46% energy market share for natural gas generation, or about 5% above what CAISO reports for natural gas fueled generation in 2014.

[50] The average of the CVs of the first five percent incremental additions of PV at 75% confidence level, shown in Table 3.

[51] Based on EIA Net Summer Capacity. http://www.eia.gov/electricity/annual/html/epa_04_02_a.html , http://www.eia.gov/electricity/annual/html/epa_04_06.html , http://www.eia.gov/electricity/annual/html/epa_04_03.html

[52] Estimated imposed cost per incremental unit of PV replacing existing CC gas and CT gas capacity instead of new would be less due to the lower estimated going-forward levelized fixed costs per MWh of existing CC gas and CT gas resources.

[53] https://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3

[54] 4.066 Billion MWhs times one percent divided by the quantity 25% capacity factor times 8,760 hours per calendar year. See: http://www.eia.gov/electricity/annual/html/epa_01_01.html

[55] ibid. (Footnote 6)

[56] Based on EIA Net Summer Capacity. http://www.eia.gov/electricity/annual/html/epa_04_02_a.html , http://www.eia.gov/electricity/annual/html/epa_04_06.html , http://www.eia.gov/electricity/annual/html/epa_04_03.html

[57] Because forecast US Total system load in 2020 is not much greater than US Total system load in 2014, and because imposed cost is a function of ratios and not scale, we provide this example using 2014 load, capacity and generation data rather than 2020. Modeling US Total generation forecast for 2020 would increase total generation, gas generation and capacity, PV generation and capacity all proportionally.

[58] Contact Tom Stacy at (937) 407-6258 or tfstacy@gmail.com

[59] These figures should not be construed to sum to the total system demand curve and are provided only to illustrate that if PV displaces only energy from CC and CT gas facilities, it does not reduce the maximum generation from the total gas fleet on some days of the year which might be the days which induce the highest gas generation days of a year.

[60] EIA provided a table of levelized costs for PV by NERC region via email. No URL has been found which reports these figures. Please contact the authors of this report for more information.