Cost and Performance Review of Generation Technologies

Recommendations for WECC 10- and 20-Year Study Process

Prepared for the Western Electric Coordinating Council
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October 9, 2012

Energy+Environmental Economics

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1 Introduction

The Western Electricity Coordinating Council (WECC) has asked E3 to provide recommendations on resource cost and performance to use in Transmission Expansion Planning and Policy Committee's (TEPPC) 10- and 20-year study plans. E3 provided generation cost and performance assumptions in 2009 and again in 2011 to use as inputs in WECC's ten-year study process. The recommendations in this document are updates to previous values E3 provided in 2009 and 2011 to ensure continued currency and accuracy of these inputs to the WECC modeling processes.

The role of generation (and transmission) capital costs in the ten-year study processes is summarized in Figure 1. In the ten-year study cycle, the primary analytical tool is production simulation modeling, which examines regional operations of the grid and calculates variable costs. The generation portfolio and transmission topology are determined exogenously; WECC staff, with assistance from stakeholders, develop assumptions for a 10-Year "Reference Case" as well as a number of "change cases" that alter some of these assumptions. In this context, the inclusion of resource capital costs in WECC's study allows for a more complete quantification of the relative costs of each "change case" relative to the reference case: in addition to the change in variable cost that results from alternative generation portfolios and/or transmission topology, there is a change in the cost of the capital investments associated with the alternative physical system simulated in the change cases.

The role of the capital costs as inputs to the twenty-year study process (shown in Figure 2), in which the expansion of generation and transmission is endogenous to the study, is quite different. In this process, the Study Case Development Tool (SCDT) and the Network Expansion Tool (NXT)—together, the Long-Term Planning Tools (LTPT)—optimize the electric sector's expansion subject to a large number of constraints in order to minimize the cost of delivered energy in 2032.

These dual roles provide the context under which E3 has conducted this review of generation resource cost and performance issues and assumptions. With the longer time frame under consideration, E3 has expanded the scope of its assessment to review not only the characteristics of current new generation resources (as in prior WECC studies), but additionally how those characteristics might evolve in the future. This report details the development of the recommended assumptions for each of the studies as well as the assumptions that informed them.

Figure 1. The role of generation and transmission capital cost assumptions as inputs to the 10-year studies.

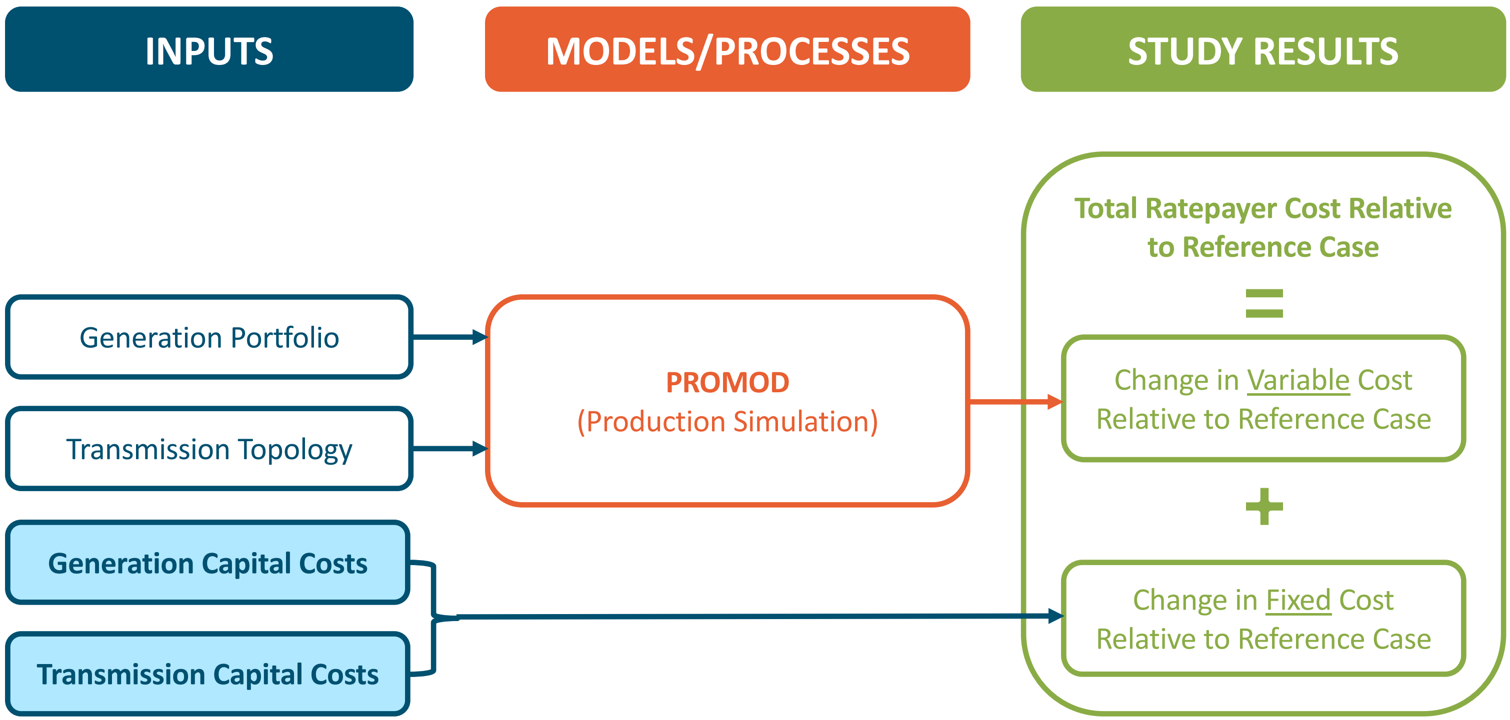
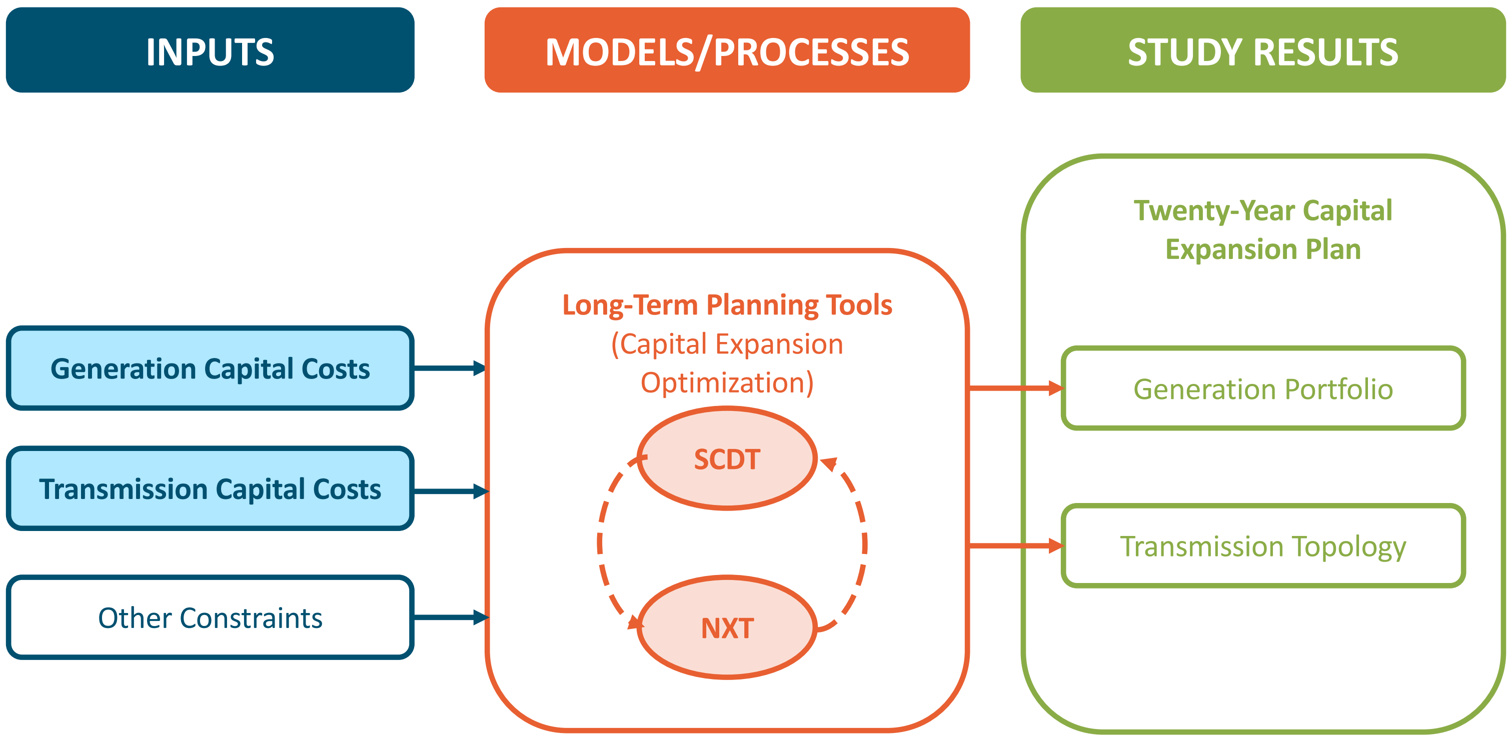


Figure 2. The role of generation and transmission capital cost assumptions as inputs to the 20-year studies.



1.1 Technologies Considered

Table 1 summarizes the technologies that were included in the scope of E3's capital cost and performance characterization. This set is intended to be comprehensive of the new generation resources included or considered in WECC's 10- and 20-year studies.

Table 1. Technologies included in E3's scope of analysis.

Technology	Subtypes
Biogas	Landfill
	Other
Biomass	
Coal	PC
	IGCC w/ CCS
Combined Heat & Power	Small (<5 MW)
	Large (>5MW)
Gas CCGT	Basic, Wet Cooled
	Advanced, Wet Cooled
	Basic, Dry Cooled
	Advanced, Dry Cooled
Gas CT	Aeroderivative
	Frame
Geothermal	
Hydro	Large
	Small
	Upgrade
Nuclear	
Solar PV	Residential Rooftop
	Commercial Rooftop
	Distributed Utility (Fixed Tilt)
	Distributed Utility (Tracking)

Technology	Subtypes
	Large Utility (Fixed Tilt)
	Large Utility (Tracking)
Solar Thermal	No Storage
	Six Hour Storage
Wind	Onshore
	Offshore

1.2 Assumptions

E3's recommendations are based on the following assumptions:

1. Present-day capital costs correspond to systems and/or plants installed in 2012.
2. All resource costs are expressed in 2010 dollars.
3. Capital costs presented represent all-in plant costs and are inclusive of all engineering, procurement, and construction (EPC); owner's costs; and interest during construction (IDC).
4. Fixed Operations and Maintenance (O&M) costs include O&M labor, administrative overhead. For renewable technologies, fixed O&M also includes property taxes and insurance (see Section 5.3.3 for further details on treatment of property tax & insurance).
5. All costs are intended to represent the U.S. average costs for new generation; E3's technology-specific regional multipliers (see Section 7) can be used to estimate plant capital costs for each state in the WECC.

2 Methodology

2.1 Review of Current Resource Characteristics

In order to determine appropriate assumptions for resource costs for the array of generation technologies considered in the WECC modeling process, E3 conducted a thorough review of literature. E3 aggregated information from a wide range of sources and used the results to inform recommendations for the capital and fixed O&M costs for each type of generation technology. Types of sources considered in E3's review include:

- Studies commissioned by government entities (e.g. National Renewable Energy Laboratory (NREL), National Energy Technology Laboratory (NETL), Energy Information Administration (EIA)) of the comparative costs of generation technologies;
- Integrated resource plans published by utilities located in the WECC (e.g. NV Energy, Arizona Public Service Company (APS), PacifiCorp);
- Actual data on installed cost of generation technologies (e.g. CSI installation database, APS PV data)

A full list of the sources considered in the review of capital costs is included in Section 8.2.

It should be noted that an approach that relies on publicly available data poses some obvious challenges, particularly for technologies that are in evolutionary stages and whose costs are changing quickly. In some cases, a lack of publicly available data makes a robust characterization difficult; such was the case with both solar thermal power towers and coal plants using the integrated gasification combined cycle (IGCC) technology with carbon capture and sequestration (CCS). Another challenge that arises is that the costs of some technologies is in a state of rapid change; in such cases, there is a natural time lag between the vintage of the published data and the technology as it is currently installed. This was E3's experience with solar photovoltaics (PV) and, to a lesser extent, wind technologies. In the face of such challenges, E3 coupled its review of literature with expert judgment based on experience working in the electric sector.

2.2 Projections of Future Plausible Technology Innovation

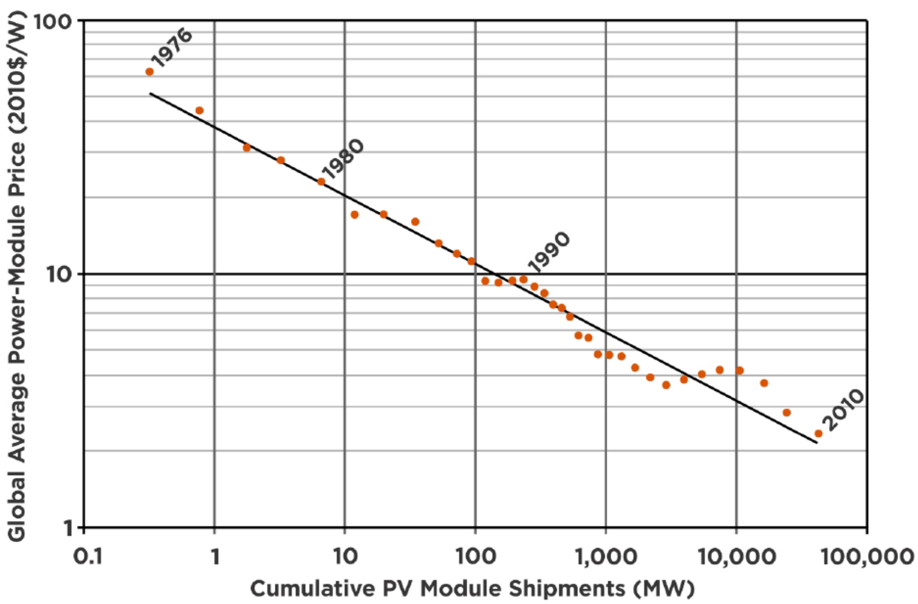
To provide meaningful inputs for WECC's 20-year study cycle, E3 has also considered how the costs of generation resources may change in the future. Most of the generation resources included in the scope of E3's analysis can be classified as mature technologies; for these resources, E3 has made a simplifying assumption that capital costs will remain stable in real terms over time. There are several notable exceptions to this classification, however: wind, solar PV, and solar thermal technologies are all more appropriately described as emerging technologies, and most studies indicate that the capital costs of these resources will decline as the technologies mature.

To project future costs of these generation resources, E3 uses two primary approaches: (1) the application of historically-derived "learning curves" to estimate cost reductions as global experience grows, and (2) literature review of point projections for future technology costs. A brief description of each of these methods and the situations in which each one is applied in this study follows.

2.2.1 LEARNING CURVES

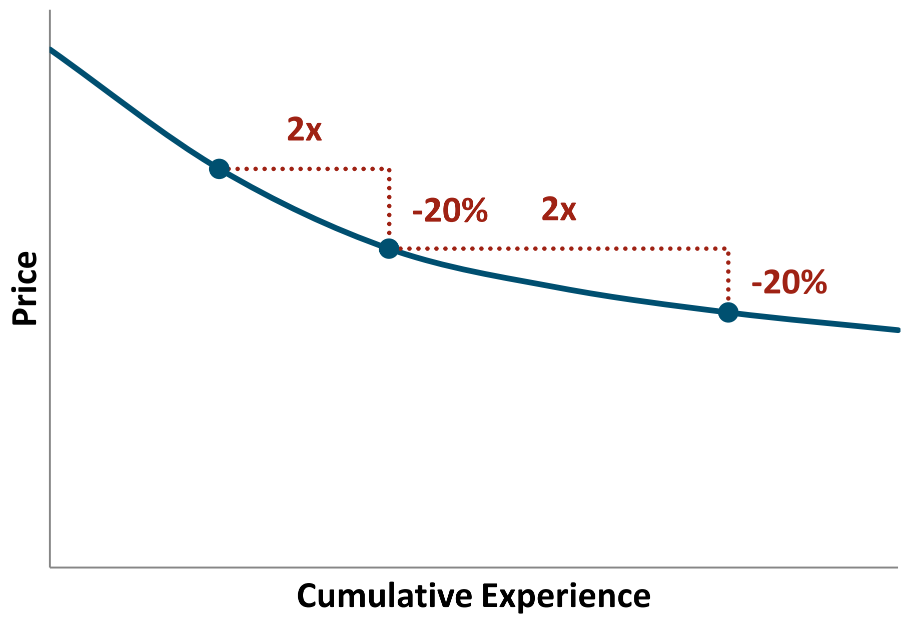
One method used to evaluate cost reduction potential of various generation technologies is the application of forward-looking learning curves. Learning curves describe an observed empirical relationship between the cumulative experience in the production of a good or resource and the cost to produce it; namely, with increasing experience, costs tend to reduce as a result of increased efficiency and scale-up of the manufacturing process. This trend has been observed across a number of technologies and industries, but one of the clearest examples is the persistent reduction in the cost to produce photovoltaic modules that has accompanied the industry's rapid growth over the past several decades. This effect is shown in Figure 3 (note the logarithmic scales).

Figure 3. Over the long term, factory gate PV module prices have decreased as the global industry has grown (Figure source: DOE Sunshot Study).



Learning curves are most often expressed as the percentage reduction in cost that accompanies a doubling in cumulative production experience; this percentage metric is known as the **learning rate**. One natural result captured by this functional form is that the marginal impact of each unit of production on cost decreases as the technology matures. As a result, learning curves capture the commonly observed trend that the costs of emerging technologies often drop rapidly as production scales up, whereas the costs of more mature technologies are more stable over time. This effect is summarized in Figure 4, which highlights the decreasing marginal impact of cumulative production experience on production cost.

Figure 4. Representative learning curve for an example learning rate. In this example, each doubling of cumulative experience results in a reduction of cost of 20%.



In cases where E3 uses learning curves to predict future cost reductions, learning rates are determined on a technology-specific (or, in the case of solar PV, component-specific) basis through a review of literature on historically observed capital cost trends. Where a consensus learning rate has been established in literature, E3 has assumed this rate of progress will continue.

The other key parameter needed to establish a future learning curve for a specific technology is a forecast of global installed capacity. E3 acknowledges that there is a large amount of uncertainty in the choice of this parameter. E3 has relied predominantly on the International Energy Agency's (IEA) *Medium-Term Renewable Energy Market Report 2012* (IEA, 2012) as a credible source for such forecasts. To ensure the reasonableness of these forecasts, E3 has compared them to forecasts produced by industry associations such as the European Photovoltaic Industry Association (EPIA) and the Global Wind Energy Council (GWEC).

2.2.2 LITERATURE REVIEW

For nascent technologies with a very small installed global capacity whose commercialization is just beginning, it is not possible to rely on a learning rate that is well supported by the available literature. In these cases, E3 has adopted a more direct approach to forecasting cost reductions, relying on a survey of projected point estimates of future costs to determine appropriate assumptions for potential cost reductions. E3 relies on the same types of sources used to evaluate present-day technology costs, including utility IRPs, engineering assessments of potential cost reductions, and consulting reports.

2.3 Annualization of Costs for WECC Studies

Both WECC's 10- and 20-year study cycles are "snapshot" analyses—that is, they evaluate the infrastructure requirements and operations of the grid during a single year in the future. To allow WECC to make use of the capital cost recommendations in its snapshot analyses, E3 has developed a set of financial models that translate capital costs (as well as annual O&M and fuel costs for applicable technologies) into levelized, annual costs. These financial models amortize the capital costs of the various technologies over their lifetimes to determine, on an annual basis, the magnitude of the costs that would be borne by ratepayers to fund a project's construction. E3's financial models include detailed cash flow models for project finance under ownership by an independent power producer (IPP), an investor-owned utility (IOU), or a tax-exempt publically-owned utility (POU); as well as a simple non-cash flow annualization calculation developed for use in the WECC LTPT. Further detail on these models can be found in Sections 5.1 and 5.2.

3 Characteristics of Conventional Technologies

3.1 Coal (Pulverized Coal)

3.1.1 TECHNOLOGY DESCRIPTION

Capital costs shown below are for a pulverized coal-fired power plant without CCS. All sources except for Idaho Power identify the resource as using supercritical steam generator technology.

3.1.2 PRESENT-DAY COST

Table 2. Coal-fired steam generator capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
Avista IRP		$3,475	$66.9	8,910
B&V/NREL	2010	$3,556	$23.4	9,370
EIA/RW Beck		$3,833	$36.0	8,800
IPC IRP		$3,393	$4.8	9,200
Lazard		$3,000	$20.4	8,750
NETL[a]		$2,577	$27.8	8,687
NWPCC	2008	$4,582	$64.9	9,000
PacifiCorp IRP[b]	2020	$3,077	$38.8	9,106
		$3,484	$36.0	9,214
Recommendation		**$3,600**	**$30.0**	**9,000**

[a] Property tax and insurance have been excluded from NETL's fixed O&M estimate shown in this table.
[b] Low and high capital cost estimates (and corresponding fixed O&M and heat rates) correspond to plants built in Utah and Wyoming, respectively.

3.2 Coal (IGCC with CCS)

3.2.1 TECHNOLOGY DESCRIPTION

E3's recommendation for coal-fired integrated gasification combined cycle (IGCC) plants with CCS is higher than those surveyed since there are few existing plants that have been built and operated. Additionally, there are both fixed and variable costs associated with CCS that are not captured in the surveys, including the CO_2 pipeline from the power plant to the geologic sequestration site, CO_2 transport costs, CO_2 injection costs, and long-term liability risks of storing CO_2 (together referred to as the costs of transport, storage, and monitoring, or TS&M). A recent NETL study focused on this subject produced estimates of TS&M costs that would increase plant capital costs by $150-$1,200 per kW and O&M costs by $1-6 per kW-year (the plant-specific costs vary based on the generator's proximity to the sequestration site; the lower and upper values presented correspond to transport distances of 10 and 250 miles, respectively) (NETL, 2010b).

3.2.2 PRESENT-DAY COST

Table 3. IGCC with CCS capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
Avista IRP		$5,173	$66.9	10,652
B&V/NREL	2020	$8,443	$45.1	11,800
CEC COG	2009	$3,695	$53.2	7,580
EIA/RW Beck		$6,728	$69.3	10,700
IPC IRP		$5,332	$45.6	10,781
Lazard		$5,250	$28.2	10,520
NETL[a]		$4,413	$52.2	10,458

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
NWPCC	2008	$6,533	$64.9	10,760
PacifiCorp IRP	2030	$5,386	$53.2	10,823
		$6,099	$58.0	11,047
Recommendation		**$8,000**	**$60.0**	**11,000**

[a] Property tax and insurance have been excluded from NETL's fixed O&M estimate shown in this table.

3.3 Combined Heat & Power

3.3.1 TECHNOLOGY DESCRIPTION

E3 considered two options for new combined heat & power systems, small (up to 5 MW) and large (above 5 MW). Within these general classes, E3 has not attempted to distinguish between specific technology options, instead opting to offer generic capital costs that are representative of the multiple technologies available for each size application. Small CHP is presumed to be used primarily to meet on-site loads but may export to the grid if the relative thermal load is large enough; large CHP is presumed to be developed to export substantial amounts of electricity to the grid while serving a large thermal load.

3.3.2 PRESENT-DAY COST

Table 4. Small CHP (<5 MW) capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
ICF[a]	2010 - 2015	$4,674		8,022
		$5,431		9,975
ICF[b]	2010 – 2015	$2,376		14,085
ICF[c]	2010 – 2015	$2,812		12,247
		$3,006		13,950
ICF[d]	2010 - 2015	$1,406		9,760
		$2,667		12,637
Recommendation		**$3,700**	**$0.0**	**8,910**

[a] Fuel cell (low and high costs capture variations in system size)
[b] Gas turbine
[c] Microturbine (low and high costs capture variations in system size)
[d] Small reciprocating engine (low and high costs capture variations in system size)

Table 5. Large CHP (>5 MW) capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
ICF[a]	2010 – 2015	$1,135		9,220
		$1,474		11,765
ICF[b]	2010 – 2015	$1,406		8,486
Recommendation		**$1,600**	**$0.0**	**6,920**

[a] Gas turbine (low and high costs capture variations in system size)
[b] Small reciprocating engine

3.4 Gas (Combined Cycle)

3.4.1 TECHNOLOGY DESCRIPTION

Combined cycle gas turbine (CCGT) technologies include both basic and advanced designs. Basic CCGTs typically utilize two F-class combustion turbines

(CT), whereas advanced CCGTs typically employ one G- or H-class CT. The default assumption is that both designs have wet cooling systems, but the incremental capital cost and heat rate penalty associated with dry cooling systems are provided.

3.4.2 PRESENT-DAY COST

Table 6. Basic combined cycle capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
APS IRP		$827	$4.7	6,473
B&V/NREL	2010	$1,336	$6.4	6,705
Brattle/CH2M Hill	2015	$856	$14.1	7,096
EIA/RW Beck		$1,045	$14.4	7,050
IPC IRP[a]		$1,241	$11.6	6,800
		$1,338	$6.8	6,800
NETL		$807	$10.9	6,798
NVE IRP[b]		$1,086	$13.3	6,975
		$1,713	$26.6	6,989
PacifiCorp IRP[c]	2014	$928	$7.1	6,885
		$1,181	$13.5	7,302
Xcel IRP[d]	2011 – 2018	$719	$6.9	6,947
		$1,145	$10.8	6,733
Recommendation		**$1,100**	**$10.0**	**7,000**

[a] Low cost estimate is a 540 MW CCGT; high cost estimate is a 270 MW CCGT.
[b] Low cost estimate is 612 MW; high cost is 261 MW.
[c] The range presented includes variation in plant size and location. Low cost estimate is a 620 MW plant in the Northwest; high cost estimate is a 270 MW plant in Utah.
[d] Low cost estimate is 808 MW; high cost is 346 MW.

Table 7. Advanced combined cycle capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
Avista IRP		$1,223	$15.6	6,722
EIA/RW Beck		$1,071	$14.6	6,430
PacifiCorp IRP[a]		$1,117	$6.8	6,751
		$1,233	$6.8	6,602
PGE IRP		$1,123	$12.0	7,038
Recommendation		**$1,200**	**$10.0**	**6,700**

[a] Low cost estimate is configured with a "G" class CT; high cost estimate includes an "H" class CT

3.4.3 DRY COOLING COST AND PERFORMANCE PENALTIES

Most sources surveyed provided cost and performance estimates for combined cycle plants configured with a wet cooling system. Dry cooling will impose capital cost and heat rate penalties that are location-specific. E3 estimates the incremental capital cost and heat rate increases by surveying sources that contain estimates for similar combined cycle configurations with both wet and dry cooling systems. For basic and advanced combined cycle plants configured with dry cooling, we recommend an incremental capital cost increase of $75/kW and an incremental heat rate penalty of 200 Btu/kWh.

Table 8. Combined cycle capital costs with wet and dry cooling systems.

Source	Location	Wet Cooling [$/kW]	Dry Cooling [$/kW]	Penalty [$/kW]
APS IRP	AZ	$827	$924	$97
Avista IRP	NW	$1,223	$1,284	$61
PacifiCorp IRP	UT	$1,067	$1,104	$37
Xcel IRP	CO	$719	$786	$68
	CO	$1,145	$1,235	$89
Recommendation				**+$75**

Table 9. Combined cycle heat rates with wet and dry cooling systems.

Source	Location	Wet Cooling [Btu/kWh]	Dry Cooling [Btu/kWh]	Penalty [Btu/kWh]
APS IRP	AZ	6,473	7,311	838
Avista IRP	NW	6,722	6,856	134
PacifiCorp IRP	UT	6,885	6,963	78
Xcel IRP	CO	6,947	7,143	196
	CO	6,733	6,878	145
CEC (2006)	CA (Desert)	6,596	6,795	199
	CA (Coast)	6,573	6,596	23
Recommendation				**+200**

3.5 Gas (Combustion Turbine)

3.5.1 TECHNOLOGY DESCRIPTION

E3 offers two options for new gas-fired combustion turbines: aeroderivative and frame. Frame CTs, which include the GE 7FA, have long been considered the cheapest form of investment in new capacity; however, there is a tradeoff in performance, as these units have typically high heat rates and can generally operate economically during a very limited set of hours. Aeroderivative turbines, examples of which include the GE LM6000 and LMS100, are more advanced, offering a lower heat rate and more ramping flexibility at a higher cost. With the current concern regarding the need for flexibility to integrate intermittent renewable resources, a substantial portion of the expected investment in new gas-fired capacity in the WECC during the coming years will likely use aeroderivative technologies.

3.5.2 PRESENT-DAY COST

Table 10. Aeroderivative combustion turbine capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
APS IRP[a]		$989	$5.0	8,932
		$1,142	$7.2	9,723
Avista IRP[b]		$1,200	$14.5	9,276
		$1,286	$8.9	8,782
CEC COG[c]	2009	$1,392	$17.7	9,266
		$1,461	$24.3	9,266
IPC IRP[d]		$1,092	$12.6	9,370
		$1,274	$7.8	8,800
Lazard		$1,000	$25.0	9,100
NVE IRP		$1,284	$2.3	9,202
PacifiCorp IRP[e]	2014	$909	$9.0	9,733
		$1,273	$7.6	9,379
PGE IRP		$1,294	$3.1	9,165
Recommendation		**$1,150**	**$12.0**	**9,200**

[a] Low cost estimate: 301 MW CT; high cost estimates: 266 MW CT.
[b] Low cost estimate: 46 MW LM6000; high cost estimate: 94 MW LMS100.
[c] Low cost estimate: 100 MW CT; high cost estimate: 50 MW CT.
[d] Low cost estimate: 47 MW LM6000; high cost estimate: 100 MW LMS100.
[e] PacifiCorp's cost ranges include variation in plant size and location. Low cost estimate is a 130 MW plant in the Northwest; high cost estimate is a 257 MW plant in Wyoming.

Table 11. Frame combustion turbine capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
APS IRP[a]		$617	$3.7	10,073
		$866	$5.3	11,911
Avista IRP		$687	$12.3	11,841
B&V/NREL	2010	$685	$5.3	10,390
Brattle/CH2M Hill	2015	$676	$13.4	10,320
EIA/RW Beck[b]		$688	$6.7	9,750
		$1,008	$7.0	10,850
IPC IRP		$766	$3.9	11,870
Lazard		$800	$5.0	9,800
NVE IRP		$1,022	$1.7	11,962
PacifiCorp[c]	2014	$901	$4.9	10,446
		$1,074	$5.9	10,446
Xcel IRP		$635	$4.0	10,596
Recommendation		**$800**	**$6.0**	**10,500**

[a] Low cost estimate: 399 MW frame CT; high cost estimate: 319 MW frame CT.
[b] Low cost estimate: 210 MW CT; high cost estimate: 85 MW CT.
[c] Low cost estimate: 405 MW CT in the Northwest; high cost estimate: 330 MW CT in Wyoming.

3.6 Nuclear

3.6.1 TECHNOLOGY DESCRIPTION

Nuclear plant costs differ based on the reactor design, but most sources surveyed employed an AP1000 reactor. The cost of decommissioning for a nuclear power plant is included in fixed O&M since most utilities recover this cost through a sinking fund. E3's recommended fixed O&M for nuclear plants appears lower than many of the sources, but this is mainly a result of accounting, as WECC uses a higher variable O&M for nuclear plants ($6.00/MWh) than many of these sources. Accordingly, E3's recommended "consolidated O&M" (total O&M cost per unit of generation) is of comparable magnitude to most of the sources surveyed.

3.6.2 PRESENT-DAY COST

Table 12. Nuclear capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
APS IRP		$6,655	$50.4	10,386
Avista IRP		$6,325	$100.4	10,400
B&V/NREL	2010	$9,394	$129.1	9,720
CEC COG	2009	$6,732	$150.2	10,400
EIA/RW Beck		$8,087	$88.8	N/A
IPC IRP		$5,785	$1.0	10,488
Lazard[a]		$5,385	$12.8	10,450
		$8,199	$12.8	10,450
NWPCC	2008	$9,012	$97.4	10,400
PacifiCorp IRP	2030	$5,307	$146.7	10,710
Recommendation		**$7,500**	**$70.0**	**10,400**

[a] Range presented reflects uncertainty in nuclear costs.

4 Characteristics of Renewable Technologies

4.1 Biogas

4.1.1 TECHNOLOGY DESCRIPTION

E3 offers two biogas technology options: (1) landfill gas energy recovery plants which combust methane captured from landfills; and (2) other plants which capture gas from sources besides landfills, such as waste water treatment facilities and animal waste.

4.1.2 PRESENT-DAY COST

Table 13. Landfill biogas capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
APS IRP		$1,578	$55.3	
Avista IRP		$2,216	$29.0	10,600
CPUC		$2,750	$130.0	
EIA/RW Beck		$8,718	$373.8	18,000
NWPCC	2008	$2,693	$28.1	10,060
Recommendation		**$2,750**	**$130.0**	**12,070**

Table 14. Biogas (other) capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
CPUC (LTPP)	2010	$5,500	$165.0	
NWPCC[a]	2008	$5,729	$43.3 - $44.4	10,250
Recommendation		**$5,500**	**$165.0**	**13,200**

[a] Animal manure and waste water treatment energy recovery technologies

4.2 Biomass

4.2.1 TECHNOLOGY DESCRIPTION

The biomass technology represented in this update refers to a conventional steam electric plant using biomass as a fuel.

4.2.2 PRESENT-DAY COST

Table 15. Biomass capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	Heat Rate [Btu/kWh]
APS IRP		$4,912	$106.7	N/A
Avista IRP		$4,044	$200.7	13,500
B&V/NREL	2010	$4,124	$96.6	14,500
CEC COG	2009	$3,071	$101.2	10,500
		$3,760	$162.8	11,000
CPUC	2010	$4,529	$93.3	
EIA/RW Beck		$4,088	$100.5	13,500
Lazard		$3,000	$95.0	14,500
		$4,000	$100.5	14,500
NWPCC	2008	$4,583	$194.7	15,500
PacifiCorp IRP	2015	$3,509	$38.8	10,979
RETI 2B		$4,000	N/A	14,000
		$5,000	N/A	16,000
Recommendation		**$4,250**	**$155.0**	**14,800**

4.3 Geothermal

4.3.1 TECHNOLOGY DESCRIPTION

E3 surveyed sources which provide geothermal plant data utilizing both dual flash and binary technologies. Since geothermal costs and performance are very site-specific, E3 recommends using a generic capital cost estimate which encompasses both technologies.

4.3.2 PRESENT-DAY COST

Table 16. Geothermal capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	
APS IRP		$5,012	$78.6	
Avista IRP		$4,865	$195.2	
B&V/NREL	2010	$6,728	$0.0	
CEC COG[a]	2009	$4,500	$59.4	
		$4,914	$48.2	
CPUC (LTPP)	2010	$5,155	$0.0	
EIA/RW Beck[a]		$6,214	$84.3	
		$4,613	$84.3	
IPC IRP[b]		$6,798	$131.9	
		$7,362	$131.9	
Lazard[c]		$4,600	$0.0	
		$7,250	$0.0	
PacifiCorp IRP[a]	2015	$4,277	$110.9	
	2017	$6,132	$209.4	
RETI 2B		$6,300	N/A	
Recommendation		**$5,800**	**$150.0**	

[a] The ranges presented in these sources represent the difference in installed costs for geothermal systems utilizing dual flash and binary technologies. However, there is not a uniform consensus on which option is lower cost among the sources surveyed: CEC and PacifiCorp attribute higher costs to binary systems; EIA attributes higher costs to dual flash systems.
[b] Range of costs presented by IPC captures location-specific nature of geothermal plant costs; low capital cost is for systems in Nevada; high cost is for systems in Idaho.
[c] Range of costs represents high and low cost estimates for geothermal systems.

4.4 Hydro

4.4.1 TECHNOLOGY DESCRIPTION

Capital costs for new hydroelectric facilities are very site-specific. This report provides generic cost estimates for two broadly defined categories: (1) large (or conventional) hydro, which typically exceed 30 MW in size, whose capacity is dispatchable; and (2) small hydro, usually less than 30 MW, which are often run-of-river facilities. Due to natural economies of scale, capital costs tend to be lower for large hydro plants than for small hydro. The distinction between these two types of hydroelectric facilities is not made only for cost purposes; many WECC states' Renewable Portfolio Standards allow generation from small hydro facilities to count towards compliance obligations whereas generation from large hydro plants is excluded.

4.4.2 PRESENT-DAY COST

Table 17. Large hydro capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	
B&V/NREL	2010	$3,843	$15.3	
CPUC	2010	$3,360	$30.0	
EIA/RW Beck		$3,322	$13.4	
Recommendation		**$3,000**	**$30.0**	

Table 18. Small hydro capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	
CEC COG	2009	$1,977	$17.9	
CPUC	2010	$3,960	$30.0	
IPC IRP		$4,531	$13.6	
NWPCC	2008	$3,394	$97.4	
Recommendation		**$3,500**	**$30.0**	

Table 19. Hydro upgrade capital and O&M costs.

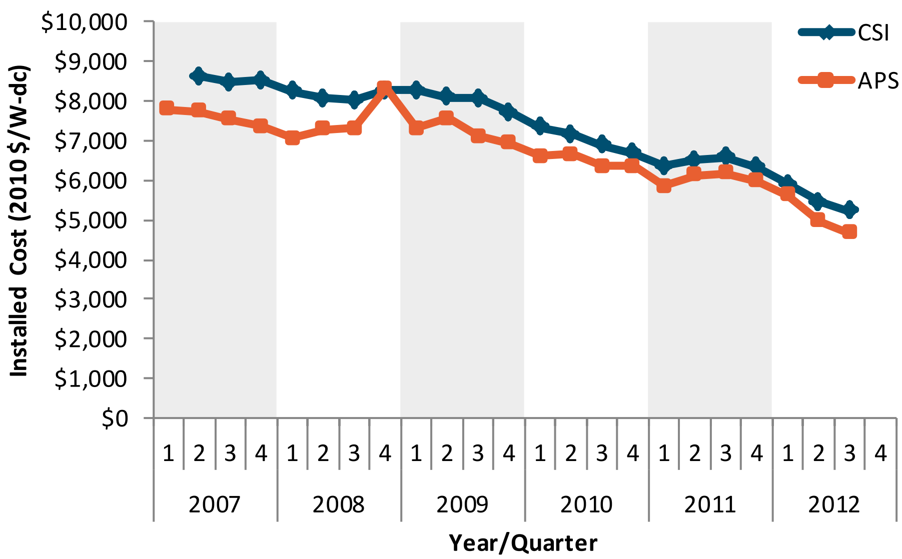
Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	
CEC COG	2009	$881	$12.8	
Recommendation		**$1,500**	**$23.0**	

4.5 Solar PV

4.5.1 TECHNOLOGY DESCRIPTION

Costs of new solar PV systems have been changing rapidly from year to year due to the technology's continued maturation. Reductions in factory gate module prices (see Figure 3) and lower balance-of-system costs have led to recent drops in costs for all system types, from central station plants developed under utility contract to residential rooftop systems financed by homeowners. Figure 5, which shows actual installed residential system costs in Arizona and California, highlights the persistence of the long-term cost reductions into 2012.

Figure 5. Quarterly average capital systems for residential PV systems installed under the California Solar Initiative (CSI) and in the Arizona Public Service (APS) territory (costs have been adjusted for inflation and are expressed in 2010 dollars).



Data source: *data downloaded from California Solar Statistics (CSI) and Arizona Goes Solar (APS) on September 5, 2012*

With such a rapidly evolving technology, there is a natural challenge to identifying today's capital costs; published cost figures and estimates quickly become outdated, while projected costs are speculative and span a wide range. Accepting that the lag in reported costs and the uncertainty in future costs can obscure today's true costs, the cost estimates provided herein represent E3's best understanding of current solar PV costs at the time this survey was completed.

The continued reductions in solar PV costs have been accompanied by substantial interest in development at all scales. To allow WECC to study the tradeoffs between various PV system types, E3 has developed capital cost estimates for six different representative systems: residential rooftop and commercial rooftop, distributed utility-scale (fixed tilt and single-axis tracking), and central station utility-scale (fixed tilt and single-axis tracking).

Capital costs shown for solar PV in Table 20 through Table 25 technologies are expressed relative to the system's DC nameplate rating. However, WECC's modeling requires the capital cost inputs expressed relative to the system's AC rated output; E3 has converted its DC recommendations to an AC basis assuming inverter efficiency of 85%; this translation is shown in Table 26.

4.5.2 PRESENT-DAY COSTS

Table 20. Residential rooftop solar PV capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW$_{PDC}$]	Fixed O&M [$/kW-yr]	Capacity [kW]
LBNL (TTS)	2010	$6,600		
NREL	2010	$5,710		
	2011	$4,257		
B&V/NREL	2010	$6,050	$50.8	
	2015	$4,413	$48.8	
CSI Data[a]	2011	$6,496		
	2012	$5,642		
AZ Solar Data[b]	2011	$6,126		
	2012	$5,176		
Recommendation	**2012**	**$5,300**	**$65.0**	**<10**

[a] CSI costs shown are calculated as capacity-weighted averages of residential installations (<10 kW) based on the CSI Working Data Set as downloaded September 5, 2012.
[b] Costs from Arizona Goes Solar are calculated as a capacity-weighted average of residential systems (<10 kW) installed in the Arizona Public Service (APS) territory.

Table 21. Commercial rooftop solar PV capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW$_{PDC}$]	Fixed O&M [$/kW-yr]	Capacity [kW]
LBNL (TTS)	2010	$5,800		100 - 500
NREL	2010	$4,590		217
	2011	$3,326		217
B&V/NREL	2010	$4,870	$50.8	100
	2015	$3,904	$48.8	100
CSI Data[a]	2011	$5,676		
	2012	$5,204		
AZ Solar Data[b]	2011	$5,505		
	2012	$4,692		
Recommendation	**2012**	**$4,500**	**$55.0**	**10-1,000**

[a] CSI costs shown are calculated as capacity-weighted averages based on the CSI Working Data Set as downloaded September 5, 2012.
[b] Costs from Arizona Goes Solar are calculated as a capacity-weighted average of non-residential systems installed in the Arizona Public Service (APS) territory.

Table 22. Small utility scale solar PV (fixed tilt) capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW$_{PDC}$]	Fixed O&M [$/kW-yr]	Capacity [MW]
B&V/NREL	2010	$3,701	$50.8	1
		$3,009	$50.8	10
	2015	$3,382	$48.8	1
		$2,712	$48.8	10
CPUC	2012	$2,730		5
		$2,590		20
EIA/RW Beck		$5,273		
Lazard		$2,750	$15.0	10
APS IRP		$1,808	$24.2	17
Recommendation	**2012**	**$2,825**	**$50.0**	**1-20**

Table 23. Small utility scale solar PV (single axis tracking) capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW$_{PDC}$]	Fixed O&M [$/kW-yr]	Capacity [MW]
B&V/NREL	2010	$4,062	$50.8	1
		$3,286	$50.8	10
	2015	$3,637	$48.8	1
		$2,956	$48.8	10
CPUC	2012	$3,325		1
Lazard		$3,500	$25.0	10
APS IRP	2015	$2,026	$24.2	17
Recommendation	**2012**	**$3,225**	**$50.0**	**1-20**

Table 24. Large utility scale solar PV (fixed tilt) capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW$_{PDC}$]	Fixed O&M [$/kW-yr]	Capacity [MW]
CPUC	2010	$3,400	$32.0	
	2012	$2,380	$32.0	
NREL (PV)	2010	$3,800		187.5
	2011	$2,706		187.5
B&V/NREL	2015	$2,506	$48.8	100
Recommendation	**2012**	**$2,400**	**$50.0**	**100**

Table 25. Large utility scale solar PV (single axis tracking) capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW$_{PDC}$]	Fixed O&M [$/kW-yr]	Capacity [MW]
CPUC	2010	$4,000	$44.0	
	2012	$2,800	$44.0	
NREL (PV)	2010	$4,400		187.5
	2011	$3,268		187.5
B&V/NREL	2015	$2,786	$48.8	100
Recommendation	**2012**	**$2,800**	**$50.0**	**100**

Table 26. Conversion of DC cost recommendations to AC-equivalent, based on an assumed inverter conversion efficiency of 85%.

Subtype	DC Capital Cost [$/kW$_{PDC}$]	AC Capital Cost [$/kW]
Fixed (> 20 MW)	$2,400	$2,850
Tracking (> 20 MW)	$2,800	$3,300
Fixed (1-20 MW)	$2,825	$3,325
Tracking (1-20 MW)	$3,225	$3,800
Commercial Rooftop	$4,500	$5,250
Residential Rooftop	$5,300	$6,250

4.5.3 PROJECTION OF COST REDUCTIONS

The cost of solar photovoltaic installations is expected to continue the long-term downward trend. Reductions in capital costs may be achieved through a number of pathways:

+ Continued **reductions in module manufacturing costs** as the industry continues to scale up and develop are possible;
+ Natural **gains in cell efficiency** would translate to lower BOS costs through a reduction in the physical footprint—and thereby, materials and labor—required for an installation of a specified size; and
+ **General improvements in the installation process**—streamlined permitting, efficiency gains in labor, etc.—may facilitate further BOS cost reductions.

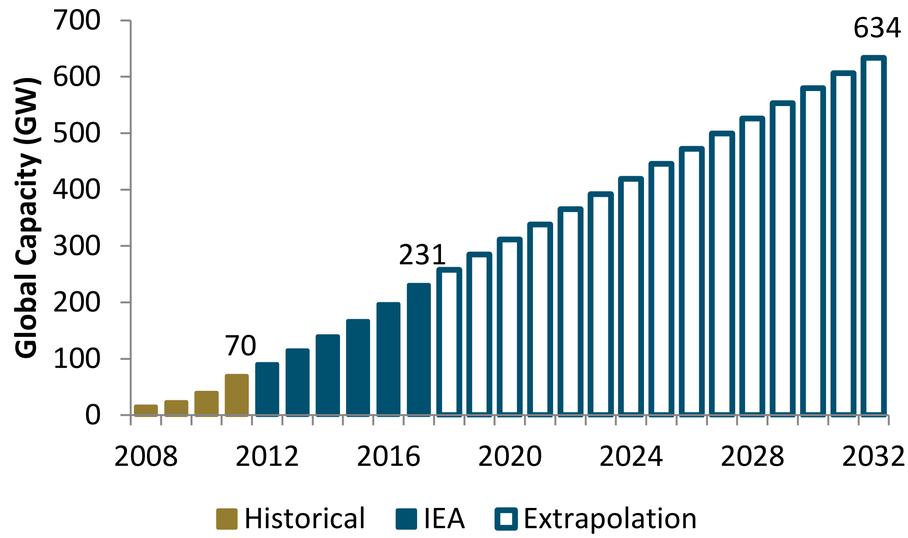
To project the plausible magnitude of these future cost reductions, E3 recommends using learning curves, applying separate learning rates to photovoltaic modules and to balance-of-systems (BOS) components of the installation. Historically, module prices have followed a learning rate of 20%

over the long term. This learning rate has been confirmed in many studies over varying time horizons; E3 adopts this rate for the module-related components of PV system costs.

There has been considerably less focus on historical learning rates for balance-of-system components. The range of estimates is considerably larger: IEA uses a learning rate of 18% for BOS, whereas a recent LBNL study found that US residential BOS costs for systems installed between 2001 and 2011 followed a learning rate of only 6% (Seel, 2012). While there are substantial opportunities to reduce BOS costs through expedited permitting and installation processes, these costs may not naturally decline along the same learning curve as module-related costs. Therefore, E3 recommends a lower learning rate of 10% for BOS-related costs.

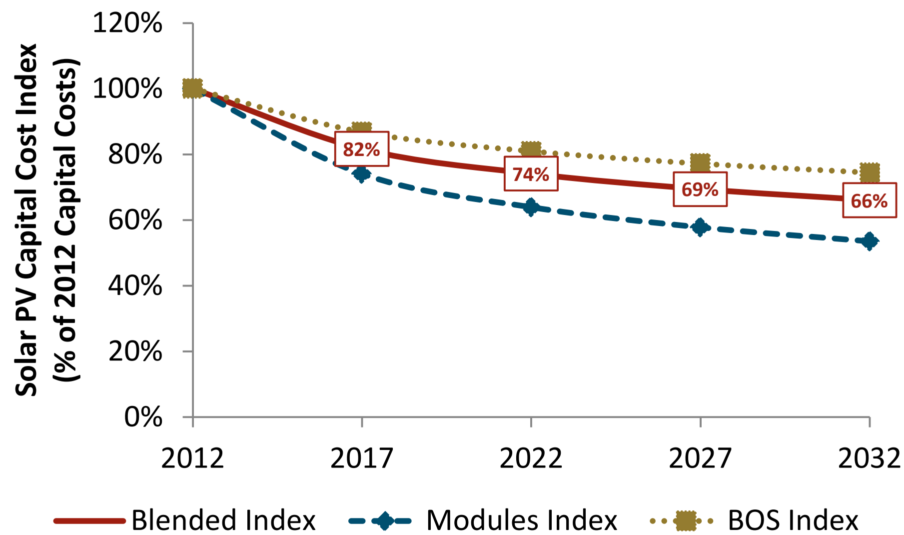
For a forecast of global installed capacity, E3 relies on the IEA's *Medium-Term Renewable Energy Market Report 2012*, which forecasts global installed capacity from 2012 through 2017. E3 extrapolates this forecast through 2032 assuming a continued linear rate of growth based on the change in global installed capacity over the original forecast period (2011-2017). The resulting forecast is shown in Figure 6.

Figure 6. Forecast of global installed solar PV capacity used to evaluate PV cost reductions through application of learning curves.



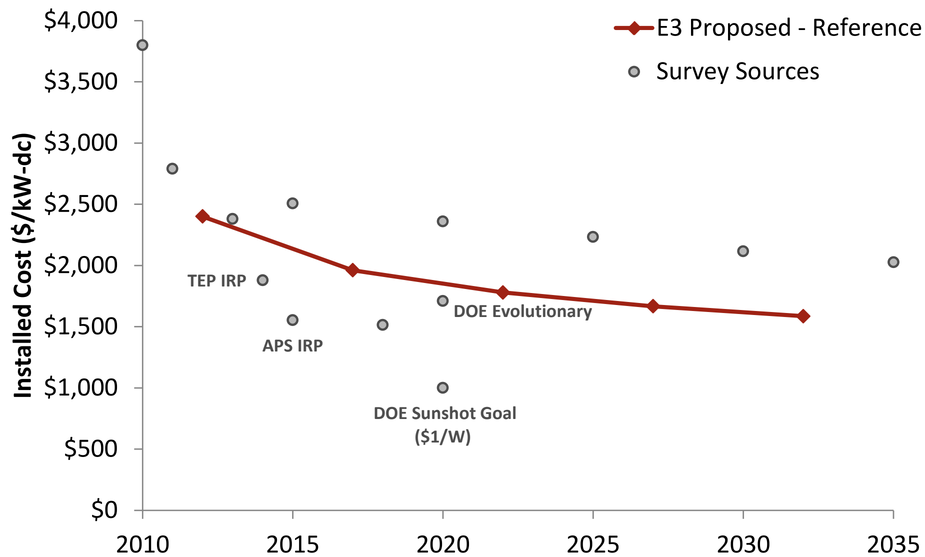
To combine the two learning curves—one for module-related costs and one for BOS components—E3 has had to make an assumption on the proportion of today's installed system costs that can attributed to each. With recent cost declines, factory-gate module prices are currently in the range of $1/W-dc. In today's systems, IRENA attributes one-third to one-half of installed system costs to modules. While the actual division between modules and BOS will vary by system type and size, E3 assumes that 40% of present-day costs are related to modules and 60% are related to BOS. Weighting the two individual learning curves by these fractions, the module- and BOS-related cost projections are married to create a single projection of system costs over the next two decades, as shown in Figure 7.

Figure 7. Projected capital cost reductions for solar PV based on learning curves.



The approach described above results in a 26% reduction in solar PV capital costs relative to 2012 levels by 2022, and a 34% reduction by 2032. E3 has benchmarked this cost reduction forecast against a number of sources that provide estimates of future PV costs. Comparisons of E3's trajectory with the surveyed sources are shown in Figure 12 for large-scale utility systems with a fixed tilt configuration.

Figure 8. E3 has benchmarked its cost reduction forecast against other sources of projected costs (large scale utility fixed tilt is shown below). E3's cost projections fall into the middle of the range of projected PV system costs.



4.5.4 POTENTIAL PERFORMANCE IMPROVEMENTS

E3 reviewed the potential for technology improvements to lead to higher capacity factors for solar PV. E3 believes that the principal factors driving technological progress – reduced module manufacturing costs, improved cell efficiencies, less labor-intensive installation practices – would reduce the installed cost of the PV systems but would be unlikely to result in a higher capacity factor. E3 does not recommend that any improvement in PV capacity factor be assumed in WECC's modeling.

4.6 Solar Thermal

4.6.1 TECHNOLOGY DESCRIPTION

In the development of cost estimates for solar thermal, E3 considered two technologies:

+ **Parabolic trough:** mirrors focus solar energy on a heat transfer fluid (HTF; commonly a synthetic oil) carried in axial tubes; the heated working fluid is used to create steam that powers a traditional steam generator.
+ **Power tower:** a field of tracking mirrors ("heliostats") focus energy on a tower to heat a working fluid and power a steam generator.

While the majority of systems currently installed rely on trough technologies, there is growing commercial interest in the development of tower alternatives. Because the LTPT does not have sufficient resolution to meaningfully distinguish between the two technologies, E3 recommends developing a single, representative technology that considers the cost, performance, and expected market shares of the two competing options. Accordingly, E3's estimate of today's capital costs is based largely on publicly available costs for trough systems—with its limited commercialization, the public literature on current tower troughs is sparse. However, in the development of future solar thermal cost estimates, E3 considers both the technical cost reduction potential for trough systems as well as the possibility that tower technologies may enter the market at substantially reduced costs in the future.

4.6.2 PRESENT-DAY COSTS

Table 27. Solar thermal without storage capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]
CPUC (LTPP)	2010	$5,300	$66.0
DOE Sunshot	2010	$4,500	$70.0
B&V/NREL	2010	$5,221	$50.8
	2015	$5,019	$50.8
APS IRP	2015	$4,576	$62.1
Lazard[a]		$5,000	$34.0
		$5,400	$66.0
Recommendation	**2012**	**$4,900**	**$60.0**

[a] Low cost estimate utilizes wet cooling; high cost estimate utilizes dry cooling.

Table 28. Solar thermal with storage capital and O&M costs (costs reflect trough systems with six hours of storage unless otherwise noted).

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]
CPUC (LTPP)	2010	$7,500	$66.0
B&V/NREL	2010	$7,508	$50.8
	2015	$7,231	$50.8
Sandia[a]	2013	$7,427	$65.0
B&V/NREL	2015	$7,231	$50.8
APS IRP	2015	$6,912	$65.9
Lazard[b]		$6,300	$60.0
		$6,500	$60.0
Recommendation	**2012**	**$7,100**	**$60.0**

[a] Tower system with nine hours of thermal storage
[b] Includes three hours of thermal energy storage

4.6.3 PROJECTION OF COST REDUCTIONS

Compared to most resources considered in this study, solar thermal generation technologies are at a very early stage of commercialization—cumulative global installed capacity only recently surpassed 2 GW (IEA, 2012)—and there are yet substantial opportunities for technology improvements that would reduce capital costs. Recent engineering-economic studies on trough (Kutscher, 2010) and tower (Kolb, 2011) technologies describe several of the key pathways to these cost reductions:

+ **Improvements in gross thermal efficiency** through the use of higher temperature heat transfer fluids (HTFs) would translate to lower capital costs through a reduction in the required solar collector area;
+ A number of opportunities for **better hardware design** in the components of the solar collectors—optimal mirror sizing, advanced receiver coatings, low cost foundations and support structures—would directly reduce system costs; and
+ **Reductions in storage system costs** could be achieved through the use of advanced HTFs that either enable storage at a higher temperature or allow for storage in a phase-change material.

Because of the relative lack of commercialization of solar thermal technologies and the uncertainty that the application of learning curves to such a technology can introduce, E3 uses a more direct approach to assess potential cost declines for solar thermal. By surveying engineering studies and integrated resource plans that have considered the potential cost declines for solar thermal over the next two decades, E3 has developed plausible trajectories for the capital costs of solar thermal with and without storage. With the substantial uncertainty surrounding any potential forecast of future costs, E3 has chosen not to distinguish between future costs of trough and tower technologies; however, the relative potential for cost reductions between the two has informed E3's evaluation of future costs.

The recommended cost trajectories for solar thermal technologies, as well as the underlying data that constitute the bases for these recommendations, are shown in Figure 9 and Figure 10. In these recommendations, E3 has specified cost reduction potential of 15% in the short-term (five years) and 30% in the long term (20 years) as plausible; year-by-year capital costs are evaluated through linear interpolation as shown in the figures. The specific point estimates of solar thermal costs shown in these two figures are summarized in detail in Table 29.

Figure 9. Comparison of E3 recommended future costs for solar thermal trough and tower technologies without storage with other projections

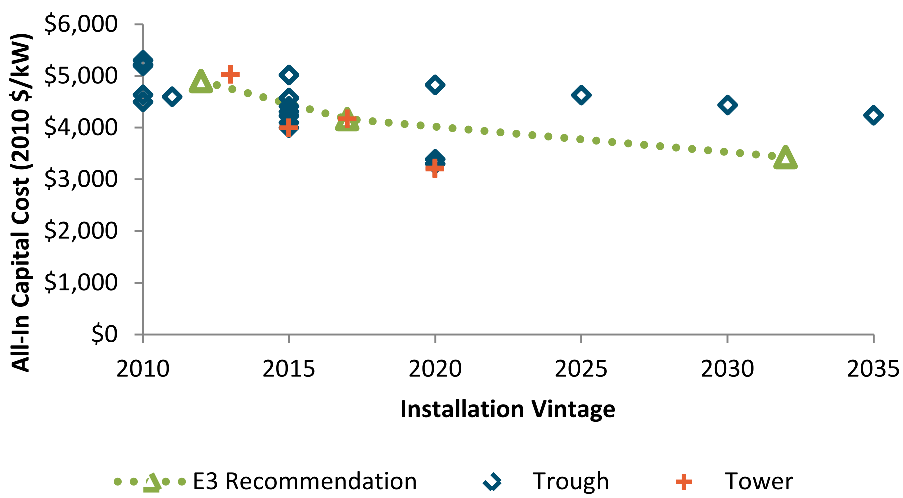


Figure 10. Comparison of E3 recommended future costs for solar thermal trough and tower technologies with six hours of thermal storage with other projections

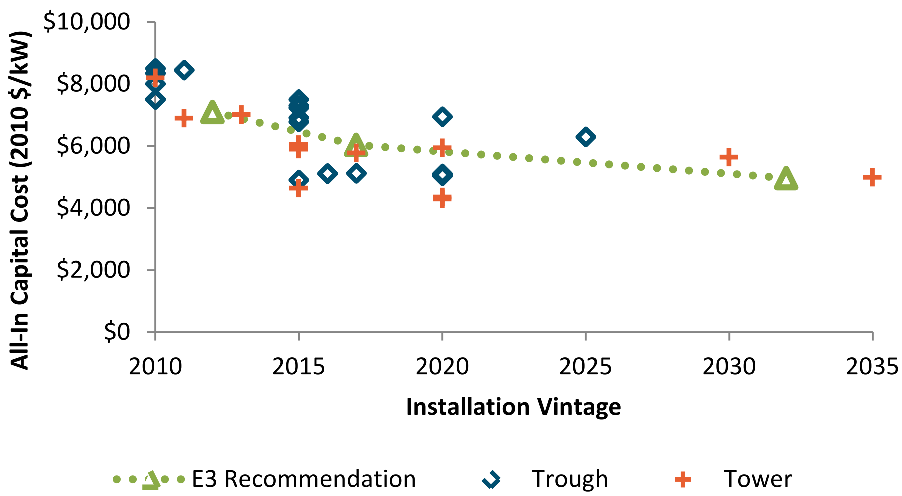


Table 29. Point estimates of future solar thermal costs with and without storage.

Source	Technology	Storage	Installation Vintage	Capital Cost [$/kW]
B&V/NREL	Trough	0 hrs	2010	$4,910
B&V/NREL	Trough	0 hrs	2015	$4,720
B&V/NREL	Trough	0 hrs	2020	$4,540
B&V/NREL	Trough	0 hrs	2025	$4,350
B&V/NREL	Trough	0 hrs	2030	$4,170
B&V/NREL	Trough	0 hrs	2035	$3,987
IRENA	Trough	0 hrs	2011	$4,600
IRENA	Trough	0 hrs	2015	$4,000
APS IRP	Trough	0 hrs	2015	$4,576
CPUC (LTPP)	Trough	0 hrs	2010	$5,300
DOE Sunshot[a]	Trough	0 hrs	2010	$4,500
DOE Sunshot[a]	Trough	0 hrs	2015	$4,100
DOE Sunshot[a]	Trough	0 hrs	2020	$3,300
DOE Sunshot[a]	Tower	0 hrs	2015	$4,000

Source	Technology	Storage	Installation Vintage	Capital Cost [$/kW]
DOE Sunshot[a]	Tower	0 hrs	2020	$3,200
Lazard	Trough	0 hrs	2010	$5,200
NREL[a]	Trough	0 hrs	2010	$4,632
NREL[a]	Trough	0 hrs	2015	$4,228
NREL[a]	Trough	0 hrs	2020	$3,385
PNM	Trough	0 hrs	2015	$4,306
TEP	Trough	0 hrs	2015	$4,411
Sandia[a]	Tower	0 hrs	2013	$5,028
Sandia[a]	Tower	0 hrs	2017	$4,172
Sandia[a]	Tower	0 hrs	2020	$3,220
B&V/NREL	Trough	6 hrs	2010	$7,508
B&V/NREL	Trough	6 hrs	2015	$7,231
B&V/NREL	Trough	6 hrs	2020	$6,944
B&V/NREL	Trough	6 hrs	2025	$6,295
B&V/NREL	Tower	6 hrs	2030	$5,647
B&V/NREL	Tower	6 hrs	2035	$4,998
IRENA	Trough	6 hrs	2011	$8,450
IRENA	Trough	6 hrs	2015	$7,300
IRENA	Tower	6 hrs	2011	$6,900
IRENA	Tower	6 hrs	2015	$6,050
APS	Trough	6 hrs	2015	$6,912
APS	Tower	6 hrs	2015	$4,650
CPUC (LTPP)	Trough	6 hrs	2010	$7,500
DOE Sunshot[a]	Trough	6 hrs	2010	$8,000
DOE Sunshot[a]	Trough	6 hrs	2015	$7,500
DOE Sunshot[a]	Trough	6 hrs	2020	$5,100
DOE Sunshot[a]	Tower	6 hrs	2015	$5,900
DOE Sunshot[a]	Tower	6 hrs	2020	$4,300
CSIRO	Trough	6 hrs	2010	$8,499
CSIRO	Trough	6 hrs	2017	$5,120
CSIRO	Tower	6 hrs	2010	$8,203
CSIRO	Tower	6 hrs	2020	$5,940

Source	Technology	Storage	Installation Vintage	Capital Cost [$/kW]
NREL[a]	Trough	6 hrs	2010	$8,341
NREL[a]	Trough	6 hrs	2015	$6,783
NREL[a]	Trough	6 hrs	2020	$5,035
TEP	Trough	6 hrs	2016	$5,115
Sandia[a]	Tower	6 hrs	2013	$7,019
Sandia[a]	Tower	6 hrs	2017	$5,777
Sandia[a]	Tower	6 hrs	2020	$4,354
PNM	Trough	6 hrs	2015	$4,907

[a] These sources do not provide estimates for each of the configurations shown in the table; rather, there is a trend to show costs for increasing incorporation of storage over time (e.g. NREL shows capital costs for 0 hrs of storage in 2010, 6 hrs in 2015, and 12 hrs in 2020). However, each of these studies provided the detailed assumptions of component unit costs used to derive capital cost estimates in each year; E3 used these unit costs in conjunction with the plant design characteristics provided in each respective report to derive approximate capital costs for each configuration in each year.

4.6.4 POTENTIAL PERFORMANCE IMPROVEMENTS

E3 also examined the potential opportunities for technological improvements to allow solar thermal facilities to operate at higher capacity factors. As with solar PV, many of these opportunities offer the potential to reduce plant costs but would have limited or negligible impact on plant capacity factors *for a specified amount of thermal storage*.[1] For instance, one of the most oft-cited pathways for improvements in solar thermal technologies is the transition to higher-temperature working fluids. A higher temperature working fluid would improve the plant's thermal efficiency. The primary impact of this increase in efficiency would be a direct reduction in many of the capital costs of plant equipment; specifically, it would reduce the size of the solar field necessary to concentrate the necessary energy from the sun and would also reduce the cost of any

[1] There is growing anecdotal evidence that systems with increasing amounts of storage will become cost-effective over time, a trend that, if realized, would result in higher capacity factors for solar thermal as a whole as systems are configured with more and more storage. As the characterization of solar thermal in WECC's models is limited to two configurations (with and without storage), the effects of a transition to increasing incorporation of storage in solar thermal systems was not considered in E3's scope. Instead, E3 focused on evaluating whether the pathways to technology improvement would result in changes to the capacity factors of the two system types characterized in the WECC model.

necessary storage systems included in the configuration. While this improvement in efficiency might also change the plant's capacity factor by changing the optimal size of the solar field, this effect is considered secondary as its magnitude is small and is sensitive to the relative costs of the solar field and other plant components. Accordingly, E3 is not recommending any assumed improvements in solar thermal capacity factors over time.

4.7 Wind

4.7.1 TECHNOLOGY DESCRIPTION

Wind power technologies include both onshore and offshore designs. Onshore wind is a mature technology, with roughly 6.8 GW of new capacity installed in the United States in 2011 (Wiser, 2012). On the other hand, no offshore wind turbines have been installed in the U.S., and this lack of commercialization is reflected in E3's capital cost recommendation.

4.7.2 PRESENT-DAY COSTS

Table 30. Onshore wind capital & O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	
CEC COG	2009	$2,281		
B&V/NREL	2010	$2,112	$61.0	
CPUC	2010	$2,399	$60.0	
LBNL (WTMR)	2010	$2,122		
RETI 2B[a]	2010	$2,150		
		$2,600		
LBNL (WTMR)	2010	$2,122		
	2011	$2,035		
Avista IRP	2012	$1,839	$49.8	
IPC IRP	2012	$1,784	$33.9	
PacifiCorp IRP[b]	2012	$2,239	$31.4	
	2012	$2,383	$31.4	
Lazard[c]		$1,300	$30.0	
		$1,900	$30.0	
Recommendation		**$2,000**	**$60.0**	

[a] RETI includes a range of potential costs for wind installations.
[b] PacifiCorp's range of costs is a result in geographic differences in installation costs; the low cost estimate is for wind farms on the East Side of the Cascades; the high cost estimate is for farms on the West Side
[c] Lazard does not present a point estimate for wind costs, instead expressing today's costs as a range.

Table 31. Offshore wind capital and O&M costs.

Source	Installation Vintage	Capital Cost [$/kW]	Fixed O&M [$/kW-yr]	
CEC COG	2009	$6,478	$27.9	
B&V/NREL[a]	2010	$3,531	$101.7	
B&V/NREL[b]	2020	$4,480	$132.2	
EIA/RW Beck		$6,269	$53.3	
Lazard		$3,100	$60.0	
		$5,000	$100.0	
Recommendation		**$6,000**	**$100.0**	

[a] Assumes fixed-bottom offshore wind technology.
[b] Assumes floating-platform offshore wind technology.

4.7.3 PROJECTION OF COST REDUCTIONS

E3 applies the learning curve approach to current onshore wind costs to assess the potential cost reductions for current wind capital costs. Compared to solar PV, there is less consensus in academic literature on an appropriate learning rate for wind; estimates range from 0%-14%. E3 has chosen to apply a learning rate of 5% in conjunction with the forecast of global installed capacity from the IEA's 2012 market report. The forecast used in this calculation is shown in Figure 11; the resulting trajectory of cost reductions follows in Figure 12.

Figure 11. Forecast of global installed wind capacity used to evaluate potential cost reductions through application of learning curves.

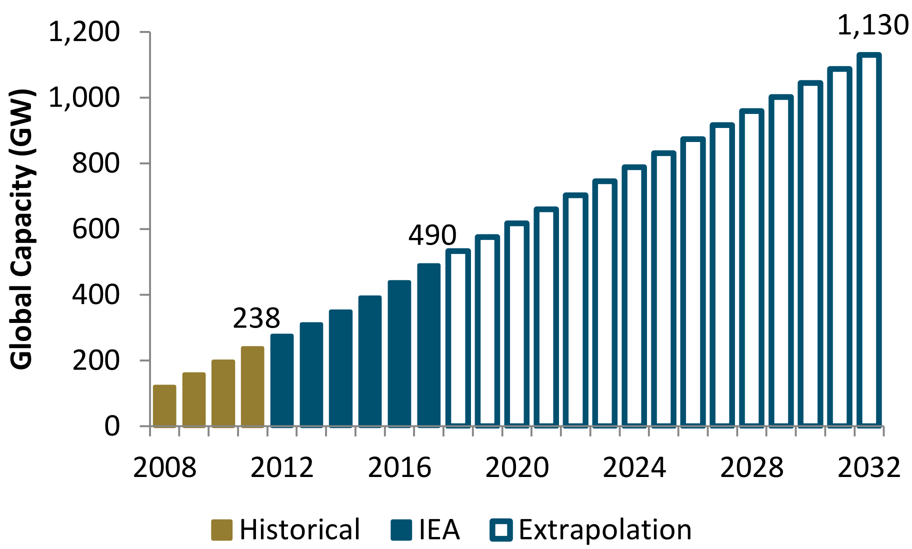
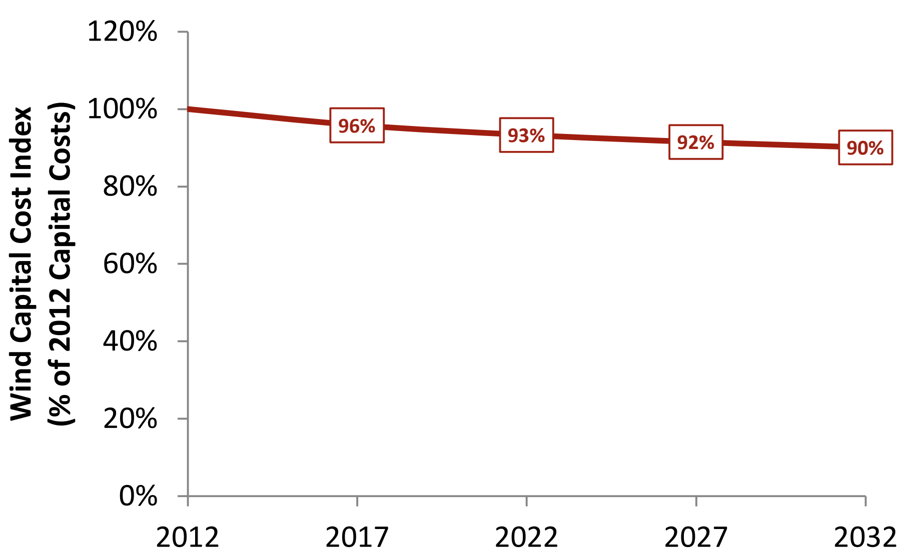


Figure 12. Projected capital cost reductions for wind based on learning curves.

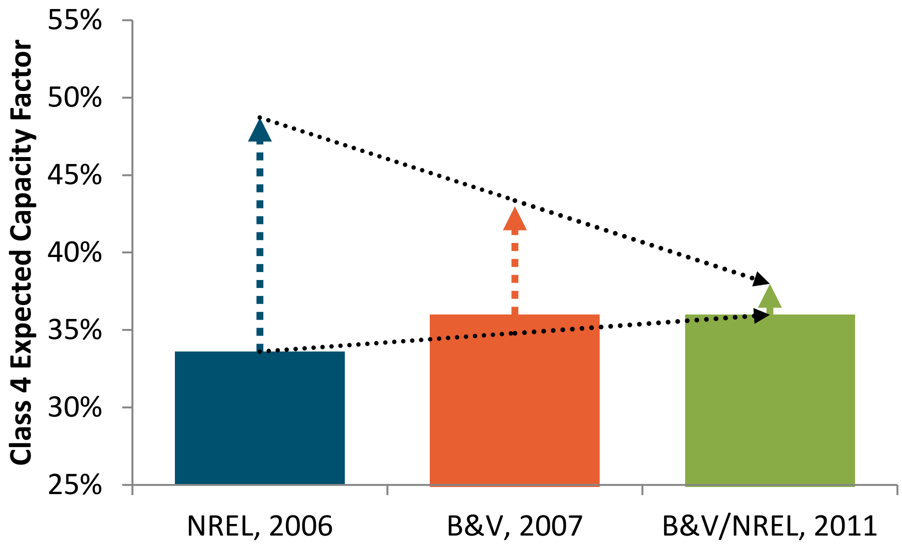


4.7.4 POTENTIAL PERFORMANCE IMPROVEMENTS

Further technological development in wind power technologies offers not just the potential to reduce capital costs but also to enable improvements in capacity factors. Considerable gains have been made in the past decade in wind turbine performance due primarily to increases in hub height and rotor diameter. Tower heights and rotor diameters of current best available technologies have reached 100 meters; as such designs continue to gain traction in the market, average levels of performance will continue to improve. So too are there opportunities for further efficiency gains through reduced losses and improvements in the drive train.

While there is much discussion of the potential gains to be reaped from improvements in wind turbine design, the body of literature that quantifies these opportunities on a technical basis is relatively limited. A widely-cited NREL report released in 2008 examined this subject (Cohen, 2008), concluding that, *relative to 2002 wind turbine designs*, a combination of these innovations might be reasonably expected to increase the capacity factor by 45%. More recent evaluations of potential gains are less optimistic: Black & Veatch's most recent resource performance review for wind turbines suggest that performance improvements on the order of 5-10% at low wind speeds and 0-5% at high wind speeds may be possible (B&V, 2012). Figure 13 highlights the evolution of this trend: for three studies of different vintages, it shows the assumed performance of a reference turbine as well as the long-term potential increase in capacity factor that was anticipated at Class 4 wind speeds. What is evident from this comparison is that the maturation of wind technologies has been accompanied by both an improvement in capacity factor through the harvesting of identified opportunities for performance gains and an increasingly conservative outlook on the potential impact of remaining pathways for technological innovation.

Figure 13. Evolution of the forecasted opportunities for improvement in wind turbine performance. Bars show the expected capacity factor for a wind turbine in a Class 4 regime during each study's reference year; arrows indicate the expected increase in capacity factor that might be achieved over the long term.



The remaining potential improvements in turbine design will likely have the largest impact on performance in low quality wind regimes (Class 3-4) and a very limited impact on performance in high quality wind regimes (Class 6-7). This is because many of the design changes allow individual wind turbines to operate more efficiently at lower wind speeds.

E3's recommendations regarding the treatment of this potential improvement in performance differ for the 10- and 20-year studies. In the 10-year study, which requires an hourly output profile for each wind plant included in the study, WECC currently uses hourly data from NREL's Western Wind Integration Dataset. Adjusting these hourly profiles to capture small potential changes in capacity factor is a sufficiently complicated task—and the performance improvements that are expected over the next decade are limited enough—that E3 recommends no change in wind performance assumptions for the 10-year study.

However, in the 20-year study, which does not require such granular inputs on wind resource performance, E3 believes it is appropriate to adjust assumptions for the potential performance improvements that may be achieved during this time horizon. E3 recommends including improvement in capacity factors on the same order of magnitude as those presented in Black & Veatch's most recent study (B&V, 2011). These are summarized in Table 32.

Table 32. Recommended improvements for wind turbine performance to include in the 20-year study. The recommendations are expressed as an additive change to capacity factors.

	Class 3	Class 4	Class 5	Class 6	Class 7
Recommended Improvement	+3%	+2%	+2%	+1%	+0%

5 Calculations of Annualized Resource Costs

5.1 Cash Flow Models for 10-Year Study

In order to translate the capital and fixed cost recommendations into values useful for WECC's snapshot studies, E3 has developed three Excel-based cash flow models that represent different options for project financing. Each model develops an annual steam of costs and revenues that results in the specified return to the financing entity.

5.1.1 INDEPENDENT POWER PRODUCER

E3 has developed a cash-flow model that evaluates a cost-based power-purchase agreement price for new generation under the assumption that a project is funded and financed by an IPP under long-term contract to a utility. The pro-forma model is designed to ensure that the long-term power price will provide equity investors with appropriate return on and of their capital investment. E3's model also maximizes leverage, assuming that projects will be debt-funded to the maximum extent possible subject to the constraint that the project's average debt-service coverage ratio remains above 1.40. Accordingly, the project's capital structure is endogenous to the financing model and is based on an assumption that the IPP's after-tax WACC, the weighted average cost of capital of debt and equity with which the project is financed, will be 8.25%. Figure 14 provides a screenshot of the first five years of the IPP cash flow model.

Figure 14. Screenshot of IPP cash flow model (first five years)

IPP Pro Forma

Year	0	1	2	3	4	5
Energy Production (MWh)		**3,723,000**	**3,713,693**	**3,704,408**	**3,695,147**	**3,685,909**
Cost of Generation ($/MWh)		$87.46	$87.46	$87.46	$87.46	$87.46
Operating Revenue		$325,597,228	$324,783,235	$323,971,277	$323,161,349	$322,353,446
Total Revenue		**$325,597,228**	**$324,783,235**	**$323,971,277**	**$323,161,349**	**$322,353,446**
Fixed O&M Costs		($5,100,000)	($5,202,000)	($5,306,040)	($5,412,161)	($5,520,404)
Variable O&M Cost		($18,607,554)	($18,932,256)	($19,262,624)	($19,598,756)	($19,940,755)
Fuel Costs		($188,837,845)	($192,613,398)	($196,464,438)	($200,392,474)	($204,399,046)
CO2 Abatement Costs		$0	$0	$0	$0	$0
Property Tax		($5,500,000)	($5,225,000)	($4,950,000)	($4,675,000)	($4,400,000)
Insurance		($2,805,000)	($2,861,100)	($2,918,322)	($2,976,688)	($3,036,222)
Total Costs		**($220,850,399)**	**($224,833,754)**	**($228,901,423)**	**($233,055,080)**	**($237,296,427)**
Operating Profit		**$104,746,830**	**$99,949,482**	**$95,069,854**	**$90,106,269**	**$85,057,019**
Interest Expense		($30,116,965)	($29,231,147)	($28,283,321)	($27,269,148)	($26,183,982)
Loan Repayment Expense (Principal)		($12,654,547)	($13,540,365)	($14,488,191)	($15,502,364)	($16,587,530)
Debt Service Reserve		$0	$0	$0	$0	$0
Interest earned on DSRF		$721,462	$721,462	$721,462	$721,462	$721,462
Net Finance Costs		**($42,050,050)**	**($42,050,050)**	**($42,050,050)**	**($42,050,050)**	**($42,050,050)**
State tax refund/(paid)		($3,830,843)	($2,221,471)	($2,154,915)	($2,070,956)	($1,972,110)
Federal tax refund (paid)		($17,813,419)	($10,329,839)	($10,020,353)	($9,629,945)	($9,170,311)
Tax Credit - Federal PTC		$0	$0	$0	$0	$0
Tax Credit - Federal ITC		$0	$0	$0	$0	$0
Taxes Refunded/(Paid)		**($21,644,262)**	**($12,551,310)**	**($12,175,268)**	**($11,700,901)**	**($11,142,421)**
Equity Investment	($140,370,848)					
After-Tax Equity Cash Flow	**($140,370,848)**	**$41,052,518**	**$45,348,122**	**$40,844,536**	**$36,355,319**	**$31,864,548**

5.1.2 INVESTOR-OWNED UTILITY/PUBLICLY-OWNED UTILITY

E3 has also developed a cash flow model for projects that are utility-owned and whose capital costs are recovered through rate base. The revenue requirement approach is based assumes a fixed utility capital structure; assumptions on the costs of debt and equity are shown in Table 33. The models for IOU- and POU-financing differ only in that POUs are exempt from income tax and projects are entirely debt financed.

Table 33. Capital structure for IOU and POU financing.

	IOU	POU
Equity Share	50%	-
Debt Share	50%	100%
Equity Cost	11.0%	-
Debt Cost	6.0%	6.3%
After-Tax WACC	**7.31%**	**6.30%**

Figure 15 provides a screenshot of the first five years of the IOU revenue requirement model.

Figure 15. Screenshot of IOU cash flow model (first five years).

IOU Pro Forma

Year	0	1	2	3	4	5
Energy Production (MWh)		**105,120**	**104,069**	**103,028**	**101,998**	**100,978**
Debt Term Flag		1	1	1	1	1
Capital Cost		$180,000,000	$180,000,000	$180,000,000	$180,000,000	$180,000,000
Starting Rate Base		$180,000,000	$160,321,500	$132,100,200	$112,991,220	$99,349,632
Accumulated Deferred Income Tax		($10,678,500)	($29,899,800)	($40,008,780)	($44,650,368)	($49,291,956)
Accumulated Depreciation		($9,000,000)	($18,000,000)	($27,000,000)	($36,000,000)	($45,000,000)
Ending Balance Rate Base	$180,000,000	$160,321,500	$132,100,200	$112,991,220	$99,349,632	$85,708,044
Debt						
Beginning Balance		$90,000,000	$80,160,750	$66,050,100	$56,495,610	$49,674,816
Interest		$5,400,000	$4,809,645	$3,963,006	$3,389,737	$2,980,489
Principal		$4,500,000	$4,500,000	$4,500,000	$4,500,000	$4,500,000
Equity						
Beginning Balance		$90,000,000	$80,160,750	$66,050,100	$56,495,610	$49,674,816
Equity Return		$9,900,000	$8,817,683	$7,265,511	$6,214,517	$5,464,230
Return of Invested Equity		$4,500,000	$4,500,000	$4,500,000	$4,500,000	$4,500,000
Book Equity Return		$14,400,000	$13,317,683	$11,765,511	$10,714,517	$9,964,230
Taxes						
Equity Return		$9,900,000	$8,817,683	$7,265,511	$6,214,517	$5,464,230
Tax on Equity Return		$3,915,450	$3,487,393	$2,873,510	$2,457,842	$2,161,103
Amortized ITC		$0	$0	$0	$0	$0
PTC		($2,358,893)	($2,382,010)	($2,405,354)	($2,428,926)	($2,452,730)
Tax Grossup - Equity		$2,561,721	$2,281,661	$1,880,022	$1,608,067	$1,413,923
Tax Grossup - ITC		$0	$0	$0	$0	$0
Tax Grossup - PTC		($1,543,329)	($1,558,453)	($1,573,726)	($1,589,149)	($1,604,722)
Revenue Requirement						
Variable O&M		$0	$0	$0	$0	$0
Fuel		$0	$0	$0	$0	$0
CO2 Abatement		$0	$0	$0	$0	$0
Fixed O&M		$2,754,000	$2,809,080	$2,865,262	$2,922,567	$2,981,018
Property Tax		$0	$0	$0	$0	$0
Insurance		$0	$0	$0	$0	$0
Interest		$5,400,000	$4,809,645	$3,963,006	$3,389,737	$2,980,489
Equity Return		$9,900,000	$8,817,683	$7,265,511	$6,214,517	$5,464,230
Depreciation		$9,000,000	$9,000,000	$9,000,000	$9,000,000	$9,000,000
Tax on Equity Return - before grossup		$3,915,450	$3,487,393	$2,873,510	$2,457,842	$2,161,103
ITC		$0	$0	$0	$0	$0
PTC		($2,358,893)	($2,382,010)	($2,405,354)	($2,428,926)	($2,452,730)
Tax Grossup - Equity		$2,561,721	$2,281,661	$1,880,022	$1,608,067	$1,413,923
Tax Grossup - ITC		$0	$0	$0	$0	$0
Tax Grossup - PTC		($1,543,329)	($1,558,453)	($1,573,726)	($1,589,149)	($1,604,722)
Total Revenue Requirement		**$29,628,950**	**$27,264,999**	**$23,868,230**	**$21,574,654**	**$19,943,311**

5.2 Simple Annualization for 20-Year Study

WECC has also requested that E3 provide a purely algebraic, non-cash flow methodology to calculate levelized costs that can be integrated simply into the 20-year LTPT models directly. This is a challenging exercise, as the effects of variances in tax benefits from year to year cannot be precisely captured without considering annual cash flow streams. However, NETL provides a calculation that reasonably approximates E3's detailed cash flows through the use of a Capital Recovery Factor (CRF) (Short, 1995). E3 has provided WECC with a simplified levelized cost calculator based on this approach to be incorporated directly in the LTPT. However, wherever possible, E3 recommends the use of its more details cash flow financing models to calculate levelized costs.

5.3 Financing and Tax Assumptions

5.3.1 RESOURCE FINANCING LIFETIMES

The recommended financing lifetimes for the various resources characterized in this study are summarized in Table 34. One important note is that the financing lifetime should not be interpreted as an expectation of the total operating lifetime of the plant. Rather, it is an assumption of the period over which the costs of the plant would be recovered passed on to ratepayers.

Most new generation resources are assumed to be developed by IPPs under long-term contract to utilities. The length of such contractual arrangements can vary from 10 to 25 years. E3 recommends assuming a uniform, 20-year PPA between the IPP and the utility through which the full capital costs are recovered.

There are several resource types that are unlikely to be developed by IPPs: any new coal, large hydro, or nuclear resources would likely be developed as utility-owned assets. For these resources, the financing lifetime is represents typical depreciable lifetimes through which the resource's capital costs would be recovered in rate base. While these assumed lifetimes can vary substantially by utility, E3 recommends assuming IOU financing over a 40-year lifetime for these resource types.

Table 34. Default assumptions for financing entities and lifetimes for each generation technology.

Technology	Default Financing Entity	Assumed Financing Lifetime
Biogas	IPP	20
Biomass	IPP	20
Coal – PC	IOU	40
Coal – IGCC	IOU	40
CHP	IPP	20
Gas – CCGT	IPP	20
Gas – CT	IPP	20
Geothermal	IPP	20
Hydro – Large	IOU	40
Hydro – Small	IPP	20
Nuclear	IOU	40
Solar Thermal	IPP	20
Solar PV	IPP	20
Wind	IPP	20

5.3.2 FEDERAL TAX POLICIES

The federal tax code currently provides three major incentives for new generation:

+ **Accelerated Depreciation:** Eligible renewable technologies are permitted to claim tax benefits associated with depreciation of capital on an accelerated basis through the Modified Accelerated Cost Recovery System (MACRS). Concentrating these tax benefits during the early years of a project's financing life reduces its levelized costs. The appropriate MACRS schedule by which these benefits accrue varies by technology. This benefit has no sunset date and hence is assumed to continue indefinitely.

+ **Production Tax Credit (PTC):** Eligible renewable technologies can claim a tax credit based on the amount of generation produced during the first ten years of the project's life. The credit varies by technology and is currently schedule to expire at the end of 2012 for wind and 2013 for other applicable technologies (projects online before these sunsets can claim the PTC for the full ten-year horizon).
+ **Investment Tax Credit (ITC):** Eligible technologies can claim a tax credit equal to 30% of applicable capital costs. This credit is currently scheduled to expire at the end of 2016, at which point it would revert to a credit of 10% that is part of the tax code and has no sunset date.

The eligibility of each technology for these tax credits/benefits according to the current tax code is summarized in Table 35.

Table 35. Current federal tax policies applicable to generation technologies.

Technology	Production Tax Credit[a] [$/MWh]	Investment Tax Credit [%]	MACRS [yrs]
Biogas	$11		10
Biomass	$22		10
Coal – PC			20
Coal – IGCC			20
CHP			10
Gas – CCGT			20
Gas – CT			20
Geothermal	$22		5
Hydro – Large	$11		20
Hydro – Small	$11		20
Nuclear			20
Solar Thermal		30%	5
Solar PV		30%	5
Wind	$22		5

[a] The production tax credit applies to all generation during the first ten years of a project's operation.

The sunset dates of these tax credits have important implications on the costs of developing new renewable resources. This impact is summarized in Figure 16, which shows the combined effects of the forecast reduction in resource capital costs with the expiration of applicable tax credits based on current sunset dates.

Figure 16. Impact of tax credit sunsets on levelized resource costs. PTC expires in 2012 (wind) and 2013 (other resources); ITC expires in 2016 (solar).

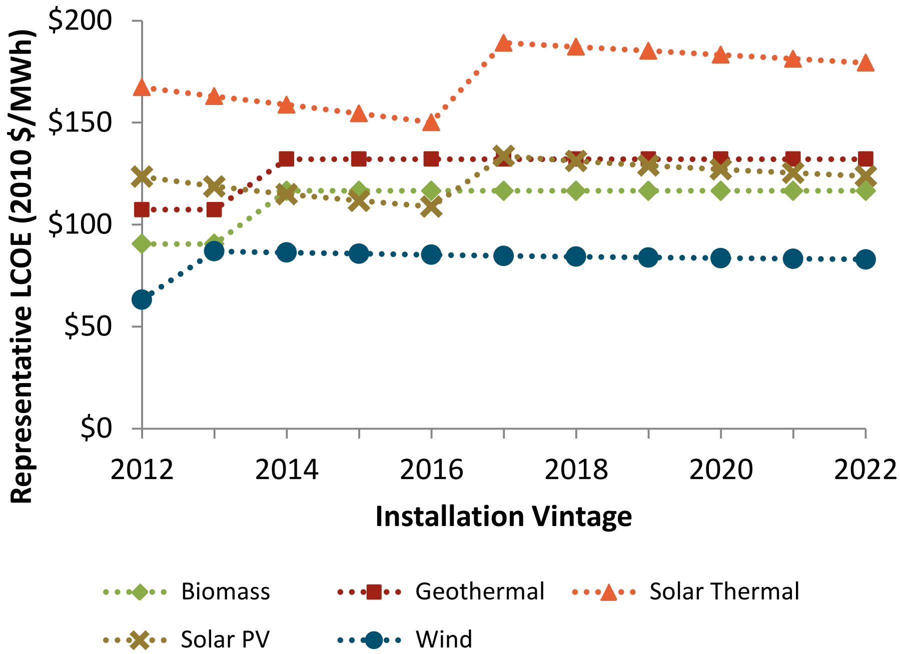


Figure 17. Recommended treatment of tax incentives for Reference Case 10-year study.

Recommendation:

+ Include the impact of the current PTC on levelized resource costs for applicable resources;
+ Include the impact of the ITC at a level of 30% on levelized resource costs for applicable resources; and
+ Assume MACRS schedules for generation resources as summarized in Table 35.

Figure 18. Recommended treatment of tax incentives for Reference Case 20-year study.

Recommendation:

- Exclude the impact of the PTC on levelized resource costs for applicable resources;
- Include the impact of the ITC at a level of 10% on levelized resource costs for applicable resources; and
- Assume MACRS schedules for generation resources as summarized in Table 35.

5.3.3 PROPERTY TAX AND INSURANCE

Property taxes and insurance are an additional important consideration in the cost of new generation; however, these expenses are not treated in a uniform manner among the sources surveyed. Many sources that estimate costs of renewable technologies include these costs in fixed O&M; in contrast, many estimates of fixed O&M for thermal plants exclude this expense. Since E3's recommendations are based on these sources, they reflect the differential treatment of property tax and insurance among generation technologies. Specifically, the fixed O&M costs for biogas, biomass, geothermal, solar thermal, solar PV, and wind are assumed to include property tax and insurance.

For all other technologies, E3's financing models calculate property tax endogenously. Both are calculated based on resource capital costs:

- **Annual property tax** is calculated as 1% of the remaining plant's value. For simplicity, the remaining value of the plant is calculated assuming straight-line asset depreciation over the economic life of the plant.

+ **Annual insurance** is calculated as 0.5% of the initial capital cost and escalates at 2.5% per year.

5.4 Capital Cost Vintages

Since neither of WECC's study plans evaluates the detailed year-by-year investment cycles that will occur between the present day and the snapshot years studied, E3 recommends applying a single vintage of capital costs for all projects of a specific type in each of the study cycles.

E3 anticipates that a large share of the renewable development that occurs over the time horizon considered in the 10-year study will take place during the early half of the decade, expedited by the prospect that the ITC and PTC may not be renewed. Therefore, when considering investment decisions over the course of this time horizon, it is appropriate to use a cost corresponding to a vintage not far in the future; 2015 is a reasonable choice for this.

Figure 19. Recommended installation cost vintage for Reference Case 10-year study.

Recommendation:

+ In the 10-year study cycle, evaluate 2022 resource costs based on capital costs of a plant installed in 2015.

In the context of the 20-year study, there is considerably more uncertainty as to the timing of renewable resource additions; with such uncertainty, E3 recommends using a vintage corresponding to the midpoint of the second decade of analysis (2027). This vintage would be used for projects developed between 2022 and 2032; for projects with online dates in 2022 or before, E3 recommends continuing to use the 2015 capital costs.

Figure 20. Recommended installation cost vintage for Reference Case 20-year study.

Recommendation:

+ In the 20-year study cycle, evaluate 2032 resource costs based on capital costs of a plant installed in 2027.

6 Summary of Recommendations

This section summarizes the recommended capital costs for application in WECC's 10- and 20-year studies.

6.1 10-Year Study

Table 36. Recommended capital cost inputs to the 10-year study.

Technology	Subtypes	Present-Day Capital Cost [$/kW]	Recommended Cost for 10-Year Study[a] [$/kW]
Biogas	Landfill	$2,750	$2,750
	Other	$5,500	$5,500
Biomass		$4,250	$4,250
Coal	PC	$3,600	$3,600
	IGCC w/ CCS	$8,000	$8,000
CHP	Small (<5 MW)	$3,700	$3,700
	Large (>5MW)	$1,600	$1,600
Gas CCGT	Basic, Wet Cooled	$1,100	$1,100
	Advanced, Wet Cooled	$1,200	$1,200
	Basic, Dry Cooled	$1,175	$1,175
	Advanced, Dry Cooled	$1,275	$1,275
Gas CT	Aeroderivative	$1,150	$1,150
	Frame	$800	$800
Geothermal		$5,800	$5,800

Technology	Subtypes	Present-Day Capital Cost [$/kW]	Recommended Cost for 10-Year Study[a] [$/kW]
Hydro	Large	$3,000	$3,000
	Small	$3,300	$3,300
	Upgrade	$1,500	$1,500
Nuclear		$7,500	$7,500
Solar PV	Residential Rooftop	$6,250	$5,480
	Commercial Rooftop	$5,250	$4,600
	Distributed Utility (Fixed Tilt)	$3,325	$2,910
	Distributed Utility (Tracking)	$3,800	$3,330
	Large Utility (Fixed Tilt)	$2,850	$2,500
	Large Utility (Tracking)	$3,300	$2,890
Solar Thermal	No Storage	$4,900	$4,460
	Six Hour Storage	$7,100	$6,461
Wind	Onshore	$2,000	$1,950
	Offshore	$6,000	$5,850

[a] Recommended capital costs for the 10-Year Study correspond to plants installed in 2015.

6.2 20-Year Study

Table 37. Recommended capital cost inputs to the 20-year study.

Technology	Subtypes	Present-Day Capital Cost [$/kW]	Recommended Cost for 20-Year Study[a] [$/kW]
Biogas	Landfill	$2,750	$2,750
	Other	$5,500	$5,500
Biomass		$4,250	$4,250
Coal	PC	$3,600	$3,600
	IGCC w/ CCS	$8,000	$8,000
CHP	Small (<5 MW)	$3,700	$3,700
	Large (>5MW)	$1,600	$1,600
Gas CCGT	Basic, Wet Cooled	$1,100	$1,100
	Advanced, Wet Cooled	$1,200	$1,200

Technology	Subtypes	Present-Day Capital Cost [$/kW]	Recommended Cost for 20-Year Study[a] [$/kW]
	Basic, Dry Cooled	$1,175	$1,175
	Advanced, Dry Cooled	$1,275	$1,275
Gas CT	Aeroderivative	$1,150	$1,150
	Frame	$800	$800
Geothermal		$5,800	$5,800
Hydro	Large	$3,000	$3,000
	Small	$3,300	$3,300
	Upgrade	$1,500	$1,500
Nuclear		$7,500	$7,500
Solar PV	Residential Rooftop	$6,250	$4,340
	Commercial Rooftop	$5,250	$3,650
	Distributed Utility (Fixed Tilt)	$3,325	$2,310
	Distributed Utility (Tracking)	$3,800	$2,640
	Large Utility (Fixed Tilt)	$2,850	$1,980
	Large Utility (Tracking)	$3,300	$2,290
Solar Thermal	No Storage	$4,900	$3,675
	Six Hour Storage	$7,100	$5,325
Wind	Onshore	$2,000	$1,830
	Offshore	$6,000	$5,490

[a] Recommended capital costs for the 10-Year Study correspond to plants installed in 2027.

7 Regional Multipliers

The capital cost recommendations that E3 has provided represent the average cost of building new generation in the United States; however, due to regional differences in the cost of labor and materials, plant construction costs will vary from state to state. To account for the regional differences in expected plant costs, E3 has developed state-specific multipliers for each technology based on the cost indices in the US Army Corps Civil Works Construction Cost Indexing System (CWCCIS) (USACE, 2011). A summary of the indices for the WECC states and provinces is shown in column 2 of the table below. Based on information obtained from the ACE Cost Analysis Department, the input costs for this index are about 37% labor, 37% materials, and 26% equipment. For this analysis, E3 estimated that 100% of labor costs were variable by region, 50% of materials costs were variable by region, and equipment costs were constant across all regions. Using the proportion of the Army Corp of Engineers costs that came from each expense category, E3 backed out a multiplier for each area that would apply only to the variable portion (i.e. labor costs and 50% of material costs) of any project, shown as the Variable Cost Index below.

Table 38. USACE Civil Works Construction Cost Indices and the regional differences in regionally-variable costs.

State/Province	CWCCIS Cost Index	Variable Cost Index
Alberta	1.00	1.00
Arizona	0.96	0.93
British Columbia	1.00	1.00
California	1.18	1.32
Colorado	0.99	0.98
Idaho	0.95	0.91
Montana	0.97	0.95
New Mexico	0.95	0.91
Nevada	1.08	1.14
Oregon	1.07	1.13
Texas	0.87	0.77
Utah	0.95	0.91
Washington	1.07	1.13
Wyoming	0.90	0.82

To determine a technology-specific regional adjustment for each technology, E3 has developed assumptions on the relative contribution of labor, equipment, and materials to each type of new generation. These assumptions are shown in

Table 39. Contribution of labor, materials, and equipment to the capital costs of each type of new generation.

Technology	Labor	Materials	Equipment
Biogas	25%	15%	60%
Biomass	45%	15%	40%
CHP	20%	8%	73%
Coal – PC	33%	5%	63%
Coal – IGCC	28%	5%	68%
Gas CCGT	20%	8%	73%
Gas CT	50%	15%	35%
Geothermal	15%	35%	50%
Hydro – Large	40%	30%	30%
Hydro – Small	50%	30%	20%
Nuclear	40%	40%	20%
Solar PV	15%	15%	70%
Solar Thermal	20%	40%	40%
Wind	10%	20%	70%

Maintaining the assumptions that 100% of labor costs, 50% of materials costs, and 0% of equipment costs are variable by region, the information in Table 39 and Table 40 are combined to derive technology-specific state cost adjustment factors. These adjustment factors are shown in Table 40.

It should be noted that while these adjustment factors capture directional differences in the cost of plant development across the WECC, they are approximations, and actual plant construction costs may vary substantially from the results obtained using these factors. Besides variances in capital related to regional costs of labor and materials, the costs of building and operating new generation will be affected by such site-specific factors as property taxes, state and local sales taxes. Accordingly, while these factors are useful for WECC modeling, it should be understood that they are not a replacement for site-specific evaluations of project capital and O&M costs.

Table 40. Technology-specific regional cost multipliers (technology-specific multipliers apply to capital costs; fixed O&M multiplier applies to fixed O&M for all technologies).

State/Province	Alberta	Arizona	British Columbia	California	Colorado	Idaho	Montana	Nevada	New Mexico	Oregon	Texas	Utah	Washington	Wyoming
Biogas	1.000	0.977	1.000	1.105	0.994	0.971	0.982	1.047	0.971	1.041	0.924	0.971	1.041	0.941
Biomass	1.000	0.962	1.000	1.170	0.991	0.953	0.972	1.076	0.953	1.066	0.877	0.953	1.066	0.905
CHP	1.000	0.983	1.000	1.077	0.996	0.979	0.987	10.34	0.979	1.030	0.944	0.979	1.030	0.957
Coal – PC	1.000	0.975	1.000	1.114	0.994	0.968	0.981	1.050	0.968	1.044	0.918	0.968	1.044	0.937
Coal – IGCC	1.000	0.978	1.000	1.097	0.973	0.984	0.973	1.038	1.043	0.930	0.973	1.038	0.946	0.700
Gas CCGT	1.000	0.983	1.000	1.077	0.996	0.979	0.987	10.34	0.979	1.030	0.944	0.979	1.030	0.957
Gas CT	1.000	0.959	1.000	1.186	0.990	0.948	0.969	1.083	0.948	1.073	0.865	0.948	1.073	0.896
Geothermal	1.000	0.977	1.000	1.105	0.994	0.971	0.982	1.047	0.971	1.041	0.924	0.971	1.041	0.941
Hydro – Large	1.000	0.960	1.000	1.178	0.990	0.950	0.970	1.079	0.950	1.069	0.871	0.850	1.069	0.901
Hydro – Small	1.000	0.953	1.000	1.211	0.988	0.941	0.965	1.094	0.941	1.082	0.848	0.941	1.082	0.883
Nuclear	1.000	0.957	1.000	1.195	0.989	0.946	0.968	1.086	0.946	1.076	0.859	0.946	1.076	0.892
Solar PV	1.000	0.984	1.000	1.073	0.996	0.980	0.988	1.032	0.980	1.028	0.947	0.980	1.028	0.959
Solar Thermal	1.000	0.971	1.000	1.130	0.993	0.964	0.978	1.058	0.964	1.050	0.906	0.964	1.050	0.928
Wind	1.000	0.986	1.000	1.065	0.996	0.982	0.989	1.029	0.982	1.025	0.953	0.982	1.025	0.964
Fixed O&M	1.000	0.971	1.000	1.130	0.993	0.964	0.978	1.058	0.964	1.050	0.906	0.964	1.050	0.928

8 Sources

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8.2 Survey Sources & Cost Adjustments

This section presents a summary of the studies that provided technology cost estimates that were included in E3's review, as well as the cost adjustments made to each study to allow for side-by-side comparison of the studies. Table 41 provides a comprehensive listing of the studies under the same abbreviated study names that are used in the capital cost tables. Each study's reported results were converted to 2010 dollars from the cost basis year reported in the table below using the inflation adjustments in Table 43. For sources that provided only overnight capital costs, E3 multiplied these estimates by assumed interest-during-construction (IDC) adjustments calculated based on the assumed WACC and construction schedules, most of which were based on the CEC's Cost of Generation model.[2] These assumed capital cost adjustments are shown in Table 42.

[2] E3's IDC adjustments correspond closely to the CEC's allowance for funds used during construction (AFUDC) multipliers with one exception: for coal technologies, the CEC's construction schedule is a single year; E3 has used

Table 41. Studies included in the survey of generation capital costs & applicability of inflation/IDC adjustments to each.

Study	Author	Cost Basis Year	Cost Basis
APS IRP	Arizona Public Service Company	2011	Overnight
AZ Solar Data	Arizona Goes Solar	Nominal	All-In
Avista IRP	Avista	2011	All-In
B&V/NREL	Black & Veatch	2009	Overnight
Brattle/CH2M Hill	Spees, K., et al	2015	All-In
CEC COG	Klein, J.	2009	All-In
CPUC	California Public Utilities Commission	2010	All-In
CSI Data	California Solar Statistics	Nominal	All-In
DOE Sunshot	Department of Energy	2010	All-In
EIA/RW Beck	Energy Information Administration	2010	Overnight
ICF	Hedman, B., et al.	2011	All-In
IPC IRP	Idaho Power Company	2011	All-In
IRENA	International Renewable Energy Agency	2010	All-In
Lazard	Lazard	2010	All-In
LBNL (PV)	Barbose, G., et al.	2010	All-In
LBNL (WTMR)	Wiser R., et al.	2011	All-In
RETI 2B	Black & Veatch	2010	All-In

longer time horizons (five and six years for PC and IGCC w/ CCS, respectively) to calculate appropriate adjustments.

Study	Author	Cost Basis Year	Cost Basis
NETL	National Energy Technology Laboratory	2007	Overnight
NREL	Goodrich, A., et al.	2010	All-In
NVE IRP	Nevada Energy	2012	Overnight
NWPCC	Northwest Power and Conservation Council	2006	Overnight
PacifiCorp IRP	PacifiCorp	2010	All-In
PGE IRP	Portland General Electric	2011	Overnight
Sandia	Kolb, G., et al.	2010	All-In
Xcel IRP	Xcel Energy	2011	All-In

Table 42. Assumed IDC adjustments used to translate cost estimates from sources that provided overnight capital costs to all-in costs.

Technology	Subtype	IDC Adjustment
Biogas		105.9%
Biomass		105.9%
Coal	PC	121.0%
	IGCC w/ CCS	125.8%
Combined Heat & Power		103.5%
Gas CCGT		106.8%
Gas CT		103.5%
Geothermal		111.4%
Hydro	Large	108.0%
	Small	104.1%
	Upgrade	104.1%
Nuclear		151.5%
Solar PV	Residential Rooftop	100.0%

Technology	Subtype	IDC Adjustment
	Commercial Rooftop	100.0%
	Distributed Utility (Fixed Tilt)	104.6%
	Distributed Utility (Tracking)	104.6%
	Large Utility (Fixed Tilt)	104.6%
	Large Utility (Tracking)	104.6%
Solar Thermal	No Storage	104.6%
	Six Hour Storage	104.6%
Wind		104.9%

Table 43. Consumer Price Index (CPI) factors used to translate capital cost estimates to 2010 dollars.

Year	CPI
2005	195.3
2006	201.6
2007	207.3
2008	215.3
2009	214.5
2010	218.1
2011	224.9
2012	232.4

9 Stakeholder Comments

E3 presented its initial cost recommendations to the Technical Analysis Subcommittee (TAS) and the Scenario Planning Steering Group (SPSG). WECC received a wide range of comments from stakeholders on these initial values. E3 and WECC value the input of all stakeholders, and the comments provided have helped E3 to refine its recommendations for inputs to the WECC process. These comments are detailed in Table 44, along with E3's responses. A number of the comments focused on two points in particular: (1) E3's methodology to forecast cost reductions over time; and (2) the set of resources included in the technologies characterized by E3. E3 offers more general responses on each of these subjects below.

E3 General Comments on Learning Curves: E3 has reviewed stakeholder comments on the application of learning curves to forecast cost declines of generation technologies. The comments on learning curves, as well as those that address the question of how generation costs may change in the future on a more general level, suggest that several revisions to E3's use of learning curves are appropriate:

1. In cases where a long historical record suggests a consensus learning rate for a particular technology, it is difficult to justify a departure from this learning rate. Therefore, E3 agrees that it is appropriate to utilize historically observed learning rates for technologies for which literature has established a strong record.

2. In some situations, the use of learning curves can be overly constraining and can hinder the ability to capture potential future cost declines. This is particularly true for nascent technologies with a very small installed global capacity whose commercialization is just beginning; in these cases, the lack of a supporting historical record makes the choice of a learning rate—a parameter to which future cost declines are enormously sensitive—a very challenging exercise. Moreover, without an empirically observed learning curve, it is not possible to determine whether today's costs—a short-term market observation—fall above, below, or on any prospective long-term learning curve. In this case, E3 has adopted a more direct approach to forecasting cost reductions, relying on a survey of projected point estimates of future costs to determine an appropriate assumption for the potential cost reductions.

E3 General Comments on Competing Technologies: A number of the comments received by E3 suggested adding additional technology options to the set of resources characterized in this study. Generally, these recommended additions have cost and performance characteristics comparable to resources already included in the scope of E3's study. In such cases, WECC's LTPT model does not have sufficient granularity or detail to draw a meaningful distinction between resources that are effectively substitutes for one another; in the interest of preserving simplicity, it is therefore WECC's preference (and E3's recommendation) not to add these direct substitutes to the set of resources considered. E3 does note, however, that in these cases, the cost assumptions that are provided for one of such a pair of resources may be used by WECC as a proxy for other resource that is not included in the data set.

Table 44. Stakeholder comments received by E3 and E3 responses.

Commenter	Comment	E3 Response
Bill Pascoe (TWE)	It is appropriate to use conservative estimates of learning curve effects for Solar PV in light of the recent significant reduction in Solar PV costs.	E3 has provided its best estimates of unbiased trajectories for the future costs of generation technologies.

Commenter	Comment	E3 Response
Bill Pascoe (TWE)	Significant reduction in Solar PV costs may be caused in part by current market conditions. It will be important to run appropriate sensitivity cases with higher PV costs.	E3 agrees that it will be important to consider a range of PV costs in sensitivity studies.
Bill Pascoe (TWE)	E3's recommendations for Solar PV appear to be aggressive when compared to the RMI data. It will be important to run appropriate sensitivity cases with higher PV costs.	E3 agrees that it will be important to consider a range of PV costs in sensitivity studies.
Bryce Freeman	E3's recommended capital cost for IGCC with CCS seems arbitrarily high ($8,000 for the 2012 update) - it is higher than the capital cost listed by any source on this slide. A simple average of the 9 estimates listed on this page would result a cost of $5,178/kW. I believe a more reasonable estimate of the capital cost associated with IGCC w/CCS is in the range of $5,000/kW.	E3's choice of a high cost for IGCC with CCS is motivated by the fact that this technology has not been demonstrated as commercially viable at this point. Engineering cost estimates of the first of such types of projects tend to be affected by "technological optimism" and understate capital costs. Because little commercial development of this technology is expected, E3's projection of future costs for this technology, which remains high, reflects the expectation that this technology will still be in a nascent phase of development between 2020 and 2030.

Commenter	Comment	E3 Response
Bryce Freeman	It is well documented that both experience and production scale can dramatically increase efficiencies which in turn lowers cost. E3 has applied these concepts to the capital and production costs estimates for both wind and solar generation resources. I question why this same learning curve theory would not also be applicable to other evolving generation technologies, in particular nuclear and coal, both steam and IGCC with CCS. As these technologies advance there will no doubt be opportunities to refine them, make them more efficient and less costly. In fact, because they are so nascent at this point, one could argue that a much steeper learning curve should apply to them than would apply to current wind and solar technologies. I recommend a learning curve be applied to new coal and nuclear technologies that is at least equal to the 10% learning curve applied to solar thermal as shown on slide 72.	E3 has decided not to apply learning curves to IGCC and nuclear technologies. In the case of IGCC, E3's choice not to apply learning curves reflects two factors: (1) the expectation that IGCC w/ CCS will experience very little commercial development over the next decade, and (2) the lack of historical data supporting a learning curve. In the case of nuclear (and all other conventional generation options for which E3 has not forecast cost reductions), E3 has made the simplifying assumption that the learning rate is small enough, and that global installed capacity is growing slowly enough, that changes in capital costs due to learning should be negligible.
Fred Heutte/NWEC	We support the use of the experience curve (learning curve) approach as detailed in the accompanying paper, "Experience Curves and Solar PV."	E3 has modified its approach to the application of learning curves to solar PV to a segmented approach: for modules and related costs, E3 will use the historically observed learning rate of 20% per doubling of capacity; for BOS components, E3 will use a lower rate of 10%, reflecting the consensus expectation that BOS costs will not naturally decline at the same pace as modules. Each of these components is assumed to currently represent approximately 50% of the installed costs of current systems. See E3 General Comments on Learning Curves for more detail on the motivation behind this revision.

Commenter	Comment	E3 Response
Fred Heutte/NWEC	"The choice of a forecast of future installations has a significant impact on anticipated future cost declines; The impact of an additional MW of capacity declines as the cumulative installed capacity increases"; these observations all fit well with an experience curve perspective	E3 agrees that it is important to consider the forecast of global installed capacity in conjunction with the assumed learning rate. In its original recommendation, E3 used a forecast of capacity based on the average of the two scenarios presented in the European Photovoltaic Industry Association's (EPIA) near term outlook. Since this time, the International Energy Agency's (IEA) recently released Medium-Term Renewable Energy Market Report 2012. E3 believes that this forecast, which is comparable to the lower of the EPIA's two forecasts, presents a more unbiased view of the growth of solar PV over the near-term, and is therefore recommending the utilization of this slightly lower forecast in conjunction with the new learning rates as discussed above.
Fred Heutte/NWEC	While "Recent cost reductions have not followed the longer-term trends of historical learning" for solar PV, it is clear that the mid-2000s deviation was temporary due to the pronounced and later receding impact of the feed in tariff policies of Germany and Spain, and cost has reverted closer to the historical experience curve.	See E3 General Comments on Learning Curves.
Fred Heutte/NWEC	Analysis suggests continuing to use separate experience curve learning rates of 20% and 17% for solar PV module costs and balance-of-system, respectively, as well as separate cost basis for utility-scale and end-use solar PV applications.	See E3 General Comments on Learning Curves.

Commenter	Comment	E3 Response
Fred Heutte/NWEC	"Past trends do not guarantee future declines, and other factors influence technology costs." This is true within limits; aside from short-term deviations in costs relative to trend, however, experience curves tend to represent cost declines well over time, but significant outside factors including market conditions and policy interventions can expand or decrease the cumulative doubling time.	See E3 General Comments on Learning Curves.
Fred Heutte/NWEC	"E3 recommends a learning rate of 10% for solar PV, which is applied to the entire capital cost (not just modules); No guarantee that historical rates (17%) will continue." There is no support in the literature for a change of this magnitude. Solar PV experience curves are based on over 30 years of data so there should be confidence in the relationship between cumulative production and cost. The major question is how much additional cumulative production will accrue over 10 or 20 years, given different assumptions about market and policy factors. Where point estimates are necessary, as for the 10-year RTEP Common Case plan, reasonable market size can be assessed based on trends, including consideration of factors such as grid parity, and moderate policy. For the 20-year RTEP scenario-based plan, each scenario can have a characteristic solar PV market saturation based on factors specific to the scenario, which will give a useful test of market and policy sensitivity under the different scenarios. Recommendation: retain the consensus solar PV experience learning rates of 20% for modules and 17% for balance-of-system, applied separately to utility-scale and end-use PV applications.	See E3 General Comments on Learning Curves.

Commenter	Comment	E3 Response
Fred Heutte/NWEC	In general, concentrating solar and other resources should retain the existing consensus experience curve learning rates.	See E3 General Comments on Learning Curves.
Fred Heutte/NWEC	In general, wind and other resources should retain the existing consensus experience curve learning rates.	See E3 General Comments on Learning Curves.
IREC, by Larry Chaset and Giancarlo Estrada	Stated capital costs for residential solar PV installations are too conservative and do not reflect the latest, best data -- See the attached Comments of IREC [comment also made with reference to slide 99]	E3 has gathered cost data on residential PV installed in 2012 in Arizona (APS) and California (CSI) that were not available at the time of the original survey. These data support a lower cost for residential PV; E3 is recommending a reduction in residential PV cost from $6,000/kW-dc to $5,300/kW-dc. **Additional Note:** For further data on recent actual installed costs of residential PV systems in California and Arizona, see Figure 21 and Figure 22.
IREC, by Larry Chaset and Giancarlo Estrada	Stated capital costs for non-residential (i.e., distributed commercial) solar PV installations are too conservative and do not reflect the latest, best data -- See the attached Comments of IREC [comment also made with reference to slide 99]	E3 has gathered cost data on commercial PV installed in 2012 in Arizona (APS) and California (CSI) that were not available at the time of the original survey. These data support a lower cost for commercial PV; E3 is recommending a reduction in residential PV cost from $5,000/kW-dc to $4,500/kW-dc. **Additional Note:** For further data on recent actual installed costs of commercial PV systems in California and Arizona, see Figure 21 and Figure 22.

Commenter	Comment	E3 Response
IREC, by Larry Chaset and Giancarlo Estrada	Stated capital costs for utility-scale solar PV installations are too conservative and do not reflect the latest, best data -- See the attached Comments of IREC	E3 has reviewed the sources that constitute the basis for this recommendation of reduced utility-scale cost, and note that the cost estimates provided correspond to systems installed in the future (APS: 2015; TEP: 2014) and therefore incorporate some expectation of learning. Additionally, E3's survey approach considers all the sources which provide cost estimates for single technologies and does not rely on any one or two sources to determine appropriate cost recommendations.
Jim Baak	Capital costs for Solar Thermal, No Storage are too high. Use $4,600 instead of $4,900. Include a cost for CSP Tower, No Storage - $5,100, and CSP Tower, 6 hrs storage - $7,500. (See spreadsheet for sources)	E3 values the additional sources provided, which help to provide a more complete picture of the costs of solar thermal. However, taken in the context of all the information on solar thermal costs that E3 has gathered, this new information does not imply that a revision to present day solar thermal costs is appropriate.
Jim Baak	The cost reductions for CSP are too conservative. For 2022, use 45% and for 2032 use 65%. (See spreadsheet for sources)	E3 has reviewed the sources on solar thermal potential cost reductions provided and does not agree that such aggressive cost reduction potential should be assumed in a Reference Case. Testing such a dramatic breakthrough in solar thermal may be a useful sensitivity.

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Jim Baak	We have provided multiple, credible reports, studies and presentations that describe in detail how and why trough and tower costs and performance will diverge over time (in no small part due to the higher operating temperatures and potential for greatly improved efficiencies for towers). We recommend adding separate fields for trough and tower, using the data provided in the separate spreadsheet.	E3 does not disagree with the supposition that trough and tower technologies will diverge in both cost and performance. However, for the purpose of WECC's modeling, the two are competing technologies for which E3 is not recommending to include individual characterizations (see E3 General Comments on Competing Technologies). Therefore, E3 continues to recommend a single generic solar thermal technology whose changing costs over time will reflect the expected shift in the future towards tower technologies. E3 has also determined that the application of learning curves to solar thermal, with its limited global installed base (2 GW), is challenging and may not be appropriate (see E3 General Comments on Learning Curves). E3 has instead used the information provided along with other sources to directly project solar thermal costs in 2022 and 2032. E3 values the sources provided, which show future point estimates for solar thermal in the future that E3 uses to derive future cost assumptions.
Jim Baak	The B&V data is not supported by any other source we consulted - recommend using data from CSP_Data.xls spreadsheet.	E3 values these sources, which have been used to assess potential future cost reductions for solar thermal (see E3 General Comments on Learning Curves).
Jim Baak	Recommend adding CSP Tower w/ & w/o storage and adjusting all data per CSP_Data spreadsheet.	See E3 General Comments on Competing Technologies.
Keith White - Calif PUC	Regarding assumed expiration of PTC & ITC, and impact on assumed in-service date: show how E3 folded PTC expiration into assumed "cost".	E3 has addressed this comment in its final report.

Commenter	Comment	E3 Response
Keith White - Calif PUC	It would be helpful to show how the future PV cost is calculated based on explicit numbers for (1) current cost, (2) assumed MW deployment by 2015, 2017, 2022, 2027, and 2032, and (3) resulting projected cost based on 10% learning rate. Also -- similar for wind (with 5% learning rate).	E3 has addressed this comment in its final report.
Keith White - Calif PUC	Considering slides 17, 62, 63,68,69,128 - - - High priority (and high visibility) "optimistic" PV case(s) should be run assuming a learning rate of at least 15% (per doubling) and very close to the "EPIA Policy Driven" (Slide 68) level of deployment.	E3 agrees that it will be important to consider a range of PV costs in sensitivity studies.
Keith White - Calif PUC	Generally, it will be important to attach reasonable uncertainty ranges to major infrastructure investment costs. Useful long-term planning studies will need to find some way to communicate risks and opportunities (option values), not just mid-point estimates.	E3 agrees that there is substantial uncertainty in its assumptions of new infrastructure costs--more so in the long-term projections. However, the methodology for incorporating resource capital costs into the WECC studies requires point estimates of current and future costs. The uncertainty (or range) in potential future costs should be thoroughly evaluated by WECC through sensitivity analysis.
PacifiCorp	Cost of aeroderivative gas turbines appears to be high. The cost is closer to $1,050/kW per the recent PacifiCorp Integrated Resource Plan (2011).	E3 has reviewed the sources it gathered with costs for aeroderivative CTs, and has reduced its recommended CT cost to $1,150/kW.

Commenter	Comment	E3 Response
PacifiCorp	Financing life estimates are too short. Coal should be 40 years, gas turbines should be 30 years, gas turbine combined cycle should be 35 years, nuclear should be 40 years, large hydro facilities should be at least 30 years. Supporting documentation can be found in recent depreciation studies conducted by state agencies as well as industry practice.	In general, E3 recommends assuming that new generation projects are financed by an IPP and are contracted to utilities either through a PPA or a tolling agreement. It is rare that the terms of such contractual agreements should exceed 20 years, so E3 has recommended a default assumption that new generation is financed through this type of arrangement (this applies to new gas and renewable projects); the 20-year lifetime thus reflects the costs that would be passed on to ratepayers under the PPA agreement executed between utility and IPP. There are several notable exceptions to this, though: coal, nuclear, and large hydro projects are more likely to be developed under utility ownership such that costs would be recovered in rate base. In these circumstances, the financing lifetime recommended by E3 is intended to reflect representative depreciable lifetimes for these types of assets. After further review of utility IRP financing assumptions, E3 agrees that a depreciable lifetime of 40 years is more consistent with general utility practice for nuclear, coal and large hydro resources.
PacifiCorp	With the recent EPA CO2 regulations the steam coal option should include carbon capture and sequestration (CCS).	The PC w/ CCS generation option is a comparable substitute for IGCC w/ CCS; see E3 General Comments on Competing Technologies.

Commenter	Comment	E3 Response
Ravi Aggarwal (BPA)	This is the first slide where the omission of reciprocating or internal combustions generators is evident. There have been significant improvements in 'recip' cost and performance and they compare favorably with aeroderivative simple cycle combustion turbines (see attached details). This technology should be included in the scope of the generation capital cost analysis and resulting model data. Affected slides include G-11, 26, 27, 38, 47 (perhaps), 91, 94, 97, add slides after 110 for this technology, add slide after 136 for this technology, add reference on slide 153.	Reciprocating engines are a comparable substitute for aeroderivative CTs in WECC's model; see E3 General Comment on Competing Technologies.

Figure 21. Trends in residential & non-residential installed PV costs in California (data from CSI, 2012). Data for 2012 includes systems installed through September.

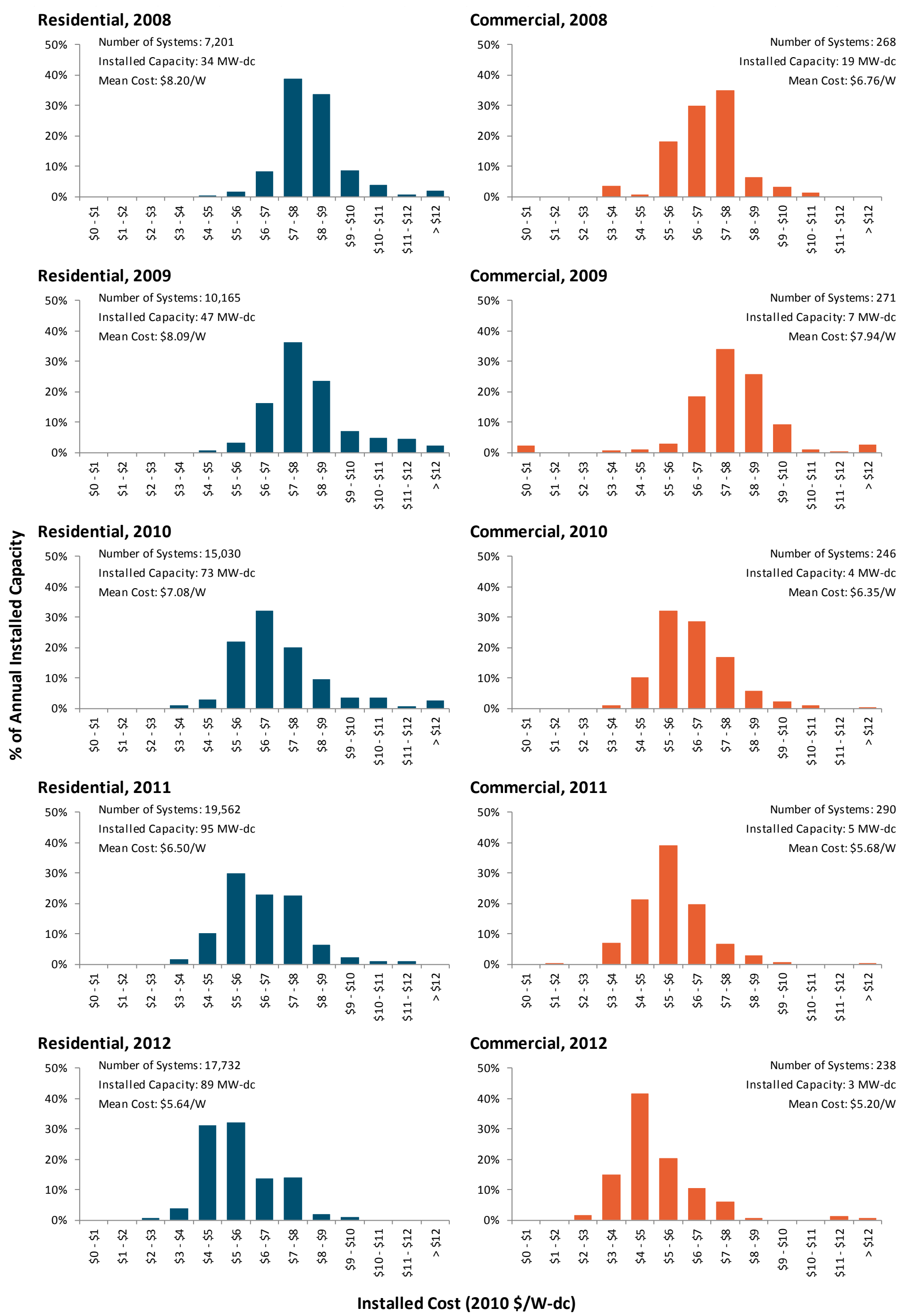

Figure 22. Trends in residential & non-residential installed PV costs in Arizona (data from Arizona Goes Solar, 2012). Data for 2012 includes systems installed through September.