COST REPORT

COST AND PERFORMANCE DATA FOR POWER GENERATION TECHNOLOGIES

Prepared for the
National Renewable Energy Laboratory

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1 Introduction

Black & Veatch contracted with the National Renewable Energy Laboratory (NREL) in 2009 to provide the power generating technology cost and performance estimates that are described in this report. These data were synthesized from various sources in late 2009 and early 2010 and therefore reflect the environment and thinking at that time or somewhat earlier, and not of the present day.

Many factors drive the cost and price of a given technology. Mature technologies generally have a smaller band of uncertainty around their costs because demand/supply is more stable and technology variations are fewer. For mature plants, the primary uncertainty is associated with the owner-defined scope that is required to implement the technology and with the site-specific variable costs. These are site-specific items (such as labor rates, indoor versus outdoor plant, water supply, access roads, labor camps, permitting and licensing, or lay-down areas) and owner-specific items (such as sales taxes, financing costs, or legal costs). Mature power plant costs are generally expected to follow the overall general inflation rate over the long term.

Over the last ten years, there has been doubling in the nominal cost of all power generation technologies and an even steeper increase in coal and nuclear because the price of commodities such as iron, steel, concrete, copper, nickel, zinc, and aluminum have risen at a rate much greater than general inflation; construction costs peak in 2009 for all types of new power plants. Even the cost of engineers and constructors has increased faster than general inflation has. With the recent economic recession, there has been a decrease in commodity costs; some degree of leveling off is expected as the United States completes economic recovery.

It is not possible to reasonably forecast whether future commodity prices will increase, decrease, or remain the same. Although the costs in 2009 are much higher than earlier in the decade, for modeling purposes, the costs presented here do not anticipate dramatic increases or decreases in basic commodity prices through 2050. Cost trajectories were assumed to be based on technology maturity levels and expected performance improvements due to learning, normal evolutionary development, deployment incentives, etc.

Black & Veatch does not encourage universal use solely of learning curve effects, which give a cost reduction with each doubling in implementation dependent on an assumed deployment policy. Many factors influence rates of deployment and the resulting cost reduction, and in contrast to learning curves, a linear improvement was modeled to the extent possible.

1.1 ASSUMPTIONS

The cost estimates presented in this report are based on the following set of common of assumptions:

1. Unless otherwise noted in the text, costs are presented in 2009 dollars.
2. Unless otherwise noted in the text, the estimates were based on on-site construction in the Midwestern United States.
3. Plants were assumed to be constructed on “greenfield” sites. The sites were assumed to be reasonably level and clear, with no hazardous materials, no standing timber, no wetlands, and no endangered species.
4. Budgetary quotations were not requested for this activity. Values from the Black &Veatch proprietary database of estimate templates were used.
5. The concept screening level cost estimates were developed based on experience and estimating factors. The estimates reflect an overnight, turnkey Engineering Procurement Construction, direct-hire, open/merit shop, contracting philosophy.

6. Demolition of any existing structures was not included in the cost estimates.
7. Site selection was assumed to be such that foundations would require cast-in-place concrete piers at elevations to be determined during detailed design. All excavations were assumed to be “rippable” rock or soils (i.e., no blasting was assumed to be required). Piling was assumed under major equipment.
8. The estimates were based on using granular backfill materials from nearby borrow areas.
9. The design of the HVAC and cooling water systems and freeze protection systems reflected a site location in a relatively cold climate. With the exception of geothermal and solar, the plants were designed as indoor plants.
10. The sites were assumed to have sufficient area available to accommodate construction activities including but not limited to construction offices, warehouses, lay-down and staging areas, field fabrication areas, and concrete batch plant facilities, if required.
11. Procurements were assumed to not be constrained by any owner sourcing restrictions, i.e., global sourcing. Manufacturers’ standard products were assumed to be used to the greatest extent possible.
12. Gas plants were assumed to be single fuel only. Natural gas was assumed to be available at the plant fence at the required pressure and volume as a pipeline connection. Coal plants were fueled with a Midwestern bituminous coal.
13. Water was assumed to be available at the plant fence with a pipeline connection.
14. The estimates included an administration/control building.
15. The estimates were based on 2009 costs; therefore, escalation was not included.
16. Direct estimated costs included the purchase of major equipment, balance-of-plant (BOP) equipment and materials, erection labor, and all contractor services for “furnish and erect” subcontract items.
17. Spare parts for start-up and commissioning were included in the owner’s costs.
18. Construction person-hours were based on a 50-hour workweek using merit/open shop craftspersons.
19. The composite crew labor rate was for the Midwestern states. Rates included payroll and payroll taxes and benefits.
20. Project management, engineering, procurement, quality control, and related services were included in the engineering services.
21. Field construction management services included field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control. Also included was technical direction and management of start-up and testing, cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services.
22. Engineering, procurement, and construction (EPC) contractor contingency and profit allowances were included with the installation costs.
23. Construction management cost estimates were based on a percentage of craft labor person-hours. Construction utilities and start-up utilities such as water, power, and fuel were to be provided by the owner. On-site construction distribution infrastructures for these utilities were included in the estimate.
24. Owner’s costs were included as a separate line item.
25. Operational spare parts were included as an owner’s cost.
26. Project insurances, including “Builders All-Risk” insurance, were included in the estimates as an owner’s cost.
27. Construction permits were assumed to be owner’s costs.

28. The estimates included any property, sales or use taxes, gross receipt tax, import or export duties, excise or local taxes, license fees, value added tax, or other similar taxes in the owner's costs.
29. Costs to upgrade roads, bridges, railroads, and other infrastructure outside the site boundary, for equipment transportation to the facility site, were included in the owner's costs.
30. Costs of land, and all right-of-way access, were provided in the owner's Costs.
31. All permitting and licensing were included in the owner's costs.
32. All costs were based on scope ending at the step-up transformer. The electric switchyard, transmission tap-line, and interconnection were excluded.
33. Similarly, the interest during construction (IDC) was excluded.
34. Other owner's costs were included.

In some cases, a blended average technology configuration was used as the proxy for a range of possible technologies in a given category. For example, a number of concentrating solar power technologies may be commercialized over the next 40 years. Black & Veatch used trough technology for the early trajectory and tower technology for the later part of the trajectory. The costs were meant to represent the expected cost of a range of possible technology solutions. Similarly, many marine hydrokinetic options may be commercialized over the next 40 years. No single technology offering is modeled.

For technologies such as enhanced geothermal, deep offshore wind, or marine hydrokinetic where the technology has not been fully demonstrated and commercialized, estimates were based on Nth plant costs. The date of first implementation was assumed to be after at least three full-scale plants have successfully operated for 3–5 years. The first Nth plants were therefore modeled at a future time beyond 2010. For these new and currently non-commercial technologies, demonstration plant cost premiums and early financial premiums were excluded. In particular, although costs are in 2009 dollars, several technologies are not currently in construction and could not be online in 2010.

The cost data presented in this report provide a future trajectory predicted primarily from historical pricing data as influenced by existing levels of government and private research, development, demonstration, and deployment incentives.

Black & Veatch estimated costs for fully demonstrated technologies were based on experience obtained in EPC projects, engineering studies, owner's engineer and due diligence work, and evaluation of power purchase agreement (PPA) pricing. Costs for other technologies or advanced versions of demonstrated technologies were based on engineering studies and other published sources. A more complete discussion of the cost estimating data and methodologies follows.

1.2 ESTIMATION OF DATA AND METHODOLOGY

The best estimates available to Black & Veatch were EPC estimates from projects for which Black & Veatch performed construction or construction management services. Second best were projects for which Black & Veatch was the owner's engineer for the project owner. These estimates provided an understanding of the detailed direct and indirect costs for equipment, materials and labor, and the relationship between each of these costs at a level of detail requiring little contingency. These detailed construction estimates also allowed an understanding of the owner's costs and their impact on the overall estimate. Black & Veatch tracks the detailed estimates and often uses these to perform studies and develop estimates for projects defined at lower levels of detail. Black & Veatch is able to stay current with market conditions through due diligence work it does for financial institutions and others and when it reviews energy prices for new PPAs. Finally, Black & Veatch also prepares proposals for projects of a similar nature. Current market insight is used to adjust detailed estimates as required to keep them up-to-date. Thus, it is an important part of the company's business model to stay current with costs for all types of projects. Project costs for site-specific engineering studies and for more generic engineering studies are frequently adjusted by adding, or subtracting, specific scope items associated with a particular site location. Thus, Black & Veatch has an understanding of the range of costs that might be expected for particular technology applications. (See Text Box 1 for a discussion of cost uncertainty bands.)

Black & Veatch is able to augment its data and to interpret it using published third-party sources; Black & Veatch is also able to understand published sources and apply judgment in interpreting third-party cost reports and estimates in order to understand the marketplace. Reported costs often differ from Black & Veatch's experience, but Black & Veatch is able to infer possible reasons depending upon the source and detail of the cost data. Black & Veatch also uses its cost data and understanding of that data to prepare models and tools.

Though future technology costs are highly uncertain, the experiences and expertise described above enable Black & Veatch to make reasonable cost and performance projections for a wide array of generation technologies. Though technology costs can vary regionally, cost data presented in this report are in strong agreement with other technology cost estimates (FERC 2008, Kelton et al. 2009, Lazard 2009). This report describes the projected cost data and performance data for electric generation technologies.

Text Box 1. Why Estimates Are Not Single Points

In a recent utility solicitation for (engineering, procurement and construction) EPC and power purchase agreement (PPA) bids for the same wind project at a specific site, the bids varied by 60%. More typically, when bidders propose on the exact scope at the same location for the same client, their bids vary by on the order of 10% or more. Why does this variability occur and what does it mean? Different bidders make different assumptions, they often obtain bids from multiple equipment suppliers, different construction contractors, they have different overheads, different profit requirements and they have better or worse capabilities to estimate and perform the work. These factors can all show up as a range of bids to accomplish the same scope for the same client in the same location.

Proposing for different clients generally results in increased variability. Utilities, Private Power Producers, State or Federal entities, all can have different requirements that impact costs. Sparing requirements, assumptions used for economic tradeoffs, a client's sales tax status, or financial and economic assumptions, equipment warranty requirements, or plant performance guarantees inform bid costs. Bidders' contracting philosophy can also introduce variability. Some will contract lump sum fixed price and some will contract using cost plus. Some will use many contractors and consultants; some will want a single source. Some manage with in-house resources and account for those resources; some use all external resources. This variation alone can impact costs still another 10% or more because it impacts the visibility of costs, the allocation of risks and profit margins, and the extent to which profits might occur at several different places in the project structure.

Change the site and variability increases still further. Different locations can have differing requirements for use of union or non-union labor. Overall productivity and labor cost vary in different regions. Sales tax rates vary, local market conditions vary, and even profit margins and perceived risk can vary.

Site-specific scope is also an issue. Access roads, laydown areas,[1] transportation distances to the site and availability of utilities, indoor vs. outdoor buildings, ambient temperatures and many other site-specific issues can affect scope and specific equipment needs and choices.

Owners will also have specific needs and their costs will vary for a cost category referred to as Owner's costs. The Electric Power Research Institute (EPRI) standard owner's costs include 1) paid-up royalty allowance, 2) preproduction costs, 3) inventory capital and 4) land costs. However, this total construction cost or total capital requirement by EPRI does not include many of the other owner's costs that a contractor like Black & Veatch would include in project cost comparisons. These additional elements include the following:

- **Spare parts and plant equipment** includes materials, supplies and parts, machine shop equipment, rolling stock, plant furnishings and supplies.
- **Utility interconnections** include natural gas service, gas system upgrades, electrical transmission, substation/switchyard, wastewater and supply water or wells and railroad.
- **Project development** includes fuel-related project management and engineering, site selection, preliminary engineering, land and rezoning, rights of way for pipelines, laydown yard, access roads, demolition, environmental permitting and offsets, public relations, community development, site development legal assistance, man-camp, heliport, barge unloading facility, airstrip and diesel fuel storage.
- **Owner's project management** includes bid document preparation, owner's project management, engineering due diligence and owner's site construction management.

[1] A laydown yard or area is an area where equipment to be installed is temporarily stored.

- **Taxes/ins/advisory fees/legal** includes sales/use and property tax, market and environmental consultants and rating agencies, owner's legal expenses, PPA, interconnect agreements, contract-procurement and construction, property transfer/title/escrow and construction all risk insurance.

- **Financing** includes financial advisor, market analyst and engineer, loan administration and commitment fees and debt service reserve fund.

- **Plant startup/construction support** includes owner's site mobilization, operation and maintenance (O&M) staff training and pre-commercial operation, start-up, initial test fluids, initial inventory of chemical and reagents, major consumables and cost of fuel not covered recovered in power sales.

Some overlap can be seen in the categories above, which is another contributor to variability - different estimators prepare estimates using different formats and methodologies.

Another form of variability that exists in estimates concerns the use of different classes of estimate and associated types of contingency. There are industry guidelines for different classes of estimate that provide levels of contingency to be applied for the particular class. A final estimate suitable for bidding would have lots of detail identified and would include a 5 to 10% project contingency. A complete process design might have less detail defined and include a 10 to 15% contingency. The lowest level of conceptual estimate might be based on a total plant performance estimate with some site-specific conditions and it might include a 20 to 30% contingency. Contingency is meant to cover both items not estimated and errors in the estimate as well as variability dealing with site-specific differences.

Given all these sources of variability, contractors normally speak in terms of cost ranges and not specific values. Modelers, on the other hand, often find it easier to deal with single point estimates. While modelers often conveniently think of one price, competition can result in many price/cost options. It is not possible to estimate costs with as much precision as many think it is possible to do; further, the idea of a national average cost that can be applied universally is actually problematic. One can calculate a historical national average cost for anything, but predicting a future national average cost with some certainty for a developing technology and geographically diverse markets that are evolving is far from straightforward.

Implications

Because cost estimates reflect these sources of variability, they are best thought of as ranges that reflect the variability as well as other uncertainties. When the cost estimate ranges for two technologies overlap, either technology could be the most cost effective solution for any given specific owner and site. Of course, capital costs may not reflect the entire value proposition of a technology, and other cost components, like O&M or fuel costs with their own sources of variability and uncertainty, might be necessary to include in a cost analysis.

For models, we often simplify calculations by using points instead of ranges that reflect variability and uncertainty, so that we can more easily address other important complexities such as the cost of transmission or system integration. However, we must remember that when actual decisions are made, decision makers will include implicit or explicit consideration of capital cost uncertainty when assessing technology trade-offs. This is why two adjacent utilities with seemingly similar needs may procure two completely different technology solutions. Economic optimization models generally cannot be relied on as the final basis for site-specific decisions. One of the reasons is estimate uncertainty. A relatively minor change in cost can result in a change in technology selection. Because of unknowns at particular site and customer specific situations, it is unlikely that all customers would switch to a specific technology solution at the same time. Therefore, modelers should ensure that model algorithms or input criteria do not allow major shifts in technology choice for small differences in technology cost. In addition, generic estimates should not be used in site- specific user-specific analyses.

2 Cost Estimates and Performance Data for Conventional Electricity Technologies

This section includes description and tabular data on the cost and performance projections for "conventional" non-renewable technologies, which include fossil technologies (natural gas combustion turbine, natural gas combined-cycle, and pulverized coal) with and without carbon capture and storage, and nuclear technologies. In addition, costs for flue gas desulfurization2 (FGD) retrofits are also described.

2.1 NUCLEAR POWER TECHNOLOGY

Black & Veatch's nuclear experience spans the full range of nuclear engineering services, including EPC, modification services, design and consulting services and research support. Black & Veatch is currently working under service agreement arrangements with MHI for both generic and plant specific designs of the United States Advanced Pressurized Water Reactor (US-APWR). Black & Veatch historical data and recent market data were used to make adjustments to study estimates to include owner's costs. The nuclear plant proxy was based on a commercial Westinghouse AP1000 reactor design producing 1,125 net MW. The capital cost in 2010 was estimated at 6,100$/kW +30%. We anticipate that advanced designs could be commercialized in the United States under government-sponsored programs. While we do not anticipate cost savings associated with these advanced designs, we assumed a cost reduction of 10% for potential improved metallurgy for piping and vessels. Table 1 presents cost and performance data for nuclear power. Figure 1 shows the 2010 cost breakdown for a nuclear power plant.

[2] Flue gas desulfurization (FGD) technology is also referred to as SO_2 scrubber technology.

Table 1. Cost and Performance Projection for a Nuclear Power Plant (1125 MW)

Year	Capital Cost ($/kW)	Fixed O&M[a] ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR[b] (%)	FOR[c] (%)	Min. Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	6,230	–	–	–	–	–	–	5.00	5.00
2010	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2015	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2020	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2025	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2030	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2035	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2040	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2045	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00
2050	6,100	127	9,720	60	6.00	4.00	50	5.00	5.00

[a] O&M = operation and maintenance
[b] POR = planned outage rate
[c] FOR = forced outage rate

All costs in 2009$

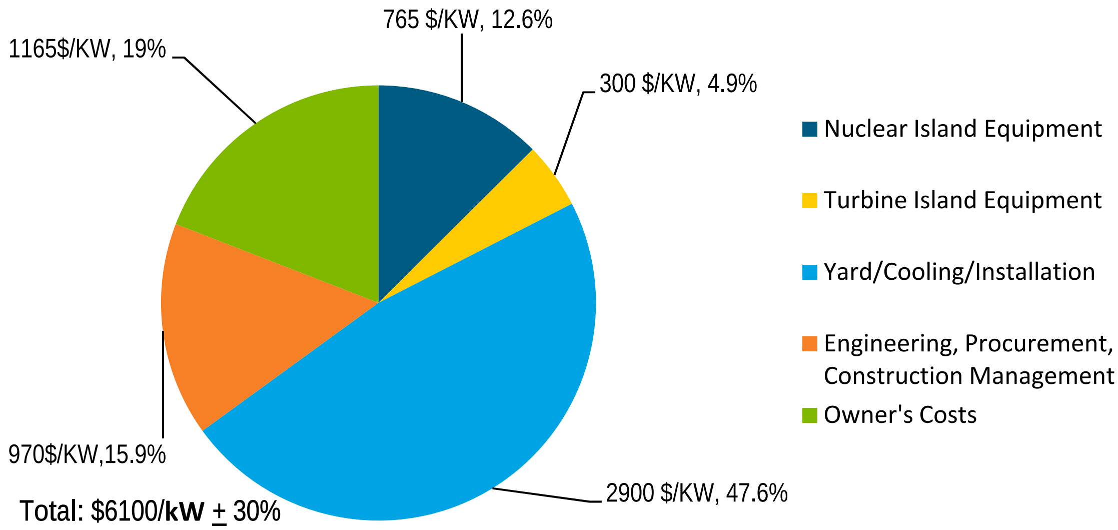

Figure 1. Capital cost breakdown for a nuclear power plant

The total plant labor and installation is included in the Yard/Cooling/ Installation cost element. The power plant is assumed to be a single unit with no provision for future additions. Switchyard, interconnection and interest during construction are not included. Owner's costs are defined in Text Box 1 above.

2.2 COMBUSTION TURBINE TECHNOLOGY

Natural gas combustion turbine costs were based on a typical industrial heavy-duty gas turbine, GE Frame 7FA or equivalent of the 211-net-MW size. The estimate did not include the cost of selective catalytic reduction (SCR)/carbon monoxide (CO) reactor for NOx and CO reduction. The combustion turbine generator was assumed to include a dry, low NOx combustion system capable of realizing 9 parts per million by volume, dry (ppmvd) @ 15% O2 at full load. A 2010 capital cost was estimated at 651 $/kW ±25%. Cost uncertainty for this technology is low. Although it is possible that advanced configurations will be developed over the next 40 years, the economic incentive for new development has not been apparent in the last few decades (Shelley 2008). Cost estimates did not include any cost or performance improvements through 2050. Table 2 presents cost and performance data for gas turbine technology. Table 3 presents emission rates for the technology. Figure 2 shows the 2010 capital cost breakdown by component for a natural gas combustion turbine plant.

Table 2. Cost and Performance Projection for a Gas Turbine Power Plant (211 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min. Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	671	–	–	–	–	–	–	–	–	–
2010	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2015	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2020	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2025	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2030	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2035	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2040	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2045	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20
2050	651	29.9	5.26	10,390	30	5.00	3.00	50	8.33	22.20

Table 3. Emission Rates for a Gas Turbine Power Plant

SO_2 (Lb/mmbtu)	NOx (Lb/mmbtu)	PM10 (Lb/mmbtu)	CO_2 (Lb/mmbtu)
0.0002	0.033	0.006	117

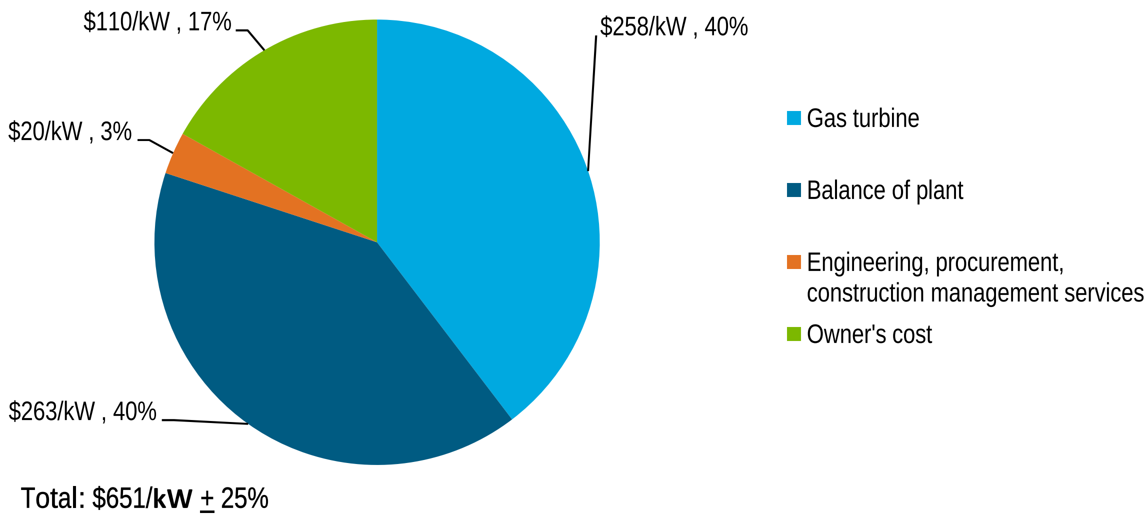

Figure 2. Capital cost breakdown for a gas turbine power plant

2.3 COMBINED-CYCLE TECHNOLOGY

Natural gas combined-cycle (CC) technology was represented by a 615- MW plant. Costs were based on two GE 7FA combustion turbines or equivalent, two heat recovery steam generators (HRSGs), a single reheat steam turbine and a wet mechanical draft cooling tower. The cost included a SCR/CO reactor housed within the HRSGs for NOx and CO reduction. The combustion turbine generator was assumed to include dry low NOx combustion system capable of realizing 9 ppmvd @ 15% O_2 at full load.

2010 capital cost was estimated to be 1,230 $/kW +25%. Cost uncertainty for CC technology is low. Although it is possible that advanced configurations for CC components will be developed over the next 40 years, the economic incentive for new development has not been apparent in the last few decades. The cost estimates did not include any cost reduction through 2050. Table 4 presents cost and performance data for combined-cycle technology. Table 5 presents emission data for the technology. The 2010 capital cost breakdown for the combined-cycle power plant is shown in Figure 3.

Table 4. Cost and Performance Projection for a Combined-Cycle Power Plant (580 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min. Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	1250	–	–	–	–	–	–	–	–	–
2010	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2015	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2020	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2025	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2030	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2035	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2040	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2045	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50
2050	1230	3.67	6.31	6,705	41	6.00	4.00	50	5.00	2.50

Table 5. Emission Rates for a Combined-Cycle Power Plant

SO_2 (Lb/mmbtu)	NO_X (LB/mmbtu)	PM10 (Lb/mmbtu)	CO_2 (Lb/mmbtu)
0.0002	0.0073	0.0058	117

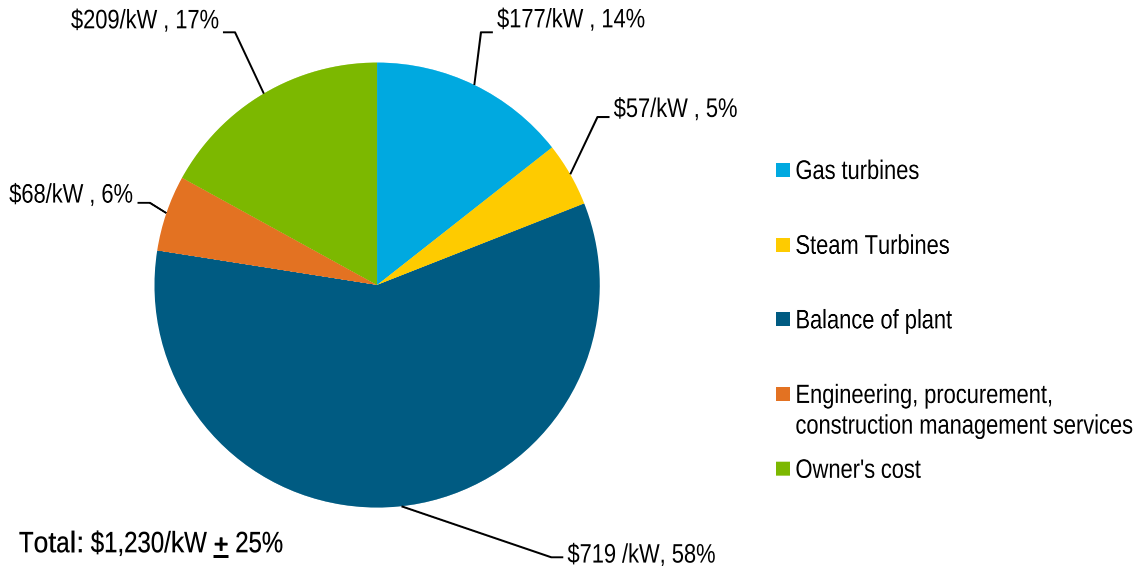

Figure 3. Capital cost breakdown for a combined-cycle power plant

2.4 COMBINED-CYCLE WITH CARBON CAPTURE AND SEQUESTRATION

Carbon capture and sequestration (CCS) was added to the above CC. Black & Veatch has no EPC estimates for CCS since it is not commercial at this time. However, Black & Veatch has participated in engineering and cost studies of CCS and has some understanding of the range of expected costs for CO2 storage in different geologic conditions. The CC costs were based on two combustion turbines, a single steam turbine and wet cooling tower producing 580 net MW after taking into consideration CCS. This is the same combined cycle described above but with CCS added to achieve 85% capture. CCS is assumed to be commercially available after 2020. 2020 capital cost was estimated at 3,750$/kW +35%. Cost uncertainty is higher than for the CC without CCS due to the uncertainty associated with the CCS system. Although it is possible that advanced CC configurations will be developed over the next 40 years, the economic incentive for new gas turbine CC development has not been apparent in the last decade. Further, while cost improvements in CCS may be developed over time, it is expected that geologic conditions will become more difficult as initial easier sites are used. The cost of perpetual storage insurance was not estimated or included. Table 4 presents cost and performance data for combined-cycle with carbon capture and sequestration technology. Table 5 presents emission data for the technology.

Table 6. Cost and Performance Projection for a Combined-Cycle Power Plant (580 MW) with Carbon Capture and Sequestration

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Const. Schedule (Months)	POR (%)	FOR (%)	Min Load (%	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	3860	–	–	–	–	–	–	–	–	–
2010	–	–	–	–	–	–	–	–	–	–
2015	–	–	–	–	–	–	–	–	–	–
2020	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2025	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2030	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2035	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2040	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2045	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50
2050	3750	10	18.4	10,080	44	6.00	4.00	50	5.00	2.50

Table 7. Emission Rates for a Combined-Cycle Power Plant with Carbon Capture and Sequestration

SO_2 (Lb/mmbtu)	NOx (LB/mmbtu)	PM10 (Lb/mmbtu)	CO_2 (Lb/mmbtu)
0.0002	0.0073	0.0058	18

2.5 PULVERIZED COAL-FIRED POWER GENERATION

Pulverized coal-fired power plant costs were based on a single reheat, condensing, tandem-compound, four-flow steam turbine generator set, a single reheat supercritical steam generator and wet mechanical draft cooling tower, a SCR, and air quality control equipment for particulate and SO2 control, all designed as typical of recent U.S. installations. The estimate included the cost of a SCR reactor. The steam generator was assumed to include low NOx burners and other features to control NOx. Net output was approximately 606 MW.

2010 capital cost was estimated at 2,890 $/kW +35%. Cost certainty for this technology is relatively high. Over the 40-year analysis period, a 4% improvement in heat rate was assumed. Table 8 presents cost and performance data for pulverized coal-fired technology.

Table 9 presents emissions rates for the technology. The 2010 capital cost breakdown for the pulverized coal-fired power plant is shown in Figure 4.

Table 8. Cost and Performance Projection for a Pulverized Coal-Fired Power Plant (606 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min Load (%)	Spin Ramp Rate (%/min)
2008	3040	–	–	–	–	–	–	–	–
2010	2890	3.71	23.0	9,370	55	10	6	40	2.00
2015	2890	3.71	23.0	9,370	55	10	6	40	2.00
2020	2890	3.71	23.0	9,370	55	10	6	40	2.00
2025	2890	3.71	23.0	9,000	55	10	6	40	2.00
2030	2890	3.71	23.0	9,000	55	10	6	40	2.00
2035	2890	3.71	23.0	9,000	55	10	6	40	2.00
2040	2890	3.71	23.0	9,000	55	10	6	40	2.00
2045	2890	3.71	23.0	9,000	55	10	6	40	2.00
2050	2890	3.71	23.0	9,000	55	10	6	40	2.00

Table 9. Emission Rates for a Pulverized Coal-Fired Power Plant

SO_2 (Lb/mmbtu)	NO_x (Lb/mmbtu)	PM10 (Lb/mmbtu)	Hg (% removal)	CO_2 (Lb/mmbtu)
0.055	0.05	0.011	90	215

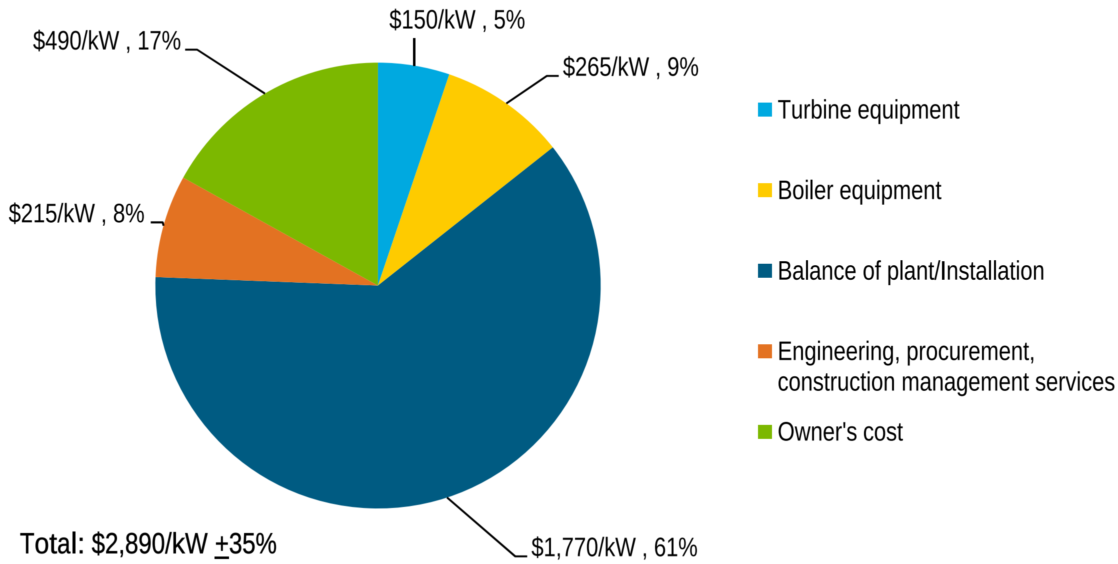

Figure 4. Capital cost breakdown for a pulverized coal-fired power plant

2.6 PULVERIZED COAL-FIRED POWER GENERATION WITH CARBON CAPTURE AND SEQUESTRATION

Black & Veatch is a leading designer of electric generating stations and the foremost designer and constructor of coal-fueled power generation plants worldwide. Black & Veatch's coal-fueled generating station experience includes 10,000 MW of supercritical pulverized coal-fired power plant projects.

The pulverized coal-fired power plant costs were based on a supercritical steam cycle and wet cooling tower design typical of recent U.S. installations, the same plant described above but with CCS. Net output was approximately 455 MW. CCS would be based on 85% CO2 removal. CCS was assumed to be commercially available after 2020. 2020 capital cost was estimated at 6,560$/kW -45% and +35%. Cost uncertainty is higher than for the pulverized coal-fired plant only due to the uncertainty associated with the CCS.

We assumed a 4% improvement in heat rate to account for technology potential already existing but not frequently used in the United States. The cost of perpetual storage insurance was not estimated or included. Table 8 presents cost and performance data for pulverized coal-fired with carbon capture and sequestration technology.

Table 911 presents emissions rates for the technology.

Table 10. Cost and Performance Projection for a Pulverized Coal-Fired Power Plant (455 MW) with Carbon Capture and Sequestration

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min Load (%)	Spin Ramp Rate (%/min)
2008	6890	–	–	–	–	–	–	–	–
2010	–	–	–	–	–	–	–	–	2.00
2015	–	–	–	–	–	–	–	–	2.00
2020	6560	6.02	35.2	12,600	66	10	6	40	2.00
2025	5640	6.02	35.2	12,100	66	10	6	40	2.00
2030	5640	6.02	35.2	12,100	66	10	6	40	2.00
2035	5640	6.02	35.2	12,100	66	10	6	40	2.00
2040	5640	6.02	35.2	12,100	66	10	6	40	2.00
2045	5640	6.02	35.2	12,100	66	10	6	40	2.00
2050	5640	6.02	35.2	12,100	66	10	6	40	2.00

Table 11. Emission Rates for a Pulverized Coal-Fired Power Plant with Carbon Capture and Sequestration

SO_2 (Lb/mmbtu)	NO_x (Lb/mmbtu)	PM10 (Lb/mmbtu)	Hg (% removal)	CO_2 (Lb/mmbtu)
0.055	0.05	0.011	90	32

2.7 GASIFICATION COMBINED-CYCLE TECHNOLOGY

Black & Veatch is a leading designer of electric generating stations and the foremost designer and constructor of coal-fueled power generation plants worldwide. Black & Veatch's coal-fueled generating station experience includes integrated gasification combined-cycle technologies. Black & Veatch has designed, performed feasibility studies, and performed independent project assessments for numerous gasification and gasification combined-cycle (GCC) projects using various gasification technologies. Black & Veatch historical data were used to make adjustments to study estimates to include owner's costs. Special care was taken to adjust to 2009 dollars based on market experience. The GCC estimate was based on a commercial gasification process integrated with a conventional combined cycle and wet cooling tower producing 590 net MW. 2010 capital cost was estimated at 4,010$/kW-+35%.. Cost certainty for this technology is relatively high. We assumed a 12% improvement in heat rate by 2025. Table 812 presents cost and performance data for gasification combined-cycle technology.

Table 913 presents emissions rates for the technology. The Black & Veatch GCC estimate is consistent with the FERC estimate range.

Table 12. Cost and Performance Projection for an Integrated Gasification Combined-Cycle Power Plant (590 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/kWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Min Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	4210	–	–	–	–	–	–	–	–	–
2010	4010	6.54	31.1	9,030	57	12	8	50	5	2.50
2015	4010	6.54	31.1	9,030	57	12	8	50	5	2.50
2020	4010	6.54	31.1	9,030	57	12	8	50	5	2.50
2025	4010	6.54	31.1	7,950	57	12	8	50	5	2.50
2030	4010	6.54	31.1	7,950	57	12	8	50	5	2.50
2035	4010	6.54	31.1	7,950	57	12	8	50	5	2.50
2040	4010	6.54	31.1	7,950	57	12	8	50	5	2.50
2045	4010	6.54	31.1	7,950	57	12	8	50	5	2.50
2050	4010	6.54	31.1	7,950	57	12	8	50	5	2.50

Table 13. Emission Rates for an Integrated Gasification Combined-Cycle Power Plant

SO_2 (Lb/mmbtu)	NO_x (Lb/mmbtu)	PM10 (Lb/mmbtu)	Mercury (% Removal)	CO_2 (Lb/mmbtu)
0.065	0.085	0.009	90	215

2.8 GASIFICATION COMBINED-CYCLE TECHNOLOGY WITH CARBON CAPTURE AND SEQUESTRATION

Black & Veatch is a leading designer of electric generating stations and the foremost designer and constructor of coal-fueled power generation plants worldwide. Black & Veatch's coal-fueled generating station experience includes integrated gasification combined-cycle technologies. Black & Veatch has designed, performed feasibility studies, and performed independent project assessments for numerous gasification and IGCC projects using various gasification technologies. Black & Veatch historical data were used to make adjustments to study estimates to include owner's costs. The GCC was based on a commercial gasification process integrated with a conventional CC and wet cooling tower, the same plant as described above but with CCS. Net capacity was 520 MW. Carbon capture, sequestration, and storage were based on 85% carbon removal. Carbon capture and storage is assumed to be commercially available after 2020. 2020 capital cost was estimated at 6,600 $/kW +35%. The cost of perpetual storage insurance was not estimated or included. Table 814 presents cost and performance data for gasification combined-cycle technology integrated with carbon capture and sequestration.

Table 915 presents emissions rates for the technology.

Table 14. Cost and Performance Projection for an Integrated Gasification Combined-Cycle Power Plant (520 MW) with Carbon Capture and Sequestration

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Heat Rate (Btu/KWh)	Construction Schedule (Months)	FOR (%)	POR (%)	Min Load (%)	Spin Ramp Rate (%/min)	Quick Start Ramp Rate (%/min)
2008	6,930	–	–	–	–	–	–	–	5.00	2.50
2010	–	–	–	–	–	–	–	–	5.00	2.50
2015	–	–	–	–	–	–	–	–	–	–
2020	6,600	10.6	44.4	11,800	59	12.0	8.00	50	5.00	2.50
2025	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50
2030	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50
2035	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50
2040	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50
2045	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50
2050	6,600	10.6	44.4	10,380	59	12.0	8.00	50	5.00	2.50

Table 15. Emission Rates for an Integrated Gasification Combined-Cycle Power Plant with Carbon Capture and Sequestration

SO_2 (Lb/mmbtu)	NOx (Lb/mmbtu)	PM10 (Lb/mmbtu)	Hg (% Removal)	CO_2 (Lb/mmbtu)
0.065	0.085	0.009	90%	32

2.9 FLUE GAS DESULFURIZATION RETROFIT TECHNOLOGY

Flue gas desulfurization (FGD) retrofit was assumed to be a commercial design to achieve 95% removal of sulfur dioxide and equipment was added to meet current mercury and particulate standards. A wet limestone FGD system, a fabric filter, and a powdered activated carbon (PAC) injection system were included. It is also assumed that the existing stack was not designed for a wet FGD system; therefore, a new stack was included. Black & Veatch estimated retrofit capital cost in 2010 to be 360 $/kW +25% with no cost reduction assumed through 2050. Table 16 presents costs and a construction schedule for flue gas desulfurization retrofit technology.

Table 16. Cost and Schedule for a Power Plant (606 MW) with Flue Gas Desulfurization Retrofit Technology

Year	Retrofit Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)
2008	371	–	–	–
2010	360	3.71	23.2	36
2015	360	3.71	23.2	36
2020	360	3.71	23.2	36
2025	360	3.71	23.2	36
2030	360	3.71	23.2	36
2035	360	3.71	23.2	36
2040	360	3.71	23.2	36
2045	360	3.71	23.2	36
2050	360	3.71	23.2	36

Text Box 2. Cycling Considerations

- Cycling increases failures and maintenance cost.
- Power plants of the future will need increased flexibility and increased efficiency; these qualities run counter to each other.
- Higher temperatures required for increased efficiency mean slower ramp rates and less ability to operate off-design. Similarly, environmental features such as bag houses, SCR, gas turbine NOx control, FGD, and carbon capture make it more difficult to operate at off-design conditions.
- Early less-efficient power plants without modern environmental emissions controls probably have more ability to cycle than newer more highly-tuned designs.
- Peak temperature and rate of change of temperature are key limitations for cycling. Water chemistry is an issue.
- The number of discrete pulverizers is a limitation for pulverized coal power plants and the number of modules in add-on systems that must be integrated to achieve environmental control is a limitation.

<u>The ramp rate for coal plants is not linear as it is a function of bringing pulverizers on line as load increases.</u> A 600-MW pulverized coal-fired unit (e.g., Powder River Basin) can have six pulverizers. Assuming an N+1 sparing philosophy, five pulverizers are required for full load so each pulverizer can provide fuel for about 20% of full load.

From minimum stable load at about 40% to full load, it is the judgment of Black & Veatch, based on actual experience in coal plant operations, that the ramp rate will be 5 MW/minute at high loads. This is about 1%/minute for a unit when at 500 MW.

<u>The ramp rate for a combined-cycle plant is a combination of combustion turbine ramp rate and steam turbine ramp rate.</u> The conventional warm start will take about 76 minutes from start initiation to full load on the combined cycle. The combined ramp rate from minute 62 to minute 76 is shown by GE to be about 5%/minute for a warm conventional start-up.

GE shows that the total duration of a "rapid response" combined-cycle start-up assuming a combustion turbine fast start is 54 minutes as compared to a conventional start duration of 76 minutes for a warm start. The ramp rate is shown by GE to be slower during a rapid start-up. The overall duration is shorter but the high load combined ramp rate is 2.5%.

After the unit has been online and up to temperature, we would expect the ramp rate to be 5%.

3 Cost Estimates and Performance Data for Renewable Electricity Technologies

This section includes cost and performance data for renewable energy technologies, including biopower (biomass cofiring and standalone), geothermal (hydrothermal and enhanced geothermal systems), hydropower, ocean energy technologies (wave and tidal), solar energy technologies (photovoltaics and concentrating solar power), and wind energy technologies (onshore and offshore).

3.1 BIOPOWER TECHNOLOGIES

3.1.1 Biomass Cofiring

From initial technology research and project development, through turnkey design and construction, Black & Veatch has worked with project developers, utilities, lenders, and government agencies on biomass projects using more than 40 different biomass fuels throughout the world. Black & Veatch has exceptional tools to evaluate the impacts of biomass cofiring on the existing facility, such as the VISTA™ model, which evaluates impacts to the coal fueled boiler and balance of plant systems due to changes in fuels.

Although the maximum injection of biomass depends on boiler type and the number and types of necessary modifications to the boiler, biomass cofiring was assumed to be limited to a maximum of 15% for all coal plants. For the biomass cofiring retrofit, Black & Veatch estimated 2010 capital costs of 990 $/kW -50% and +25%. Cost uncertainty is significantly impacted by the degree of modifications needed for a particular fuel and boiler combination. Significantly less boiler modification may be necessary in some cases. Black & Veatch did not estimate any cost improvement over time. Table 17 presents cofiring cost and performance data. In the present convention, the capital cost to retrofit a coal plant to cofire biomass is applied to the biomass portion only3. Similarly, O&M costs are applied to the new retrofitted capacity only. Table 17 shows representative heat rates; the performance characteristics of a retrofitted plant were assumed to be the same as that of the previously existing coal plant. Many variations are possible but were not modeled. Table 18 shows the range of costs using various co-firing approaches over a range of co-firing fuel levels varying from 5% to 30%. Emissions control equipment performance limitations may limit the overall range of cofiring possible.

[3] For example, retrofitting a 100 MW coal plant to cofire up to 15% biomass has a cost of 100 MW x 15% x $990,000/MW = $14,850,000.

Table 17. Cost and Performance Projection for Biomass Cofiring Technology

Year	Capital Cost ($/kW)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-Yr)	Heat Rate (Btu/KWh)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	1,020	–	–	–	–	–	–
2010	990	0	20	10,000	12	9	7
2015	990	0	20	10,000	12	9	7
2020	990	0	20	10,000	12	9	7
2025	990	0	20	10,000	12	9	7
2030	990	0	20	10,000	12	9	7
2035	990	0	20	10,000	12	9	7
2040	990	0	20	10,000	12	9	7
2045	990	0	20	10,000	12	9	7
2050	990	0	20	10,000	12	9	7

Table 18. Costs for Co-Firing Methods versus Fuel Amount

Co-firing Level (%)	Fuel Blending ($/kW)	Separate Injection ($/kW)	Gasification ($/kW)
5	1000-1500	1300-1800	2500-3500
10	800-1200	1000-1500	2000-2500
20	600	700-1100	1800-2300
30	–	700-1100	1700-2200

3.1.2 Biomass Standalone

Black & Veatch is recognized as one of the most diverse providers of biomass (solid biomass, biogas, and waste-to-energy) systems and services. From initial technology research and project development, through turnkey design and construction, Black & Veatch has worked with project developers, utilities, lenders, and government agencies on biomass projects using more than 40 different biomass fuels throughout the world. This background was used to develop the cost estimates vetted in the Western Renewable Energy Zone (WREZ) stakeholder process and to subsequently update that pricing and adjust owner's costs.

A standard Rankine cycle with wet mechanical draft cooling tower producing 50 MW net is initially assumed for the standalone biomass generator.[4] Black & Veatch assumed the 2010 capital cost to be 3,830 $/kW -25% and +50%. Cost certainty is high for this mature technology, but there are more high cost than low cost outliers due to unique fuels and technology solutions. For modeling purposes, it was assumed that gasification combined-cycle systems displace the direct combustion systems gradually resulting in an average system heat rate that improves by 14% through 2050. However, additional cost is likely required initially to achieve this heat rate improvement and therefore no improvement in cost was assumed for the costs. Table 19 presents cost and performance data for a standalone biomass power plant. The capital cost breakdown for the biomass standalone power plant is shown in Figure 5.

[4] "Standalone" biomass generators are also referred to as "dedicated" plants to distinguish them from co-fired plants.

Table 19. Cost and Performance Projection for a Stand-Alone Biomass Power Plant (50 MW Net)

Year	Capital Cost $/kW	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-Yr)	Heat Rate (Btu/KWh)	Construction Schedule (Months)	POR (%)	FOR (%)	Minimum Load (%)
2008	4,020	–	–	–	–	–	–	–
2010	3,830	15	95	14,500	36	7.6	9	40
2015	3,830	15	95	14,200	36	7.6	9	40
2020	3,830	15	95	14,000	36	7.6	9	40
2025	3,830	15	95	13,800	36	7.6	9	40
2030	3,830	15	95	13,500	36	7.6	9	40
2035	3,830	15	95	13,200	36	7.6	9	40
2040	3,830	15	95	13,000	36	7.6	9	40
2045	3,830	15	95	12,800	36	7.6	9	40
2050	3,830	15	95	12,500	36	7.6	9	40

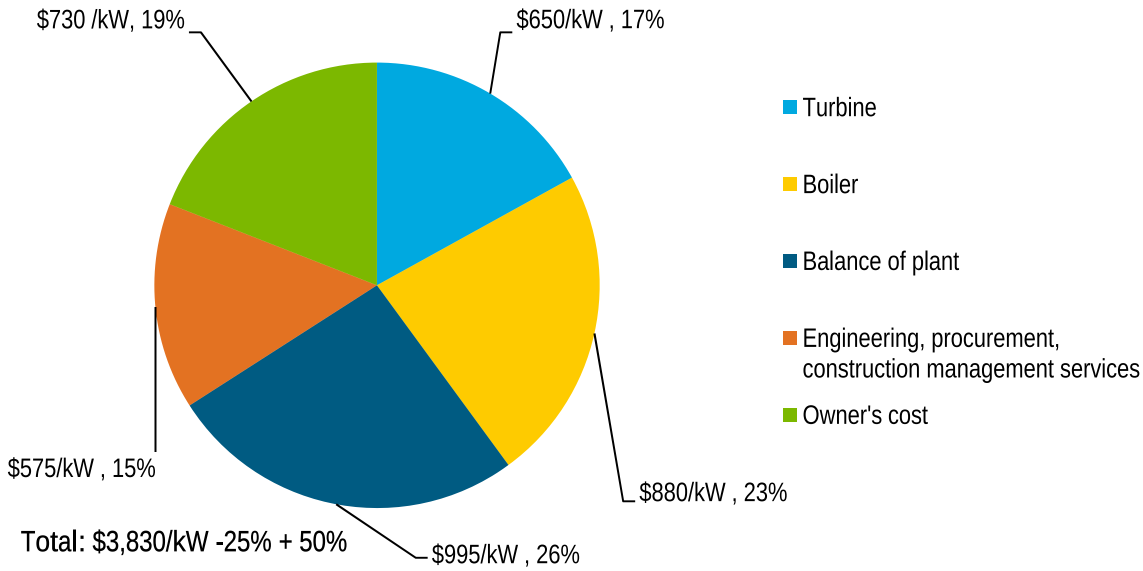

Figure 5. Capital cost breakdown for a standalone biomass power plant

3.2 GEOTHERMAL ENERGY TECHNOLOGIES

Hydrothermal technology is a relatively mature commercial technology for which cost improvement was not assumed. For enhanced geothermal systems (EGS) technology, Black & Veatch estimated future cost improvements based on improvements of geothermal fluid pumps and development of multiple, contiguous EGS units to benefit from economy of scale for EGS field development. The quality of geothermal resources are site- and resource-specific, therefore costs of geothermal resources can vary significantly from region to region. The cost estimates shown in this report are single-value generic estimates and may not be representative of any individual site. Table 20 and Table 21 present cost and performance data for hydrothermal and enhanced geothermal systems, respectively, based on these single-value estimates.

Table 20. Cost and Performance Projection for a Hydrothermal Power Plant

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	6,240	–	–	–	–	–
2010	5,940	31	0	36	2.41	0.75
2015	5,940	31	0	36	2.41	0.75
2020	5,940	31	0	36	2.41	0.75
2025	5,940	31	0	36	2.41	0.75
2030	5,940	31	0	36	2.41	0.75
2035	5,940	31	0	36	2.41	0.75
2040	5,940	31	0	36	2.41	0.75
2045	5,940	31	0	36	2.41	0.75
2050	5,940	31	0	36	2.41	0.75

Table 21. Cost and Performance Projection for an Enhanced Geothermal Systems Power Plant

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	10,400	31	0	36	2.41	0.75
2010	9,900	31	0	36	2.41	0.75
2015	9,720	31	0	36	2.41	0.75
2020	9,625	31	0	36	2.41	0.75
2025	9,438	31	0	36	2.41	0.75
2030	9,250	31	0	36	2.41	0.75
2035	8,970	31	0	36	2.41	0.75
2040	8,786	31	0	36	2.41	0.75
2045	8,600	31	0	36	2.41	0.75
2050	8,420	31	0	36	2.41	0.75

The capital cost breakdown for the hydrothermal geothermal power plant is shown in Figure 6.

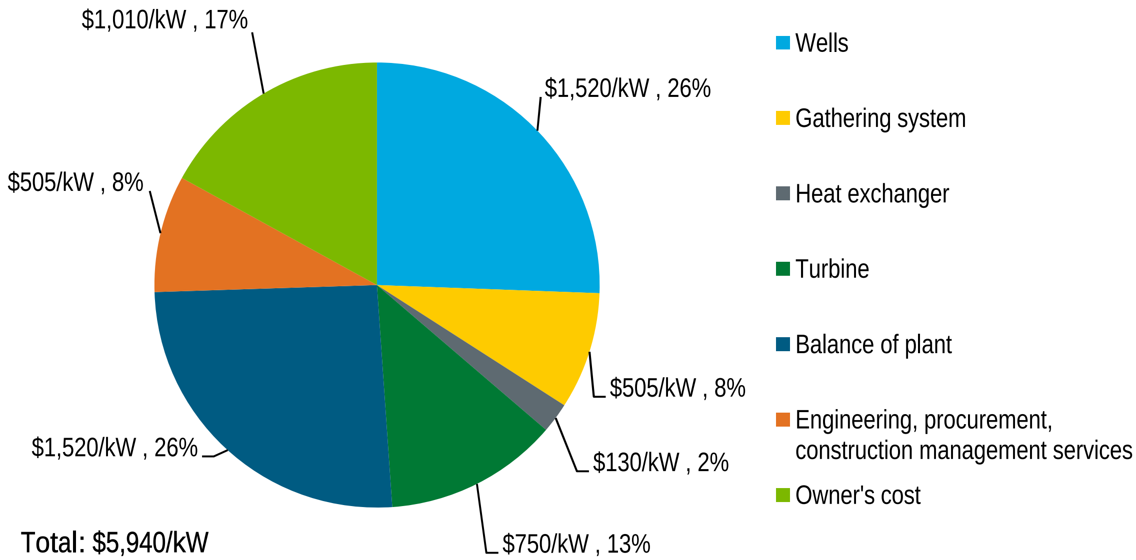

Figure 6. Capital cost breakdown for a hydrothermal geothermal power plant

The capital cost breakdown for the enhanced geothermal system power plant is shown in Figure 7.

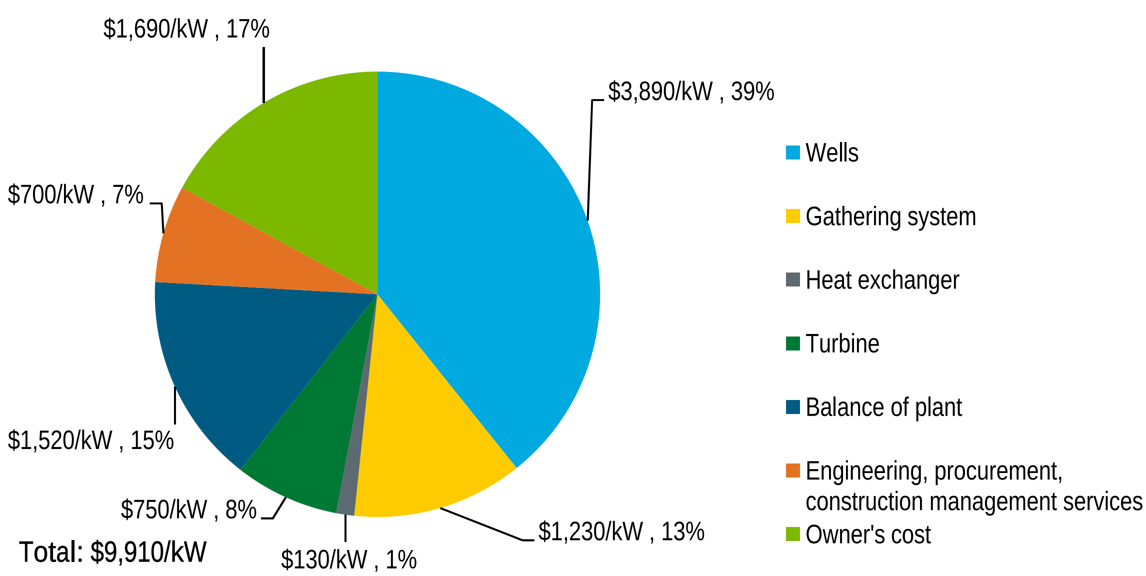

Figure 7. Capital cost breakdown for an enhanced geothermal system power plant

Enhanced geothermal system cost reductions will occur primarily in the wells, turbine, and BOP categories over time.

3.3 HYDROPOWER TECHNOLOGIES

Nearly 500 hydropower projects totaling more than 50,000 MW have been served by Black & Veatch worldwide. The Black & Veatch historical database incorporates a good understanding of hydroelectric costs. Black & Veatch used this historical background to develop the cost estimates vetted in the WREZ (Pletka and Finn 2009) stakeholder process and to subsequently update that pricing and adjust owner's costs as necessary.

Similar to geothermal technologies, the cost of hydropower technologies can be site-specific. Numerous options are available for hydroelectric generation; repowering an existing dam or generator, or installing a new dam or generator, are options. As such, the cost estimates shown in this report are single-value estimates and may not be representative of any individual site. 2010 capital cost for a 500 MW hydropower facility was estimated at 3,500 $/kW +35%. Table 22 presents cost and performance data for hydroelectric power technology.

Table 22. Cost and Performance Data for a Hydroelectric Power Plant (500 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	3,600	–	–	–	–	–
2010	3,500	6	15	24	1.9	5.0
2015	3,500	6	15	24	1.9	5.0
2020	3,500	6	15	24	1.9	5.0
2025	3,500	6	15	24	1.9	5.0
2030	3,500	6	15	24	1.9	5.0
2035	3,500	6	15	24	1.9	5.0
2040	3,500	6	15	24	1.9	5.0
2045	3,500	6	15	24	1.9	5.0
2050	3,500	6	15	24	1.9	5.0

The capital cost breakdown for the hydroelectric power plant is shown in Figure 8.

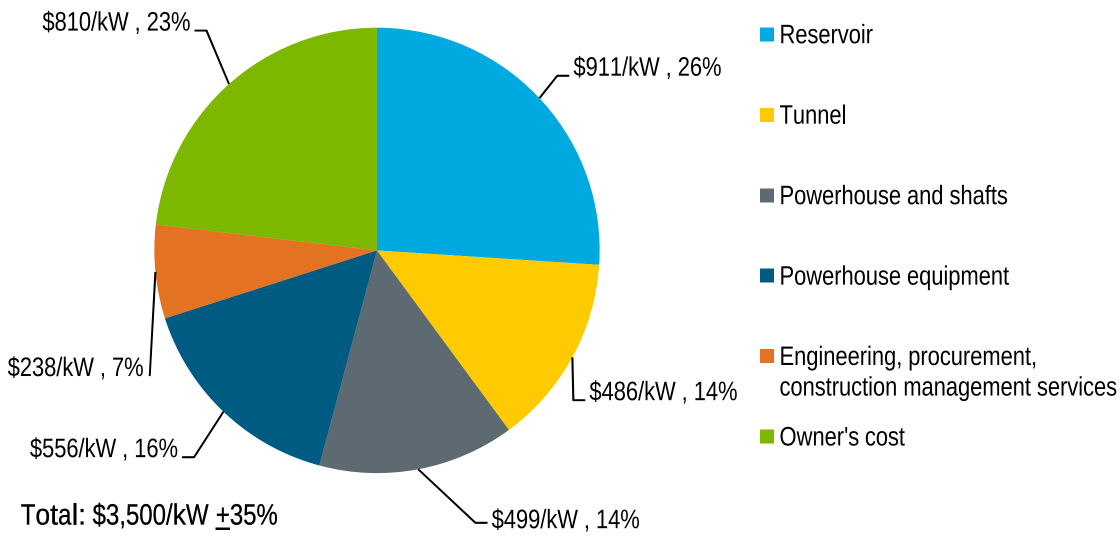

Figure 8. Capital cost breakdown for a hydroelectric power plant

Hydroelectric power plant cost reductions will be primarily in the power block cost category over time.

3.4 OCEAN ENERGY TECHNOLOGIES

Wave and tidal current resource assessment and technology costs were developed based on European demonstration and historical data obtained from studies. A separate assessment of the hydrokinetic resource uncertainty is included in Appendices A and B, informed by a Black & Veatch analysis that includes an updated resource assessment for wave and tidal current technologies and assumptions used to develop technology cost estimates. Wave capital cost in 2015 was estimated at 9,240 $/kW – 30% and +45%. This is an emerging technology with much uncertainty and many options available. A cost improvement of 63% was assumed through 2040 and then a cost increase through 2050reflecting the need to develop lower quality resources. Tidal current technology is similarly immature with many technical options. Capital cost in 2015 was estimated at 5,880 $/kW - 10% and + 20%. A cost improvement of 45% was assumed as the resource estimated to be available is fully utilized by 2030. Estimated O&M costs include insurance, seabed rentals, and other recurring costs that were not included in the one-time capital cost estimate. Wave O&M costs are higher than tidal current costs due to more severe conditions. Table 23 and

Table 24 present cost and performance for wave and tidal current technologies, respectively. The capital cost breakdown for wave and current power plants are shown in Figure 9 and Figure 10, respectively.

Table 23. Cost and Performance Projection for Ocean Wave Technology

Year	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2015	9,240	474	24	1	7
2020	6,960	357	24	1	7
2025	5,700	292	24	1	7
2030	4,730	243	24	1	7
2035	3,950	203	24	1	7
2040	3,420	175	24	1	7
2045	4,000	208	24	1	7
2050	5,330	273	24	1	7

Table 24. Cost and Performance Projection for Ocean Tidal Current Technology

Year	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2015	5,880	198	–	–	–
2020	4,360	147	24	1.0	6.5
2025	3,460	117	24	1.0	6.5
2030	3,230	112	24	1.0	6.5
2035	–	112	24	1.0	6.5
2040	–	112	24	1.0	6.5
2045	–	112	24	1.0	6.5
2050	–	112	24	1.0	6.5

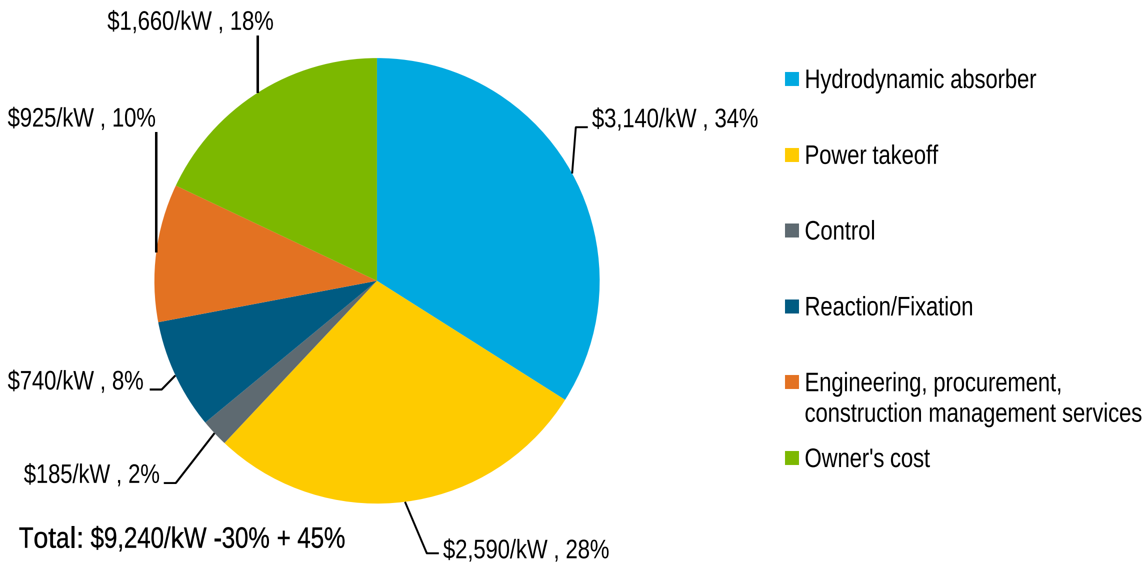

Figure 9. Capital cost breakdown for an ocean wave power plant

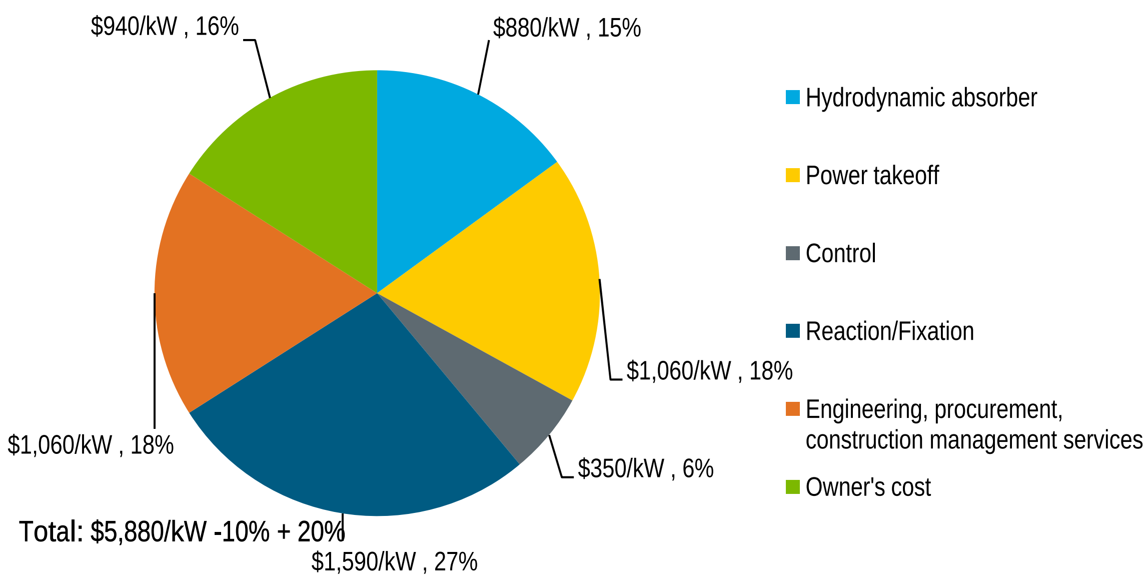

Figure 10. Capital cost breakdown for an ocean tidal power plant

Appendices A and B highlight the uncertainty associated with estimates of wave and tidal energy resources. They form the basis for the estimates above.

3.5 SOLAR ENERGY TECHNOLOGIES

3.5.1 Solar Photovoltaic Technologies

Black & Veatch has been involved in the development of utility scale solar photovoltaic (PV) systems, including siting support, interconnection support, technology due diligence, and conceptual layout. Specifically Black & Veatch has performed due diligence on more than 200 MW of utility scale PV projects for lenders and owners as well as assisted in the development of more than 1,500 MW of projects for utilities and developers. Black & Veatch has been the independent engineer for 35 distributed PV projects totaling 16 MW in California and an independent engineer for two of the largest PV systems in North America. It has also reviewed solar PV new PPA pricing and done project and manufacturer due diligence investigations. This background was used to develop the cost estimates vetted in the WREZ stakeholder process and to subsequently update that pricing and adjust owner's costs.

Estimates for a number of different residential, commercial and utility options ranging from 40 KW (direct current (DC)) to 100 MW (DC) are provided. The capital costs were assumed to have uncertainties of +25%. Cost uncertainty is not high for current offerings but over time, a number of projected, potential technology improvements may affect costs for this technology. Choosing the non-tracking utility PV with a 100-MW (DC) size as a representative case, a 35% reduction in cost was expected through 2050. Table 25 presents cost and performance data for a wide range of PV systems. Table 25 includes 2008 costs to illustrate the impact (in constant 2009 dollars) of the commodity price drop that occurred between 2008 and 2010. For most generation technologies, the decline in commodity prices over the two years results in a 3%–5% reduction in capital cost. As seen in Table 25, the drop in PV technology costs is significantly greater. For PV, the 2008 costs were based on actual market data adjusted to 2009 dollars. Over these two years, PV experienced a drastic fall in costs, due to technology improvements, economies of scale, increased supply in raw materials, and other factors. The capital cost breakdown for the PV power plant (non-tracking Utility PV with a 10 MW (DC) install size) is shown in Figure 11. Note that 100-MW utility PV systems representing nth plant configurations are not available in 2010.

Table 25. Cost and Performance Projection for Solar Photovoltaic Technology

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
Residential PV with a 4 kW (DC) install size						
2008	7690	–	–	–	–	–
2010	5950	0	50	2.0	2.0	0.0
2015	4340	0	48	1.9	2.0	0.0
2020	3750	0	45	1.8	2.0	0.0
2025	3460	0	43	1.7	2.0	0.0

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2030	3290	0	41	1.6	2.0	0.0
2035	3190	0	39	1.5	2.0	0.0
2040	3090	0	37	1.5	2.0	0.0
2045	3010	0	35	1.4	2.0	0.0
2050	2930	0	33	1.3	2.0	0.0
Commercial PV with a 100 kW (DC) install size						
2008	5610	–	–	–	–	–
2010	4790	0	50	6.0	2.0	0.0
2015	3840	0	48	5.7	2.0	0.0
2020	3340	0	45	5.4	2.0	0.0
2025	3090	0	43	5.1	2.0	0.0
2030	2960	0	41	4.9	2.0	0.0
2035	2860	0	39	4.6	2.0	0.0
2040	2770	0	37	4.4	2.0	0.0
2045	2690	0	35	4.2	2.0	0.0
2050	2620	0	33	4.0	2.0	0.0
Non-Tracking Utility PV with a 1-MW (DC) Install Size						
2008	4610	–	–	–	–	–
2010	3480	0	50	8.0	2.0	0.0
2015	3180	0	48	7.6	2.0	0.0
2020	3010	0	45	7.2	2.0	0.0
2025	2880	0	43	6.9	2.0	0.0
2030	2760	0	41	6.5	2.0	0.0
2035	2660	0	39	6.2	2.0	0.0
2040	2570	0	37	5.9	2.0	0.0
2045	2490	0	35	5.6	2.0	0.0
2050	2420	0	33	5.3	2.0	0.0
Non-Tracking Utility PV with a 10-MW (DC) Install Size						
2008	3790	–	–	–	–	–
2010	2830	0	50	12.0	2.0	0.0

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2015	2550	0	48	11.4	2.0	0.0
2020	2410	0	45	10.8	2.0	0.0
2025	2280	0	43	10.3	2.0	0.0
2030	2180	0	41	9.8	2.0	0.0
2035	2090	0	39	9.3	2.0	0.0
2040	2010	0	37	8.8	2.0	0.0
2045	1940	0	35	8.4	2.0	0.0
2050	1870	0	33	8.0	2.0	0.0
Non-Tracking Utility PV with a 100-MW (DC) Install Size						
2008	3210	–	–	–	–	–
2010						
2015	2357	0	48	17.1	2.0	0.0
2020	2220	0	45	16.2	2.0	0.0
2025	2100	0	43	15.4	2.0	0.0
2030	1990	0	41	14.7	2.0	0.0
2035	1905	0	39	13.9	2.0	0.0
2040	1830	0	37	13.2	2.0	0.0
2045	1760	0	35	12.6	2.0	0.0
2050	1700	0	33	11.9	2.0	0.0
1-Axis Tracking Utility PV with a 1-MW (DC) Install Size						
2008	5280	–	–	–	–	–
2010	3820	0	50	10.0	2.0	0.0
2015	3420	0	48	9.5	2.0	0.0
2020	3100	0	45	9.0	2.0	0.0
2025	2940	0	43	8.6	2.0	0.0
2030	2840	0	41	8.1	2.0	0.0
2035	2750	0	39	7.7	2.0	0.0
2040	2670	0	37	7.4	2.0	0.0
2045	2590	0	35	7.0	2.0	0.0
2050	2520	0	33	6.6	2.0	0.0

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
1-Axis Tracking Utility PV with a 10-MW (DC) Install Size						
2008	4010	–	–	–	–	–
2010	3090	0	50	14.0	2.0	0.0
2015	2780	0	48	13.3	2.0	0.0
2020	2670	0	45	12.6	2.0	0.0
2025	2560	0	43	12.0	2.0	0.0
2030	2380	0	41	11.4	2.0	0.0
2035	2380	0	39	10.8	2.0	0.0
2040	2300	0	37	10.3	2.0	0.0
2045	2230	0	35	9.8	2.0	0.0
2050	2170	0	33	9.3	2.0	0.0
1-Axis Tracking Utility PV with a 100-MW (DC) Install Size						
2008	3920	–	–	–	–	–
2010						
2015	2620	0	48	13.3	2.0	0.0
2020	2510	0	45	12.6	2.0	0.0
2025	2410	0	43	12.0	2.0	0.0
2030	2310	0	41	11.4	2.0	0.0
2035	2230	0	39	10.8	2.0	0.0
2040	2160	0	37	10.3	2.0	0.0
2045	2090	0	35	9.8	2.0	0.0
2050	2030	0	33	9.3	2.0	0.0

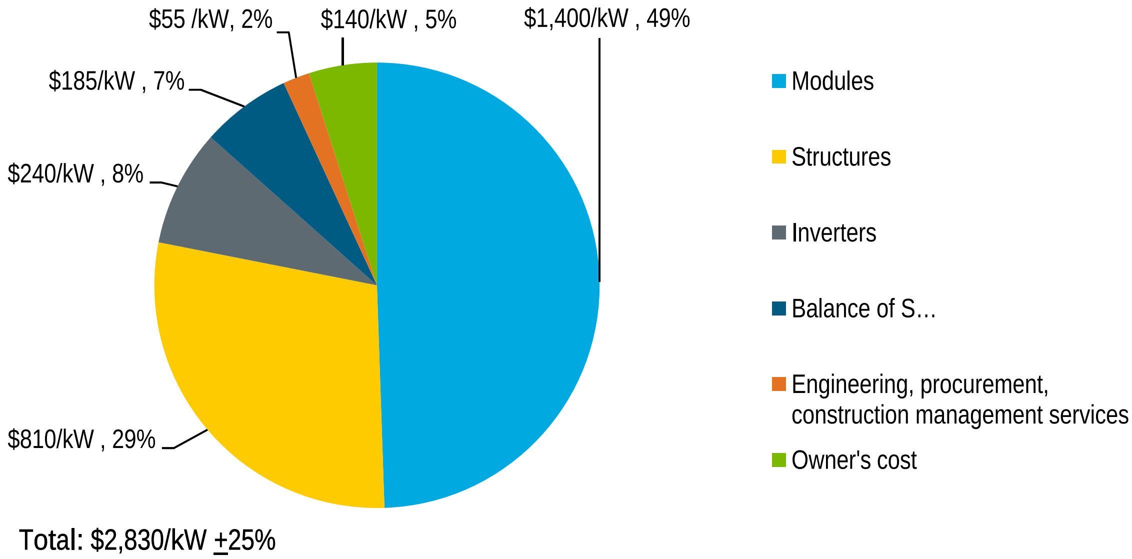

Figure 11. Capital cost breakdown for a solar photovoltaic power plant

Appendix C presents further breakdowns for photovoltaic costs.

3.5.2 Concentrating Solar Power Technologies

Black & Veatch has participated in numerous concentrating solar power (CSP) pilot plant and study activities since the 1970s. The company has been the independent engineer for CSP projects and has performed due diligence on CSP manufacturers. Black & Veatch has also reviewed costs in new CSP purchase agreements. This historical knowledge and recent market data was used to develop the cost estimates vetted in the WREZ stakeholder process and to subsequently update that pricing and make adjustments to owner's costs.

Multiple CSP options were represented, including CSP without storage and CSP with storage. The CSP without storage option was assumed to be represented by trough systems for all years. For the CSP option with storage, the cost data represented trough systems until 2025, after which, tower systems were represented. These model assumptions do not represent CSP technology choice predictions by Black & Veatch. The location assumed for costing of CSP systems is the Southwest United States, not the Midwest as used for other technologies. All CSP systems were based on dry-cooled technologies. The cost and performance data presented here were based on 200-MW net power plants. Multiple towers were used in the tower configuration.

Black & Veatch estimated capital costs to be 4,910 $/kW -35% and +15% without storage and 7,060 $/kW -35% and +15% with storage for 2010. There is greater downside potential than upside cost growth due to the expected emergence of new technology options. New CSP technologies are expected to be commercialized before 2050, and 30%-33% capital cost improvements were assumed for all systems through 2050. Table 26 and Table 27present cost and performance data for CSP power plants without and with storage, respectively. For the with storage option, trough costs were represented in years up to and including 2025; tower costs were provided after 2025. Capital cost breakdown for the 2010 CSP plants with storage are shown in Figure 12 and Figure 13 for trough and tower systems, respectively.

Table 26. Cost and Performance Projection for a Concentrating Solar Power Plant without Storagea

Year	Capital Cost ($/kW)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-Yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	5,050	–	–	–	–	–
2010	4,910	0	50	24	0	6
2015	4,720	0	50	24	0	6
2020	4,540	0	50	24	0	6
2025	4,350	0	50	24	0	6
2030	4,170	0	50	24	0	6
2035	3,987	0	50	24	0	6
2040	3,800	0	50	24	0	6
2045	3,620	0	50	24	0	6
2050	3,430	0	50	24	0	6

[a] Concentrating solar power dry cooling, no storage, and a solar multiple of 1.4.

Table 27. Cost and Performance Projection for a Concentrating Solar Power Plant with Storagea

Year	Capital Cost ($/kW)	Variable O&M Cost ($/MWh)	Fixed O&M Cost ($/kW-Yr)	Construction Schedule (months)	POR (%)	FOR (%)
2008	7280	–	–	–	–	–
2010	7060	0	50	24	0	6
2015	6800	0	50	24	0	6
2020	6530	0	50	24	0	6
2025	5920	0	50	24	0	6
2030	5310	0	50	24	0	6
2035	4700	0	50	24	0	6
2040	4700	0	50	24	0	6
2045	4700	0	50	24	0	6
2050	4700	0	50	24	0	6

[a] Concentrating solar power dry cooling, 6-hour storage, and a solar multiple of 2.

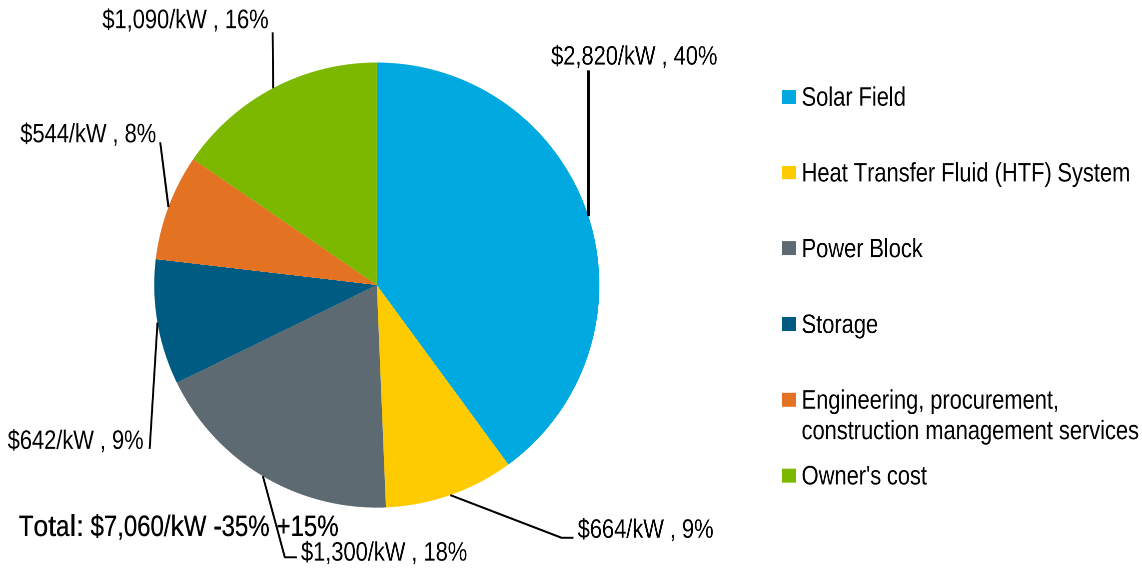

Figure 12. Capital cost breakdown for a trough concentrating solar power plant with storage

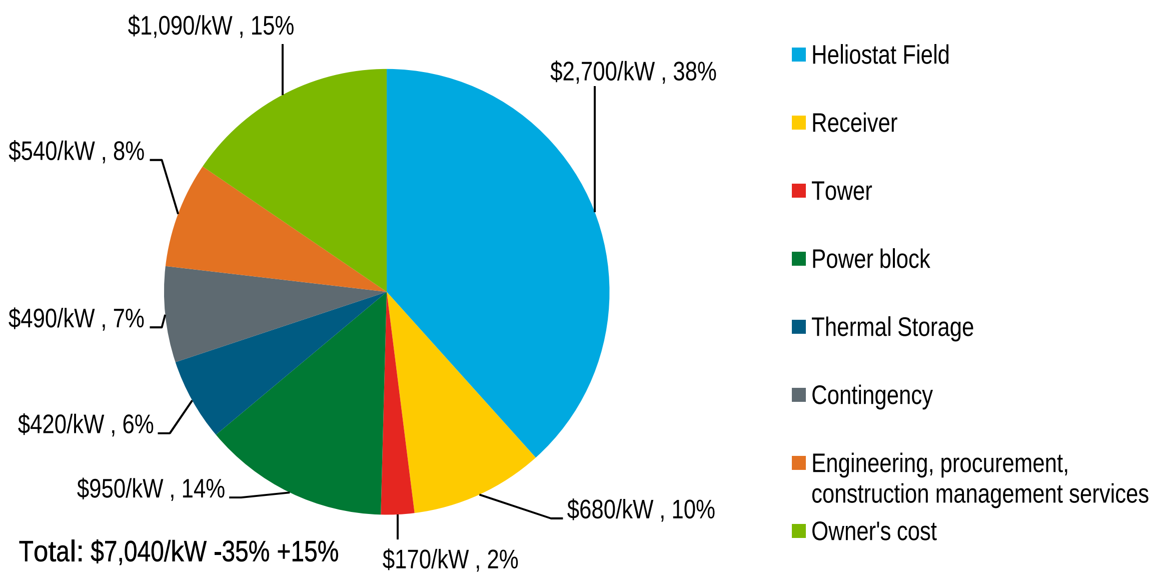

Figure 13. Capital cost breakdown for a tower concentrating solar power plant with storage

3.6 WIND ENERGY TECHNOLOGIES

Black & Veatch has experience achieved in 10,000 MW of wind engineering, development, and due diligence projects from 2005 to 2010. In addition, significant understanding of the details of wind cost estimates was obtained by performing 300 MW of detailed design and 300 MW of construction services in 2008. Black & Veatch also has reviewed wind project PPA pricing. This background was used to develop the cost estimates vetted in the WREZ stakeholder process and to subsequently update that pricing and adjust owner's costs. Costs are provided for onshore, fixed-bottom offshore and floating-platform offshore wind turbine installations. These cost and performance estimates are slightly more conservative than estimates identified in O'Connell and Pletka 2007 for the "20% Wind Energy by 2030" study. Improvements seen since 2004 to 2006 have been somewhat less than previously estimated as the technology more fully matures. Additional improvement is expected but at a slightly slower pace. There is both increased cost and increased performance uncertainty for floating-platform offshore systems.

3.6.1 Onshore Technology

Black & Veatch estimated a capital cost at 1,980 $/kW +25%. Cost certainty is relatively high for this maturing technology and no cost improvements were assumed through 2050. Capacity factor improvements were assumed until 2030; further improvements were not assumed to be achievable after 2030.

3.6.2 Fixed-Bottom Offshore Technology

Fixed-bottom offshore wind projects were assumed to be at a depth that allows erection of a tall tower with a foundation that touches the sea floor. Historical data for fixed-bottom offshore wind EPC projects are not generally available in the United States, but NREL reviewed engineering studies and published data for European projects. Black & Veatch estimated a capital cost at 3,310 $/kW +35%. Cost and capacity factor improvements were assumed to be achievable before 2030; cost improvements of approximately 10% were assumed through 2030 and capacity factor improvements were assumed for lower wind classes through 2030.

3.6.3 Floating-Platform Offshore Technology

Floating-platform offshore wind technology was assumed to be needed in water depths where a tall tower and foundation is not cost effective/feasible. Black & Veatch viewed the floating-platform wind turbine cost estimates as much more speculative. This technology was assumed to be unavailable in the United States until 2020. Fewer studies and published sources exist compared with onshore and fixed-bottom offshore systems. Black & Veatch estimated a 2020 capital cost at 4,200 $/kW +35%. Cost improvements of 10% were assumed through 2030 and capacity factor improvements were assumed for lower wind classes until 2030.

Table 28 through Table 33 present wind cost and performance data, including capacity factors, for onshore, fixed-bottom offshore, and floating-platform offshore technologies. Capital cost breakdowns for these technologies are shown in Figure 14 through Figure 16.

Table 28. Cost and Performance Projection for Onshore Wind Technology

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	2,060	–	–	–	–	–
2010	1,980	0	60	12	0.6	5
2015	1,980	0	60	12	0.6	5
2020	1,980	0	60	12	0.6	5
2025	1,980	0	60	12	0.6	5
2030	1,980	0	60	12	0.6	5
2035	1,980	0	60	12	0.6	5
2040	1,980	0	60	12	0.6	5
2045	1,980	0	60	12	0.6	5
2050	1,980	0	60	12	0.6	5

Table 29. Capacity Factor Projection for Onshore Wind Technology

	Capacity Factor (%)				
Year	Class 3	Class 4	Class 5	Class 6	Class 7
2010	32	36	41	44	46
2015	33	37	41	44	46
2020	33	37	42	44	46
2025	34	38	42	45	46
2030	35	38	43	45	46
2035	35	38	43	45	46
2040	35	38	43	45	46
2045	35	38	43	45	46
2050	35	38	43	45	46

Table 30. Cost and Performance Projection for Fixed-bottom Offshore Wind Technology

Year	Capita Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2008	3,410	–	–	–	–	–
2010	3,310	0	100	12	0.6	5
2015	3,230	0	100	12	0.6	5
2020	3,150	0	100	12	0.6	5
2025	3,070	0	100	12	0.6	5
2030	2,990	0	100	12	0.6	5
2035	2,990	0	100	12	0.6	5
2040	2,990	0	100	12	0.6	5
2045	2,990	0	100	12	0.6	5
2050	2,990	0	100	12	0.6	5

Table 31. Capacity Factor Projection for Fixed-bottom Offshore Wind Technology

	Capacity Factor (%)				
Year	Class 3	Class 4	Class 5	Class 6	Class 7
2010	36	39	45	48	50
2015	36	39	45	48	50
2020	37	39	45	48	50
2025	37	40	45	48	50
2030	38	40	45	48	50
2035	38	40	45	48	50
2040	38	40	45	48	50
2045	38	40	45	48	50
2050	38	40	45	48	50

Table 32. Cost and Performance Projection for Floating-Platform Offshore Wind Technology

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-Yr)	Construction Schedule (Months)	POR (%)	FOR (%)
2020	4,200	0	130	12	0.6	5
2025	4,090	0	130	12	0.6	5
2030	3,990	0	130	12	0.6	5
2035	3,990	0	130	12	0.6	5
2040	3,990	0	130	12	0.6	5
2045	3,990	0	130	12	0.6	5
2050	3,990	0	130	12	0.6	5

Table 33. Capacity Factor Projection for Floating-Platform Offshore Wind Technology

	Capacity Factor (%)				
Year	Class 3	Class 4	Class 5	Class 6	Class 7
2020	37	39	45	48	50
2025	37	40	45	48	50
2030	38	40	45	48	50
2035	38	40	45	48	50
2040	38	40	45	48	50
2045	38	40	45	48	50
2050	38	40	45	48	50

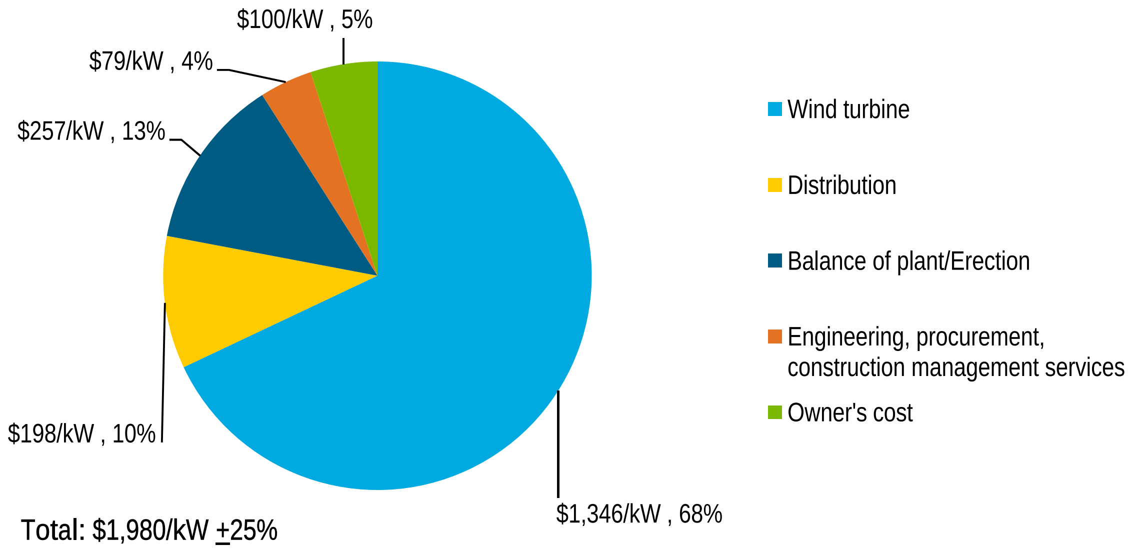

Figure 14. Capital cost breakdown for an onshore wind power plant

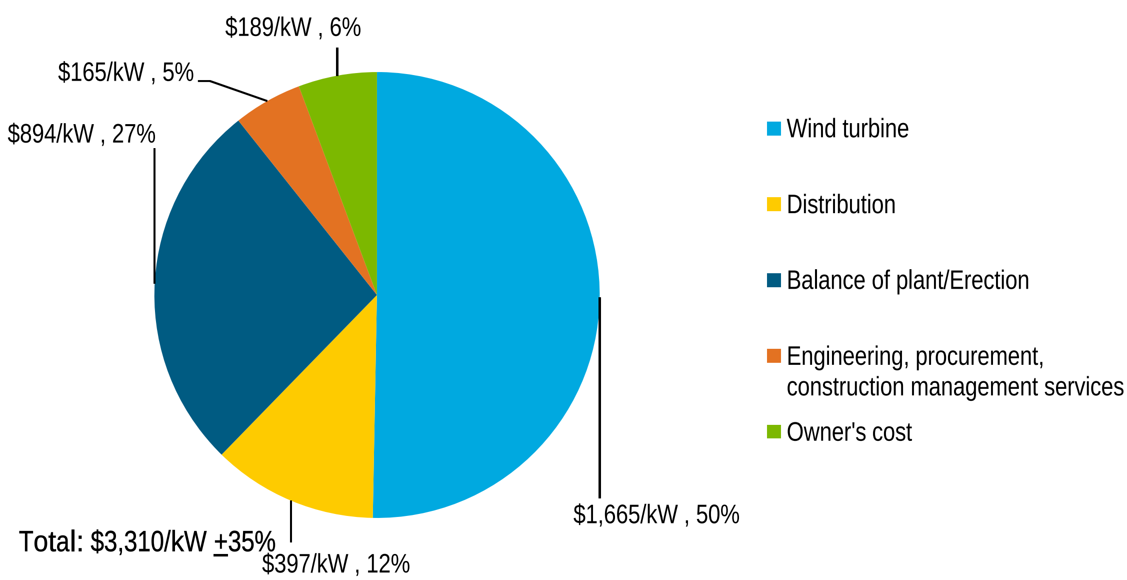

Figure 15. Capital cost breakdown for a fixed-bottom offshore wind power plant

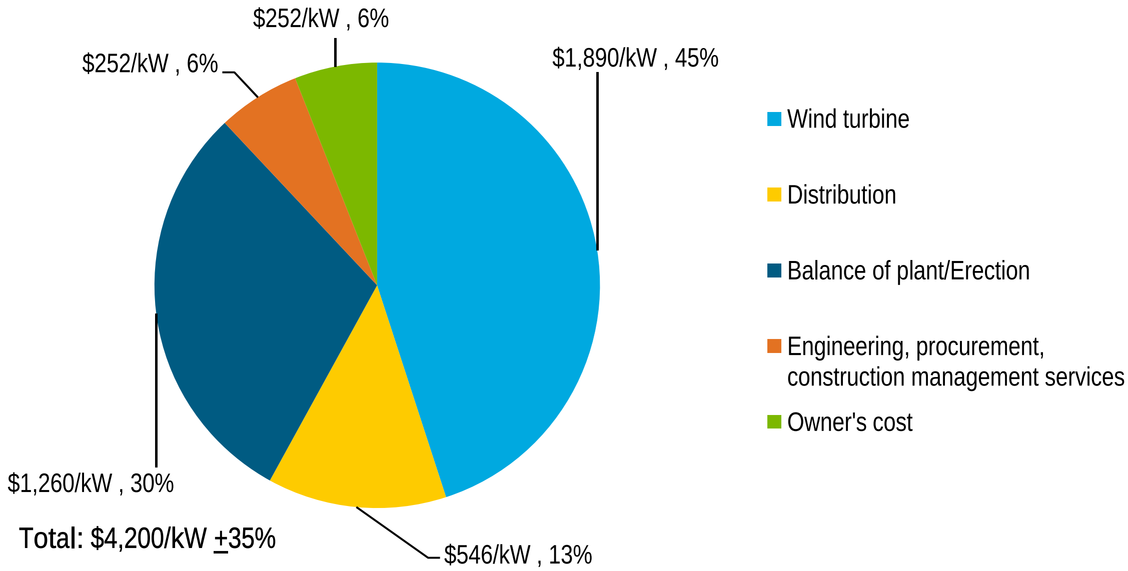

Figure 16. Capital cost breakdown for a floating-platform offshore wind power plant

4 Cost and Performance Data for Energy Storage Technologies

Selecting a representative project definition for compressed air energy storage (CAES) and pumped-storage hydropower (PSH) technologies that can then be used to identify a representative cost is extremely difficult; one problem is that a very low cost can be estimated for these technologies if the best circumstances are assumed (e.g., use of existing infrastructure). For example, an assumption can be made for CAES that almost no below ground cost is contributed when building a small project that can be accommodated by an abandoned gas well of adequate size. For PSH, one can assume only two existing reservoirs need to be connected with a pump and turbine at the lower reservoir. These low cost solutions can be compared to high cost solutions; for CAES, excavation of an entire cavern out of hard rock could be assumed, and for PSH construction of new reservoirs and supply of pump/turbine and interconnections between reservoirs could be assumed. These scenarios are entirely different from possible low cost or mid-cost options. While this situation makes identifying a representative, or average, project difficult, this selection must be made before the discussion of costs can be opened. The design options and associated costs for CAES and PSH are unlimited. History is no help because circumstances are now different from those that existed when the previous generation of pumped hydropower was built and because there are not a large number of existing CAES units to review. Another issue with PSH is that transmission has been equally challenging with cost and environmental issues limiting pumped options.

No CAES or PSH plants have been built recently. Further, in the case of PCH, the Electric Power Research Institute has indicated, "scarcity of suitable surface topography that is environmentally acceptable is likely to inhibit further significant domestic development of utility pumped-hydro storage."5

Black & Veatch initially selected point estimates for CAES and PSH with ranges around points that can capture a broad range of project configuration assumptions. The disadvantage of the storage estimates initially selected is that they might not adequately reflect the very lowest cost options that may eventually be available. However, the advantage is that they are examples of what real developers have recently considered for development; developers have considered projects with these costs and descriptions to be worthy of study. They are not the least cost examples that could someday be available for consideration by developers, but they are recent examples of site and technology combinations that developers actually have had available for consideration. In addition, the PSH example is of relatively small capacity that may be suitable in a larger number of locations; it is not a less expensive, larger capacity system that may not be as available in many parts of the country. Lastly, because Black & Veatch views the costs as mid-range, they may be considered reasonably conservative. Black & Veatch recognizes that it could have chosen lower cost cases, but the cases initially shown here are representative of projects that developers have actually recently considered.

[5] Pumped Hydroelectric Storage, http://www.rkmaonline.com/utilityenergystorageSAMPLE.pdf

4.1 COMPRESSED AIR ENERGY STORAGE (CAES) TECHNOLOGY

A confidential CAES in-house reference study for an independent power producer has been used for the point estimate, and the range was based on historical data. A two-unit recuperated expander with storage in a solution-mined salt dome was assumed for this estimate. Approximately 262 MW net with 15 hours of storage was assumed to be provided. Five compressors were assumed to be included. A 2010capital cost was estimated at 900 $/kW -30% + 75%. No cost improvement was assumed over time . Table 34 presents costs and performance data for CAES. Table 535 presents emission data for the technology.

Table 34. Cost and Performance Projection for a Compressed Air Energy Storage Plant (262 MW)

Year	Heat Rate (Btu/kWh)	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-year)	Round-Trip Efficiency	FOR (%)	POR (%)	Construction Schedule (Months)	Min. Load (%)	Spin Ramp Rate (%/min.)	Quick Start Ramp Rate (%/min.)
2008	4910	927	–	–	–	–	–	–	–	–	–
2010	–	–	–	–	–	–	–	–	–	–	–
2015	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2020	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2025	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2030	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2035	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2040	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2045	4910	900	1.55	11.6	1.25	3	4	18	50	10	4
2050	4910	900	1.55	11.6	1.25	3	4	18	50	10	4

Table 35. Emission Rates for Compressed Air Energy Storage

SO_2 (lb/ hr)	NO_X (lb/hr)	Hg Micro (lb/hr)	PM10 (lb/hr)	CO_2 (kpph)
3.4	47	0	11.6	135

The capital cost breakdown for the CAES plant is shown in Figure 17.

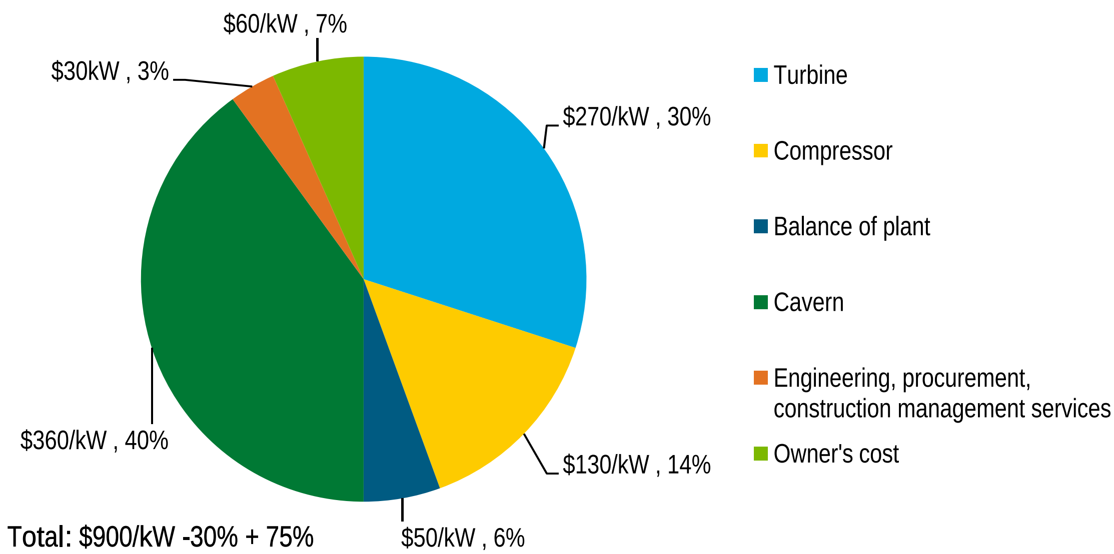

Figure 17. Capital cost breakdown for a compressed air energy storage power plant

CAES plant cost savings will occur in all cost categories over time.

4.2 PUMPED-STORAGE HYDROPOWER TECHNOLOGY

A confidential in-house reference study for an independent power producer was used for the point estimate, and the range was established based on historical data. The PSH cost estimate assumed a net capacity of 500 MW with 10 hours of storage. A 2010 capital cost was estimated at 2,004 $/kW +50%. Appendix D provides additional detail on cost considerations for PSH technologies. This is a mature technology with no cost improvement assumed over time.. A list of current FERC preliminary licenses indicates an average size between 500 and 800 MW. Cost and performance data for PSH are presented in Table 36.

Table 36. Cost and Performance Projection for a Pumped-Storage Hydropower Plant (500 MW)

Year	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Round-Trip Efficiency (%)	FOR (%)	POR (%)	Construction Schedule (Months)	Min. Load (%)	Spin Ramp Rate (%/min.)	Quick Start Ramp Rate (%/min.)
2008	2297	–	–	–	–	–	–	–	–	–
2010	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2015	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2020	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2025	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2030	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2035	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2040	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2045	2230	0	30.8	0.8	3.00	3.80	30	33	50	50
2050	2230	0	30.8	0.8	3.00	3.80	30	33	50	50

The capital cost breakdown for the pumped-storage hydropower plant is shown in Figure 18.

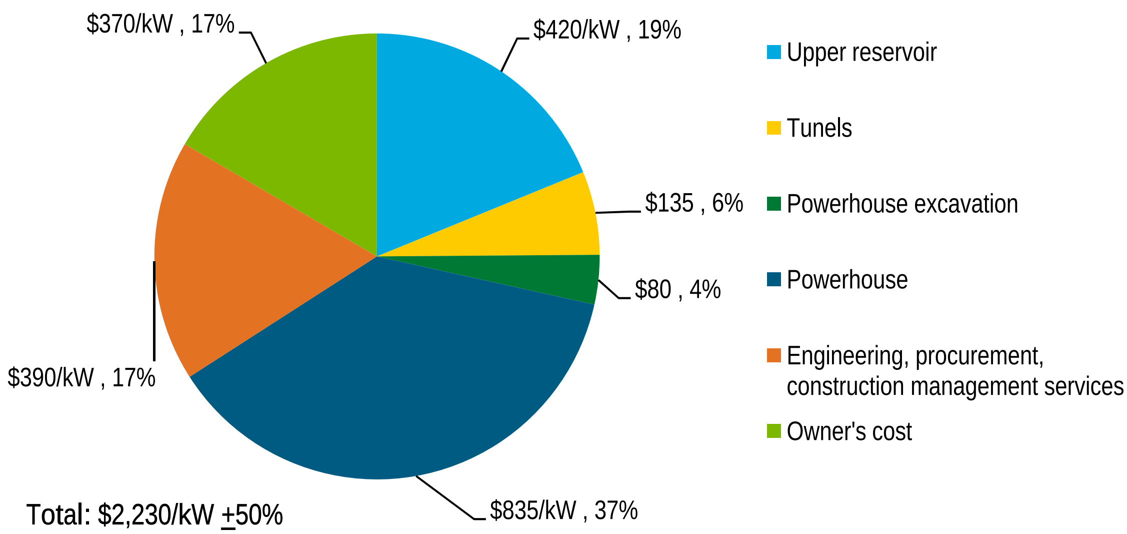

Figure 18. Capital Cost breakdown for a pumped-storage hydropower plant

Pumped hydroelectric power plant cost savings will occur primarily in the powerhouse category over time.

4.3 BATTERY ENERGY STORAGE TECHNOLOGY

A confidential in-house reference study for an independent power producer has been used for the point estimate, and the range has been established based on historical data. The battery proxy was assumed to be a sodium sulfide type with a net capacity of 7.2 MW. The storage was assumed to be 8.1 hours. A capital cost is estimated at 3,990 $/kW (or 1,000 $/kW and 350 $/kWh) +75%. Cost improvement over time was assumed for development of a significant number of new battery options. Table 37 presents cost and performance data for battery energy storage. The O&M cost includes the cost of battery replacement every 5,000 hours.

Table 37. Cost and Performance Projection for a Battery Energy Storage Plant (7.2 MW)

(Year)	Capital Cost ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Round-Trip Efficiency (%)	FOR (%)	POR (%)	Construction Schedule (Months)	Min. Load (%)	Spin Ramp Rate (%/sec)	Quick Start Ramp Rate (%/sec)
2008	4110	–	–	–	–	–	–	–	–	–
2010	3990	59	25.2	0.75	2.00	0.55	6	0	20	20
2015	3890	59	25.2	0.75	2.00	0.55	6	0	20	20
2020	3790	59	25.2	0.75	2.00	0.55	6	0	20	20
2025	3690	59	25.2	0.75	2.00	0.55	6	0	20	20
2030	3590	59	25.2	0.75	2.00	0.55	6	0	20	20
2035	3490	59	25.2	0.75	2.00	0.55	6	0	20	20
2040	3390	59	25.2	0.75	2.00	0.55	6	0	20	20
2045	3290	59	25.2	0.75	2.00	0.55	6	0	20	20
2050	3190	59	25.2	0.75	2.00	0.55	6	0	20	20

The capital cost breakdown for the battery energy storage plant is shown in Figure 19.

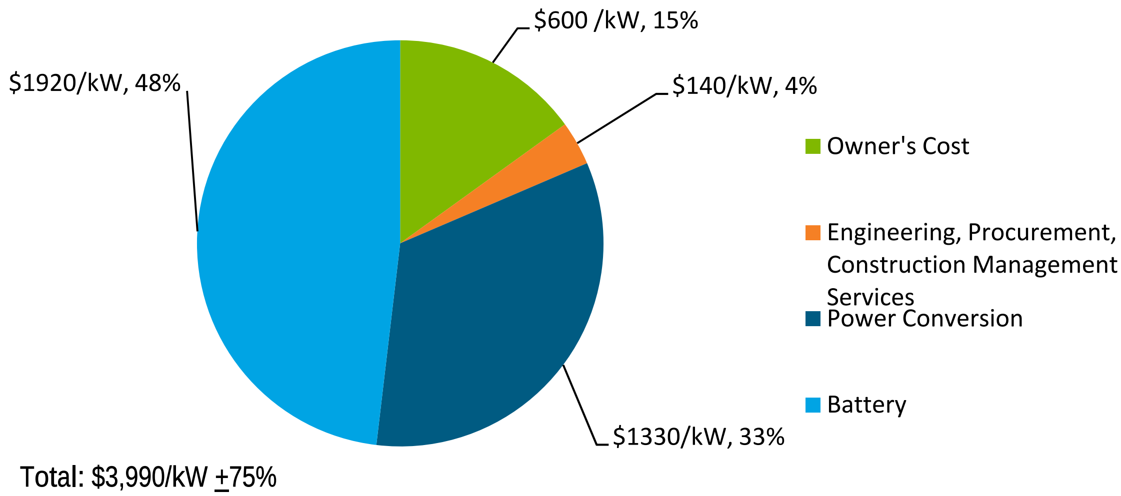

Figure 19. Capital Cost Breakdown for a Battery Energy Storage Plant

Battery energy storage plant cost reductions will occur primarily in the battery cost category over time.

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Appendix A. Energy Estimate for Wave Energy Technologies

RESOURCE ESTIMATE

This appendix documents an analysis of the wave energy resource in the United States and provides the basis for information presented in Section 0 above.

Coastline of the United States

Using Google Earth, Black & Veatch sketched a rough outline of the East and West Coasts of the United States, and divided each into coastal segments to match the available wave data, as described in Figure A-1 and Table A-1. The states of Alaska and Hawaii were not included.

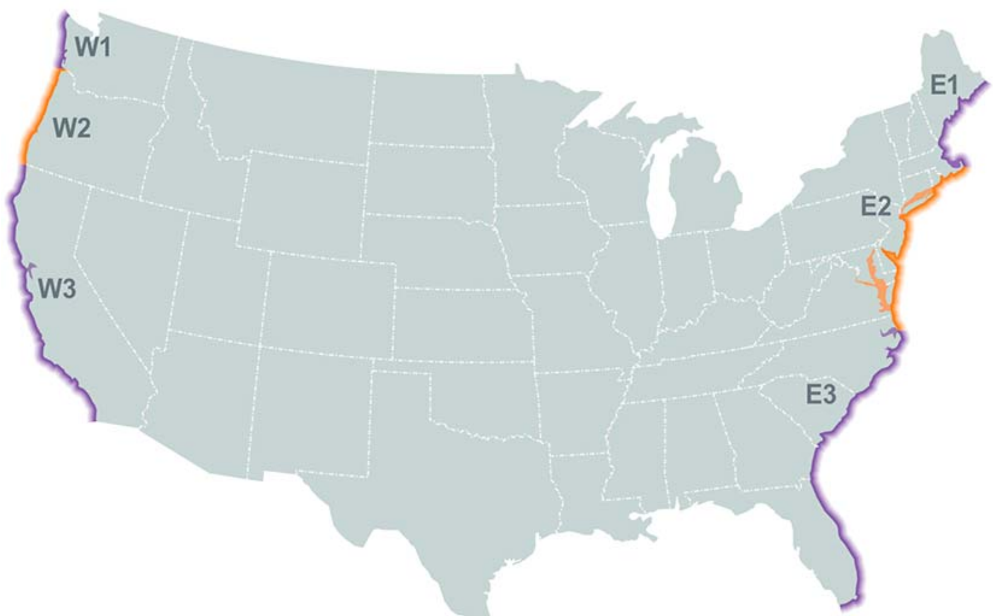


Figure A-1. Designated Coastal Segments

W1: Neah Bay, WA (26.5 kW/m @ ? m)
W2: Coquille, OR (21.2 kW/m @ 64 m)
W3: San Francisco, CA (20 kW/m @ 52 m)
E1: Portland, ME(4.9 kW/m @ 19 m)
E2: Middle (13.8 kW/m @ 74 m)
E3: South East (kW/m @ m)

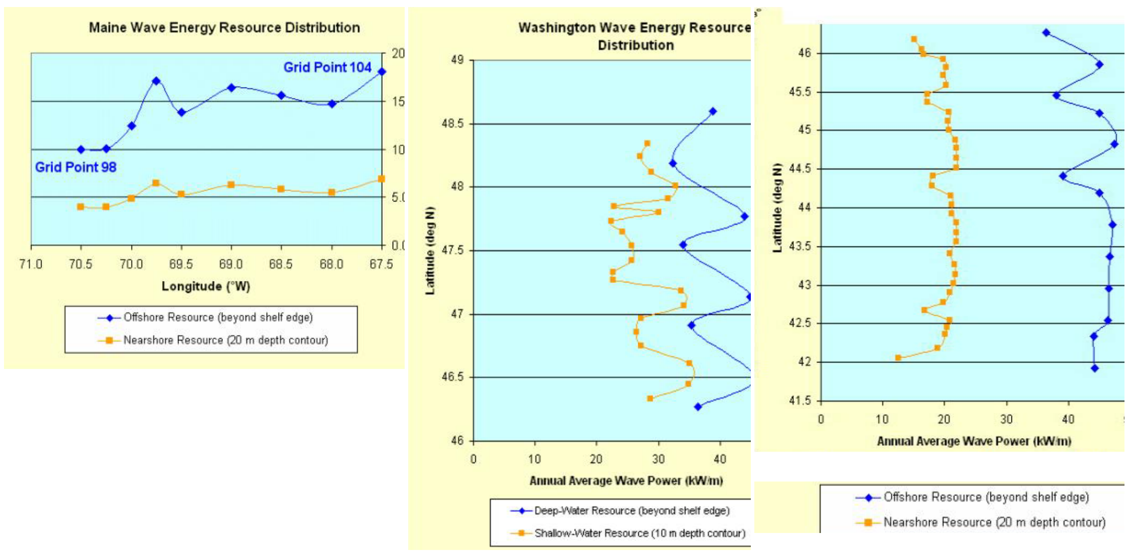
Table A-1. Length of Coastlines in United States

Coastal Segment	Coastline Length (km)	Description
W1	238	Washington
W2	492	Oregon
W3	1322	California
West Total	**2052**	
E1	465	Maine–Massachusetts
E2	942	Massachusetts–North Carolina
E3	1390	North Carolina–Florida
East Total	**2797**	

Wave Energy Resource

Wave energy resource data for West Coast sites (Washington, Oregon, and California) and northern East Coast sites (Maine and Massachusetts) were extracted from several relevant reports (EPRI n.d.).

In addition to data from a small number of specific buoys, EPRI (n.d.) contained annual average power for sites along the coasts of selected states, as shown on Figure A-2. These data were used to estimate the wave energy resource for the contiguous United States.



Maine (E1)	Washington (W1)	Oregon (W2)
(Hagerman et al. 2004a)	(Hagerman et al. 2004b)	(Hagerman et al. 2004c)

Figure A-2. Wave Flux for Maine, Washington, and Oregon

In addition to the EPRI data, wave flux results (in kW/m), from Kane (2005, Table 8) were also used to estimate California's wave energy resource as shown in Figure A-3. Most sites assessed in Kane are deeper than 100 m, but approximately 3 of the 10 sites are from shallower buoys, including Del Norte (60 m), Mendocino (82 m), and Santa Cruz (13 m, 60-80 m).

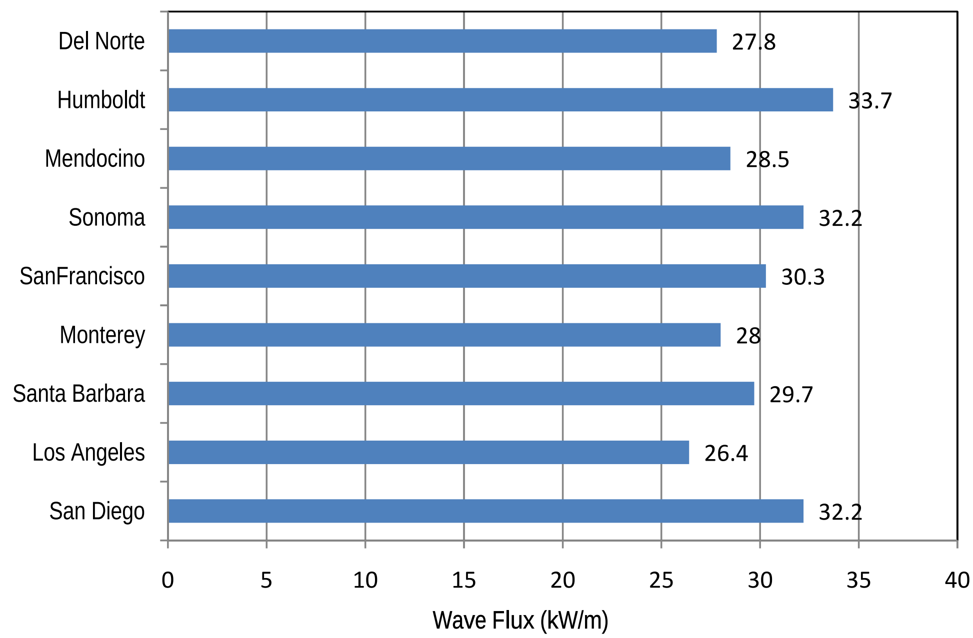


Figure A-3. Wave Flux for California

(Coastal segment W3, Figure A-1) (Kane 2005, Table 8)

The available data were used to estimate an average wave energy resource for each coastal segment. As a spot check, the EPRI (n.d.) cites 20 kW/m wave flux at 52-m depth at the San Francisco site, which approximately matches the 30 kW/m cited by Kane (2005, Table 8) for San Francisco at a deep site. Consequently, both studies were used with relative confidence. No wave resource data were found for the central (E2, Figure A-1) and southern (E3) East Coast.

Normalizing to 50-m Depth

All wave resources were normalized to a 50-m depth contour. This depth is believed to represent for the next 10 years the average depth targeted by most wave energy developers, and is the basis for the cost estimates presented below. Within the next 50 years, exploiting the wave energy resource at greater depths will likely be possible. While more energy may be available at deeper sites, it might not be as commercially exploitable, as the wave direction would be more variable and grid connection costs would increase significantly.

The wave energy data presented above are sourced from deep water off the continental shelf. Results from a study by Queen's University Belfast & RPS Group (Folley et al. 2009) were used to estimate the resource at 50-m depth. Using wave data and modeling for the European Marine Energy Centre (EMEC) site in Scotland, Folley et al. calculated the gross (omni-directional), net (directionally resolved), and exploitable (net power less than four times the mean power density) for a number of site depths. Figure A-4 shows the results from this study.

Given the lack of other available data, Black & Veatch assumed the EMEC results apply to the United States and used them to estimate gross power at 50-m depth from U.S. offshore wave data from the previously mentioned sources (taken to be offshore – all directions). By multiplying the U.S. offshore data by 23.5/41 (as read from Figure A-4), the wave flux was normalized to 50-m depth.

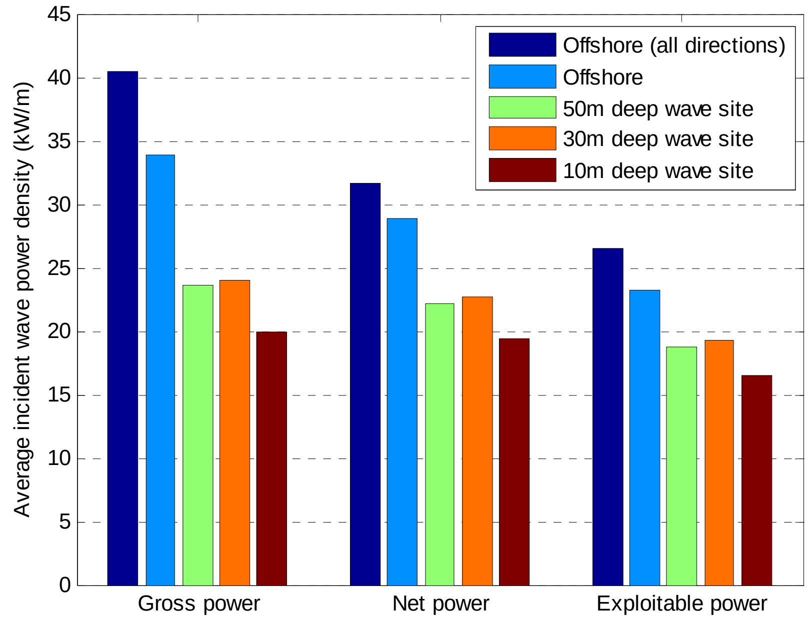


Figure A-4. Gross v. Exploitable Power at Varying Sea Depths

(Folley et al. 2009, p. 7)

However, the particular site conditions at the EMEC site might mean these conclusions are not applicable to all sites. Local bathymetry can create high and low resource areas, and the seabed slope is relatively steep at the EMEC site, which reduces the distance between deep and shallow sites and the energy dissipated between them. It is, for example, clear from Figure A-2 that the wave energy resource dissipation from offshore to near shore is much higher in Oregon than it is in Washington.

Additional studies are needed to establish the validity of this relationship for the U.S. coastline, but it is believed to be a reasonable first estimate.

Directionality

Black & Veatch was not able to locate directional wave data for U.S. sites; a directionality of 0.9, which has historically been used for UK wave energy sites, was therefore assumed for the *Base Case*.

A *Pessimistic Scenario* (low-deployment) and an *Optimistic Scenario* (high deployment) were developed to reflect the uncertainty in the U.S. wave resource. In the *Pessimistic Scenario* and the *Optimistic Scenario*, factors of 0.8 and 1.0 respectively were applied to reflect the fact that at some sites the wave resource is more focused than at others (particularly in shallower waters) and that some wave devices are able to cope with directionality more efficiently than others (e.g., point absorbers).

Spacing

The spacing between the devices was not considered in the estimate of the wave energy resource, as the resource study is based on available wave energy per wave front. Hence, no farm configuration was considered for the wave devices, and energy available is based only on a percentage of extraction from the available resource.

Conversion from Absorbed Power to Electrical Power

A wave energy converter efficiency of 70% from the absorbed power to the electrical power generated at shore was generally assumed, as 70% is the typical value used for wave devices. In the *Pessimistic Scenario*, efficiency of 60% is assumed and 80% is assumed in the *Optimistic Scenario*.

Exploitable Coastline

In the *Base Case*, 50% of the coastline length was estimated to be exploitable. In the *Optimistic Scenario*, the full length of coastline was considered exploitable, reflecting the fact that if a site would not be suitable for development at 50 m in the next few years, it might be exploitable at deeper or shallower waters in the next 50 years. Under the *Pessimistic Scenario,* 25% of the coastline was considered exploitable.

Extractable Energy from the Wave Resource

Clearly, the whole energy resource cannot be extracted from the wave front without impacting the environment and the project economics. Black & Veatch did not consider environmental issues and set the criteria for extractable wave energy on the economical cut-off point. As a wave energy project is believed to be uneconomical for wave resource lower than a 15 kW/m threshold, the percentage of extractable power compared to the available resource was set to ensure the available wave resource does not drop below this economic threshold.

Wave Energy Regime

The wave resource was classified into wave energy regimes as shown in Table A-2.

Table A-2. Wave Energy Regime Classification

Wave Energy Regime	Wave Flux at 50-m Depth (kW/m)
Very Low	< 15
Low	15–20
Medium	20–25
High	> 25

The wave energy resource (in kW/m) data were reviewed for each site, and a split in the resource was estimated (Table A-3). For example, because approximately 10 of the 13 data points for the W2 (Oregon) coastline have a wave energy resource above 25 kW/m, 75% of the resource was estimated as high," with the remainder being estimated as "medium."

Table A-3. Wave Energy Regime Split

	Very Low	Low	Medium	High
W1	–	–	100%	0%
W2	–	–	25%	75%
W3	–	100%	–	–
E1	100%	–	–	–
E2	100%	–	–	–
E3	100%	–	–	–

Coastal segment E1 (Figure A-1), with a peak average offshore wave energy resource of less than 20 kW/m, corresponding to an equivalent wave energy resource of less than 11 kW/m at 50 m, was classified as "very low" and was not counted in the wave resource estimate. Coastal segments E2 and E3 were both assumed to have a milder wave regime than E1, and therefore to also fall into the "very low" category and were not included in the resource estimate.

Wave Energy Mean Annual Resource

By multiplying the average wave energy resource (at 50 m depth) for each segment by the coastal length, and the wave energy regime split (Table ATable -3), the U.S. wave energy resource was estimated for the Base Case as shown in Table A-4. This estimate does not construe any device capacity factors but does take into account the directionality, efficiencies, and exploitable percentage explained above. The values are given in MW, and hence they represent mean annual electrical power.

Table A-4. Mean Annual U.S. Wave Energy Resource (MW)—*Base Case*

Coastal Segment	Low	Medium	High	Total
W1	–	707	–	707
W2	–	476	1,429	1,905
W3	1,539	–	–	1,539
West Total	1,500	1,200	1,400	4,100
East Total	–	–	–	–
TOTAL	1,500	1,200	1,400	4,100

As explained above, the mean annual U.S. wave energy resource for the *Pessimistic* and *Optimistic Scenarios* are shown in Table A-5 and Table A-6 respectively, consistent with the directionality, the spacing, and the percentage of coastline exploitable assumptions for these Scenarios described above.

Table A-5. Mean Annual U.S. Wave Energy Resource (MW)—*Pessimistic Scenario*

Coastal Segment	Low	Medium	High	Total
W1	–	269	–	269
W2	–	181	544	726
W3	586	–	–	586
West Total	600	500	500	1,600
East Total	–	–	–	–
TOTAL	600	500	500	1,600

Table A-6. Mean Annual U.S. Wave Energy Resource (MW)—*Optimistic Scenario*

Coastal Segment	Low	Medium	High	Total
W1	–	1,795	–	1,795
W2	–	1,210	3,629	4,838
W3	3,908	–	–	3,908
West Total	3,900	3,000	3,600	10,500
East Total	–	–	–	–
TOTAL	3,900	3,000	3,600	10,500

Capacity Factor

The U.S. wave resource is smaller than the UK resource. Black & Veatch based its cost estimates on UK-based technologies designed mostly for UK sites. The rated power and power matrix that is being used in this cost estimate was developed for an average UK site of approximately 30 kW/m, which is higher than for any U.S. site. Typically, technology developers would change the rated power conditions and tuning of their device to match a lower power resource site, however, in this analysis the technologies have not been optimized for the different site conditions.

Table A-7 shows the capacity factors that were applied in the cost estimates for the different resource bands. As explained above, these are lower than they would be if the device were optimized specifically for a U.S. site rather than for a UK site, but this is not expected to make a significant difference to the results, bearing in mind the other potential uncertainties in the analysis.

Table A-7. Capacity Factors for the Different Resource Bands in the United States

Resource Band	Representative Site	Capacity Factor
Low (15 kW/m –20 kW/m)	Massachusetts	15%
Medium (20 kW/m–25 kW/m)	Oregon	20%
High (25 kW/m–30 kW/m)	UK	25%

Installed Capacity Limits in the United States

The values in Tables A-4 to A-6 are annual average power generation as they were calculated from the annual wave energy resource available from the wave front. To estimate the corresponding installed capacity, the values stated above were divided by the capacity factors given in Table A-7. Clearly, major uncertainties are inherent to the wave resource in the United States, and hence the total wave energy resource ranges from 9,000 MW to 55,000 MW electrical installed capacity (including efficiencies), as shown in Table A-8 and Figure A-5.

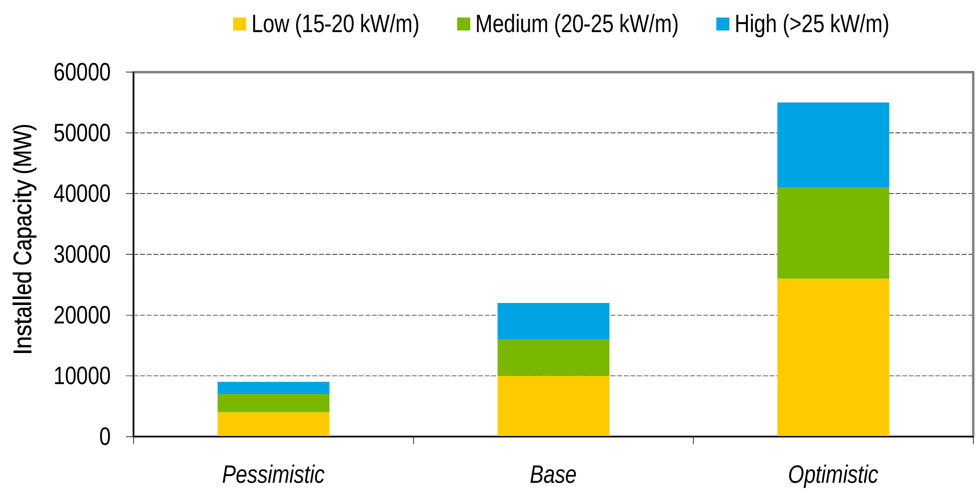


Figure A-5

Table A-8. U.S. Wave Energy Resource (MW)—Installed Capacity Summary for all Scenarios

Scenario	Low Band (15-20 kW/m)	Medium Band (20-25 kW/m)	High Band (>25 kW/m)	Total
Pessimistic	4,000	3,000	2,000	9,000
Base Case	10,000	6,000	6,000	22,000
Optimistic	26,000	15,000	14,000	55,000

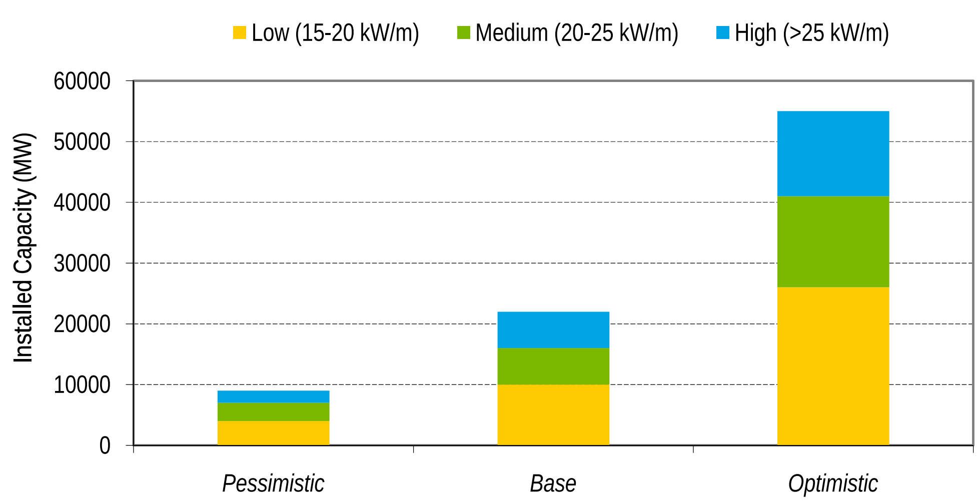


Figure A-5. Wave resource estimate for different scenarios

COST OF ENERGY ESTIMATE

To forecast the future cost of energy of wave power in the United States, a number of key assumptions must be made. Initially, a deployment scenario must be generated to forecast the potential growth of the industry; a starting cost of energy must be determined based on the current market costs; and, a learning rate or curve is required to reflect potential reductions in the cost of energy with time. This section details Black & Veatch's methods to determine a future forecast of the potential economics of the wave power industry in the United States.

Given the relative uncertainties due to the early stage of the wave power market, an *Optimistic Scenario*, a *Base Case*, and a *Pessimistic Scenario* were considered for the deployment rates, cost of electricity, and learning rates. The *Base Case* represents Black & Veatch's most likely estimate, while the *Optimistic* and *Pessimistic Scenarios* represent the potential range of the primary uncertainties in the analysis.

Wave Deployment Estimate

Global Deployment

Global deployment is required to drive the learning rate of a technology; therefore, Black & Veatch developed an assumption for the deployment of wave energy converters globally to 2050. This estimate was made identifying the planned short term (to 2030) future deployments of the leading wave energy converter technologies. The growth rate from 2020 to 2030 was then used as a basis to estimate the growth to 2050. This growth rate was decreased annually by 1% from 2030 and each subsequent year in order to represent a natural slowing of growth that is likely to occur. The year 2030 was chosen as the start date for the slowdown as this would represent approximately 20 years of high growth, which is reasonable based on slowdowns experienced in other industries (e.g., wind) that have reflected resource and supply chain constraints.

Not all developers are likely to prove successful, and naturally, not all planned installations will proceed. As such, weighting factors were applied to reflect the uncertainty related to both the developers' potential success and their projects' success.

Deployment in the United States

Deployment in the United States has been based on the growth rate of global deployment. The current installed capacity and the planned installed capacity for 2010 in the United States were calculated. These starting values were then used in combination with the global growth rate to determine the scenarios for U.S. deployment to 2050. The growth rates for the *Optimistic Scenario*, the *Base Case*, and the *Pessimistic Scenario* were based on 25% of high, 16% of base, and 8% of low global deployment scenarios respectively and therefore each was assigned a unique growth rate. The total resource installed capacities estimates for the scenarios calculated above were applied. Figure A-6 shows the results of the analysis.

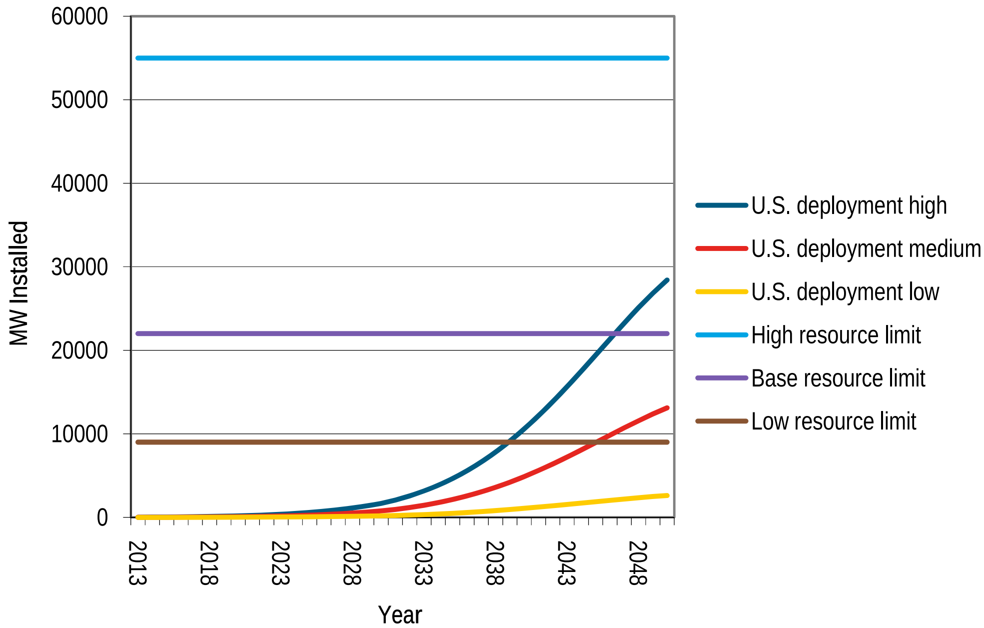


Figure A-6. Deployment Scenarios for Wave Power in the United States to 2050

The analysis shows that the United States could install to approximately13 gigawatt (GW) by 2050 in the *Base Case* with an *Optimistic* deployment scenario of approximately 28.5 GW; the *Pessimistic* deployment scenario installed 2.5 GW by 2050; none of the scenarios reaches its respective deployment limit. The growth rates vary among the deployment scenarios; these different rates are the major contributing factor to the large variance among the scenarios and reflect the current lack of understanding of the U.S. resource and the early stage of development of the wave energy converter industry.

Deployment Assumption

Given the relatively low energy density of U.S. wave resource sites, it was assumed that 1) developers would aim to maximise project economics for early projects and would thus deploy only at sites in the high-band wave resource, 2) that when this is exhausted, the medium-band resource sites would be exploited, and 3) that the low resource sites would be used only after the medium-band resource was exhausted. It is also assumed that the effects of the learning curve will make the medium- and low-resource sites more feasible in the future. This order of exploitation is a key assumption used throughout the cost modelling and will naturally result, as seen below, in distinct offsets in cost of electricity projections at the points of transition between the resource bands.

Deployment Constraints

The deployment growth is limited only by the resource constraints. It was assumed that all other factors impacting deployment would be addressed, including but not limited to: financial requirements, supply chain infrastructure, site-specific requirements, planning, and supporting grid infrastructure.

Learning

To form a judgment as to the likely learning rates that can reasonably be assumed for the coming years, it is appropriate to first consider empirical learning rates from other emerging renewable energy industries. This section provides an overview of learning experience from similar developing industries, suggests applicable learning rates for wave technology, and considers scenarios for future generation costs. Figure A-7 shows learning rate data for a range of emerging renewable energy technologies.

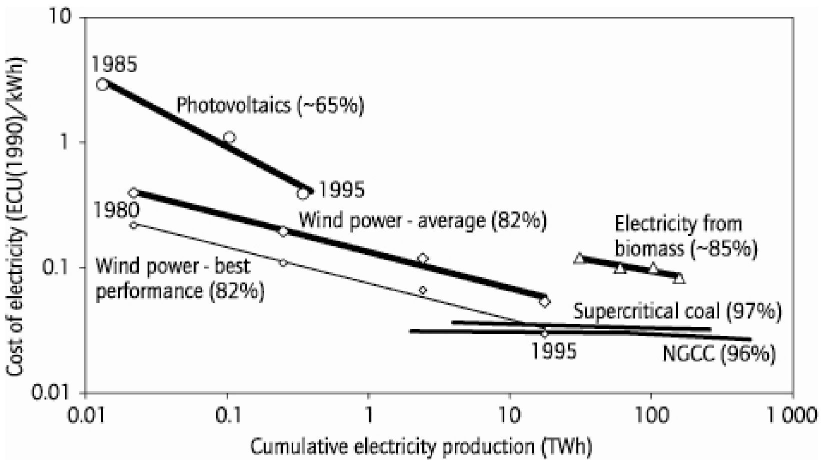


Figure A-7. Learning in Renewable Energy Technologies

(IEA 2000)

Cost and cumulative capacity are observed to exhibit a straight line when plotted on a log-log diagram; mathematically, this straight line indicates that an increase by a fixed percentage of cumulative installed capacity gives a consistent percentage reduction in cost. For example, the progress ratio for photovoltaics during 1985–1995 was approximately 65% (learning rate approximately 35%), and the progress ratio for wind power between 1980 and 1995 was 82% (learning rate 18%).

Any discussion as to the likely learning rates that may be experienced in the wave energy industry will be subjective. The closest analogy for the wave industry has been assumed to be the wind industry. A progress ratio as low as wind energy (82%) is not expected for the wave industry for the following reasons:

- In wind, much of the learning was a result of doing "the same thing bigger" or "upsizing" rather than "doing the same or something new." This upsizing has probably been the single most important contributor to cost reduction for wind, contributing approximately 7% to the 18% learning rate.[6] Most wave energy devices (particularly resonant devices) do not work in this way. A certain size of device is required for a particular location to minimize the energy cost, and simply making larger devices does not reduce energy costs in the same way. Nevertheless, wave devices can benefit from the economies of scales of building farms with larger devices and larger numbers of devices.

[6] See, for example, Coulomb and Neuhoff 2006, which calculates an 11% learning rate for wind excluding learning due to "upsizing."

- Unlike wind in which the market as mostly adopted a single technical solution (3-bladed horizontal-axis turbine), there are many different technology options for wave energy devices and there is little indication at this stage as to which technology is the best solution. This indicates that learning rate reductions will take longer to realize when measured against cumulative industry capacity.

The learning rates for wave energy converters have been developed as per the above discussion and are presented in Table A-9. The learning rates for the United States were assumed to be 1% less than what would be expected in the UK, as the energy densities of the perspective sites are lower (which suggests that there may be less room for cost improvement).

Table A-9. Learning Rates

Scenario	Learning Rate
Optimistic	15%
Base Case	11.5%
Pessimistic	8%

Cost of Energy

Cost Input Data

Black & Veatch used its experience in the wave energy converter industry to develop a cost of electricity for a first 10-MW farm assuming 50 MW installed globally, which effectively represents the cost of the initial commercial farm; these costs are presented in Table A-10. The costs presented are considered an industry average covering both off-shore and near-shore wave technologies. Learning rates were applied to the cost of electricity only after the 50 MW of capacity was installed worldwide.

Table A-10. Cost Estimate for a 10-MW Wave Farm after Installation of 50 MW

Resource	Costs	Costs ($ million)		Performance (%)		Cost of Electricity(c/kWh)
		Capital	Operating (annual)	Capacity Factor	Availability	
High-band Resource (25-30 kW/m)	*Pessimistic*	73	4.6	23%	88%	69
	Base Case	62	3.9	25%	92%	50
	Optimistic	50	3.4	28%	95%	37
Medium-band Resource (20-25 kW/m)	*Pessimistic*	77	4.8	18%	88%	91
	Base Case	66	4.1	20%	92%	67
	Optimistic	53	3.5	22%	95%	49
Low-band Resource (15-20 kW/m)	*Pessimistic*	81	5.0	14%	88%	127
	Base Case	68	4.4	15%	92%	94
	Optimistic	56	3.8	17%	95%	69

The *Pessimistic* and *Optimistic Scenarios* were generated to indicate the uncertainties in the analysis.

General Assumptions

These general assumptions were used for this analysis:

- Project life: 20 years
- Discount rate: 8%.
- Device availability: 90% in the Base Case, 92% in the *Optimistic Scenario*, and 88% in the *Pessimistic Scenario*.

Also, the cost of electricity presented is in 2008 dollars and future inflation has not been accounted for.

Cost of Energy

The cost of electricity directly depends on the learning curve and the deployment rate. Figure A-8 shows the cost of electricity forecast for the *Base Case* learning rate and the *Base Case* deployment scenario (Table A-9 and Figure A-6 respectively) based on the *Optimistic, Base Case*, and *Pessimistic* costs (Table A-8). The *Optimistic* and *Pessimistic* curves in the figure represent the upper and lower cost uncertainty bands for the *Base Case* deployment assumption and learning rate.

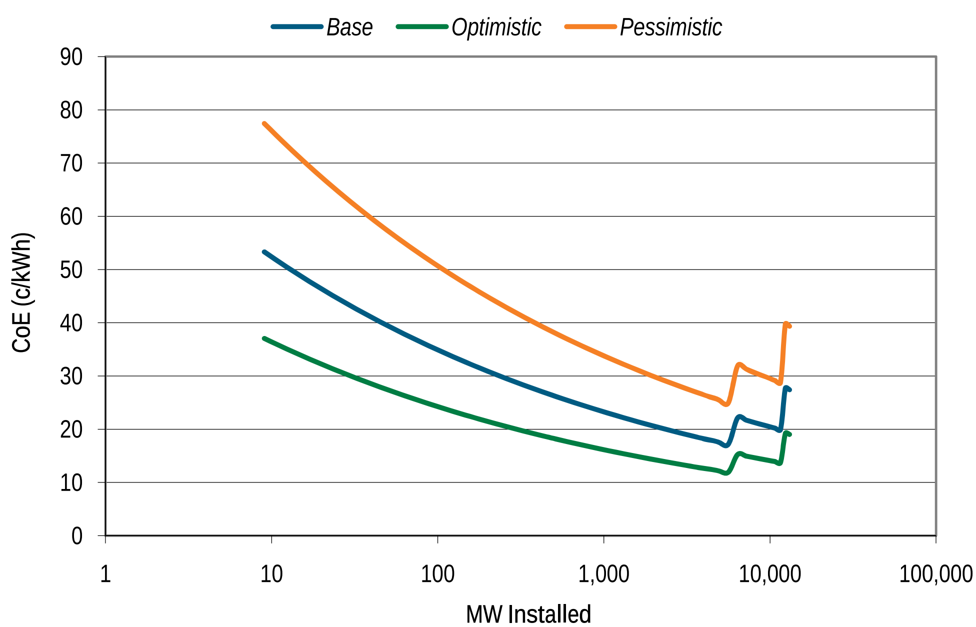


Figure A-8. Cost of energy projection with installed capacity for *Base Case* deployment and learning rates

The *Base Case* cost of energy falls to 17c/kWh after approximately 5.5GW is installed however, the cost of electricity then increases as the best sites have been exploited and is 27c/kWh after 13GW is installed (2050). The two spikes in the graph show the effect of moving from the high-band resource to the medium- band resource and from the medium-band to the low- band resource.

Figure A-9 shows the *Optimistic* deployment scenario and learning rates with the *Optimistic*, *Base Case*, and *Pessimistic* costs. These assumptions have a considerable effect on the cost of electricity, with the *Optimistic* cost of electricity reducing to a low point of approximately 8c/kWh (*Base Case* 12c/kWh) after approximately 14 GW is installed before rising as the high-band resource is exhausted and the medium-band resource is used; the cost of electricity then falls to approximately 9c/kWh (*Base Case* 13c/kWh) after 28.5 GW is installed. Sufficient resource is considered to be available so that the low-band resource is not required by 2050.

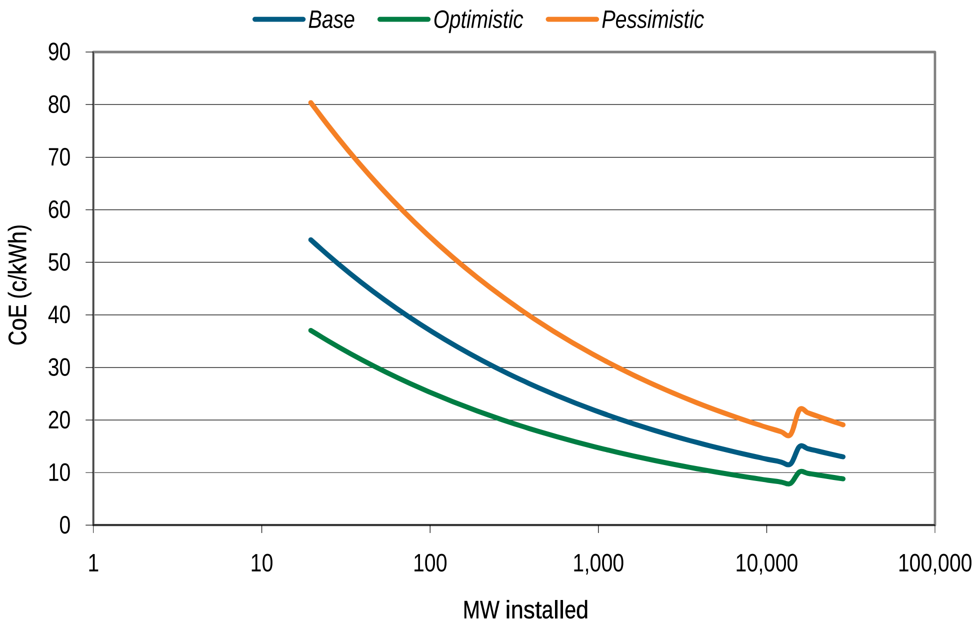


Figure A-9. Cost of energy (projection with installed capacity for *Optimistic* deployment and learning rates

Figure A-10 shows the *Pessimistic* deployment and learning rates with the *Optimistic*, *Base Case*, and *Pessimistic* costs. In this scenario, there are no high-band resource sites; therefore, the analysis starts from the medium-band resource before moving to the low-band resource. The *Pessimistic* cost of electricity falls to a low point of approximately 34c/kWh (*Base Case* 24c/kWh) after approximately 2GW is installed; the installations then require the low-band resource where the cost of electricity finishes on 42c/kWh (*Base Case* 31c/kWh) after 2.5GW is installed.

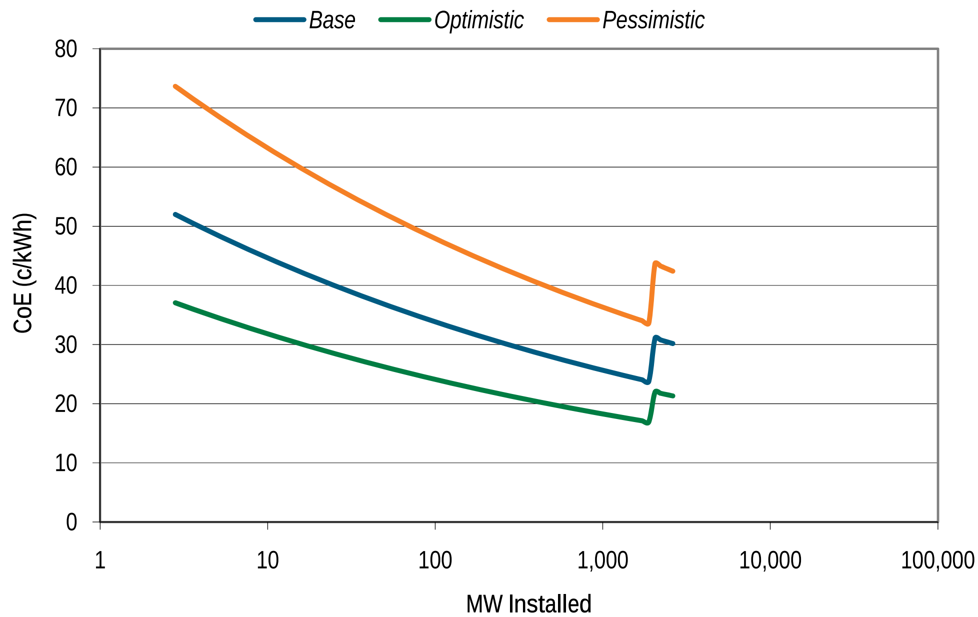


Figure A-10. Cost of energy (c/kWh) over projection with installed capacity for *Pessimistic* deployment and learning rates

Capital and Operating Costs

The capital costs for the *Base Case*, *Optimistic*, and *Pessimistic Scenarios* and the *Base Case* operating expenditure costs to 2050 are shown in Table A-11. As stated above, developers were assumed to install first at sites in the high-band resource, then at sites in medium-band resources, and finally at sites in the low-band resource; in Table A-11, the costs highlighted in green, orange, and red correspond to a high, medium and low resource bands, respectively. The construction schedule and outage rates relate to the *Base Case*. The data in Table A-11 relate directly to the costs projected in Figure A-8; the *Base Case* overnight costs were taken from the *Base Case* (middle) curve in Figure A-8; the low overnight costs were taken from the best case (lower curve) of the *Optimistic Scenario* (Figure A-9); and, the high overnight costs were taken from the worst case (upper curve) of the *Pessimistic Scenario* (Figure A-10).

Table A-11. Capital and Operating Costs to 2050

Year	*Base Case* Capacity Factor (%)	*Base Case* Overnight Cost ($/kW)	*Optimistic* Overnight Cost —High Deployment/ Learning Rate	*Pessimistic* Overnight Cost —Low Deployment/ Learning Rate	*Base Case* Fixed O&M ($/kW-Yr)	Construction Schedule (Months)	Planned Outage Rate (%)	Forced Outage Rate (%)
2008								
2010	25%	14,579	11,400	18,482	741	24	1%	7%
2015	25%	9,336	6,252	13,558	474	24	1%	7%
2020	25%	7,030	4,283	11,308	357	24	1%	7%
2025	25%	5,756	3,282	9,886	292	24	1%	7%
2030	25%	4,782	2,564	8,714	243	24	1%	7%
2035	25%	3,989	2,015	7,746	203	24	1%	7%
2040	25%	3,451	1,662	7,059	175	24	1%	7%
2045	20%	4,094	1,888	6,603	208	24	1%	7%
2050	15%	5,379	1,727	8,318	273	24	1%	7%

The data for the *Base Case* and *Optimistic Scenarios*— which assume the same (*Base Case*) cost of electricity starting point in 2015, along with the estimated cumulative installed capacity in the United States—are also presented in Table A-12. The following results are taken from the mid cases of the *Base Case* and *Optimistic Scenarios*).

Table A-12. Capital and Operating Costs to 2050 (Same Starting Costs—Middle Cases)

	Base Case			***Optimistic Scenario***		
Year	**MW Installed (in U.S.)**	***Base Case* Overnight Cost ($/kW)**	***Base Case* Fixed O&M ($/kW-yr)**	**MW Installed (in U.S.)**	***Base Case* Overnight Cost ($/kW)**	***Base Case* Fixed O&M ($/kW)**
2008	–	–	–	–	–	–
2010	–	–	–	–	–	–
2015	5	9,336	474	11	9,336	474
2020	19	7,030	357	41	6,397	325
2025	37	5,756	292	80	4,902	249
2030	140	4,782	243	304	3,830	195
2035	371	3,989	203	804	3,009	153
2040	670	3,451	175	1,452	2,482	126
2045	881	4,039	205	1,910	2,804	142
2050	735	5,379	273	1,592	2,565	130

Data Confidence Levels

The uncertainty associated with the resource data is discussed in the resource estimate section above. The greatest uncertainty for resource estimates stems from the fact that the available data is located mostly in very deep regions that would not be suitable for installation of wave energy devices. As a consequence, the data were extrapolated to shallower regions. This major uncertainty for the West Coast resource could be reduced by using hydrodynamic models to estimate the wave energy resource at different depths[7]. The total lack of data for the middle (E2, Figure A-1) and lower (E3) East Coast of the United States also adds uncertainty to the resource and cost estimates. However, because the wave energy resource is believed to be relatively small in these regions, the U.S. resource assessment could be improved by investigating the remaining areas (E1, Figure A-2) to confirm that the wave energy resource is not significant on the East Coast.

The cost data provided in this report were based on Black & Veatch's experience working with leading wave technology developers, substantiated by early prototype costs and supply chain quotes. These data are believed to represent a viable estimate of future costs; however, the industry is still in its infancy; and therefore these costs are in the main estimates. This uncertainty is reflected in the relatively large error bands.

The deployment scenarios were based on potential installations globally deemed realistic; however, they are a forecast and therefore subject to significant uncertainty. Deployment will ultimately be driven by numerous variables, including financing, grid constraints, government policy, and the strength of the supply chain.

Summary

The deployment analysis indicates that approximately 12.5 GW of wave generation could be installed in the United States by 2050 in the *Base Case* with approximately 27 GW by 2050 under an Optimistic (high-deployment) scenario, and 2.5 GW by 2050 under a Pessimistic (low-deployment) scenario. None of the scenarios reach their respective resource ceilings.

The cost of electricity analysis estimates a 17c/kWh cost of electricity for *Base Case* assumptions after approximately 5GW is installed (2050 *Base Case* installed capacity); after approximately 13 GW is installed the cost of electricity is 27c/kWh. In the *Optimistic Scenario* (deployment rate, learning rate, and costs)), the cost of electricity is estimated to be as low as 9c/kWh after approximately 28.5GW is installed (2050). In the *Pessimistic Scenario*, the cost of electricity after approximately 2.5GW is installed (2050) is estimated at 42c/kWh.

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[7] Not only the mean wave power (kW/m) must be assessed, but the yearly wave occurrence data to produce Hs/Te scatter diagrams must also be assessed, as these are crucial to apply to device performance to estimate capacity factors.

Appendix B. Energy Estimate for Tidal Stream Technologies

This appendix documents an analysis of the tidal energy resource in the United States and provides the basis for information presented in Section 0 above.

RESOURCE ESTIMATE

Raw Resource Assessment

Black & Veatch sourced tidal stream energy data from existing EPRI tidal stream energy literature (EPRI n.d.) for West Coast sites (Washington and California) and northern East Coast sites (Maine and Massachusetts). The results are summarized in Table B-1 for the contiguous United States.

Table B-1. Raw Resource Assessment Summary

State	Site	Depth (m)	Mean Annualised Power Density (kW/m^2)	Cross-section Area (m^2)	Mean Annualised Available Power (MW)
Massachusetts	Blynman Canal	2	0.93	18.2	0.02
	Muskeget Channel	25	0.95	14000	13.3
	Woods Hole Passage	4	1.32	350	0.5
	Cape Cod Canal	11	2.11	1620	3.4
	Lubec Narrows	6	5.5	750	4.1
Maine	Western Passage	55 to 75	2.2	16300	35.9
	Outer Cobscook Bay	18 to 36	1.64	14500	23.8
	Bagaduce Narrows	3 in Narrow 18 to 24 off Castine	1.94	400	0.8
	Penobscot River	18 to 21	0.73	5000	3.7
	Kennebec River entrance	9 to 20	0.44	990	0.4
	Piscataqua River	10 to 14	1.48	2300	3.4
Washington	Washington	42	1.7	62600	106.4
California	California	90	3.2	74100	237.1

The sites highlighted in Table B-1 were retained after considering depth and resource constraints. Only sites of depth greater than approximately 20 m and power density greater than 1 kW/m^2 were believed to be suitable for commercial tidal stream energy extraction. In any case, the sites not highlighted have a negligible contribution to the total)

Based on an understanding that EPRI focused its research on the most promising states, no other data than that from EPRI were reviewed and therefore the potential tidal stream resource for other locations was not assessed directly. . A cursory investigation of the U.S. coastline revealed other potentially suitable sites such as Long Island Sound, Chesapeake Bay, and Rhode Island. Assumptions about the total U.S. potential are discussed in the resource limits section below.

To estimate the amount of energy that might be actually produced from tidal energy converters (TECs), three significant impact factor (SIF)[8] values were applied to all sites corresponding to the three different scenarios as follows: 10% SIF was applied to the *Pessimistic Scenario*, 20% SIF to the *Base Case*, and 50% to the *Optimistic Scenario*. The extractable power results are summarized in Table B-2.

Table B-2. Extractable Resource Assessment Summary

State	Sites	Extractable Power (MW)		
		Pessimistic Scenario	*Base Case*	*Optimistic Scenario*
Massachusetts	Muskeget Channel	1	3	7
Maine	Western Passage	4	7	18
	Outer Cobscook Bay	2	5	12
Washington	Washington	11	21	53
California	California	24	47	119
Total		42	83	208

The total extractable resource varies from approximately 40 MW to 200 MW (approximately 80 MW for the *Base Case*).

Resource Limits

To account for yet to be discovered sites, a coefficient was applied to the three total values obtained in the raw resource assessment section above. The results are shown in Table B-3.

Table B-3. Estimated Resource Limits

	Extractable Power (MW)		
	Pessimistic Scenario	*Base Case*	*Optimistic Scenario*
Total	42	83	208
Multiplier	1	2	10
Grand Total	42	167	2082

[8] In 2004 and 2005, as part of the UK Marine Energy Challenge (MEC), Black & Veatch defined a “significant impact factor” (SIF) to estimate the tidal resource extractable in the United Kingdom, representing the percentage of the total resource at a site that could be extracted without significant economic, environmental, or ecological effects.

As there are significant uncertainties associated with the resource data associated with these estimates, and it is possible that the mean annualized power density and resource in the California and Washington sites might have been over-estimated in the EPRI studies, a factor of one was applied on the resource in the *Pessimistic Scenario*. In the *Base Case* and *Optimistic Scenario*, this possibility of overstatement of the potential of know sites was assumed to be significantly smaller than the potential of undiscovered sites; a factor of 2 was assumed in the *Base Case* and a factor of 10was applied in the *Optimistic Scenario.* Based on these assumptions, the total estimated resource for the contiguous United States. is close to the total estimated UK resource.

To derive estimates of the cost of tidal stream energy, the sites were split into three categories based on their raw power density: 3% of the sites identified earlier present a power density of less than 1.5 kW/m^2, 57% present a power density greater than 2.5 kW/m^2, and the remaining present a power density comprised between 1.5 kW/m^2 and 2.5 kW/m^2. Given the small number of sites, the factors applied to account for undiscovered sites, and Black & Veatch's experience, these figures were modified to be consistent with a more likely distribution, as shown in Table B-4.

Table B-4. Resource Bands

Resource	Proportion of Total Extractable Resource
% Low-band resource (<1.5kW/m2)	10%
% Medium-band resource (>1.5kW/m2 ; <2.5kW/m2)	50%
% High-band resource (>2.5kW/m2)	40%

COST OF ENERGY ESTIMATE

Tidal Stream Deployment Estimate

Global and U.S. Deployments

Global deployment is required to drive the learning rate of a technology. An assumption was developed for the deployment of TECs globally to 2050. This estimate was made by identifying the planned short term (to 2030) future deployments of the leading TEC technologies. The growth rate from 2020 to 2030 was then used as a basis to estimate the growth to 2050. This growth rate was decreased annually by 1% from 2030 and each subsequent year in order to represent a natural slowing of growth that is likely to occur. The year 2030 was chosen as the start date for the slowdown as this would represent approximately 20 years of high growth, which is reasonable based on slowdowns experienced in other industries (e.g., wind) that have reflected resource and supply chain constraints.

Not all developers are likely to prove successful, and naturally, not all planned installations will proceed. As such, weighting factors were applied to reflect the uncertainty related to both the developers' potential success and their projects' success.

Deployment of commercial tidal farms in the United States was assumed to be a certain percentage of the growth rate of this global deployment projection (Table B-4), consistent with the total resource ceilings identified above.

Table B-4. U.S. Contribution to Global Tidal Stream Deployment

Scenario	Proportion of World Deployment
Optimistic	30%
Base Case	20%
Pessimistic	10%

For the *Base Case*, the first 10-MW farm was estimated to be installed after approximately 50 MW had been installed worldwide. The different deployments scenarios obtained are shown in Figure B-1.

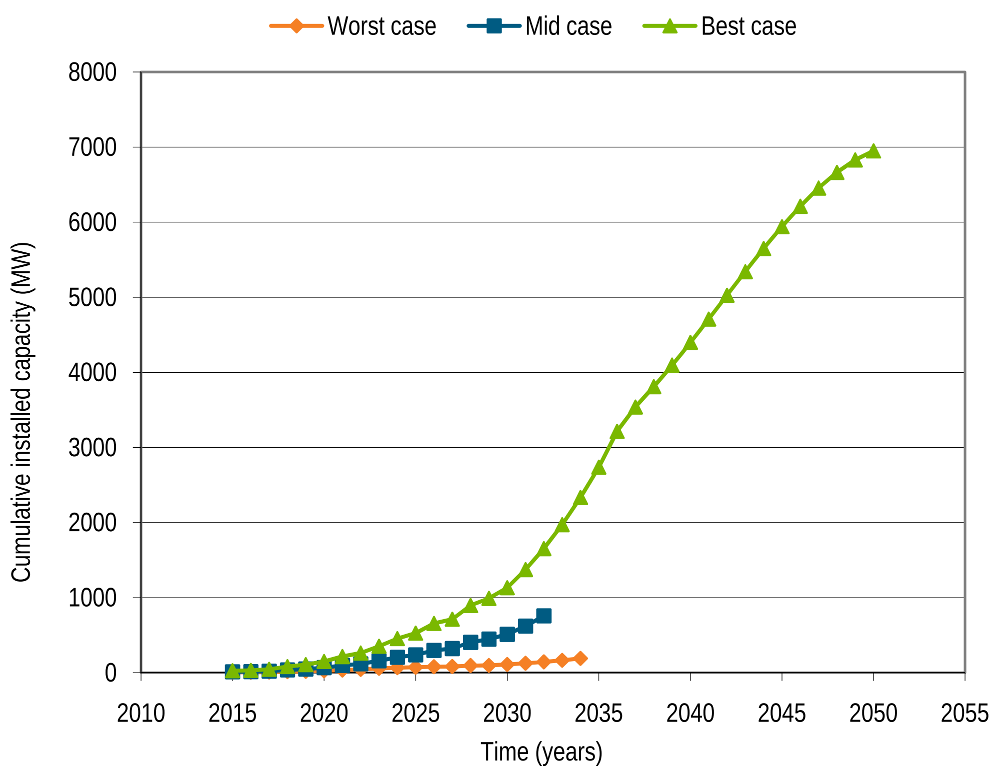

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Figure B-1. Deployment scenarios for tidal stream power (continental waters) in the United States to 2050

In the *Base Case* and *Pessimistic Scenario* cases, the resource ceilings were reached between 2030 and 2035, whereas in the *Optimistic Scenario* the resource ceiling was not reached even in 2050.

Deployment Assumptions

Given the relatively low energy density of U.S. tidal resource sites, it was assumed that 1) developers would aim to maximise project economics for early projects and would thus deploy only at sites in the high-band wave resource, 2) that when this is exhausted, the medium-band resource sites would be exploited, and 3) that the low resource sites would be used only after the medium-band resource was exhausted. It is also assumed that the effects of the learning curve will make the medium- and low-resource sites more feasible in the future.

Deployment Constraints

The deployment growth is only limited by the resource constraints. It was assumed that all other factors impacting deployment are addressed, including but not limited to: financial requirements, supply chain infrastructure, site-specific requirements, planning, and grid infrastructure.

Learning

To form a judgment as to the likely learning rates that can reasonably be assumed for the coming years, it is appropriate to first consider empirical learning rates from other emerging renewable energy industries. This section provides an overview of learning experience from similar developing industries, suggests applicable learning rates for tidal stream technology, and considers scenarios for future generation costs. Figure A-7 (Appendix A) shows learning rate data for a range of emerging renewable energy technologies.

Cost and cumulative capacity are observed to exhibit a straight line when plotted on a log-log diagram; mathematically, this straight line indicates that an increase by a fixed percentage of cumulative installed capacity gives a consistent percentage reduction in cost. For example, the progress ratio for photovoltaics over the period 1985 to 1995 was approximately 65% (learning rate approximately 35%) and that for wind power between 1980 and 1995 was 82% (learning rate 18%).

Any discussion as to the likely learning rates that might be experienced by the tidal stream industry will be subjective. The closest analogy for the tidal stream industry has been assumed to be the wind industry. A progress ratio as low as wind energy (82%) is not expected for the tidal stream industry for the following reasons:

- In the wind power industry, much of the learning was a result of doing “the same thing bigger” or “upsizing” rather than “doing the same or something new.” This upsizing has probably been the single most important contributor to cost reduction for wind, contributing approximately 7% to the 18% learning rate.9 Tidal turbines, like wind turbines, will benefit from increasing rotor swept areas until the maximum length of the blades, limited by loadings, is reached. However, unlike for wind power, the ultimate physical limit on rotor diameter can also be imposed by cavitation or limited water depth, the latter being particularly important for the relatively shallow sites of (25–35 m) that are likely to be developed in the near-term.
- Much of the learning in wind power occurred at small scale with small-scale units (<100 kW), often by individuals with very low budgets. Tidal stream on the other hand requires large investments to deploy prototypes and therefore requires a smaller number of more risky steps to develop, which tends to suggest that the learning will be slower (and the progress will be ratio higher).
- Tidal stream technology development is still in its infancy, and learning rates are often higher during this period of technology development, offsetting the points in (2).

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[9] See, for example, http://www.electricitypolicy.org.uk/pubs/wp/eprg0601.pdf, which calculates an 11% learning rate for wind excluding learning due to ‘upsizing’.

The likely range of learning rates for the tidal energy industry in the United States is believed to be between 7% and15% (progress ratios of 85%–93 %) with a mid range value of 11%.

Cost of Energy

An in-house techno-economic model was used by Black & Veatch to derive A cost of electricity was developed for a first 10-MW farm installed in the three-band resource environment discussed in the resource limits section above, assuming this installation occurred after 50 MW of capacity had been installed worldwide. The cost of electricity presented is considered an industry average for horizontal-axis axial-flow turbines. The learning rate range specified above was used to derive the future cost of electricity.

General Assumptions

As described above, the resource data used in the techno-economic analysis were sourced from EPRI (n.d.). The three resource cases were modelled and derived from the Muskeget Channel site (approximately 1 kW/m^2) and from the sites in Washington and California (respectively approximately 2 kW/m^2 and 3 kW/m^2). The current velocity distributions from the real sites were slightly modified to exactly match the generic resource mid-bands (1 kW/m^2, 2 kW/m^2, and 3 kW/m^2). These general assumptions were used for this analysis:

- Depth: 40 m for all three generic sites considered
- Project life: 25 years
- Discount rate: 8%.
- Device availability: 92.5% in the Base Case, 95% in the *Optimistic Scenario*, and 90% in the *Pessimistic Scenario*.

The cost of electricity presented is in 2009 dollars and future inflation has not been accounted for. The exchange rate used to convert any costs from GBP to USD was: 1 GBP = 1.65 USD.

Cost Results

The estimated cost of electricity is presented in Table B-5. Learning rates were only applied to the cost of electricity only after the 50 MW of capacity was installed worldwide.

Table B-5. Cost Estimate for a 10-MW Tidal Farm after Installation of 50 MW

Resource	Costs	Costs ($ million)		Performance (%)		Cost of Electricity (c/kWh)
		Capital	Operating (annual)	Capacity Factor	Availability	
High-band Resource	*Pessimistic*	69	2.5	22%	90.0%	45.0
	Base Case	59	2.0	26%	92.5%	35.8
	Optimistic	54	1.5	30%	95.0%	29.3
Medium-band Resource	*Pessimistic*	74	2.6	19%	90.0%	55.0
	Base Case	63	2.1	23%	92.5%	44.4
	Optimistic	58	1.6	26%	95.0%	35.9
Low-band Resource	*Pessimistic*	127	4.3	21%	90.0%	84.3
	Base Case	104	3.5	25%	92.5%	66.9
	Optimistic	96	2.6	29%	95.0%	55.0

Black & Veatch's techno-economic model is run in such a way that the technology (rated power of the devices) matches the resource, hence the range of capacity factors obtained in Table B-5. The *Pessimistic* and *Optimistic Scenarios* were generated to indicate the uncertainties in the analysis.

The supply curves obtained after applying the learning rates to the cost of electricity from Table B-5 are shown in Figures B-2, B-3, and B-4.

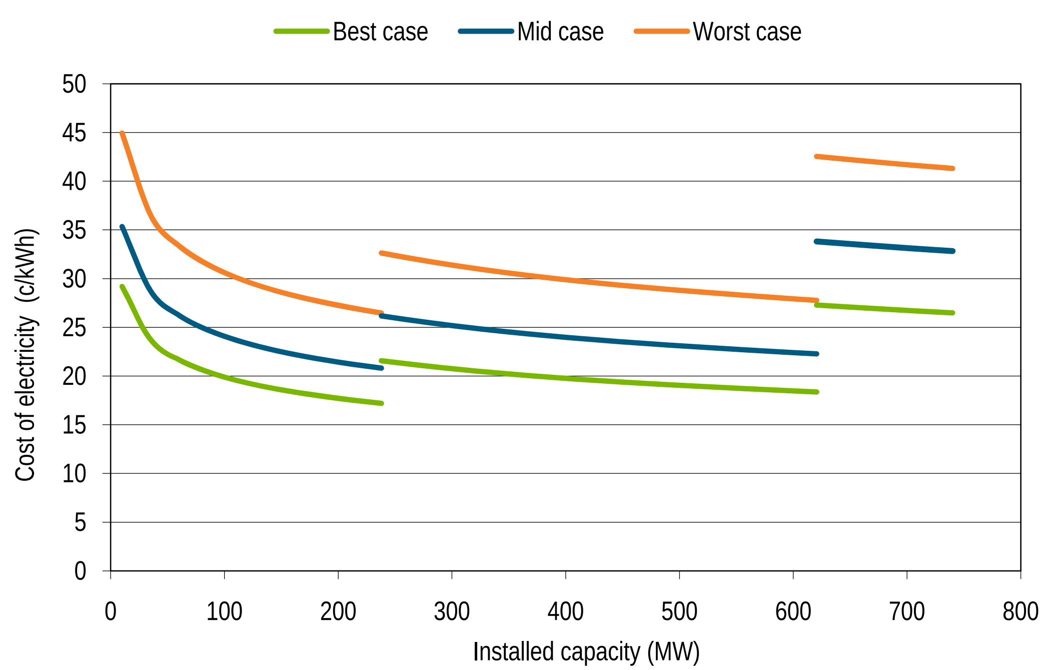

Figure B-2. Supply curve for a *Base Case* resource ceiling and an 11% learning rate

From a *Base Case* of approximately 35c/kWh, the cost of electricity dropped to approximately 20c/kWh after approximately 250 MW were installed. At that point, the most energetic sites had been exploited and the medium-band resource sites start to be exploited, hence the offset in the curve. After these additional 350 MW of medium-band resource sites had been exploited, the *Base Case* cost of electricity lies slightly above the previous 20c/kWh level. The late exploitation of the low-band resource brought the cost of electricity back to the original levels (approximately 35c/kWh in the *Base Case*).

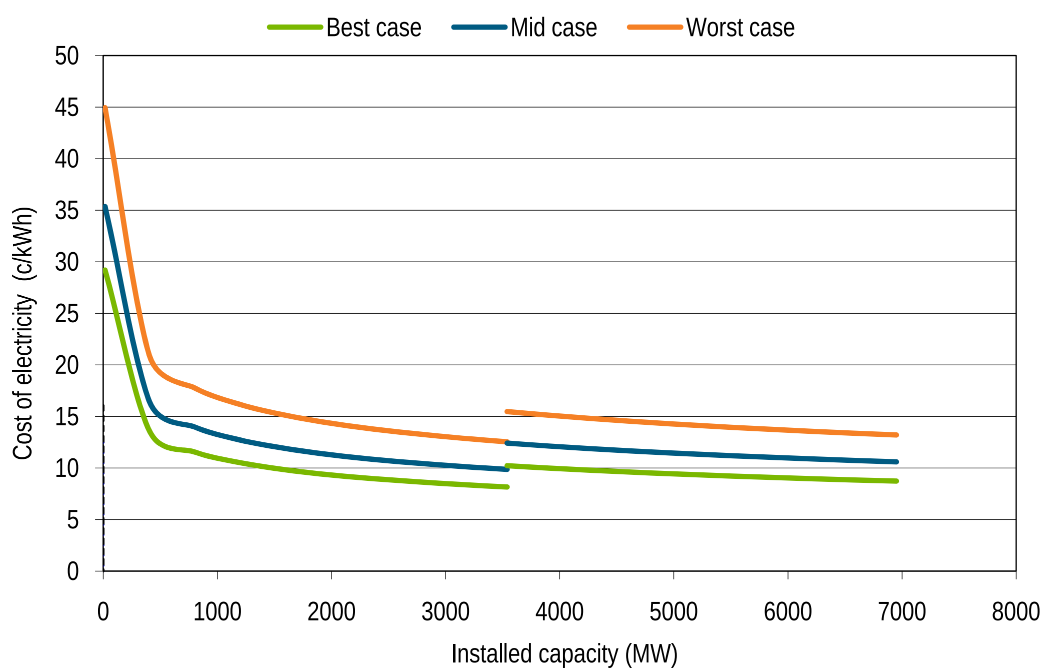

Figure B-3. Supply curve for an *Optimistic* resource ceiling and a 15% learning rate

From a *Base Case* of approximately 35c/kWh, the cost of electricity dropped to approximately 10c/kWh after approximately 3,500 MW had been installed. At that point, the most energetic sites had been exploited and the medium-band resource sites start to be exploited, hence the offset in the curve. After these extra 3,500 MW of medium resource sites had been exploited, the *Base Case* cost of electricity was back at the previous 10c/kWh level.

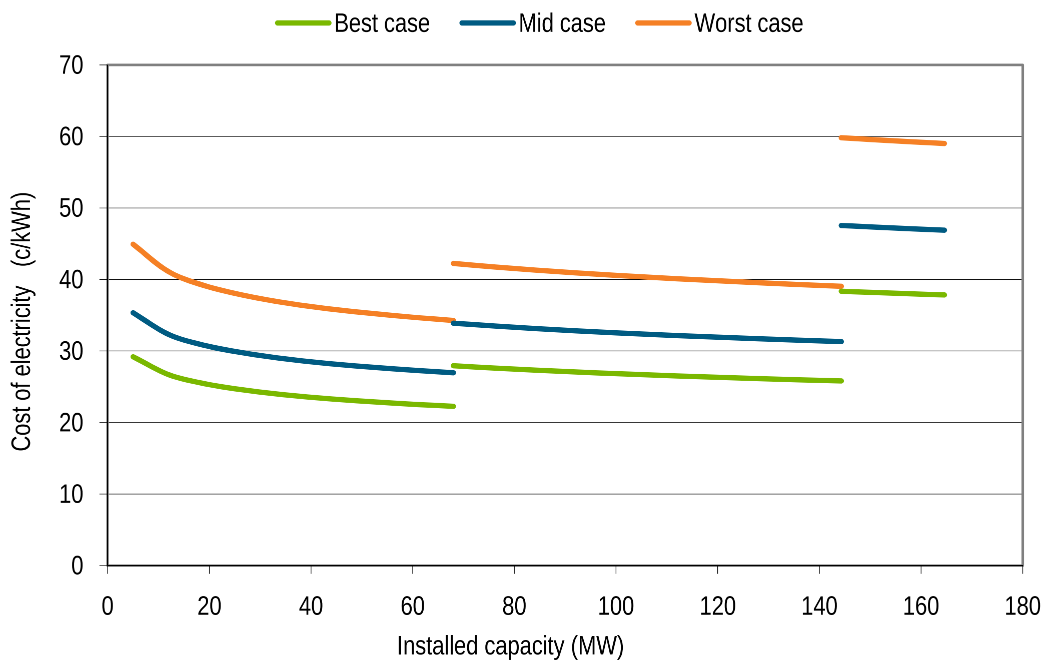

Figure B-4. Supply curve for a *Pessimistic* resource ceiling and a 7% learning rate

From a *Base Case* of approximately 35c/kWh, the cost of electricity dropped to approximately 27c/kWh after approximately 70 MW had been installed. At that point, the most energetic sites had been exploited and the medium-band resource sites start to be exploited, hence the offset in the curve. After these extra 90 MW of medium-band resource sites had been exploited, the *Base Case* cost of electricity reaches approximately 30c/kWh level. The late exploitation of the low-band resource took the cost of electricity to the highest levels reached in this analysis (approximately 48c/kWh in the *Base Case*).

Capital and Operating Costs

The capital costs for the *Base Case*, *Optimistic* and *Pessimistic Scenarios* and the *Base Case* operating costs to 2050 are shown in Table B-6. As stated above, developers were assumed to install first at sites in the high-band resource, then at sites in medium-band resources, and finally at sites in the low-band resource. In Table B-6, the costs highlighted in green, orange, and red correspond to a high, medium, and low resource bands, respectively. The construction schedule and outage rates relate to the *Base Case*. The data in Table B-6 relate directly to the costs projected in Figures B-2 through B-4. The *Base Case* overnight costs were taken from the *Base Case (*middle curve) of Figure B-2; the low overnight costs were taken from the best case (lower curve) of the *Optimistic Scenario* (Figure B-3); and, the high overnight costs were taken from the worst case (upper curve) of the *Pessimistic Scenario* (Figure B-4). In Table B-6, in the base and high overnight cost scenarios, the low-band resource sites were exploited between 2030 and 2035 and hence no red colored cells are visible.

Table B-6. Capital and Operating Costs to 2050

Year	*Base Case* Capacity Factor	*Base Case* Overnight Cost ($/KW)	*Optimistic* Overnight Cost—High Deployment/ Learning Rate ($/KW)	*Pessimistic* Overnight Cost—Low Deployment/ Learning Rate ($/KW)	*Base Case* Variable O&M ($/MWh)	*Base Case* Fixed O&M $/KW-Yr	Heat Rate (Btu/KWh)	Construction Schedule (Months)	Planned Outage Rate (%)	Forced Outage Rate (%)
2008	-	-	-	-	-	-	-	-	-	-
2010	-	-	-	-	-	-	-	-	-	-
2015	26%	5,940	5,445	6,930	-	198	-	24	1%	6.5%
2020	26%	4,401	3,293	5,843	-	147	-	24	1%	6.5%
2025	26%	3,498	2,524	5,661	-	117	-	24	1%	6.5%
2030	23%	3,267	1,962	5,381	-	112	-	24	1%	6.5%
2035		-	1,611	-	-	-	-	24	1%	6.5%
2040		-	1,540	-	-	-	-	24	1%	6.5%
2045		-	1,434	-	-	-	-	24	1%	6.5%
2050		-	1,376	-	-	-	-	24	1%	6.5%

The data for the *Base Case* and *Optimistic Scenario* are also presented in Table B-7 with the same starting points, along with the estimated cumulative installed capacity in the United States. The following results were taken from the middle cases of the *Base Case* and *Optimistic Scenario* (Figures B-2 and B-3).

Table B-7. Capital Expenditure Cost and Operating Expenditure Costs to 2050 (Same Starting Costs—Middle Cases)

Base Case				*Optimistic Scenario*			
Year	MW Installed (in U.S.)	*Base Case* Overnight Cost ($/kW)	*Base Case* Fixed O&M ($/kW-Yr)	Year	MW Installed (in U.S.)	*Base Case* Overnight Cost ($/kW)	*Base Case* Fixed O&M ($/kW-Yr)
2008				2008			
2010				2010			
2015	10	5,940	198	2015	15	5,940	198
2020	61	4,401	147	2020	131	3,591	120
2025	238	3,498	117	2025	407	2,753	92
2030	493	3,267	112	2030	1,190	2,140	71
2035	-	-	-	2035	2,756	1,758	59
2040	-	-	-	2040	4,297	1,672	57
2045	-	-	-	2045	5,813	1,557	53
2050	-	-	-	2050	6,950	1,494	51

Data Confidence Levels

The uncertainty associated with the resource data is discussed in the resource estimate section above. The U.S. resource assessment could be improved by investigating the remaining coastline that has not yet been investigated and by using hydrodynamic modeling on the most promising sites.

The cost data provided in this report were based on Black & Veatch's experience working with leading tidal stream technology developers, substantiated by early prototype costs and supply chain quotes. These data are believed to represent a viable current estimate of future costs; however, the industry is still in its infancy and therefore these costs are in the main estimates.. This uncertainty is reflected in the relatively large error bands.

The deployment scenarios were based on potential installations globally deemed realistic; however, they are a forecast and therefore are subject to significant uncertainty. Deployment will ultimately be driven by numerous variables including financing, grid constraints, government policy, and the strength of the supply chain.

Summary

The analysis estimates a 20c/kWh cost of electricity for *Base Case* assumptions after 250 MW is installed; after 720 MW is installed (*Base Case* total resource ceiling), the cost of electricity is estimated to be 34c/kWh due to the late exploitation of the low-band resource. In the *Optimistic Scenario* (deployment rate, learning rate, and costs), the cost of electricity is estimated to be as low as 10c/kWh after 7 GW is installed (2050 resource level). In the *Pessimistic Scenario,* the cost of electricity after 180 MW is installed (*Pessimistic* Scenario total resource ceiling) is estimated at 48c/kWh.

The cost of tidal stream energy extraction in the United States cannot be further investigated until a full national resource assessment is completed.

Appendix C. Breakdown of Cost for Solar Energy Technologies

This appendix documents capital cost breakdowns for both photovoltaic and concentrating solar power technologies, and provides the basis for information presented in Sections 0 above.

SOLAR PHOTOVOLTAICS

Figure C-1 and Table C-1 show capital cost ($/W) projection for a number of different residential, commercial and utility options ranging from 40 KW (direct current (DC)) to 100 MW (DC), assuming no owner's costs and no extra margin. Table C-2 breaks these costs down by component.

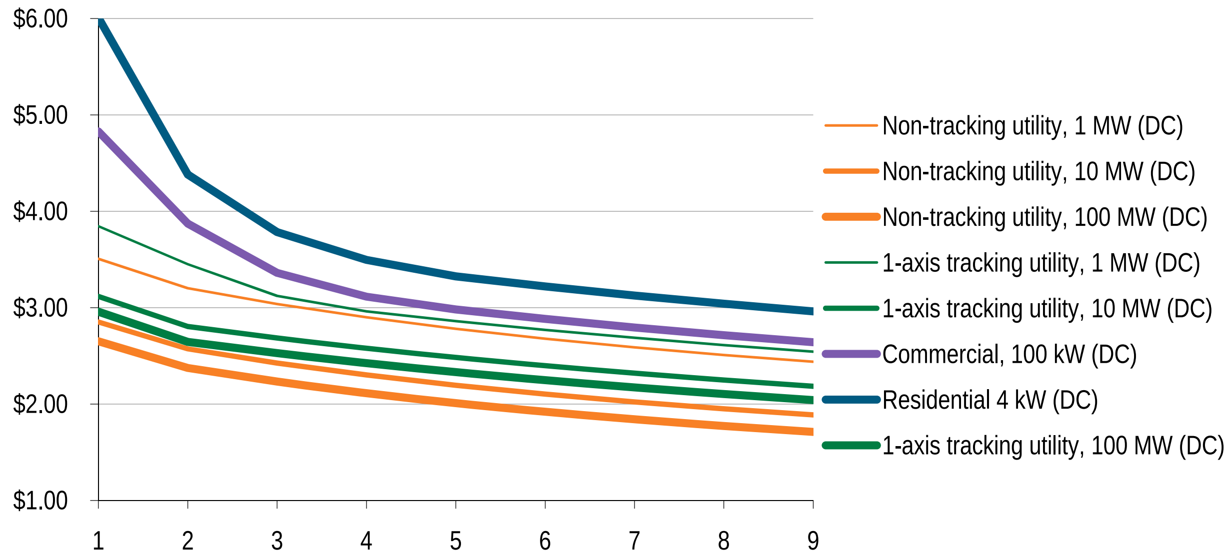

Figure C-1. Capital cost projection for solar photovoltaic technology

Table C-1. Solar Photovoltaics Capital Costs ($/W) by Type and Size of Installation

	Utility PV Non-Tracking			Utility PV 1-Axis Tracking			Commercial PV	Residential PV
	1 MW (DC)	10 MW (DC)	100 MW (DC)	1 MW (DC)	10 MW (DC)	100 MW (DC)	100 kW (DC)	4 kW (DC)
2010	$3.19	$2.59	$2.41	$3.50	$2.83	$2.69	$4.39	$5.72
2015	$2.91	$2.34	$2.16	$3.14	$2.55	$2.40	$3.52	$4.17
2020	$2.76	$2.21	$2.03	$2.84	$2.44	$2.30	$3.06	$3.60
2025	$2.64	$2.09	$1.92	$2.69	$2.34	$2.20	$2.83	$3.33
2030	$2.53	$2.00	$1.83	$2.60	$2.26	$2.12	$2.71	$3.17
2035	$2.43	$1.91	$1.75	$2.52	$2.18	$2.04	$2.62	$3.07
2040	$2.35	$1.84	$1.67	$2.44	$2.11	$1.98	$2.54	$2.98
2045	$2.28	$1.77	$1.61	$2.37	$2.05	$1.91	$2.47	$2.90
2050	$2.22	$1.72	$1.56	$2.31	$1.99	$1.86	$2.40	$2.82

Table C-2. Solar Photovoltaics Capital Cost ($/W) Breakdown by Type and Size of Installation—No Owner's Costs, No Extra Margin

	Non-Tracking Utility		1-Axis tracking Utility		Commercial		Residential	
Year	1 MW (DC)	10 MW (DC)	100 MW (DC)	1 MW (DC)	10 MW (DC)	100 MW (DC)	100 kW (DC)	4 kW (DC)
2010	$3.19	$2.59	$2.41	$3.50	$2.83	$2.69	$4.39	$5.72
2015	$2.91	$2.34	$2.16	$3.14	$2.55	$2.40	$3.52	$4.17
2020	$2.76	$2.21	$2.03	$2.84	$2.44	$2.30	$3.06	$3.60
2025	$2.64	$2.09	$1.92	$2.69	$2.34	$2.20	$2.83	$3.33
2030	$2.53	$2.00	$1.83	$2.60	$2.26	$2.12	$2.71	$3.17
2035	$2.43	$1.91	$1.75	$2.52	$2.18	$2.04	$2.62	$3.07
2040	$2.35	$1.84	$1.67	$2.44	$2.11	$1.98	$2.54	$2.98
2045	$2.28	$1.77	$1.61	$2.37	$2.05	$1.91	$2.47	$2.90
2050	$2.22	$1.72	$1.56	$2.31	$1.99	$1.86	$2.40	$2.82
2010								
Overnight EPC	**$3.19**	**$2.59**	**$2.41**	**$3.50**	**$2.83**	**$2.69**	**$4.39**	**$5.72**
Modules	$1.68	$1.47	$1.42	$2.20	$1.80	$1.75	$2.33	$3.00
Balance of system (BOS)	$0.73	$0.51	$0.49	$0.56	$0.49	$0.49	$0.66	$0.76
Labor, engineering, and construction	$0.67	$0.51	$0.40	$0.65	$0.47	$0.38	$1.27	$1.77
Shipping	$0.10	$0.10	$0.10	$0.08	$0.06	$0.06	$0.13	$0.19
Module efficiency	9.5%	9.5%	9.5%	15.0%	15.0%	15.0%	15.0%	15.0%
Ground coverage ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%

	Non-Tracking Utility		1-Axis tracking Utility		Commercial		Residential	
Year	1 MW (DC)	10 MW (DC)	100 MW (DC)	1 MW (DC)	10 MW (DC)	100 MW (DC)	100 kW (DC)	4 kW (DC)
2015								
Overnight EPC	**$2.91**	**$2.34**	**$2.16**	**$3.14**	**$2.55**	**$2.40**	**$3.52**	**$4.17**
Modules	$1.45	$1.27	$1.23	$1.88	$1.56	$1.51	$2.00	$2.19
BOS	$0.75	$0.51	$0.50	$0.57	$0.51	$0.50	$0.63	$0.73
Labor, engineering, and construction	$0.62	$0.46	$0.34	$0.60	$0.42	$0.33	$0.76	$1.07
Shipping	$0.09	$0.09	$0.09	$0.08	$0.06	$0.06	$0.12	$0.18
Module efficiency	11.0%	11.0%	11.0%	16.0%	16.0%	16.0%	16.0%	16.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2020								
Overnight EPC	**$2.76**	**$2.21**	**$2.03**	**$2.84**	**$2.44**	**$2.30**	**$3.06**	**$3.60**
Modules	$1.33	$1.17	$1.13	$1.60	$1.47	$1.42	$1.65	$1.76
BOS	$0.74	$0.50	$0.49	$0.57	$0.50	$0.50	$0.58	$0.68
Labor, engineering, and construction	$0.61	$0.45	$0.33	$0.59	$0.41	$0.32	$0.72	$0.99
Shipping	$0.08	$0.08	$0.08	$0.08	$0.06	$0.06	$0.12	$0.17
Module efficiency	12.0%	12.0%	12.0%	17.0%	17.0%	17.0%	17.0%	17.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2025								
Overnight EPC	**$2.64**	**$2.09**	**$1.92**	**$2.69**	**$2.34**	**$2.20**	**$2.83**	**$3.33**
Modules	$1.23	$1.08	$1.04	$1.47	$1.39	$1.34	$1.50	$1.61

	Non-Tracking Utility		1-Axis tracking Utility		Commercial		Residential	
Year	1 MW (DC)	10 MW (DC)	100 MW (DC)	1 MW (DC)	10 MW (DC)	100 MW (DC)	100 kW (DC)	4 kW (DC)
BOS	$0.73	$0.50	$0.48	$0.56	$0.50	$0.49	$0.57	$0.67
Labor, engineering, and construction	$0.60	$0.44	$0.32	$0.58	$0.40	$0.31	$0.65	$0.88
Shipping	$0.08	$0.08	$0.08	$0.07	$0.06	$0.06	$0.11	$0.16
Module efficiency	13.0%	13.0%	13.0%	18.0%	18.0%	18.0%	18.0%	18.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2030								
Overnight EPC	**$2.53**	**$2.00**	**$1.83**	**$2.60**	**$2.26**	**$2.12**	**$2.71**	**$3.17**
Modules	$1.14	$1.00	$0.96	$1.39	$1.32	$1.27	$1.42	$1.53
BOS	$0.73	$0.49	$0.48	$0.56	$0.49	$0.49	$0.57	$0.67
Labor, engineering, and construction	$0.59	$0.43	$0.32	$0.58	$0.40	$0.31	$0.62	$0.82
Shipping	$0.07	$0.07	$0.07	$0.07	$0.05	$0.05	$0.10	$0.16
Module efficiency	14.0%	14.0%	14.0%	19.0%	19.0%	19.0%	19.0%	19.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2035								
Overnight EPC	**$2.43**	**$1.91**	**$1.75**	**$2.52**	**$2.18**	**$2.04**	**$2.62**	**$3.07**
Modules	$1.07	$0.93	$0.90	$1.33	$1.25	$1.21	$1.35	$1.45
BOS	$0.72	$0.49	$0.47	$0.55	$0.49	$0.48	$0.56	$0.66
Labor, engineering, and construction	$0.58	$0.43	$0.31	$0.57	$0.39	$0.30	$0.61	$0.81
Shipping	$0.07	$0.07	$0.07	$0.07	$0.05	$0.05	$0.10	$0.15

	Non-Tracking Utility		1-Axis tracking Utility		Commercial		Residential	
Year	**1 MW (DC)**	**10 MW (DC)**	**100 MW (DC)**	**1 MW (DC)**	**10 MW (DC)**	**100 MW (DC)**	**100 kW (DC)**	**4 kW (DC)**
Module efficiency	15.0%	15.0%	15.0%	20.0%	20.0%	20.0%	20.0%	20.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2040								
Overnight EPC	**$2.35**	**$1.84**	**$1.67**	**$2.44**	**$2.11**	**$1.98**	**$2.54**	**$2.98**
Modules	$1.00	$0.88	$0.84	$1.26	$1.19	$1.15	$1.29	$1.38
BOS	$0.72	$0.48	$0.47	$0.55	$0.48	$0.48	$0.56	$0.66
Labor, engineering, and construction	$0.57	$0.42	$0.30	$0.57	$0.39	$0.30	$0.60	$0.79
Shipping	$0.06	$0.06	$0.06	$0.06	$0.05	$0.05	$0.10	$0.14
Module efficiency	16.0%	16.0%	16.0%	21.0%	21.0%	21.0%	21.0%	21.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%
2045								
Overnight EPC	**$2.28**	**$1.77**	**$1.61**	**$2.37**	**$2.05**	**$1.91**	**$2.47**	**$2.90**
Modules	$0.94	$0.82	$0.79	$1.20	$1.14	$1.10	$1.23	$1.32
BOS	$0.71	$0.48	$0.46	$0.55	$0.48	$0.47	$0.55	$0.66
Labor, engineering, and construction	$0.57	$0.41	$0.30	$0.56	$0.38	$0.29	$0.60	$0.79
Shipping	$0.06	$0.06	$0.06	$0.06	$0.05	$0.05	$0.09	$0.14
Module efficiency	17.0%	17.0%	17.0%	22.0%	22.0%	22.0%	22.0%	22.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%

	Non-Tracking Utility		1-Axis tracking Utility		Commercial		Residential	
Year	**1 MW (DC)**	**10 MW (DC)**	**100 MW (DC)**	**1 MW (DC)**	**10 MW (DC)**	**100 MW (DC)**	**100 kW (DC)**	**4 kW (DC)**
2050								
Overnight EPC	**$2.22**	**$1.72**	**$1.56**	**$2.31**	**$1.99**	**$1.86**	**$2.40**	**$2.82**
Modules	$0.89	$0.78	$0.75	$1.15	$1.09	$1.05	$1.17	$1.26
BOS	$0.71	$0.47	$0.46	$0.54	$0.48	$0.47	$0.55	$0.65
Labor, engineering, and construction	$0.56	$0.41	$0.29	$0.56	$0.38	$0.29	$0.59	$0.78
Shipping	$0.06	$0.06	$0.06	$0.06	$0.04	$0.04	$0.09	$0.13
Module efficiency	18.0%	18.0%	18.0%	23.0%	23.0%	23.0%	23.0%	23.0%
Ground Coverage Ratio	43.0%	43.0%	43.0%	30.0%	30.0%	30.0%	50.0%	100.0%

CONCENTRATING SOLAR POWER

Tables C-3 and C-6 show performance and cost for trough systems in 2010 and 2050. Tables C-4 and C-5 show performance and cost for tower systems in 2010 and 2050.

Table C-3. Solar Trough Performance for 2010 and 2050

Parameter	2010		2050	
	Without Storage	With Storage	Without Storage	With Storage
Plant size (MW)	200	200	200	200
Design direct normal irradiance (DNI) W/m^2	950	950	950	950
Solar multiple	1.4	2	1.4	2
Storage (hours)	0	6	0	6
Solar to thermal efficiency	0.6	0.6	0.65[a]	0.65
Thermal to electric efficiency	0.37	0.37	0.37	0.365[b]
Design thermal output (MWth-hours)	541	541	541	548
Required aperture (m^2)	1327643	1896633	1225517	1774721
Thermal storage (MWth-hours)	0	3243	0	3288

[a] Improved reflectivity, receiver

[b] Parallel storage penalty

Table C-4. Solar Trough Capital Cost Breakdown for 2010 and 2050

Cost Assumptions	2020		2050	
	Without Storage	With Storage	Without Storage	With Storage
Solar field ($\$/m^2$)	300	300	195[a]	195
Heat transfer fluid (HTF) system ($/kWe)	500	500	375[b]	375
Power block ($\$/kW_e$)	975	975	900	900
Storage ($\$/kWh_{th}$)	0	40	0	30
Contingency	10	10	10	10[c]
Solar field and site ($)	398,293,030	568,990,043	238,975,818	346,070,656
HTF and power block ($)	295,000,000	295,000,000	255,000,000	255,000,000
Storage ($)	0	129,729,730	0	97,479,452
Total with contingency ($)	762,622,333	1,093,091,750	543,373,400	768,406,119
Direct Costs ($/kW)	3,813	5,465	2,717	3,842
Engineering, procurement, construction (%)	10	10	10	10
Owners costs (%)	20	20	20	20
Indirect costs (%)	30	31	30	30
Total Cost ($/kW)	4,957	7,135	3,532	4,995

[a] Reduced material, installation

[b] Lower pressure drop, advanced HTF

[c] slightly higher temperature

Table C-5. Solar Tower Plant Parameters 2010 and 2050

Plant Parameters	2010	2050
Storage (hours)	6	6
Capacity factor (5)	40	41
Collector field aperture (m^2)	1147684	1081000[a]
Receiver surface area (m^2)	847	677.6[b]
Plant capacity (MW_e)	100	100
Thermal storage (hours)	6	6
Thermal to electric efficiency	0.425	0.425
Tower height (m)	228	228
Design thermal output (MW_{th})	235	235
Thermal storage (kWh_{th})	1411765	1411765

[a] Better reflectivity, less spillage; Better availability, less receiver heat loss

[b] Higher flux levels; better coatings

Table C-6. Solar Tower Capital Cost Breakdown for 2010 and 2050

Assumption	2010		2050	
Capacity factor	40%		41%	
Heliostat field	235 $\$/m^2$ aperture	$269,705,740	235 $\$/m^2$ aperture	$167,555,000
Receiver	80000 $\$/m^2$ receiver	$67,760,000	50000 $\$/m^2$ receiver	$33,880,000
Tower	901500 0.01298 $\$/m^2$ aperture	$17,387,382	901500 0.01298 $\$/m^2$ aperture	$17,387,382
Power block	950 $\$/kW_e$	$95,000,000	875 $\$/kW_e$	$87,500,000
Thermal storage	30 $\$/kWh_{th}$	$42,352,941	18 $\$/kWh_{th}$	$25,764,706
Total direct costs		$492,206,063		$332,087,088
Total with contingency	10%	$541,426,669	10%	$365,295,797
Indirect costs				
EPC	10%		10%	
Owners	20%		20%	
Total Direct and Indirect Costs	30%	$704,017,098	30%	$474,884,535
Total Cost ($/kW)		$7,040		$4,749

Appendix D. Technical Description of Pumped-Storage Hydroelectric Power

This appendix presents a generic technical description and characteristics of a representative 500 MW pumped-storage hydroelectric (PSH) plant that has as its primary purpose energy storage.

DESIGN BASIS

Pumped storage is an energy storage technology that involves moving water between an upper and lower reservoir. The system is charged by pumping water from the lower reservoir to a reservoir at a higher elevation. To discharge the system's stored energy water is allowed to flow from the upper reservoir through a turbine to the lower reservoir. The overall efficiency of the system is determined by the efficiency of the equipment (pump/turbine, motor generator) as well as the hydraulic and hydrologic losses (friction and evaporation) which are incurred. Overall cycle efficiencies of 75%–80% are typical.

Most often, a pumped storage system design utilizes a unique reversible Francis pump/turbine unit that is connected to a motor/generator. Equipment costs typically account for 30%–40% of the capital cost with civil works making up the vast majority of the remaining 60%–70%.

The configuration of the pumped-storage plant used in this report is described as follows:

1. The 500-MW pumped-storage project will operate on a daily cycle with energy stored on a 12-hour cycle and generated on a 10-hour cycle. Approximately 322 cycles per year would be assumed.
2. For purposes of this evaluation, the energy storage requirement is equal to 500 MW for 10 hours or 5,000 megawatt hours of daily peaking energy.
3. The lower reservoir is assumed to exist and a site for a new upper reservoir can be found that has the appropriate characteristics.
4. For evaluation purposes, the pumping and generating head is based on the average difference in the upper and lower reservoir levels. The reality is that the heads in both pumping and generating modes will constantly fluctuate during their respective cycles. This fluctuation must be designed
5. This evaluation is based on an average net operating head (H) for both pumping and generating cycles of 800 feet.
6. The distance from the outlet of the upper reservoir to the outlet of the lower reservoir is assumed to be 2,000 feet resulting in an L/H ratio of 2.5, which is excellent by industry standards.
7. The calculated generating flow assuming a 0.82 generating efficiency is 9,000 cubic feet per second (cfs).
8. The active water storage in the reservoirs required for this flow over the 10 hours generating cycle is 7,438 acre-feet. Adding 10 percent for inactive storage yields a total reservoir storage requirement of about 8,200 acre-feet.
9. The lower reservoir is assumed to be an existing reservoir that can afford a fluctuation of 7,438 acre-feet without environmental or other fluctuation issues.

STUDY BASIS DESCRIPTION AND COST

Based on the above project sizing criteria, the following reconnaissance-level project design and associated capital cost was estimated:

1. Assuming an upper reservoir depth of 100 feet yields a surface area of 82 acres. Using a circular reservoir construction results in a 2,132-foot diameter and a circumference of 6,700 ft. The assumed dam would be a gravity type constructed using roller-compacted concrete (RCC). Other types such as concrete-faced rock fill, concrete arch, or embankment are possible depending on site conditions. The total volume of RCC is estimated at 670,000 cubic yards (cy). At a cost of $200/cy, RCC would cost roughly $134 million. The following are other upper reservoir estimated costs:

    A. Reservoir clearing: $10 million

    B. Emergency spillways: $5 million

    C. Excavation and grout curtain: $20 million

    D. Inlet/Outlet structure and accessories: $20 million

    The total reservoir cost is roughly $189 million.

2. The tunnels from the lower reservoir to powerhouse and from powerhouse to upper reservoir would include 20-foot diameter access tunnel (assumed to be 1,000 ft long) and 2x20 foot diameter penstock and draft tube tunnels (total of 4,200 ft long). Other tunnels and shafts for ventilation and power lines would be required. About $60 million is assumed for tunneling.
3. The powerhouse would be constructed underground and be approximately 100 feet and 200 feet for a 2x250 MW pump turbine unit. The excavation of the powerhouse would cost approximately $35 million.
4. At an estimate cost of $750 per installed kW, the powerhouse structures, equipment, and balance of plant would cost about $375 million.
5. The total estimate construction cost is therefore:

    A. Upper reservoir: $189 million

    B. Tunnels: $60 million

    C. Powerhouse excavation: $35 million

    D. Powerhouse: $375 million

    Total: $659 million

6. The following additional technical assumptions have been made for this option:

    A. The site features geological formations ideal for upper reservoir and underground development.

    B. A relatively flat 82-acre site is required for the upper reservoir. A total site area, including underground rights is about 200 acres.

    C. The site is on land where no existing human-made structures exist.

    D. No offsite roads are included.

E. The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.

F. Construction power and water is assumed to be available at the site boundary.

G. No consideration was given to possible future expansion of the facilities.

H. A 345-kV generator step-up (GSU) transformer is included. Transmission lines and substations/switchyards are not included in the base plant cost estimate. An auxiliary transformer is included.

I. Provision for protection or relocation of existing fish and wildlife habitat, wetlands, threatened and endangered species or historical, cultural, and archaeological artifacts is not included.

J. The upper reservoir will be capable of overtopping due to accidental over-pumping. A service spillway equal to the pumping flow is assumed.

OTHER COSTS AND CONTINGENCY

The following are potential additional costs:

1. Plant location is assumed to be where land is not of significant societal value, with a cost of $5,000 per acre or $1 million total.
2. Transmission and substation are assumed to be adjacent to the site and is a major siting factor.
3. Project management and design engineering at 5% of construction cost or $33 million.
4. Construction management and start-up support at 5% of construction cost of $33 million.
5. A contingency of $109 million (15%) is assumed.

Total: $176 million.

Based on the total Construction Cost of $659 million and the above Other Costs and Contingency of $176 million, the total capital cost is estimated to be $835 million, or roughly 1,670 $/kW. A 20% addition for owner's costs of the type described in Text Box 1 in section 1.2 above yields a cost of 2,004 $/kW that is comparable to the other cost estimates provided.

OPERATING AND MAINTENANCE COST

Operating and maintenance costs are dependent on the mode of operation. For hydroelectric plants, the following are the typical annual operating and maintenance costs:

1. Routine Maintenance and spare parts: $500,000
2. Personnel wages (20 total @$65,000): $1.3 million

   A. One plant manager

   B. Two administrative staff

   C. Eight operators

   D. Two maintenance supervisors

   E. Seven maintenance and craft

3. Personnel burden @ 40% of wages: $520,000

4. Staff supplies @ 5% of wages: $65,000

   Total: $2.385 million per year

Hydroelectric plants typically operate for 5-10 years without significant major repair or overhaul costs. For evaluation purposes, a major overhaul reserve available at year 10 of $100 per installed kilowatt or $50 million is assumed. When spread over a 10-year period, the annual major overhaul cost is $5 million per year.

CONSTRUCTION SCHEDULE

A PSH project is a major civil works infrastructure project that would take many years to develop but would provide a project life that exceeds that of the other renewable technologies evaluated in this report. Project life can be expected to be at least 50 years. Many hydropower projects constructed in the early 1900s are still in service today. The development of an impound project would have the following estimated milestone schedule:

1. Permitting, design, and land acquisition: 2-4 years
2. Equipment manufacturing: 2 years
3. Construction: 3 years

   Total: 7-9 years

OPERATING FACTORS

A hydroelectric plant can be designed to provide the following operating factors:

1. Normal start-up and shutdown time for a PSH project is less than 1-5 minutes depending on the status of the water passages. If the unit is watered to the wicket gates and plant auxiliaries are running, unit start-up time is only a function of wicket gate opening to bring the unit up to speed and synchronize.
2. A PSH unit can be tripped off instantaneously as long as the turbine is designed to operate at runaway until the wicket gates are closed. This would be an emergency case.
3. A PSH plant can load follow and provide system frequency/voltage control.
4. Pumped-storage hydroelectric plants can black-start assuming a small emergency generator is provided for unit auxiliaries and field flashing.
5. A major feature of PSH is its ability to operate as spinning or non-spinning reserve, change from pumping to generating within 20 minutes, synchronous condensing, and it can be designed to meet grid system operator certification of these benefits.