STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY ("IPL"), AN INDIANA CORPORATION, FOR APPROVAL OF CLEAN ENERGY PROJECTS AND QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR CONSTRUCTION AND USE OF CLEAN COAL TECHNOLOGY; FOR ONGOING REVIEW; FOR APPROVAL OF THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECTS THROUGH IPL'S ENVIRONMENTAL COMPLIANCE COST RECOVERY ADJUSTMENT("ECCRA"); FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECT; FOR THE USE OF CONSTRUCTION WORK IN PROGRESS RATEMAKING; AND FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, AND OPERATION AND MAINTENANCE COSTS, UNTIL SUCH COSTS ARE REFLECTED FOR RATEMAKING PURPOSES, ALL PURSUANT TO IND. CODE §§ 8-1-2-6.1, 8-1-2-6.7, 8-1-2-6.8, 8-1-2-42(a), 8-1-8.4, 8-1-8.7, 8-1-8.8 AND 170 IAC 4-6-1 ET SEQ.	))	**CAUSE NO. 44242**

SUBMISSION OF REDACTED
SURREBUTTAL TESTIMONY AND EXHIBITS OF JEREMY FISHER

Citizens Action Coalition of Indiana and Sierra Club (collectively "Joint Intervenors"), by counsel, respectfully submit the following redacted testimony and exhibits of Jeremy Fisher, PhD, in the above referenced Cause, under seal, to the Indiana Utility Regulatory Commission.

Respectfully submitted,

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CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail or U.S. Mail, first class postage prepaid, this 3rd day of April, 2013, to the following:

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Exhibit C

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANAPOLIS POWER & LIGHT COMPANY ("IPL"), AN INDIANA CORPORATION, FOR APPROVAL OF CLEAN ENERGY PROJECTS AND QUALIFIED POLLUTION CONTROL PROPERTY AND FOR ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR CONSTRUCTION AND USE OF CLEAN COAL TECHNOLOGY; FOR ONGOING REVIEW; FOR APPROVAL OF THE TIMELY RECOVERY OF COSTS INCURRED DURING CONSTRUCTION AND OPERATION OF SUCH PROJECTS THROUGH IPL'S ENVIRONMENTAL COMPLIANCE COST RECOVERY ADJUSTMENT("ECCRA"); FOR APPROVAL OF DEPRECIATION PROPOSAL FOR SUCH PROJECT; FOR THE USE OF CONSTRUCTION WORK IN PROGRESS RATEMAKING; AND FOR AUTHORITY TO DEFER COSTS INCURRED DURING CONSTRUCTION AND OPERATION, INCLUDING CARRYING COSTS, DEPRECIATION, AND OPERATION AND MAINTENANCE COSTS, UNTIL SUCH COSTS ARE REFLECTED FOR RATEMAKING PURPOSES, ALL PURSUANT TO IND. CODE §§ 8-1-2-6.1, 8-1-2-6.7, 8-1-2-6.8, 8-1-2-42(a), 8-1-8.4, 8-1-8.7, 8-1-8.8 AND 170 IAC 4-6-1 ET SEQ.	)	**CAUSE NO. 44242**

Surrebuttal Testimony of
Jeremy I. Fisher, PhD

PUBLIC VERSION

On Behalf of
Citizens Action Coalition and Sierra Club

April 3, 2013

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1. INTRODUCTION AND PURPOSE OF TESTIMONY

Q Please state your name, business address, and position.

A My name is Jeremy Fisher. I am a scientist with Synapse Energy Economics, Inc. (Synapse), which is located at 485 Massachusetts Avenue, Suite 2, in Cambridge, Massachusetts.

Q Are you the same Jeremy Fisher who submitted direct testimony in this cause on January 28, 2013?

A Yes, I am.

Q What is the purpose of your testimony?

A My testimony responds to the Settlement agreement entered into by Indianapolis Power and Light ("the Company") and certain parties on March 13, 2013, and to a late-breaking analysis that the Company did not include in its rebuttal testimony. Instead, results of this analysis were provided to Joint Intervenors in a discovery response at the close of March 8, 2013, three business days prior to certain parties entering the Settlement with the Company. Joint Intervenors requested an opportunity to review and respond to this analysis in light of its relevance to the economic issues at stake in this proceeding and the Settlement reached by the Company and certain parties. This testimony constitutes my review of this analysis.

Q Please describe this late-breaking analysis.

A The Company contracted with Ventyx to run the MIDAS Gold ("MIDAS") model, the same platform used by the Company to perform their Integrated Resource Plan ("IRP"), to test the economic viability of retrofitting the Big Five coal-fired generating units, Petersburg 1-4 and Harding Street 7. In this analysis ("the MIDAS Analysis"), the Company ran scenarios in which the units were retrofit with MATS and other environmental compliance equipment (the "retrofit scenarios"), and scenarios in which the units were replaced with equivalently-sized natural gas combined cycle ("NGCC") units in 2017 (the "replacement scenarios"). The Company indicates that the net benefit of the retrofit is the difference between these two scenarios.

Q Does the Company consider the MIDAS analysis important?

A Yes. So much so that the primary witness presented by the Company in its initial application supporting the economic prudence of the decision to retrofit the Big Five units, Mr. Ayers, was unable to provide rebuttal testimony because "Mr. Ayers was undertaking [this] additional analysis."[1] Mr. Ayers did not, however, execute this analysis: "The model used for the evaluation was Ventyx's and fully executed by Ventyx."[2]

Despite his engagement in this important work, the Company judged that "because this analysis confirmed the earlier conclusion … it was unnecessary to present this analysis as part of IPL's rebuttal case." It is unclear if the Company would have deemed it necessary to present the results of the MIDAS Analysis if the analysis did not confirm the earlier conclusions reached by the Company.

Q How does this modeling effort compare to the Company's analysis put forth in the initial application?

A While the MIDAS Analysis includes a number of flaws and omissions that undermine its results, the modeling is far more comprehensive and provides a more viable platform for understanding, evaluating, and commenting upon the Company's retrofit proposal than the initial analysis provided by Mr. Ayers and included in its application ("the Spreadsheet Analysis"). I advanced a number of concerns in my direct testimony with the "back of the envelope" spreadsheet analysis conducted in the initial application. While the economic modeling

[1] In response to CAC-SC DR 4-17b,"Explain why Charles Adkins, rather than Mr. Ayers, provided rebuttal testimony regarding the testimony of Jeremy Fisher," IPL stated, in part, that "Mr. Adkins was retained to provide rebuttal testimony <u>because there was a limited time available for preparation of rebuttal testimony and Mr. Ayers was undertaking additional analysis</u> to validate his conclusions based on updated cost information regarding the CCGT and other environmental compliance. Because this analysis confirmed the earlier conclusion and the updated cost issues were addressed in Mr. Adkins' testimony, it was unnecessary to present this analysis as part of IPL's rebuttal case. A copy of the aforementioned analysis is provided as CAC/SC DR 4-17, Confidential Attachment 1 and CAC/SC DR 4-17 Attachment 2." [Emphasis added]

[2] Response to CAC-SC DR 6-2a.

addressed here raises other questions and concerns, broadly speaking it is consistent with the economic modeling methodology that utilities typically use to attempt to justify major capital expenditures such as those at issue in this proceeding.

Importantly, this new analysis thoroughly rebuts witness Charles Adkins' contention that "the proper context for this type of capital investment…is a straight-forward benefit/cost analysis"[3] and that it would be inappropriate to conduct IRP-type modeling in this analysis. In light of the Company's new analysis, it is also clear that Mr. Adkins' efforts to illustrate breakeven gas and carbon dioxide (CO_2) prices using a highly simplified equation is merely an academic exercise, incorrectly executed and irrelevant to the important questions facing the Company and this Commission.

I recommend that the Commission and parties use the MIDAS analysis as the model of record – not Mr. Ayer's initial Spreadsheet Analysis, nor my cash-flow model provided as an improvement upon the Company's estimate, nor Mr. Adkins' incorrectly modified version of my cash flow model. This MIDAS Analysis, provided in mid-March to Intervenors is the correct initial basis from which to begin to answer if retrofitting the Big Five is a least cost choice for Indiana ratepayers.

That being said, the parties have been provided an extremely short timeframe in which to review the bases, reasonableness, and validity of this MIDAS analysis. Whereas parties were provided nearly four and a half months to question, analyze, and review the Company's initial application and analysis,[4] I have had one month since the disclosure of this analysis, and two weeks since the receipt of the underlying inputs, outputs, and assumptions to review the Company's new results. Parties entering into the Settlement were likely not aware of the MIDAS analysis, which was provided to Joint Intervenors almost as an aside three business days

[3] Rebuttal Testimony of Mr. Charles Adkins p7, lines 14-17
[4] Initial application submitted September 26, 2012. Intervener direct testimony due January 28, 2013.

prior to the finalized Settlement, and which was, and continues to be, unsupported by testimony.

Q **What are your findings from this analysis?**

A I evaluated the Company's base case MIDAS Analysis for each of the Big Five coal units, and found significant errors and inconsistencies in the Company's revised analysis. The errors are of a significant enough magnitude to reverse the Company's findings at Petersburg 1 and 2, and Harding Street 7. I will describe each of the following problems in depth later in my testimony, but a brief accounting includes:

1. **The coal unit is not replaced at the end of its life**. In the MIDAS analysis, the Company assumes that when the coal units are retired in 2040 or 2035 (in the retrofit scenario), they are replaced with market purchases of capacity and energy. However, when the units are retired in 2017 (in the replacement scenario), they are replaced with a new NGCC unit;
2. **Coal prices have been lowered from initial assumptions.** The coal price used in the MIDAS analysis is far lower in out-years than the Ventyx reference coal price assumed by Ventyx and provided by the Company in the initial spreadsheet analysis; and
3. **Gas and market prices are inconsistent**. The Company's projected gas prices for the NGCC replacement unit are inconsistent with assumptions driving the cost of market power, causing the NGCC to reduce its output in out-years dramatically.

Individually, each of these problems biases the Company's estimated benefit of retaining the coal units incrementally. Taken together, they indicate that even without consideration of carbon or other risks, three of the Company's coal units are non-economic to retrofit.

Q **Have you adjusted the Company's analysis to account for these errors and inconsistencies?**

A Yes. I show the outcome of the adjustments described above in Confidential Table 1, below. For each of the units shown here, the Company has estimated a net benefit of the retrofit; this estimated benefit is shown in the first column ("Base Case MIDAS Analysis"). In the three subsequent columns, I show the net benefit of retrofitting the Big Five units after various individual adjustments. The columns each represent a single correction of the base case and are not cumulative. Finally, in the last column, I have merged all of these adjustments for my estimated net benefit of retrofit in the absence of a price on carbon dioxide (CO_2) emissions.[5]

Confidential Table 1. Net benefit of retrofitting the Big Five coal units (M 2012$) in the base case (no CO_2 price) as presented by the Company and as adjusted for inconsistent assumptions.[6]

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

As shown in Confidential Table 1, above, the Company predicts a moderate to significant benefit to maintain the Big Five coal units in the "Base Case", ostensibly supporting their contention that these units should be retrofit. However, after adjusting for faults and inconsistencies in this analysis, I find that these benefits are significantly degraded and actually reversed for Harding Street 7 and Petersburg 1 & 2, which show a marginal to moderate benefit for retirement,

[5] The sum of changes between the base case and each column do not add up to the change in the "All Adjustments" column because of a partial overlap between the "New NGCC in 2040/2035" and the "Ventyx Coal Price." Both of these changes impact revenue requirements of total fossil fuel expenses in the retrofit case from 2040-2046. The "All Adjustments" value reflects the cost of an NGCC from 2040-2046 in the fuel expense column.

[6] Note that parentheses around values denote a negative value, or in this case a negative net benefit of retrofit, or a positive benefit for retirement.

rather than retrofit. The case for Petersburg 3 & 4 is degraded significantly as well from a fairly strong position to more tenuous benefit.

Q **How do the Big Five units fare in light of a potential CO_2 price?**

A In the Company's "moderate environmental" scenario, which <u>is the only scenario in the MIDAS analysis</u> that used a CO_2 price forecast, the outlook is predictably worse for the Big Five units. Indeed, even without adjusting for the errors noted above, the Company shows that Harding Street 7 would be clearly non-economic, and that Petersburg 1 & 2 are marginally non-economic. Adjusting for the same errors and inconsistencies as above, I find that the analysis indicates that <u>all</u> of the Company's units are moderately to significantly non-economic in the face of even a fairly low price on CO_2. I show the outcome of my adjustments in Confidential Table 2, below. Again, the left-most column shows the net benefit of retrofitting each coal unit using the Company's "Moderate Environmental" analysis. Columns to the right show the outcomes of individual adjustments, and the final column shows my estimated net benefit of retrofit after taking into account all of the adjustments.

Confidential Table 2. Net benefit of retrofitting the Big Five coal units (M 2012$) in the base case (no CO_2 price) as presented by the Company and as adjusted for inconsistent assumptions.

	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Q **Do you have other concerns with this analysis, aside from the three that you have mentioned above?**

A Yes. In addition to those I mentioned above, I have five other pressing concerns that I have not had the opportunity to correct or explore in more depth due to the short turnaround available here, but that certainly impact the Company's analysis

– each biasing towards the selection of the coal retrofit option. I will also describe each of these concerns in more depth later in my testimony:

1. **Unmitigated carbon risk:** Almost all of the Company's sensitivities completely ignore the risk of carbon regulation or legislation;
2. **Connected gas and carbon price:** In the singular test case for a CO_2 price the analysis is biased by an assumed increase in the natural gas price as well;
3. **Influence of off-system sales:** The net benefit of retrofitting the coal units hinges on the opportunity for the Company to make off-system sales;
4. **High gas fixed O&M costs:** The effective fixed operations and maintenance (O&M) cost of the NGCC unit is about double the cost estimated by the Company in workpapers; and
5. **No avoided maintenance costs:** The Company continues to assume that high-cost, long-term life extending maintenance cannot be avoided at retiring coal units.

Q Have you calculated the impact that these additional concerns have on the Company's analysis?

A Generally, no. In some cases, I will provide a rough order-of-magnitude figure to give a sense of scale for these concerns. I assert that it is the Company's burden to substantively address, correct, or given sufficient evidence, dismiss these concerns.

Q What is your recommendation based on your findings?

A My recommendation here remains similar to my recommendation in direct testimony. Based on my review of the MIDAS modeling provided by Mr. Ayers in response to discovery and my adjustments to account for errors in that modeling, I recommend that:

1. The Commission unconditionally deny CPCN for Petersburg Units 1 & 2, and Harding Street 7 as there is no evidence that the continued operation of these units will provide a net benefit for ratepayers; and

2. The Commission conditionally deny CPCN for Petersburg Units 3 & 4 until such time that the Company produces an evaluation of these two units in light of the three errors and five additional concerns I discuss in this testimony. The CPCN should be granted only if the Company is able to produce reasonable and sound evidence that the balance of risk favors the retrofit of Petersburg 3 & 4.

Q In your direct testimony, you recommended that "the Commission order the Company to re-file the application for CPCN on Petersburg Unit 3 and Harding Street Unit 7 at such time that the Company is able to produce a reasonable and transparent economic analysis of the costs and benefits of retrofitting these units, with adequate alternatives and sensitivities explored and explained." Does the Company's MIDAS analysis here satisfy your requirement?

A For the most part, yes. The MIDAS analysis provides a solid basis and reasonable modeling platform for the evaluation of the costs and benefits of retrofitting the Company's Big Five units, and to that extent my concerns regarding IPL's use in its application of a spreadsheet analysis rather than economic modeling would be satisfied if this were the model of record.

However, the extremely late stage at which the MIDAS analysis has been provided restricts the opportunity for Intervenors and Commission Staff to examine the analysis assumptions and outputs, and provide critical feedback. Thus, this Commission will be faced with making a decision from a poorly vetted model with clear errors and inconsistencies. In other cases for similar applications, the process of discovery and testimony provides the Company and parties opportunities to gradually converge on a vetted model platform, the basic structure of which most parties can agree upon. In this case, the disclosure of this type of model would have been beneficial at the start of this docket, rather than at the tail end.

Q On page 9 of his rebuttal analysis, Mr. Adkins indicates that performing production cost modeling for this CPCN would have been restrictive "because it would delay the decision to such a point that IPL would not be

able to implement the capital investments to bring the units into compliance with MATs." How long did it take the Company to conduct this analysis?

A The Company states that "Mr. Ayers began the evaluation with respect to Petersburg Unit 2 only on or about January 7, 2013. The analysis was expanded on or about January 15, 2013, to include all the Big Five units."[7] "Mr. Ayers completed the additional analysis on or about March 7, 2013."[8] Overall, this modeling process took less than two months – shorter than the period that intervenors had to review the Company's original filing.

Q Mr. Adkins is Vice President in the Consulting Practice of Ventyx,[9] the same organization that licensed and executed the MIDAS analysis. Was Mr. Adkins involved in the MIDAS analysis?

A No. According to the Company "Mr. Adkins was not directly involved in performing the analysis, but he did review the results."

Q Is the cost or accessibility of the MIDAS model a factor that should have prevented the Company from pursuing the MIDAS analysis earlier?

A No. The Company agreed to pay [redacted] to execute the portfolio simulations.[10] At less than [redacted] of the cost of the anticipated retrofits (or [redacted]), this is a trivial expense to ensure that ratepayers are served with reasonable and economic power. Interestingly, the cost of setting up and executing the MIDAS analysis was less than a [redacted] of the cost the Company agreed to pay Mr. Adkins to defend the Company's erroneous spreadsheet analysis.[11]

2. <u>COAL UNIT IS NOT REPLACED AT THE END OF ITS LIFE</u>

Q How does the Company treat the coal units at the end of their life in this analysis?

A In this analysis, the Company makes an inconsistent assumption between the scenario in which units are retired in 2016 versus the scenario in which units are

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[7] Response to CAC-SC DR 6-1a.
[8] Response to CAC-SC DR 6-1b.
[9] Rebuttal Testimony of Charles Adkins, page 1, lines 3-4.
[10] See Response to CAC-SC 6-2ciii, CAC-SC DR 6-2, Confidential Attachment 1.pdf.
[11] See Response to CAC-SC 5-1, CAC-SC DR 6-1, Confidential Attachment 1.pdf.

retrofit and reach the end of their life in 2040 or 2035 (Petersburg 1). In the 2016 retirement scenario, the units are replaced one year later by a new natural gas combined cycle (NGCC) unit, while in the retrofit scenario the units are replaced by requisite purchases of capacity and market-based energy. The Company's view with regards to retiring some of the Big 5 units in 2016 is that "sole reliance on the MISO market would not be reasonable given the amount of capacity and energy needed for replacement power, the replacement alternative -- a comparable amount of CCGTs -- is the best approach."[12] It seems illogical that the Company would be concerned today about the availability of capacity and energy, but would assume that these concerns will be absent in two decades.

Confidential Figure 1 below shows the assumed system effective capacity in IPL according to the Company's MIDAS analysis output in the scenario where Petersburg 4 is retrofit. Note the large capacity market purchase from 2040 through 2046.

[redacted]

Confidential Figure 1. IPL system effective capacity in the Petersburg 4 retrofit scenario.

[12] Rebuttal Testimony of Charles Adkins, page 8 lines 13-16.

Confidential Figure 2 below, shows the same graphic, but for the scenario where Petersburg 4 is retired. Note that the replacement NGCC unit comes online after a single year, and is assumed to operate through the entire scenario.

[redacted]

Confidential Figure 2. IPL system effective capacity in the Petersburg 4 replacement scenario.

Q Were you able to adjust the Company's analysis to make the scenario assumptions consistent regarding market purchases?

A Yes. With limited time available to make substantive adjustments to the Company's analysis and no access to the MIDAS model, I made a series of simple adjustments and assumptions. First, I assumed that for Petersburg 2-4 and Harding Street 7, the effect of replacing a retiring coal unit with an equivalently sized NGCC in 2040 (and 2035 for Petersburg 1) would look identical to the scenario in which a NGCC was already operating in those years – i.e. the replacement scenario. Therefore, in the retrofit scenario, I substituted out market sales and purchases, fossil fuel expenses, and fixed and variable O&M expenses from 2040-2046 with the equivalent values from the replacement scenario. I also added in an estimated stream of capital expenses for the replacement NGCC unit assuming a 15% capital recovery factor (CRF).[13] The new present value of

[13] The 15% CRF is not based on specific company values, but experience in similar cases.

revenue requirement (PVRR) for the retrofit scenario was then compared against the replacement scenario to determine an adjusted "benefit of retrofit."

Q What was the impact of making this adjustment?

A The PVRR of the individual unit retrofit scenarios increased by [redacted] decreasing the benefit of retrofitting the units.

Q Are the Company's inconsistent assumptions regarding the replacement of coal generation in 2017 and 2040 trivial?

A No. New asset choices are a critical assumption and factor in planning analyses, and I do not consider adjustments that impact over 60% of an asserted benefit to be trivial.[14]

3. COAL PRICES HAVE BEEN LOWERED

Q What coal prices are used by the Company in this newest analysis?

A The input file for this analysis, provided by the Company in response to discovery request CAC-SC 4-17, clearly indicates that the analysts should "use Ventyx 2012 spring reference case for power, capacity, gas, coal forecasts."[15] No additional coal price input files were supplied in response to CAC-SC 6-9. In reviewing the output files, I determined that the coal price used by the Company corresponded to prices disclosed in a discovery response to SC-CAC 1-56b. On a net present value basis, these prices are abou [redacted] lower than the Ventyx 2012 spring reference case coal forecasts.[16] It is notable that the Company's coal prices are also 8% lower than estimates from the Annual Energy Outlook (AEO) 2012 forecast for the region, and more than 15% lower than the AEO 2013 Early Release forecasts for the region. Finally, all of these trajectories are significantly dampened from the tremendous price increase that the Company has actually

[14] Impact on net benefit in Petersburg 2 is a reduction of [redacted] on a benefit of [redacted] or a [redacted] reduction in benefit.

[15] See CAC-SC DR 4-17, Confidential Attachment 1 (Ventyx Production Analysis).xlsx, tabs HS7, P1, P2, P3, P4 cells A109:G109.

[16] NPV from 2017-2035 (from the decision point to the availability of other forecasts, discounted in real terms at 3.97% - or the Company's nominal WACC [6.47%] minus assumed inflation [2.5%])

witnessed in the last six years – doubling in real terms from 2006 to 2012. I show the trajectory of the Company's forecast against these other sources in Confidential Figure 3, below.

[redacted]

Confidential Figure 3. Company coal price forecast against Ventyx Spring 2012 forecast and AEO forecasts from 2012 and 2013.

Q Why is the low coal price assumption inconsistent or erroneous?

A There are four reasons. First, the data provided by the Company in response to discovery request CAC-SC 1-56b is unsupported by any documentation or ancillary materials. It is simply a series of numbers that look markedly different from the Ventyx calculation of the same. Second, the fact that the AEO has estimated that coal prices will increase in the region is contrary to the Company's low (and even declining in early years) coal price trajectory. Third, the low trajectory stands in contrast to the spiking prices that the Company has witnessed over the last six years, and the Company presented no evidence that this increasing price trajectory will not continue much less, as shown from 2015 to 2020, reverse. Finally, I assume that the Ventyx price of market power is driven, in part, by Ventyx assumed fuel prices – including coal and gas. If the fuel prices predicted by the Company are far lower than those forecast and used in the market price projection, the IPL coal units will show an enhanced performance relative to their peers – an erroneous assumption simply driven by inconsistent assumptions.

Q Where you able to adjust the Company's analysis to make the scenario assumptions consistent regarding coal prices?

Yes. I isolated the fossil fuel cost of the specific coal unit in question in each scenario (i.e. only Petersburg 2 for the Petersburg 2 model runs) and re-calculated the fuel cost of that unit with the Ventyx Spring 2012 coal price and assuming the same capacity factor and generation. I calculated a revised PVRR on the basis of this adjusted coal price.

Q What was the impact of adjusting the Company's coal price?

A The PVRR of the individual unit retrofit scenarios increased by [redacted] million, reducing the benefit of the retrofit.

Q Is the coal price inconsistency trivial?

A No. Fuel prices are a critical assumption and factor in planning analyses, and I do not consider adjustments that impact nearly 20% of an asserted benefit to be trivial.[17]

4. <u>GAS AND MARKET PRICES ARE INCONSISTENTLY DERIVED</u>

Q Please describe the capacity factor of the replacement NGCC unit in the replacement scenario.

A The replacement NGCC begins operations in 2017 with a capacity factor of about 60%, which gradually grows over the next fifteen years to a high of about 76%. However, in 2032, the capacity factor sharply turns downwards and rapidly sinks to 50% in 2035.

[17] Impact on net benefit in Petersburg 2 is a reduction of [redacted] on a benefit of [redacted] or a [redacted] reduction in benefit.

Q Why is the capacity factor of the NGCC replacement unit important in this analysis?

A The capacity factor is indicative of how often the NGCC is economic – i.e. operating in the money. The fewer hours it generates, the more often the Company has to purchase energy on the market. Also, at low capacity factors, the NGCC has fewer MWh over which to spread fixed costs, raising its effective cost.

Q Is there any logical reason that the capacity factor of the NGCC would collapse so rapidly in 2032?

A No. Unless the model or the Company anticipates an energy glut, a spike in natural gas prices, or some other specific event that would undermine the economic competitiveness of NGCC units during this time period, there is no reason that these units should see a significant decline in their competitiveness in 2032.

Q Does the Company's model anticipate an energy glut, a spike in natural gas prices, or another specific event?

A No.

The reason that the Company's model anticipates a collapse in the cost competitiveness of NGCC units in 2032 is due to a simple error and mismatch in the Company's input files. Input files for the MIDAS analysis show market prices rising through 2032, and then flattening from 2032 to the end of the analysis period in real terms (see Confidential Figure 4, below).[18] Output files from the MIDAS analysis indicate the same flattening of market prices after 2032.[19]

Output files from the MIDAS analysis show that natural gas prices rise through <u>2036</u> in real terms before flattening, four years after market prices flatten (see

[18] See CAC-SC DR 6-13, Confidential Attachment 1.xlsx, tab "c. Market Energy Prices_Monthly", row 265 (December 2032) "2.5% Esc" in all cells. Inflation rate is 2.5%, so prices are held constant in real terms post 2032.

[19] See Fisher workpapers. For example for Petersburg 2 Base Case, file P2STY Transact C Monthly Summary.csv, endpoint 2 or 4, transaction group "System", Period "Annual", "Diagnostic_Market_Price" divided by 8760 = annual average flat market price. In real terms, this price rises to 2032 and then flattens through the end of the analysis period.

Confidential Confidential Figure 4, below).[20] This trajectory is consistent with the gas prices filed with Ayer's Direct Workpapers.[21] However, they are inconsistent with the workpapers filed with the MIDAS analysis, which indicate a flattening in real terms in 2032 consistent with the market prices.[22] This appears to be an input error or omission, or the wrong input files were provided in response to discovery.

[redacted]

Confidential Figure 4. Market prices and NGCC fuel price (gas price) in MIDAS analysis output from Petersburg 2 Analysis, Replacement Scenario.[23]

Nonetheless, the point remains - while the fuel cost of operating the NGCC continues to rise over time from 2032 through 2046 – at about 2.5% per year – market prices stay the same. The impact of this error is that the NGCC appears to become rapidly less economic from 2032 through 2036, simply due to an error in input assumptions.

The capacity factor of the NGCC unit and the annual average flat dispatch margin of the NGCC (i.e. flat annual market prices minus the variable cost of the NGCC)

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[20] See Fisher workpapers. For example for Petersburg 2 Base Case, file P2STY Monthly Thermal 20130314.csv, endpoint 4 for generator "415 MW CC-2017". Convert to real terms with inflation rate of 2.5%.

[21] See file IPL Witness Ayers Workpapers (Confidential).XLS, tab "Ventyx Gas Prices"

[22] See CAC-SC DR 6-13, Confidential Attachment 1.xlsx, tab "a. Base Gas Prices"

[23] Source: CAC-SC DR 6-9, P2STY Monthly Thermal 20130314.csv

are shown in Confidential Figure 5, below. The capacity factor collapses from 2032 to 2036, closely tracking the flat annual dispatch margin.

[redacted]

Confidential Figure 5. Replacement NGCC capacity factor (left axis, line) and NGCC operating margin (right axis, bars) in the base case Petersburg 2 replacement scenario.

Q Is it reasonable to believe that market prices would flatten while natural gas prices would continue to rise in this timeframe?

A No. This is clearly an input assumption error. Market clearing prices are, and can reasonably expect to continue to be, driven by natural gas prices. Thus, I would expect the trajectory of these two factors to be reasonably well matched over time.

Q What is the impact of this error on the Company's MIDAS analysis?

A The impact is actually quite pronounced. The amount of market energy that the Company has to purchase increases, and the overall cost of the gas unit is markedly more expensive in out-years than comparable resources in the retrofit scenario.

I estimated the impact of this inconsistency by fixing all variable costs in the out years of the replacement scenario, holding market sales and purchases, fossil fuel expenses, and variable O&M costs constant (in real terms) from 2031 through the end of the analysis period in 2046. The result is that the PVRR of the individual unit replacement scenarios decreased by [redacted] million, reducing the benefit of the retrofit.

Q Is the use of inconsistent market and gas prices trivial?

A No. Consistent fuel and market prices are a critical assumption and factor in planning analyses, and I do not consider adjustments that impact over [redacted] of an asserted benefit to be trivial.[24]

Q Does this mismatch occur in the coal retrofit scenario as well?

A Yes; the coal price used by the MIDAS model continues to increase while the market prices remain flat after 2032. However, the impact on the retrofit scenario is far less pronounced – coal prices only rise by [redacted] per year in real terms after 2032 (as opposed to gas, which rises at [redacted] per year in real terms), and the coal unit reaches the end of its service life in 2040, creating fairly short and flat discrepancy. I have not adjusted for this coal/market price mismatch, but overall it would lend a very minor benefit to the retrofit – far smaller in magnitude than the gas price mismatch[25] and thus likely quite trivial in the overall impact.

Q Are the errors and inconsistencies you have described cumulative or mutually exclusive?

A They are almost entirely cumulative. The first two inconsistencies, the lack of a new NGCC in 2035/2040 and the cost of coal, impact the last six years and the first 23 years of the retrofit scenario, respectively, with virtually no overlap. The third inconsistency, the mismatch between gas and market prices, impacts only the replacement scenario.

[24] Impact on net benefit in Petersburg 2 is a reduction of $[redacted] on a benefit of [redacted] or a [redacted] eduction in benefit. Individually, this adjustment negates the benefit of the Petersburg 2 retrofit.

[25] The gas price mismatch is five times steeper over the period 2032-2036 ([redacted] real increase for gas per year versus [redacted] real increase for coal), and the coal unit is retired in 2040, ending any mismatch, while the gas unit continues operation through 2046.

Taken together, these adjustments completely negate the net benefit of the retrofits for Petersburg 1 & 2, and Harding Street 7, and significantly decrease the net benefit of the retrofits at Petersburg 3 & 4.

Q Do you have any other thoughts regarding the output of the Company's units as predicted from the MIDAS analysis?

A Yes. As I show in Confidential Figure 5, above, the capacity factor of the NGCC unit remains between 60% and 75% up through 2033 in the MIDAS Analysis, a very high utilization. This high capacity factor stands in contrast to the 50% capacity factor assumed in Mr. Ayers' direct testimony spreadsheet analysis, and is an acute rebuttal to the assertion made by Mr. Adkins that "Witness Ayers did use production cost modeling in the estimate of capacity factors [in his spreadsheet analysis]. However, in the context of this evaluation, capital costs and dispatch spreads are in the vital 20 percent and a more detailed production cost analysis is in the trivial 80%."[26] I have shown here that the capacity factor of the NGCC is quite important in the overall outcome of a production-cost model. In fact, in the erroneous construction of the original Spreadsheet Analysis, a higher capacity factor at the NGCC replacement (indicating better performance and economic viability) resulted in a significant detriment to the NGCC replacement option – a completely backwards outcome.[27]

5. UNMITIGATED CARBON RISK

Q Do you have other concerns with the Company's new MIDAS analysis?

A Yes. I have found five other unresolved problems with the Company's analysis. I have not fully quantified the impact of these concerns, but these are all significant problems that differentially bias the Company's analysis in favor of the retrofit.

[26] Rebuttal testimony of Charles Adkins, page 11 lines 16-18.

[27] This analytical error is so significant in the spreadsheet analysis that assuming that the NGCC replacement does not operate at all (i.e. a zero capacity factor), yet still incurs capital and fixed costs, results in a nearly break-even result at Petersburg 2 – a significantly better outcome than as filed by the Company.

Q Please describe the Company's analysis of carbon risk in this new analysis.

A With the exception of a single set of scenarios for each unit, the Company has disregarded the risk of a price on carbon in the next three decades. Out of seventeen scenarios examined for each unit (combinations of high or low capital, high or low O&M costs, and high or low gas prices), only three consider a CO_2 price, and the selected CO_2 price sets a very low threshold for the reasonable examination of carbon regulation or legislation.

Q Does the Company provide an explanation as to why most of the scenarios examined fail to review a price on carbon?

A No. The Company does, however, state that "IPL reviewed a number of documents attempting to predict the direction the EPA might take and how much legal success they might have regulating under the limitations set forth under 111(d) of the CAA."[28]

The Company then provides a litany of reasons that a carbon price imposed on IPL is unlikely, amounting to a series of unreasonable and unsupported arguments that imply that IPL would be amongst a privileged cohort of utilities that could avoid a price on carbon. This list includes the potential that "IPL may receive [credit] for its demand side management efforts or renewables portfolio, or … credit for the reductions that IPL has already achieved." [29] The Company suggests that because of "the possible conversion of Harding Street Units 5 and 6 to natural gas… IPL may already be in compliance or may be in compliance with limited effort with any such regulation. As a result, any estimation of the applicability, amount and timing of any CO2 price is speculative." [30]

Q Please describe the potential mechanisms that could foreseeably effectively impose a price on carbon.

A When considering a price on CO_2, most parties are inclined to think specifically of the last major effort to legislate on greenhouse gasses – the American Clean

[28] Response to CAC-SC DR 6-7d
[29] *Ibid*.
[30] *Ibid*.

Energy and Security Act (ACES) of 2009 (H.R. 2454) which, if passed by the Senate, would have created a "cap and trade" mechanism on greenhouse gasses in the electricity and industrial sectors. Legislation creating a cap and trade system in 2013 is unlikely with the current Congress, but there are other ways to impose costs on facilities that emit CO_2. On the regulatory side, there are potential administrative rules that could either require specific reductions at existing sources, or more likely allow emitting entities to pursue alternative programs that effectively displace emissions. Indeed, the EPA is currently working on a roadmap that would allow States to claim criteria emissions reductions from efficiency and renewable energy programs,[31] and it is fairly trivial to imagine a similar program implemented for the purposes of targeting greenhouse gasses. Similarly, the Administration can provide incentives, such as loan guarantees, to bolster non-emitting sources. The current Administration has signaled quite clearly that it is interested in pursuing mechanisms to combat climate change,[32] and the nomination of Gina McCarthy, the former head of the Connecticut DEQ and key proponent of the Northeast Regional Greenhouse Gas Initiative (RGGI), as the head of the US EPA is an affirmation of the Administration's intent.

On the legislation side, recent bills introduced into the US Senate by Senators Sanders and Boxer both indicate that individuals in the current Congress are interested in pursuing climate legislation again. These bills, including the Climate Protection Act (a direct tax on fossil fuels at the source)[33] and the Sustainable Energy Act (the revocation of federal subsidies to fossil fuel producers)[34] While

[31] *See* US EPA "Roadmap for Incorporating Energy Efficiency/Renewable Energy Policies and Programs into State and Tribal Implementation Plans." Available online at http://epa.gov/airquality/eere/pdfs/EEREmanual.pdf

[32] See 2013 State of the Union Address, Feb. 12, 2013. Second statement in energy platform: "But for the sake of our children and our future, we must do more to combat climate change. Now, it's true that no single event makes a trend. But the fact is the 12 hottest years on record have all come in the last 15. Heat waves, droughts, wildfires, floods -- all are now more frequent and more intense. We can choose to believe that Superstorm Sandy, and the most severe drought in decades, and the worst wildfires some states have ever seen were all just a freak coincidence. Or we can choose to believe in the overwhelming judgment of science -- and act before it's too late."

[33] Climate Protection Act of 2013. Introduced February, 2013. http://www.sanders.senate.gov/imo/media/doc/0121413-ClimateProtectionAct.pdf

[34] Sustainable Energy Act of 2013. Introduced February, 2013. http://www.sanders.senate.gov/imo/media/doc/021413-SustainableEnergyAct.pdf

these bills are unlikely to pass in their current state, they show that it remains reasonable to assume that legislative action to address CO2 emissions is likely over the longer term. .

These administrative actions and bills may not impose a direct tax on carbon emissions, but imposing a cost in modeling on emissions of CO_2 is a reasonable proxy for any program that seeks to reduce carbon emissions from greenhouse gas emitting sources. Regardless of what type of credit could be received by IPL for its past actions, significant or *de minimis*, a failure to examine the risk of carbon regulation on the IPL fleet over the next <u>three decades</u> is simply imprudent.

Q What carbon price is reviewed by the Company in this analysis?

A In the single scenario set that reviews the potential for a carbon price, called “Moderate Environmental,” the forecast starts at [redacted] CO_2 in [redacted] (nominal, $14/ton in 2012) and rises at [redacted] real per year to [redacted].[35] From [redacted] to the end of the analysis period, the CO_2 price [redacted] in real terms.

In all other scenarios, the carbon price is held at zero for all years.

Q What is the basis of the Moderate Environmental carbon price?

A The Company states that:

> The CO_2 emission cost adders were part of Ventyx’s “Moderate Environmental” Scenario. IPL did not identify the value of a CO_2 price adder.[36]

Q How does Ventyx derive the “Moderate Environmental” carbon price?

A There are no analyses, studies, or other documents that support the carbon price used in this analysis. Parties requested such documents[37] and were provided only the explanation that “IPL reviewed a number of documents…” However, IPL

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[35] See CAC-SC DR 5-30, Confidential Attachment 1. Conversion to real assumes 2.5% inflation rate used elsewhere in this docket.

[36] Response to CAC-SC DR 6-7b.

[37] See CAC-SC Request DR 6-7d. “Identify and produce any analyses, studies, or other documents relied on or reviewed in identifying the value of the CO2 emission cost adder.”

claims that these documents are not relevant as “IPL did not identify the value of a CO_2 price adder. IPL used Ventyx “Moderate Environmental” case as a scenario,” and thus the documents of relevance would be those used and relied upon by or supporting the Ventyx Moderate Environmental price. These were not provided, despite the fact that Ventyx is now an active participant in this docket.

Q How does this carbon price compare to other utility forecasts?

A It is at the low end.

Synapse gathered public filings from 37 utility IRP and CPCN cases from 2011-2013 and extracted the carbon forecasts from each, when they were listed (where CO_2 prices were not listed or discussed, Synapse assumed a zero CO_2 price). These forecasts are shown in Confidential Figure 6, below.

[redacted]

Confidential Figure 6. 2011-2013 CO_2 price forecasts from various utilities, Synapse, and IPL MIDAS Analysis.

Synapse does <u>not</u> employ a curve fit or weighting to particular utility plans; rather, as one of the forecast mechanisms employed, we review the cohort of utility plans filed and type of policies they represent, and estimate a range of prices that are likely high enough to impact planning procedures yet are politically viable, and that are informed by likely mitigation costs and a trajectory of falling emissions.

Nonetheless, in a *post-hoc* review of 102 forecasts from 37 public IRPs published between 2011 and 2012, the Ventyx/IPL forecast ranks quite low – at the 34th percentile of real levelized prices from 2015-2030. In comparison, the Synapse price forecasts that I described in my direct testimony[38] bound the range of other utility forecasts at the 43rd, 59th, and 78th percentiles of levelized prices for the Low, Mid, and High forecast, respectively.

To a large extent, reviewing the range of CO_2 prices used by other entities in planning is an effective mechanism of "taking the temperature" of the climate debate – all else being equal, it measures the extent to which utilities, Commissions, and other stakeholders are willing to hedge against the risk of climate regulations or legislation. IPL's choice of <u>no CO_2 price</u> in the base case, and a very low CO_2 forecast for a sensitivity means that the Company is casting <u>very</u> long odds on any form of climate regulation or legislation relative to its utility counterparts. It is my opinion that the Company's outlier position is neither prudent nor safe, and exposes ratepayers to significant risk.

It is my assessment that the zero CO_2 price used by the Company in the base case of this analysis exposes ratepayers to significant risks from any future regulation of carbon emissions and that the carbon price in the Moderate Environmental scenario is low and unsupported by the Company or their contractors.

Q In his rebuttal testimony, Mr. Adkins cites a passage from the rebuttal testimony of American Electric Power (AEP) witness Karl Bletzacker in Kentucky Case No. 2011-00401 regarding the nature of carbon risk. Would you please describe the outcome of that particular case?

A Yes. In that case, AEP requested a CPCN and the guarantee of rate recovery for nearly $1 billion in retrofits at the Big Sandy 2 generating station in Louisa,

[38] Direct Testimony of Jeremy Fisher, page 34.

Kentucky. Shortly after hearings, AEP withdrew its application.[39] In December of 2012, AEP announced that Big Sandy 2 would be retired, stating that "when we withdrew our scrubber filing last summer, we stated that we felt new opportunities were emerging that would allow us to meet our obligations at a lower cost."[40]

Q Did AEP use a carbon price in their base case in Kentucky Case No. 2011-00401?

A Yes. AEP considered and used a carbon price in their base case analysis. The price trajectory was confidential, but was similar in nature to the price trajectory considered by IPL only in a single sensitivity scenario in this docket.

Q What is Mr. Adkins' recommendation with respect to including carbon pricing in this analysis?

A Mr. Adkins casts doubt on the magnitude, cost, and probability of potential carbon legislation or regulation, and states that "these are all items that we should know before we make a drastic and irreversible decision such as retiring a power plant."[41]

Q Is granting a guarantee of rate recovery for these retrofits also a significant and irreversible decision?

A Yes. Once the Company commits to these retrofits with a guaranteed recovery, they will be committed to running these plants through the end of their depreciable life, or risk creating stranded costs for either ratepayers or shareholders. Continuing to retrofit and operate these plants, or retiring them – both have significant ramifications. However, the optionality available to the Company in the case of the retirement is far greater than if the Company pursues a retrofit. In retirement, the Company can pursue a variety of cost effective

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[39] Exhibit JIF-2, May 2012 order in 2011-00401. Available at http://www.psc.ky.gov/PSCSCF/2011%20cases/2011-00401/20120531_PSC_ORDER.pdf

[40] Exhibit JIF-3, AEP Kentucky Power Company. December 19, 2012. Kentucky Power Files to Transfer Generation Assets, available at Https://www.kentuckypower.com/info/news/viewRelease.aspx?releaseID=1338

[41] Rebuttal testimony of Charles Adkins, p27 lines 17-18.

replacement power options, including new units, market purchases, greater efficiency, and renewable energy. If the units are retrofit, the Company has exactly one option, that of continued operation for the next two and a half decades.

Q Is the lack of a carbon price in the MIDAS analysis trivial?

A No. The Company's MIDAS analysis clearly hinges on the assumption of no price on CO_2. As shown in Confidential Table 2, even at the Company's low forecast price for CO_2, the new analysis indicates that retrofitting Petersburg 1 & 2 results in a liability to ratepayers rather than an asset, and that Harding Street 7 is a significant liability. In addition, the benefit of retrofitting Petersburg units 3 & 4 drops significantly (by 60% and 81%, respectively).

Taking into account the other errors and inconsistencies I described above, each and every one of the Big Five units are fully non-economic relative to a new NGCC under the Company's low CO_2 price – from a liability of [redacted] million at Petersburg 3 to a liability of [redacted] million at Harding Street 7.

6. <u>CONNECTED GAS AND CARBON PRICE</u>

Q Please explain how gas and carbon prices are connected in the Company's Ventyx study.

A The Company puts forward the assumption that in any scenario with a CO_2 price, gas prices will also increase above base trajectories. In the Moderate Environmental scenario, gas prices rise by nearly [redacted] above the reference case with the imposition of a carbon price.

Q What is the impact of this gas price increase?

A In this analysis, the Company examines the tradeoff between existing coal and new natural gas-fired electric generating units (EGU). When gas prices are increased coincidently with CO_2 prices, any advantage conferred on gas units by virtue of having lower CO_2 emissions is minimized.

Q Is an increased gas price in the presence of a CO_2 price supported by evidence?

A No. At the moment, the theory connecting gas and CO_2 prices is largely conjecture: the hypothesis states that as CO_2 prices increase, gas plants will largely substitute for coal plants, increasing gas demand and thus increasing price pressures on gas. This hypothesis largely assumes that large numbers of coal plants will retire under a CO_2 price; also that gas plants will be the exclusive replacement for coal and that gas markets will be stretched if gas demand increases incrementally.

I demonstrated in my direct testimony that "some of the most advanced integrated energy economics models disagree with one another regarding the extent of gas price sensitivity to carbon prices."[42] I showed a graphic with modeling results from the Energy Modeling Forum (EMF) and stated that "of the ten models portrayed here, four predict <u>lower</u> gas prices, four predict <u>higher</u> gas prices, and two are unchanged compared to the baseline at any carbon price below $60/ton CO_2.[43] At carbon prices above $60/ton the majority of models consistently predict <u>lower</u> gas prices than the baseline."

Q How do the Company's assumptions compare to the results you show in the EMF graphic?

A The Company assumes a very steep and very high gas price increase with the imposition of a CO_2 price, as shown below in Confidential Figure 7, below.

[42] Direct Testimony of Jeremy Fisher, page 36 lines 13-15.
[43] With the exception of the $36/ton CO_2 mark, in which 5 of 10 predict a higher gas price.

[redacted]

Confidential Figure 7. Model results from EMF indicating natural gas changes with rising CO_2 prices;[44] with IPL assumed gas price adder with CO_2 price.[45]

Even if we were to assume some positive relationship between CO_2 prices and gas prices, the Company's relationship is clearly steeper and more pronounced than could or should be reasonably expected from these data.

It is my assessment that the gas-CO_2 price connection used by the Company in the Moderate Environmental case is unsupported and inappropriately biases this analysis against gas alternatives to the coal units.

Q Is the connection between the gas and CO_2 price trivial?

No. The Company's analysis significantly increases the running cost of the NGCC replacement unit by increasing the cost of natural gas. For example, at

[44] Data available at http://emf.stanford.edu/docs/263. NEMS (US Energy Information Administration), E2020-EC (Environment Canada), GCUBED (Brookings Institution), EPPA-MIT (Massachusetts Institute of Technology), ADAGE (Research Triangle Institute), GCAM (Joint Global Change Research Institute, Pacific Northwest National Laboratory), IMACLIM (Centre International de Recherche sur l'Environnement et le Développement), NEMS-GPRA (US Department of Energy & Onlocation, Inc.) MRN-NEEM (Charles River Associates), and RFF-Haiku (Resources for the Future)

[45] CO_2 price from CAC-SC 5-30. Gas prices derived from Petersburg 2 Monthly Thermal output as provided in 6-9, Confidential Attachment 2 (P2STY and P2CO2, Endpoint 4)

Harding Street 7, leaving all other factors constant but substituting in the standard gas price forecast instead of the inflated forecast for the 415 NGCC MW replacement unit yields an increased liability for the coal unit of another [redacted] million NPV, driving the overall <u>liability</u> of retrofit from [redacted] as shown in Confidential Table 2 to a [redacted] million liability. Making the same correction at Petersburg 4, the Company's analysis which shows an [redacted] net benefit towards retrofit with the low CO_2 price turns into an [redacted] million liability. In other words, correcting the Company's unsupported assumption regarding the relationship between gas and CO_2 prices shows that retrofitting Petersburg 4 is not economic – the opposite of the Company's earlier claim. This is certainly not trivial.

7. INFLUENCE OF OFF-SYSTEM SALES

Q Does the Company's model assume that the Company is able to sell energy off-system?

A Yes. In fact, the Company's new analysis shows significant off-system sales in the case where the coal units are retrofit versus the case in which the units are replaced with NGCC units. The presence of the coal unit is assumed to allow the Company to make significant off-system sales, while those potential sales are significantly diminished with the NGCC replacement unit.

[redacted]

Q Is it reasonable to include off-system sales in the calculation of net benefits of retrofit?

A Possibly, but with significant caution. Hedging on the benefit of off-system sales effectively puts the utility in the position of acting as a sales marketer instead of a full-service provider. There may be some benefits accrued to ratepayers for maintaining some level of off-system sales, but the decision should not rest on this factor –and it should not be a significant element of the analysis.

On this point, I agree in part with Mr. Adkins, who stated that "the inclusion of wholesale sales beyond the need to replace existing coal asset's generation is biased towards retirement. While those sales might or might not occur, it is important to view this decision without the excess sales."[46] I would alter this statement only slightly: the inclusion of wholesale sales of any option beyond the need to meet full-service requirements imparts a risk upon ratepayers, as those sales might or might not occur.

[46] Rebuttal Testimony of Charles Adkins, page 20 lines 3-5.

I did not have the opportunity to adjust and re-run the Company's model, and there was insufficient time available to perform a comprehensive estimate of how much the Company's answers would change if wholesale sales, and the generation used to support those sales, were removed from this analysis.

As an indicative measure, I simply removed the term of Market Sales from the Company's Annual Income Statement output to estimate a revised PVRR without the benefit of off-system sales. The results of this revision are shown in Confidential Confidential Table 3, below. In all cases except for Petersburg 1, the impact of removing Market Sales is a significant decrease in the PVRR of each scenario. In the case of Harding Street 7, Market Sales appear to account for almost the entire benefit of this case.

Confidential Table 3. PVRR of scenarios with and without market sales.[47]

[redacted]	[redacted]			[redacted]			[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

It is notable that this is likely a conservative case as well – in the retrofit case, the Company assumes that all energy and capacity will be purchased on the market after 2040 (or 2035 in the case of Petersburg 1). After 2040, market sales in the retrofit cases plummet. If these two scenarios were truly on par, there would be no differences between market sales after 2040 (i.e. both would choose similar replacement energy sources), and thus I would expect the change in benefit as shown in Confidential Table 3 to be much more severe.

[47] Values in the table are not corrected for any of the errors or inconsistencies discussed in the first sections of this testimony. The "PVRR without market sales" section represents only a removal of market sales and no other corrections or changes.

If off-system sales are included in this analysis, then to any extent that IPL intends on sharing off system sales revenues with shareholders instead of passing them on in their entirety to ratepayers, such a sharing mechanism should be modeled and accounted for in the Company's benefit analysis.

Q Is the inclusion of off-system sales in the Company's assessment trivial?

No. Anywhere from [redacted] of the Company's assessed value for maintaining the coal plants is due to the assumed off-system sales in these scenarios.[48] I would not consider this level of change to be trivial.

8. HIGH GAS FIXED O&M COSTS

Q What is the Company's assumed fixed O&M cost for the replacement NGCC unit?

A The input file for the analysis as provided to parties in this docket states "Fixed O&M at [redacted]/kw."[49]

Q Is this a reasonable cost for NGCC fixed O&M as far as you are aware?

A Yes. The Company did not provide the source of this figure, but there are several public sources that corroborate values within this range. The US Energy Information Administration assumes fixed O&M costs of $15.19/kW-year (2012$) for a new NGCC unit.[50] A study performed by Black and Veatch for the National Renewable Energy Laboratories (NREL) estimated $6.77/kW-year (2012$) for a new NGCC unit.[51] In The Brattle Group's estimate for the Cost of New Entry (CONE), the consultancy estimates costs from $14.3 to $15.5/kW-yr

[48] This change is -8% in the case of Petersburg 1 for unusual circumstances: in the retrofit case, the unit is assumed to retire in 2035 and thus has fewer years of off-system sales, and in fact has a higher market purchase burden, switching the influence of removing off-system sales from this equation.
[49] See CAC-SC DR 4-17, Confidential Attachment 1 (Ventyx Production Analysis).xlsx, tabs HS7 through P4 in cells E103:F103.
[50] Exhibit JIF-4, U.S. Energy Information Administration, 2012. Assumptions to the Annual Energy Outlook 2012, Electricity Market Module. Table 8.2. "Conv Gas/Oil Comb Cycle". $14.39/kW-yr in 2010$, or $15.19/kW-yr in 2012$.
[51] Exhibit JIF-5, National Renewable Energy Laboratory (NREL), February 2012. Cost and Performance Data for Power Generation Technologies: Cost Report. Prepared for NREL by Black & Veatch. Table 4. $6.31/kW-yr in 2009$, or $6.77/kW-yr in 2012$.

(2012$) for new combined cycle units.[52] PacifiCorp in their most recent IRP used estimated costs from $7.13 to 14.23/kW-year (2012$) for new NGCC units.[53] Except for the NREL study, which appears lower than the other reports, all of these are fairly consistent with each other, estimating costs of about $14-$15/kW-yr. These are not dissimilar to the values in the input file provided.

Q What value is actually used in the analysis?

A Reviewing the output files, the analysis appears to use a value of about [redacted]/kW (2012$), or [redacted] greater than the input file specifies.[54] This same review indicates that the fixed O&M costs for the coal units are precisely the same as in the input file.

While the Company did not provide access to the MIDAS model as used here, I hypothesize that either the wrong value has been used in the analysis, or an additional O&M cost, such as an interconnection cost or gas pipeline cost, may be included in the fixed cost of the replacement NGCC. If the reason that the cost is higher is due to an additional cost, this cost has not been disclosed or vetted.

In a phone call with the Company and the Ventyx consultant charged with executing this model, I asked if there were additional files or supporting workbooks that could allow us to review the specifications of the NGCC replacement unit, hoping to get a better understanding of the fixed costs and operating parameters of the NGCC, as well as source documents for those values. I was informed that all of the input information was made available in the response to 4-17, the very response that indicated the [redacted] kw cost. After I

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[52] Exhibit JIF-6, The Brattle Group, August 24, 2011. Cost of New Entry Estimates for Combustion-Turbine and Combined-Cycle Plants in PJM (Executive Summary). Table 2: Recommended Gas CC CONE for 2015/2016. $15.4-$16.7/kW-yr in 2015/2016$, adjusted with 2.5% inflation rate to $14.3-$15.5/kW-yr.

[53] Exhibit JIF-7, PacifiCorp. March 31, 2011. 2011 Integrated Resource Plan. Chapter 6 – Resource Options. Table 6.1 – East Side Supply-Side Resource Options. $6.75-13.48/kW-year in 2010$, or $7.13-14.23/kW-year in 2012$.

[54] Value extracted from Petersburg 2 Base Case replacement scenario (Endpoint 4), P2STY Monthly Thermal 415 MW CC “Sum of Fixed Cost ($) mm” and “Sum of Unit Capacity (MW)”

asked if there were other workbooks that I should review, I was informed that there were not.

Q Is the higher NGCC fixed O&M cost trivial?

No. The higher fixed O&M cost adds substantially to the cost of the replacement scenario. For example, in the Petersburg 2 base case, the net present value of the difference between the fixed O&M costs as used in the model and the input file amounts to $75 million (2012$) – or 30% percent of the stated benefit of the retrofit. In the current model, this is a significant bias towards the coal retrofit.

Q How does Mr. Adkins treat fixed O&M costs in his boundary condition analysis?

A He does not treat them at all.

In his rebuttal analysis, Mr. Adkins claims to construct a "proper boundary analysis" for finding a "breakeven cost of gas," or the "real price of delivered gas for which a generic CCGT is economically superior to a generic coal unit."[55] What he apparently means by this term "economically superior" is the gas price at which a CCGT dispatches before a coal unit. However, his exercise fails to take into account the important fixed costs of operation, which are dramatically different for a "generic CCGT" and a "generic coal unit."[56] For example, in the Petersburg 4 base-case replacement scenario, the fixed costs of operation for the gas unit are [redacted]% of its total operating cost (i.e. fuel + variable + fixed O&M), and the fixed cost of operation for the coal unit are [redacted]% of its operating cost. These differentials would clearly make a difference in the overall calculus of when a gas unit would be considered superior in a PVRR sense to a coal unit – not just on an annual variable cost basis.

[55] Rebuttal testimony of Charles Adkins, page 24 lines 5-6.
[56] See IPL Witness Ayers Workpapers (Confidential).XLS, 16 CERA New Plant Cost. CCGT = [redacted]/kW-yr fixed O&M; supercritical coal = [redacted] kW-yr.

It is notable that Mr. Adkins makes the same error in his Carbon [sic] boundary analysis, but compounds it by adding in the capital costs of a new NGCC but not of the coal retrofit.

9. NO AVOIDED MAINTENANCE COSTS

Q Did you discuss avoidable O&M expenses in your direct testimony?

A I did. I stated that "if the Company were to retire a plant in the next few years, it is quite likely that a large proportion of [large capital expenditures from 2013-2015] can either be scaled back or avoided altogether."[57]Further I stated explicitly that "these avoidable costs are important considerations in a retrofit/retirement evaluation such as this one; by not excluding avoidable capital costs, the Company biases the analysis towards the continued operation of the coal units." [58]

Q What was the Company's response?

A In a discovery response, the Company indicated that they agreed, as I noted in my direct testimony: "Costs from 2013-2015 were not included in the future life cycle cost evaluation. These costs would however be included in a retirement evaluation if the future life cycle evaluation had indicated a unit's economic viability was in question."[59]

However, in rebuttal analysis, the Company withdrew from this position. Mr. Adkins disparages the idea that such costs should even be considered:

> Avoided O&M 2013 through 2015: This is laughable. It is neither in the vital or trivial realm. This is the proverbial "kitchen sink". [sic][60]

[57] Direct Testimony of Jeremy Fisher, page 25 lines 22-24
[58] Direct Testimony of Jeremy Fisher, page 26 lines 1-4
[59] CAC-SC DR 1-50 and Direct Testimony of Jeremy Fisher, page 26 lines 0-12.
[60] Rebuttal Testimony of Charles Adkins, page 12 lines 12-13

Q When Mr. Adkin's wrote this statement, was he aware of the magnitude of the fixed costs that could be avoided?

A No, he was not. Joint Intervenors asked if Mr. Adkins had reviewed a list of expected ongoing capital expenditures at the Big Five coal units provided in earlier discovery,[61] and Mr. Adkins responded that he had not reviewed this listing.[62]The Company confirmed that Petersburg 2 expected a major maintenance outage in 2013 with a total cost of [redacted] million, and another major maintenance outage in 2015 at Petersburg 3 with a total cost of [redacted] million.[63] The Company did not deny that these projects could be avoided if the units were retired in the year 2015.[64]

Q Would you consider it reasonable to perform a major outage on a unit that would retire within two years, or that very same year?

A No. Not at all. Any significant costs incurred at a unit preparing for imminent retirement should clearly be subject to a rigorous prudence review. Spending tens of millions of dollars on life-extension projects for units that are about to retire would be an extraordinary waste of ratepayer funds.

I would expect that if the Company decides (or the Commission orders) that it does not make sense to retrofit one or more of the Big Five units, that the Company would immediately cease any plans for long-term life extension projects at that unit, or risk a future disallowance for imprudently incurred expenses.

Q Did the Company consider the avoidable costs of major maintenance outages in the MIDAS analysis?

A No. There are no avoided costs considered prior to the retirement of the units in 2015/2016.

[61] Request referenced CONFIDENTIAL workbook CAC-SC DR 1-22j, Confidential Attachment 1 (2013 - 2022 PS Capex Detail).xlsx, provided to Joint Intervenors in response to discovery response 1-22j.
[62] Response to Data Request 5-15a. "Had Witness Adkins reviewed this workbook prior to the submission of rebuttal testimony on February 25, 2013?" "No."
[63] See response to Data Request 5-15c and f.
[64] See response to Data Request 5-15d and g.

Q **Would you agree with Mr. Adkins that the avoidable O&M expenses at the Big Five coal units are "laughable"?**

A No. I do not consider charging [redacted] million to ratepayers on a whim to be "laughable."

10. <u>CONCLUSIONS</u>

Q **What conclusions can you draw from the Company's Ventyx analysis?**

A My review of the Company's MIDAS analysis indicates that, after correcting for errors and inconsistencies, three of the Company's Big Five units – Harding Street 7 and Petersburg 1 & 2 – are not economic to retrofit, <u>even in the absence of a carbon price.</u> Correcting for consistent replacement assumptions, consistent and reasonable coal price forecasts, and consistent gas and market price forecasts reveals that these units would be significant liabilities to the Company.

I also found a series of other mistakes, omissions, and biases in the MIDAS analysis that bias the results towards the choice to retrofit the coal units. These included an unmitigated carbon risk in nearly every scenario examined, inappropriately connected gas and CO_2 prices, highly influential off-system sales assumptions, unsupported NGCC fixed O&M prices, and the lack of consideration for avoidable O&M expenses prior to the retirement of any of the coal units. While I did not expressly correct for these problems, each is a significant and non-trivial error that push the Company towards retrofits that are not in the ratepayers' best interest.

The Company's MIDAS analysis confirms that even without correcting any other errors, IPL <u>must</u> bank on CO_2 inaction for the next two decades to have Harding Street 7 and Petersburg 1 & 2 pay off. If the errors are corrected, all five of the Big Five units fail to be cost effective, even under the Company's very modest CO_2 assumptions.

The Company's choice to execute the Ventyx MIDAS Gold model at this late stage is both perplexing and frustrating. On the one hand, this analysis represents a reasonable methodology from which to begin the process of understanding and evaluating the Company's choices. On the other hand, this analysis is not supported by testimony, has not been reviewed by other parties prior to settlement, and did not substantively contribute to the record during a reasonable period of evaluation – instead we are left to hastily review the Company's analysis.

I have found numerous problems and inconsistencies with this analysis, some of which are fairly obvious. The Company appears to have rushed this analysis and made mistakes along the way. The mistakes and inconsistencies are not trivial by any means – they drive the outcome of the model, and I have shown that individually and in concert many of these errors completely reverse the Company's findings.

The retrofits at Harding Street 7, and Petersburg 1 & 2 would be clear mistakes. Even under the best of circumstances, these units are liabilities to IPL and to the Company's ratepayers. Reviewing only the three major changes that I made to the Company's analysis reverses the outcome for these three units. Add to this that Petersburg 2 is currently preparing to undergo [redacted] million of major life-extension retrofits, that the gas unit is likely less expensive to operate than modeled by the Company, and that the analysis hinges on the ability of the Company to sell energy off-system, and these units are glaring liabilities in the Company's fleet.

The retrofits at Petersburg 3 & 4 are also problematic, but not to the same extent as the smaller of the Big 5 units. If the Company faces a CO_2 price, their fleet will take a huge hit; because IPL relies mostly on coal generation, the Company is heavily exposed to the risk that new regulations or legislation will impose a price on carbon emissions. The investments contemplated in this CPCN will be a series of stranded costs if the Company's coal fleet faces even a small CO_2 price or sustained low gas prices – much less the combination of the two.

The Company has a unique opportunity to re-envision its fleet and the mechanism by which it serves power to Indianapolis ratepayers. Should the Company choose to make these investments in this fleet, they will be committed to another two and a half decades of operation just to ensure that the Company can recover its costs. Rather than rush towards these particular retrofits, it is my opinion that the Company should focus on finding lower cost solutions that can meet environmental compliance obligations and provide the lowest risk for ratepayers going forward.

In light of this analysis, I recommend that:

1. The Commission unconditionally deny CPCN for Petersburg Units 1 & 2, and Harding Street 7 as there is no evidence that the continued operation of these units will provide a net benefit for ratepayers; and
2. The Commission conditionally deny CPCN for Petersburg Units 3 & 4 until such time that the Company produces an evaluation of these two units in light of the three errors and five other concerns I discuss in this testimony. CPCN should be granted only if the Company is able to produce reasonable and sound evidence that the balance of risk favors the retrofit of Petersburg 3 & 4.

Q Does this conclude your testimony?

It does.

SURREBUTTAL CONFIDENTIAL
EXHIBIT JIF-1

CITED DATA REQUEST RESPONSES AND ATTACHMENTS

SURREBUTTAL EXHIBIT JIF-2

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR APPROVAL OF ITS 2011 ENVIRONMENTAL	)	
COMPLIANCE PLAN, FOR APPROVAL OF ITS	)	
AMENDED ENVIRONMENTAL COST RECOVERY	)	**Case No. 2011-00401**
SURCHARGE TARIFF, AND FOR THE GRANT OF A	)	
CERTIFICATE OF PUBLIC CONVENIENCE AND	)	
NECESSITY FOR THE CONSTRUCTION AND	)	
ACQUISITION OF RELATED FACILITIES	)	

REBUTTAL TESTIMONY

OF

KARL R. BLETZACKER

April 16, 2012

**REBUTTAL TESTIMONY OF
KARL R. BLETZACKER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

CASE NO. 2011-00401

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**REBUTTAL TESTIMONY OF
KARL R. BLETZACKER, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY**

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION?

A. My name is Karl R. Bletzacker, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215. I am employed by the American Electric Power Service Corporation ("AEPSC") as Director-Fundamentals Analysis.

Q. DID YOU FILE DIRECT TESTIMONY IN THIS CASE?

A. No.

II. PURPOSE

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to certain arguments made by Kentucky Industrial Utility Customers, Inc. ("KIUC") witness Lane Kollen and Sierra Club, et al, ("SC") witness Mr. Jeremy Fisher in their respective direct testimonies. I will counter Mr. Kollen's contention that the natural gas pricing projections utilized in KPCo's economic analyses presented in Company witness Weaver's direct testimony are "on the high side" because of Mr. Kollen's misplaced comparison to the EIA's Annual Energy Outlook(s) and to the NYMEX futures market. Also, I will refute Mr. Fisher's assertion that CO_2 pricing projections are not reasonable and understated.

III. AEP INTERNAL NATURAL GAS PRICE PROJECTIONS ARE REASONABLE AND NOT OVERSTATED

Q. IS MR. KOLLEN CORRECT IN HIS ASSERTION THAT THE AEP PROJECTIONS OF LONG-TERM PRICING OF NATURAL GAS ARE "ON THE HIGH SIDE" WHEN COMPARED TO OTHER PUBLICLY AVAILABLE FORECASTS SUCH AS THOSE PUBLISHED BY THE EIA?

A. No, Mr. Kollen's assertion is incorrect. His anecdotal comparison on pages 19 and 20 of his testimony is flawed and is clearly unsubstantiated. First and foremost, the natural gas pricing forecast from the Energy Information Administration (EIA) Annual Energy Outlook (AEO) for both 2011 and 2012 were created under the assumption that current laws and regulations remain *unchanged*. That is, even reasonably known and emerging regulations are specifically excluded from the assumptions for such EIA-AEO projection purposes. The following excerpts are from the respective opening paragraphs of the AEO2011 and AEO2012 (Early Release) Executive Summaries.

> "Under the assumption that current laws and regulations remain unchanged throughout the projections, the *AEO2011* Reference case provides the basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future."

> "Projections in the Annual Energy Outlook 2012 (AEO2012) Reference case focus on the factors that shape U.S. energy markets in the long term, under the assumption that current laws and regulations remain generally unchanged throughout the projection period."[1]

In contrast, the AEP Fundamental Analysis group's most recent suite of natural gas price forecasts ("Fleet Transition") reflects prudent demand-induced price responses to the impending regulations that are <u>not</u> captured by the EIA. For

[1] The AEO2012 represents an "Early Release" document issued in January, 2012. The "Full Report" release of AEO2012 will occur in the spring of 2012.

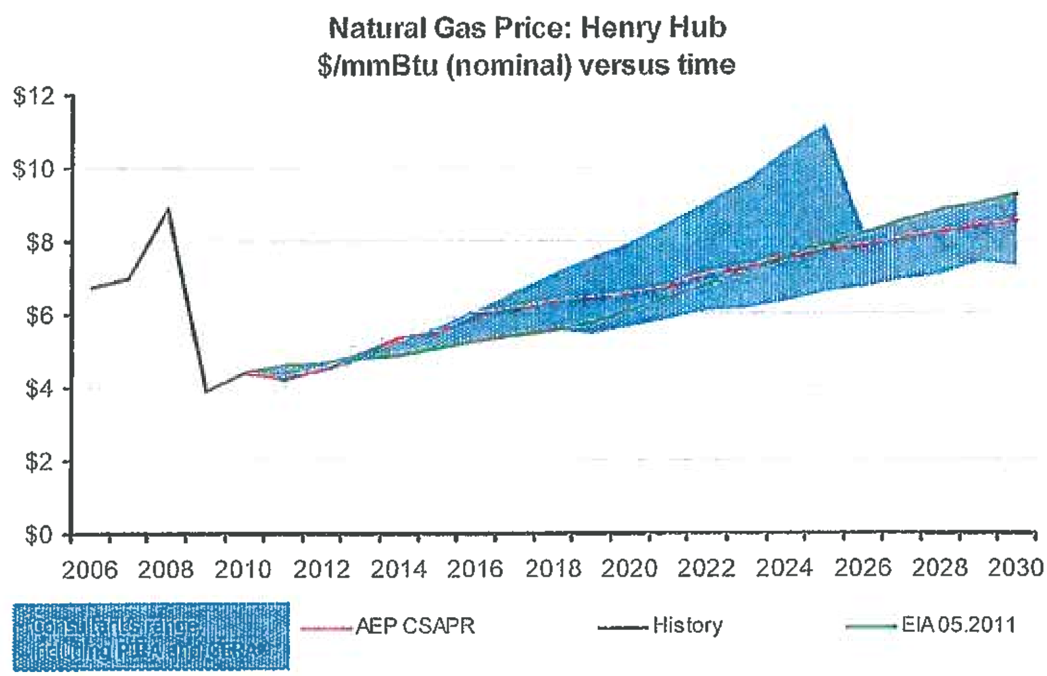
example, AEP takes into consideration the recently-finalized MATS rules, as well as subsequent emerging EPA rulemaking addressing Coal Combustion Residuals, the Clean Water Act rule 316(b) later this decade, and the prospect of a future carbon tax. It is well understood that none of these laws and regulations are factored in the EIA-AEO projections.

Mr. Kollen incorrectly ignored this difference in environmental rule assumptions, so there is no basis for his conclusions regarding a resulting increase in forecasted natural gas prices. The application of generally accepted natural gas price elasticities of supply to the increased natrual gas demand would naturally yield a "Base" ("FT-CSAPR") price forecast above these EIA's AEO projections. In contrast with Mr. Kollen's approach, the AEP "FT-LOWER Band" pricing is well-supported and reasonable, as it provides a complementing sensitivity to KPCo's Base case view. The natural gas price projections in the AEP "FT-LOWER Band" are approximately one standard deviation below those in the Base case (only a 16% likelihood of being lower – based on 5-year history). This scenario implicitly includes a somewhat lesser impact of these impending regulations.

Q. IS MR. KOLLEN'S USE OF NYMEX FORWARD PRICING REASONABLE?

A. No, it is not. The main flaw in Mr. Kollen's price comparison using the Natural gas forwards from the New York Mercantile Exchange ("NYMEX") as a benchmark is that this NYMEX forward pricing is not intended to be a reliable forecast of future, long-term natural price fundamentals. NYMEX forwards certainly represent the prices that a buyer and a seller can realize price certainty, but those commercial expectations may not represent the fundamentals of demand, supply and the resulting price. Nearer-term natural gas prices are primarily affected by weather's deviation from normal (measured as heating degree-days) which then results in deficit or surplus levels of natural gas storage. A warmer-than-normal or colder-than-normal winter has a direct effect on winter prices, but the effect also extends throughout the storage refill season until the storage inventory is fully replenished. NYMEX forwards may be affected beyond storage replenishment because the cost of gas in storage will affect withdrawal decisions within the context of winter season's cash natural gas price (again affected by weather). Mr. Kollen's chart of January 2012 NYMEX natural gas forwards, for example, illustrates the lingering effect of this winter's much warmer-than-normal temperatures.

Consequently, it is unreasonable for Mr. Kollen not to place also KPCo's Base natural gas price forecast in the context of the range of recently-established industry consultant's Base case forecasts—which, likewise, do incorporate anticipated current and emerging future environmental rulemaking—and which is represented below:



Note: PIRA's forecast ends in 2025 resulting in the steep decline in the Consultant's Range

IV. KPCO's CO_2 PRICE PROJECTIONS ARE REASONABLE AND NOT UNDERSTATED

Q. HOW DO YOU JUSTIFY THE INITIAL TIMING OF THE CO_2 PRICES UTILIZED IN KPCO'S LONG-TERM FUNDAMENTAL FORECAST?

A. It is the assessment of Company experts, external consultants and others that the likelihood of any federal climate legislation is very low over the next three years and still unlikely through the tenure of the 113th Congress. Passage of federal climate legislation would almost certainly require Democratic control of both the House and Senate and at least a 60 vote majority in the Senate. There are virtually no political analysts who believe this is even remotely possible and there is considerable doubt as to whether this could even be accomplished after the 2014 elections with the 2015-16 Congress. This suggests that the earliest reasonable date for a climate proposal to pass through committee, reach the floor, and be approved by both House and Senate for eventual passage is 2017. Given that any legislation will require an implementation period of approximately five years (as seen in previous climate proposals or other major Clean Air Act legislation), 2022 is the earliest reasonable projection as to when such legislation *could* become effective. Consequently, KPCo believes Mr. Fisher's 2018 implementation of any CO_2 legislation to be highly speculative for a "Base Case" view.

Q. DO YOU BELIEVE THAT THE KPCO CO_2 PRICE FORECASTS REASONABLY CAPTURE THE POTENTIAL COST IMPACTS IF THERE IS FUTURE FEDERAL CLIMATE LEGISLATION ON THE BIG SANDY POWER PLANT?

A. Yes. I do. In fact, Mr. Fisher's claims that KPCo price forecasts are "insignificant" and low is completely false. The forecast price of CO_2, or KPCo's "forecast modeling proxy," is a moderately aggressive CO_2 value. This is especially true because this price was applied to <u>all</u> CO_2 tonnes produced, whereas, in the cap and trade programs considered by Congress previously, there were provisions for an allocation of "free" allowances – which effectively reduced the CO_2 costs to incumbent generators. (Note that such "free" allocation provisions were politically very popular for states that were most affected by climate legislation, since lower generator costs in regulated cost-of-service states such as Kentucky meant significantly lower electricity cost and rate impacts to customers of regulated utilities such as KPCo under a climate bill. As such, if there is eventual passage of federal legislation, it will almost certainly include such provisions.) Thus, if the ultimate legislation that does pass contains a 50% free allocation of allowances, for example, then the effective cost of our KPCo modeling proxy of $15 per ton which is applied to all tons in the analysis is equivalent to a CO_2 price of $30 per ton which is a very aggressive price.

Also, new regulations and standards in just the past couple of years such as EPA's recently finalized MATS (i.e. mercury and air toxics standards), and CSAPR (cross-state air pollution rule) as well as its proposed CCR (coal combustion residuals) rule will likely result in a minimum of a 50,000 MW (or a 15-20%) national reduction in more inefficient coal-fired electric capacity based on utility plans or filings on retirements or gas conversions of such plants that have been announced to date. This factor alone is expected to result in an estimated 5-10% reduction in electric utility CO_2 emissions since 2010. This creates a de facto system of CO_2 reductions that is certain to reduce the required CO_2 values or prices needed to hit reduction targets than prices that came from earlier (now outdated) cap and trade program estimates.

Q. DO YOU AGREE WITH MR. FISHER'S ASSERTION THAT KPCO'S CO_2 PRICE IS NOT EFFECTIVE OR LIKELY; IT IS A "TOKEN" PRICE THAT HAS NO IMPACT?

A. No, I do not agree with Mr. Fisher's assertions. The forecast modeling proxy for CO_2 used by KPCo is far more realistic than much higher values because; 1) near-term action on cap and trade legislation is highly unlikely, 2) in order for any federal cap and trade legislation to ultimately pass, the effective price <u>will have to be moderate</u> at least for the early years of the program, and, 3) actions to regulate CO_2 from electric generation will more likely take other forms that won't necessarily put a price on carbon – such as through further energy efficiency standards, or renewable or clean-energy standards for utility generation . Further, a price of approximately $15/tonne for every tonne produced is "not effective" or a "token" value in that it would add approximately $81,000,000 to the variable costs of Big Sandy 2 in 2022 – a very significant cost increase

Q. WHAT IS YOUR ASSESSMENT OF THE SYNAPSE ENERGY ECONOMICS, INC. CARBON DIOXIDE PRICE FORECAST DATED FEBRUARY 11, 2011 ("SYNAPSE STUDY") WITH RESPECT TO GREENHOUSE GAS ALLOWANCE PRICE PROJECTIONS?

A. The Synapse Study represents a high level overview of climate change policy action/inaction and a summary of older, now very "dated" analyses of prior cap-and-trade legislative proposals in support of a range of CO_2 pricing trajectories. These CO_2 prices represent dated point-forecasts of various climate proposals that were not enacted and have no current political movement. Further, they were also all based on a very different set of price projections for natural gas (generally much higher) which biased their CO_2 price estimates to much higher levels than would be currently more realistic. As such, these past analyses are currently irrelevant in speculating what is an appropriate CO_2 price for the future. .

Q. DOES THE SYNAPSE STUDY REFLECT A CURRENT CONSENSUS VIEW OF CO_2 PRICE RISK?

A. The Synapse Study does not represent a current consensus view of carbon pricing but rather a range of potential outcomes for CO_2 pricing under a single legislative regime, cap-and-trade, that might have resulted from past federal legislative proposals that did NOT pass into law. The Synapse Study cannot be used as support for a current reasonable forecast of CO_2 pricing in the future. Such a view, including Mr. Fisher's, is flawed for several reasons. First, none of the proposals considered in the Synapse Study were passed into law and their defeat was largely due to the high economic impacts of the legislation. This strongly suggests that an ultimate federal legislative solution would have to be one that contained more moderate emission caps and hence lower CO_2 prices. Second, all the pricing analyses of the underlying proposals were conducted two to three years ago when other complementary EPA regulations and standards that will dramatically limit emissions were not yet promulgated. These regulations include more stringent CAFÉ standards, tighter energy efficiency standards and other EPA regulations on coal fired power plants such as the utility MATS rule and CSAPR rule as described earlier which will result in significantly reduced CO_2 emissions from coal and oil combustion during the coming decade. Third and perhaps most significantly, natural gas prices have substantially declined since these analyses were conducted. All of these factors would suggest the resulting CO_2 pricing of the proposals, if remodeled with current assumptions, would be substantially lower.

Lastly and most crucially, Synapse largely ignored other possible pathways that could address CO_2, such as federal alternative clean energy requirements or clean energy standards which at this point appear more likely to garner political support in the future instead of federal climate legislation. Such regulations would not directly result in a CO_2 price but at the very least would result in a lower effective CO_2 price on coal fired generators in the event climate legislation is also passed.

Q. DOES SYNAPSE USE OF THE CO_2 PRICES IN THE KPCO ANALYSIS EXAGERATE THE COST IMPACTS OF CO_2 PRICING UNDER LIKELY FEDERAL LEGISLATION?

A. Yes. In addition to the problems with the Synapse price forecasts themselves which causes them to be very high relative to a more realistic assessment, Synapse's USE of these prices as applying to EVERY ton of CO_2 emissions at Big Sandy is a substantial exaggeration of the actual cost impacts under federal climate cap and trade legislation. As noted, the use of the CO_2 prices referenced by Synapse did not address the implications that a free allocation system would have on reducing effective CO_2 costs to incumbent existing generators.

Q. IS MR. FISHER CORRECT IN THE APPLICATION OF HIS CO_2 ASSUMPTIONS AND OTHER NECESSARY INPUTS FOR THE PURPOSE OF COMPARING THE CUMULATIVE PRESENT WORTH OF REVENUE REQUIREMENTS OF KPCO POWER SUPPLY OPTIONS, AS PRESENTED IN EXHIBIT JIF-3E?

A. No, Mr. Fisher has not correctly applied his CO_2 assumptions. Without question, the creation of a Long-Term Forecast which considers a range of CO_2 costs MUST include correlative changes to other input drivers. It is imprudent to ignore: 1) the effect of coal plant dispatch costs on coal prices due to changes in coal-fired generation demand, 2) changes in gas-fired plant utilization and the effect on natural gas prices, 3) changes in plant retirement schedules and new-build profiles, or 4) the price elasticity of residential, commercial and industrial demand, for example. These "feedback loops" (iterations) are critically necessary to create a prudent set of long-term forecasts to be used as the foundation for comparison of KPCo's power supply options. In its simplest form, the imposition of "high" CO_2 prices would necessitate a "high" gas price response in reaction to increased gas demand – which creates an inconsistency in Mr. Fisher's conclusions. "High" CO_2 values coupled with "low" gas prices is misleading as one or the other is incorrect. Mr. Fisher's "a la carte" usage of dated Synapse Study CO_2 values to produce discrete CPW of Revenue Requirement results as presented in Exhibit JIF-3E without the mandatory feedback/iteration of other model inputs is erroneous and should be ignored.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

VERIFICATION

The undersigned, KARL R. BLETZACKER, being duly sworn, deposes and says he is Director, Fundamental Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

Karl R Bletzacker

KARL R. BLETZACKER

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Karl R. Bletzacker, this the 13 day of April 2012.

Holly M. Charles

Notary Public

NOTARY PUBLIC STATE OF OHIO

Holly M. Charles
Notary Public-State of Ohio
My Commission Expires
March 7, 2016

My Commission Expires: March 7, 2016

SURREBUTTAL EXHIBIT JIF-3

12/19/2012

KENTUCKY POWER FILES TO TRANSFER GENERATION ASSETS

FRANKFORT, KY -- Kentucky Power customers will save millions of dollars in environmental-related costs through a filing made today with the Kentucky Public Service Commission. The filing outlines Kentucky Power's proposal to address environmental compliance at its Big Sandy Power Plant located near Louisa and replaces a "scrubber system" filing the company withdrew from consideration six months ago.

Today's filing seeks approval to recover approximately $530 million in costs associated with transferring 50 percent of the ownership of the Mitchell Generation Station, currently owned by AEP Ohio, an American Electric Power subsidiary, to Kentucky Power. The generation obtained from Mitchell would substantially replace the generation of the 800-megawatt Unit 2 at Big Sandy, which will be retired from service in 2015.

The Mitchell Plant is located near Moundsville, W.Va., and has a total generating output of 1,560 megawatts. Kentucky Power seeks to obtain 50 percent of the output of Mitchell's 770-megawatt Unit 1 and 790-megawatt Unit 2, for a total transfer of 780 total megawatts. Both Mitchell units are equipped with advanced environmental controls, including flue gas desulfurization systems (FGD) or "scrubbers" and meet all current EPA requirements. The other 50 percent ownership in both units would be transferred to Appalachian Power Company (APCO), another AEP subsidiary, pending approval of APCO's regulatory authorities. APCO will operate and maintain the Mitchell Plant.

The filing today -- along with savings from the termination of a power interconnection agreement coinciding at the time of the transfer -- will result in an estimated eight (8) percent increase on customers' bills. This means customers using 1,000 kilowatt hours per month would see an increase on their bills of approximately $6.00 per month. Currently, those customers pay about $94.00 per month; after the increase they would pay approximately $100.00 per month.

Under Kentucky Power's previous filing, the company planned to install a scrubber system on Big Sandy's Unit 2. That project would have resulted in a roughly 31 percent increase on monthly bills or an increase of about $31.00 on a customer using 1,000 kilowatt hours.

In addition to approval from the Kentucky Public Service Commission, the transfer also requires the approval of the Federal Energy Regulatory Commission (FERC). If approved, customers will not see a rate increase associated with this filing until Jan. 1, 2014 at the earliest, pending additional approval of a future base rate case.

"At this time, and after much study and evaluation, we think this filing represents the best path forward for the company to meet both its environmental and customer obligations. While it does represent an increase in customer's rates of about eight percent, it is substantially less than our previous filing and will save our customers millions of dollars while bringing us into environmental compliance," said Greg Pauley, president and chief operating officer of Kentucky Power.

"When we withdrew our scrubber filing last summer, we stated that we felt new opportunities were emerging that would allow us to meet our obligations at a lower cost. The possibility of transferring these Mitchell Units was among those opportunities and doing so will allow us to reduce the impact on customers' bills," Pauley said.

Kentucky Power has yet to decide the future of Big Sandy's 278-megawatt Unit 1, the smaller and older of the plant's two generating units. A filing to cover the future generating capacity of that unit will be submitted to the Kentucky Public Service Commission sometime in 2013. In the meantime, the company plans to issue a Request for Proposals (RFP) early next year to potentially replace the generation from the Unit. The proposals will be evaluated along with the possibility of converting Unit 1 to natural gas combustion. Unit 1 is scheduled to be retired as a coal-fired generator in 2015.

"In the coming months, we will determine a plan to address the remaining generating unit at Big Sandy Plant," Pauley said. "We will perform our due diligence to determine an affordable plan that balances the needs of our customers, shareholders and the environment. When we reach that decision, we will announce it publicly. Until then, we appreciate our customers' and employees' continued patience as we evaluate and determine the best means to address the future of Big Sandy," Pauley said.

"Although the plant will continue to run as it does today for a couple more years, any employee affected by today's announcement will have the opportunity to pursue other job prospects with AEP and Kentucky Power," Pauley said.

Another component of the filing seeks approval to defer approximately $30 million dollars associated with study and engineering work involving this and other environmental filings concerning Big Sandy Plant.

Kentucky Power is an operating unit of American Electric Power and provides electricity to approximately 173,000 customers in all or parts of 20 Eastern Kentucky counties. The company is headquartered in Frankfort and has major operating facilities in Ashland, Hazard, Louisa and Pikeville.

American Electric Power is one of the largest electric utilities in the United States, delivering electricity to more than 5 million customers in 11 states. AEP ranks among the nation's largest generators of electricity, owning nearly 38,000 megawatts of generating capacity in the U.S. AEP also owns the nation's largest electricity transmission system, a nearly 39,000-mile network that includes more 765-kilovolt extra-high voltage transmission lines than all other U.S. transmission systems combined. AEP's transmission system directly or indirectly serves about 10 percent of the electricity demand in the Eastern Interconnection, the interconnected transmission system that covers 38 eastern and central U.S. states and eastern Canada, and approximately 11 percent of the electricity demand in ERCOT, the transmission system that covers much of Texas. AEP's utility units operate as AEP Ohio, AEP Texas, Appalachian Power (in Virginia and West Virginia), AEP Appalachian Power (in Tennessee), Indiana Michigan Power, Kentucky Power, Public Service Company of Oklahoma, and Southwestern Electric Power Company (in Arkansas, Louisiana and east Texas). AEP's headquarters are in Columbus, Ohio.

###

Ronn Robinson
502.696.7003

SURREBUTTAL EXHIBIT JIF-4

Electricity Market Module

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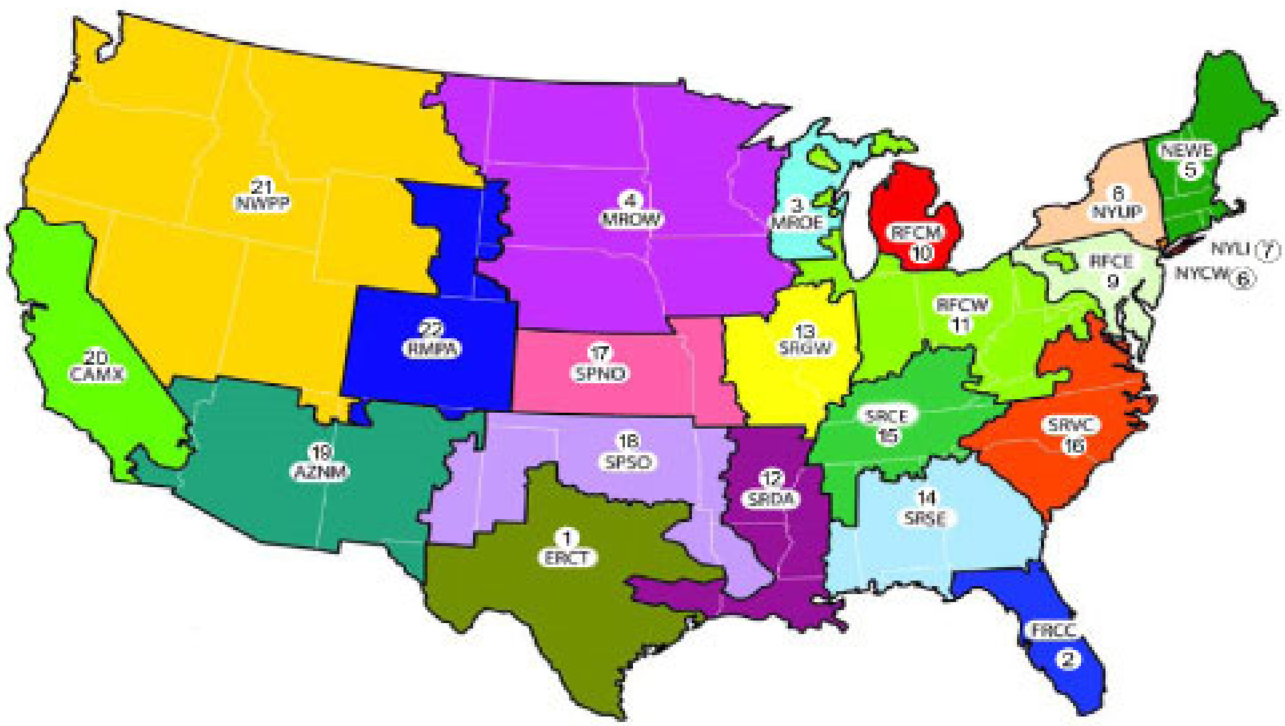
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, electricity load and demand, and electricity finance and pricing. It includes nonutility capacity and generation, and electricity transmission and trade. A detailed description of the EMM is provided in the EIA publication, Electricity Market Module of the National Energy Modeling System 2012, DOE/EIA-M068(2012).

Based on fuel prices and electricity demands provided by the other modules of the NEMS, the EMM determines the most economical way to supply electricity, within environmental and operational constraints. There are assumptions about the operations of the electricity sector and the costs of various options in each of the EMM submodules. This section describes the model parameters and assumptions used in EMM. It includes a discussion of legislation and regulations that are incorporated in EMM as well as information about the climate change action plan. The various electricity and technology cases are also described.

EMM regions

The supply regions used in EMM are based on the North American Electric Reliability Corporation regions and subregions shown in Figure 6.

Figure 6. Electricity Market Model Supply Regions



1.	ERCT	ERCOT All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Model parameters and assumptions

Generating capacity types

The capacity types represented in the EMM are shown in Table 8.1.

Table 8.1. Generating capacity types represented in the Electricity Market Module

Capacity Type
Existing coal steam plants[1]
High Sulfur Pulverized Coal with Wet Flue Gas Desulfurization
Advanced Coal - Integrated Coal Gasification Combined Cycle
Advanced Coal with carbon sequestration
Oil/Gas Steam - Oil/Gas Steam Turbine
Combined Cycle - Conventional Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle - Advanced Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle with carbon sequestration
Combustion Turbine - Conventional Combustion Turbine
Advanced Combustion Turbine - Steam Injected Gas Turbine
Molten Carbonate Fuel Cell
Conventional Nuclear
Advanced Nuclear - Advanced Light Water Reactor
Generic Distributed Generation - Baseload
Generic Distributed Generation - Peak
Conventional Hydropower - Hydraulic Turbine
Pumped Storage - Hydraulic Turbine Reversible
Geothermal
Municipal Solid Waste
Biomass - Fluidized Bed
Solar Thermal - Central Tower
Solar Photovoltaic - Fixed Tilt
Wind
Wind Offshore

[1]The EMM represents 32 different types of existing coal steam plants, based on the different possible configuration of NO_x, particulate and SO_2 emission control devices, as well as future options for controlling mercury.
Source: U.S. Energy Information Administration.

New generating plant characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 8.2). These characteristics are used in combination with fuel prices from the NEMS fuel supply modules and foresight on fuel prices, to compare options when new capacity is needed. Heat rates for fossil-fueled technologies are assumed to decline linearly through 2025.

For the *AEO2011*, EIA commissioned an external consultant to develop current cost estimates for utility-scale electric generating plants [1]. This report continues to be the basis for the cost assumptions for *AEO2012*. A cost adjustment factor, based on the producer price index for metals and metal products, allows the overnight costs to fall in the future if this index drops, or rise further if it increases.

The overnight costs shown in Table 8.2 represent the estimated cost of building a plant in a typical region of the country. Differences in plant costs due to regional distinctions are calculated by applying regional multipliers. Regional multipliers by technology were also updated for *AEO2012* based on regional cost estimates developed by the consultant. The regional variations account for multiple factors, such as differences in terrain, weather, population, and labor wages. The base overnight cost is multiplied by a project contingency factor and a technological optimism factor (described later in this chapter), resulting in the total construction cost for the first-of-a-kind unit used for the capacity choice decision.

Table 8.2. Cost and performance characteristics of new central station electricity generating technologies

Technology	Online Year[1]	Size (mW)	Lead time (years)	Base Overnight Cost in 2010 (2010 $/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost in 2010[4] (2010 $/kW)	Variable O&M[5] (2010 $/mWh)	Fixed O&M (2010$/kW)	Heatrate[6] in 2011 (Btu/KWh)	nth-of-a-kind Heatrate (Btu/KWh)
Scrubbed Coal New[7]	2015	1300	4	2,658	1.07	1.00	2,844	4.25	29.67	8,800	8,740
Integrated Coal-Gasification Comb Cycle (IGCC)[7]	2015	1200	4	3,010	1.07	1.00	3,220	6.87	48.90	8,700	7,450
IGCC with carbon sequestration	2017	520	4	4,852	1.07	1.03	5,348	8.04	69.30	10,700	8,307
Conv Gas/Oil Comb Cycle	2014	540	3	931	1.05	1.00	977	3.43	14.39	7,050	6,800
Adv Gas/Oil Comb Cycle (CC)	2014	400	3	929	1.08	1.00	1,003	3.11	14.62	6,430	6,333
Adv CC with carbon sequestration	2017	340	3	1,834	1.08	1.04	2,060	6.45	30.25	7,525	7,493
Conv Comb Turbine[8]	2013	85	2	927	1.05	1.00	974	14.70	6.98	10,745	10,450
Adv Comb Turbine	2013	210	2	634	1.05	1.00	666	9.87	6.70	9,750	8,550
Fuel Cells	2014	10	3	5,918	1.05	1.10	6,836	0.00	350.00	9,500	6,960
Adv Nuclear	2017	2236	6	4,619	1.10	1.05	5,335	2.04	88.75	10,460	10,460
Distributed Generation - Base	2014	2	3	1,366	1.05	1.00	1,434	7.46	16.78	9,050	8,900
Distributed Generation - Peak	2013	1	2	1,640	1.05	1.00	1,722	7.46	16.78	10,056	9,880
Biomass	2015	50	4	3,519	1.07	1.02	3,859	5.00	100.55	13,500	13,500
Geothermal[7,9]	2011	50	4	2,393	1.05	1.00	2,513	9.64	108.62	9,760	9,760
MSW - Landfill Gas	2011	50	3	7,694	1.07	1.00	8,233	8.33	378.76	13,648	13,648
Conventional Hydropower[9]	2015	500	4	2,134	1.10	1.00	2,347	2.55	14.27	9,760	9,760
Wind	2011	100	3	2,278	1.07	1.00	2,437	0.00	28.07	9,760	9,760
Wind Offshore	2015	400	4	4,345	1.10	1.25	5,974	0.00	53.33	9,760	9,760
Solar Thermal[7]	2014	100	3	4,384	1.07	1.00	4,691	0.00	64.00	9,760	9,760
Photovoltaic[7,10]	2013	150	2	4,528	1.05	1.00	4,755	0.00	16.70	9,760	9,760

[1]Online year represents the first year that a new unit could be completed, given an order date of 2011. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occuring in anticipation of the expiration of the Production Tax Credit.
[2]A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur."
[3]The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.
[4]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2011.
[5]O&M = Operations and maintenance.
[6]For hydro, geothermal, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2010. This is used for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.
[7]Capital costs are shown before investment tax credits are applied.
[8]Combustion turbine units can be built by the model prior to 2013 if necessary to meet a given region's reserve margin.
[9]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.
[10]Costs and capacities are expressed in terms of net AC power available to the grid for the installed capacity.
Sources: For the *AEO2012* cycle, EIA continues to use the previously developed cost estimates for utility-scale electric generating plants, prepared by external consultants for *AEO2011*. This report can be found at www.eia.gov/oiaf/beck_plantcosts/index.html. Site-specific costs for geothermal were provided by the National Energy Renewable Laboratory, "Updated U.S. Geothermal Supply Curve," February 2010.

Technological optimism and learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and technological optimism and learning factors.

The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained (after building 4 units) the technological optimism factor is gradually reduced to 1.0.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary or mature. Different learning rates are assumed for each component, based on the level of experience with the design component (Table 8.3). Where technologies use similar components, these components learn at the same rate as these units are built. For example, it is assumed that the underlying turbine generator for a combustion turbine, combined cycle and integrated coal-gasification combined cycle unit is basically the same. Therefore construction of any of these technologies would contribute to learning reductions for the turbine component.

The learning function has the nonlinear form:

$$OC(C) = a*C^{-b},$$

where C is the cumulative capacity for the technology component.

Table 8.3. Learning parameters for new generating technology components

Technology Component	Period 1 Learning Rate (LR1)	Period 2 Learning Rate(LR2)	Period 3 Learning Rate (LR3)	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2025
Pulverized Coal	-	-	1%	-	-	5%
Combustion Turbine - conventional	-	-	1%	-	-	5%
Combustion Turbine - advanced	-	10%	1%	-	5	10%
HRSG[1]	-	-	1%	-	-	5%
Gasifier	-	10%	1%	-	5	10%
Carbon Capture/Sequestration	20%	10%	1%	3	5	20%
Balance of Plant - IGCC	-	-	1%	-	-	5%
Balance of Plant - Turbine	-	-	1%	-	-	5%
Balance of Plant - Combined Cycle	-	-	1%	-	-	5%
Fuel Cell	20%	10%	1%	3	5	20%
Advanced Nuclear	5%	3%	1%	3	5	10%
Fuel prep - Biomass	20%	10%	1%	3	5	20%
Distributed Generation - Base	-	5%	1%	-	5	10%
Distributed Generation - Peak	-	5%	1%	-	5	10%
Geothermal	-	8%	1%	-	5	10%
Municipal Solid Waste	-	-	1%	-	-	5%
Hydropower	-	-	1%	-	-	5%
Wind	-	-	1%	-	-	1%
Wind Offshore	20%	10%	1%	3	5	20%
Solar Thermal	20%	10%	1%	3	5	10%
Solar PV - Module	20%	10%	1%	1	5	10%
Balance of Plant - Solar PV	20%	10%	1%	1	5	10%

[1]HRSG = Heat Recovery Steam Generator
Note: Please see the text for a description of the methodology for learning in the Electricity Market Module.
Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis.

The progress ratio (pr) is defined by speed of learning (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (LR) is an exogenous parameter input for each component (Table 8.3). The progress ratio and LR are related by:

$pr = 2^{-b} = (1 - LR)$

The parameter "b" is calculated from the second equality above (b =-(ln(1-LR)/ln(2)). The parameter "a" is computed from initial conditions, i.e.

$a = OC(C_0)/C_0^{-b}$

where C_0 is the initial cumulative capacity. Once the rates of learning (LR) and the cumulative capacity (C_0) are known for each interval, the parameters (a and b) can be computed. Three learning steps were developed to reflect different stages of learning as a new design is introduced into the market. New designs with a significant amount of untested technology will see high rates of learning initially, while more conventional designs will not have as much learning potential. Costs of all design components are adjusted to reflect a minimal amount of learning, even if new capacity additions are not projected. This represents cost reductions due to future international development or increased research and development.

Once the learning rates by component are calculated, a weighted average learning factor is calculated for each technology. The weights are based on the share of the initial cost estimate that is attributable to each component (Table 8.4). For technologies that do not share components, this weighted average learning rate is calculated exogenously, and input as a single component.

These technologies may still have a mix of revolutionary components and more mature components, but it is not necessary to include this detail in the model unless capacity from multiple technologies would contribute to the component learning. In the case of the solar PV technology, it is assumed that the module component accounts for 50 percent of the cost, and that the balance of system components accounts for the remaining 50 percent. Because the amount of end-use PV capacity (existing and projected) is significant relative to total solar PV capacity, and because the technology of the module component is common across the end-use and electric power sectors, the calculation of the learning factor for the PV module component also takes into account capacity built in the residential and commercial sectors.

Table 8.5 shows the capacity credit toward component learning for the various technologies. It was assumed that for all combined-cycle technologies, the turbine unit contributed two-thirds of the capacity, and the steam unit one-third. Therefore, building one gigawatt of gas combined cycle would contribute 0.67 gigawatts toward turbine learning, and 0.33 gigawatts toward steam learning. Components that do not contribute to the capacity of the plant, such as the balance of plant category, receive 100 percent capacity credit for any capacity built with that component. For example, when calculating capacity for the "Balance of plant - CC" component, all combined cycle capacity would be counted 100 percent, both conventional and advanced.

Table 8.4. Component cost weights for new technologies

Technology	Pulverized Coal	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	15%	20%	41%	0%	24%	0%	0%	0%
IGCC with carbon sequestration	0%	0%	10%	15%	30%	30%	15%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	30%	0%	40%	0%	0%	0%	0%	30%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	30%	40%	0%	0%	0%	0%	30%	0%
Adv CC with carbon sequestration	0%	0%	20%	25%	0%	40%	0%	0%	15%	0%
Conv Comb Turbine	0%	50%	0%	0%	0%	0%	0%	50%	0%	0%
Adv Comb Turbine	0%	0%	50%	0%	0%	0%	0%	50%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	50%

Note: All unlisted technologies have a 100 percent weight with the corresponding component. Components are not broken out for all technologies unless there is overlap with other technologies.
HRSG = Heat Recovery Steam Generator.
Source: Market-Based Advanced Coal Power Systems, May 1999, DOE/FE-0400.

Table 8.5. Component capacity weights for new technologies

Technology	Pulverized Coal	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	67%	33%	100%	0%	100%	0%	0%	0%
IGCC with carbon sequestration	0%	0%	67%	33%	100%	100%	100%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon sequestration	0%	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turbine	0%	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turbine	0%	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	100%

HRSG = Heat Recovery Steam Generator.
Source: U.S. Energy Information Administration, Office of Electricity, coal, Nuclear and Renewables Analysis.

Distributed generation

Distributed generation is modeled in the end-use sectors (as described in the appropriate chapters) as well as in the EMM. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their highest). The second generic technology for distributed generation represents base load capacity (capacity that is operated on a continuous basis under a variety of demand levels). See Table 8.2 for costs and performance assumptions. It is assumed that these plants reduce the costs of transmission upgrades that would otherwise be needed.

Demand storage

The electricity model includes the option to build a new demand storage technology to simulate load shifting, through programs such as smart meters. This is modeled as a new technology build, but with operating characteristics similar to pumped storage. The technology is able to decrease the load in peak slices, but must generate to replace that demand in other time slices. There is an input factor that identifies the amount of replacement generation needed, where a factor of less than 1.0 can be used to represent peak shaving rather than purely shifting the load to other time periods. This plant type is limited to operating only in the peak load slices, and for *AEO2012*, it is assumed that this capacity is limited to 3 percent of peak demand on average, with limits varying from 2 percent to 6 percent of peak across the regions.

Representation of electricity demand

The annual electricity demand projections from the NEMS demand modules are converted into load duration curves for each of the EMM regions (based on North American Electric Reliability Corporation regions and subregions) using historical hourly load data. The load duration curve in the EMM is made up of 9 time slices. First, the load data is split into three seasons (winter - December through March, summer - June through September, and fall/spring). Within each season the load data is sorted from high to low, and three load segments are created - a peak segment representing the top 1 percent of the load, and then two off-peak segments representing the next 49 percent and 50 percent, respectively. The seasons were defined to account for seasonal variation in supply availability.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are determined within the model through an iterative approach comparing the marginal cost of capacity and the cost of unserved energy. The target reserve margin is adjusted each model cycle until the two costs converge. The resulting reserve margins from the *AEO2012* Reference case range from 8 to 21 percent.

Fossil fuel-fired and nuclear steam plant retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Plants are assumed to retire when it is no longer economical to continue running them. Each year, the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. A plant is assumed to retire if the expected revenues from it are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, operations and maintenance costs and annual capital additions, which are plant-specific and based on historical data. The average capital additions for existing plants are $8 per kilowatt (kW) for oil and gas steam plants, $16 per kW for coal plants and $22 per kW for nuclear plants (in 2010 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age an additional $6 per kW capital charge for fossil plants, and $32 per kW charge for nuclear plants is included in the retirement decision to reflect further investment to address impacts of aging. Age-related cost increases are due to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increased maintenance costs to mitigate the effects of aging.

EIA assumes all retirements reported as planned during the next ten years on the Form EIA-860 will occur. Additionally, the *AEO2012* nuclear projection assumes an additional 5.5 gigawatts of nuclear plant retirements by 2035 based on the uncertainty related to resolving issues associated with long-term operations and aging management.

Biomass co-firing

Coal-fired power plants are assumed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure is assumed to be $274 per kW of biomass capacity. A coal-fired unit modified to allow co-firing can generate up to 15 percent of the total output using biomass fuel, assuming sufficient residue supplies are available.

Nuclear uprates

The *AEO2012* nuclear power projection assumes capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that must be approved by the U.S. Nuclear Regulatory Commission (NRC). Uprates can vary from small (less than 2 percent) increases in capacity, which require very little capital investment or plant modification, to extended uprates of 15-20 percent, requiring significant modifications. Historically, most uprates were small, and the *AEO* projections accounted for them only after they were implemented and reported, but recent surveys by the NRC and EIA have indicated that more extended power uprates are expected in the near future. *AEO2012* assumes that all of those uprates reported to EIA as planned modifications on the Form EIA-860 will take place, representing 0.8 gigawatts of additional capacity. EIA also assumes an additional 6.5 gigawatts of nuclear power uprates will be completed over the projection period, based on interactions with industry stakeholders and the NRC. Table 8.6 provides a summary of projected uprate capacity additions by region.

Table 8.6. Nuclear uprates by EMM region
gigawatts

Texas Reliability Entity	0.25
Florida Reliability Coordinating Council	0.67
Midwest Reliability Council - East	0.00
Midwest Reliability Council - West	0.49
Northeast Power Coordinating Council/New England	0.25
Northeast Power Coordinating Council/NYC-Westchester	0.00
Northeast Power Coordinating Council/Long Island	0.00
Northeast Power Coordinating Council/Upstate	0.50
ReliabilityFirst Corporation/East	0.82
ReliabilityFirst Corporation/Michigan	0.25
ReliabilityFirst Corporation/West	0.97
SERC Reliability Corporation/Delta	0.25
SERC Reliability Corporation/Gateway	0.00
SERC Reliability Corporation/Southeastern	0.25
SERC Reliability Corporation/Central	0.75
SERC Reliability Corporation/Virginia-Carolina	1.10
Southwest Power Pool/North	0.00
Southwest Power Pool/South	0.00
Western Electricity Coordinating Council/Southwest	0.25
Western Electricity Coordinating Council/California	0.50
Western Electricity Coordinating Council/Northwest Power Pool Area	0.00
Western Electricity Coordinating Council/Rockies	0.00
Total	7.31

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis, based on Nuclear Regulatory Commission survey www.nrc.gov/reactors/operating/licensing/power-updates.html.

Interregional electricity trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve the trading of capacity and energy to help another region satisfy its reserve margin requirement, while economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the North American Electric Reliability Corporation and Western Electricity Coordinating Council Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America. Known firm power contracts are obtained from NERC's Electricity Supply and Demand Database 2007 and information provided in the 2011 Summer and Winter Assessments. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2016 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2016, they are assumed to be phased out by 2025. The EMM includes an option to add interregional transmission capacity. In some cases it may be more economic to build generating capacity in a neighboring region, but additional costs to expand the transmission grid will be incurred as well. Explicitly expanding the interregional transmission capacity may also make the line available for additional economy trade.

Economy transactions are determined in the dispatching submodule by comparing the marginal generating costs of adjacent regions in each time slice. If one region has less expensive generating resources available in a given time period (adjusting for transmission losses and transmission capacity limits) than another region, the regions are assumed to exchange power.

International electricity trade

Two components of international firm power trade are represented in the EMM—existing and planned transactions, and unplanned transactions. Data on existing and planned transactions are obtained from the North American Electric Reliability Corporation's Electricity Supply and Demand Database 2007. Unplanned firm power trade is represented by competing Canadian supply with U.S. domestic supply options. Canadian supply is represented via supply curves using cost data from the Department of Energy report, "Northern Lights: The Economic and Practical Potential of Imported Power from Canada," (DOE/PE-0079). International economy trade is determined endogenously based on surplus energy expected to be available from Canada by region in each time slice. Canadian surplus energy is determined using Canadian electricity supply and demand projections from the MAPLE-C model developed for Natural Resources Canada.

Electricity pricing

Electricity pricing is forecast for 22 electricity market regions in *AEO2012* for fully competitive, partially competitive and fully regulated supply regions. The price of electricity to the consumer comprises the price of generation, transmission, and distribution including applicable taxes. Transmission and distribution are considered to remain regulated in the AEO; that is, the price of transmission and distribution is based on the average cost to build, operate and maintain these systems. In competitive regions, an algorithm in place allows customers to compete for better rates among rate classes as long as the overall average cost is met. The price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class. In the competitive regions, the generation component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched. The competitive generation price includes the marginal cost (fuel and variable operations and maintenance), taxes, and a reliability price adjustment, which represents what customers are willing to pay for added capacity to avoid outages in periods of high demand. The price of electricity in the regions with a competitive generation market consists of the competitive cost of generation summed with the average costs of transmission and distribution. The price for mixed regions is a load-weighted average of the competitive price and the regulated price, based on the percent of electricity load in the region that has taken action to deregulate. In competitively supplied regions, a transition period is assumed to occur (usually over a ten-year period) from the effective date of restructuring, with a gradual shift to marginal cost pricing.

The Reference case assumes a transition to full competitive pricing in the three New York regions and in the ReliabilityFirst Corporation/ East region, and a 97-percent transition to competitive pricing in New England (Vermont being the only fully-regulated State in that region). Six regions fully regulate their electricity supply, including the Florida Reliability Coordinating Council, three of the SERC Reliability Corporation subregions - Southeastern (SRSE), Central (SRCE) and Virginia-Carolina (SRVC) - Southwest Power Pool Regional Entity/North (SPNO), and the Western Electricity Coordinating Council / Rockies (RMPA). The Texas Reliability Entity, which in the past was considered fully competitive by 2010, now reaches only 88-percent competitive, since many cooperatives have declined to become competitive or allow competitive energy to be sold to their customers. California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998, with only 7 percent competitive supply sold currently in the Western Electricity Coordinating Council (WECC)/ California region. All other regions are a mix of both competitive and regulated prices.

There have been ongoing changes to pricing structures for ratepayers in competitive States since the inception of retail competition. The AEO has incorporated these changes as they have been incorporated into utility tariffs. These have included transition period rate reductions and freezes instituted by various States, and surcharges in California relating to the 2000-2001 energy crisis there. Since price freezes for most customers have ended or will end in the next year or two, a large survey of utility tariffs found that many costs related to the transition to competition were now explicitly added to the distribution portion, and sometimes the transmission portion of the customer bill regardless of whether or not the customer bought generation service from a competitive or regulated supplier. There are some unexpected costs relating to unforeseen events. For instance, as a result of volatile fuel markets, State regulators have had a hard time enticing retail suppliers to offer competitive supply to residential and smaller commercial and industrial customers. They have often resorted to procuring the energy themselves through auction or competitive bids or have allowed distribution utilities to procure the energy on the open market for their customers for a fee. For *AEO2012*, typical charges that all customers must pay on the distribution portion of their bill (depending on where they reside) include: transition charges (including persistent stranded costs), public benefits charges (usually for efficiency and renewable energy programs), administrative costs of energy procurement, and nuclear decommissioning costs. Costs added to the transmission portion of the bill include the Federally Mandated Congestion Charges (FMCC), a bill pass-through associated with the Federal Energy Regulatory Commission passage of Standard Market Design (SMD) to enhance reliability of the transmission grid and control congestion. Additional costs not included in historical data sets have been added in adjustment factors to the transmission and distribution operations and maintenance costs, which impact the cost of both competitive and regulated electricity supply. Since most of these costs, such as transition costs, are temporary in nature, they are gradually phased out throughout the forecast. Regions found to have these added costs include the Northeast Power Coordinating Council/ New England and New York regions, the ReliabilityFirst Corporation/ East and West regions, and the WECC/ California region.

Fuel price expectations

Capacity planning decisions in the EMM are based on a life cycle cost analysis over a 30-year period. This requires foresight assumptions for fuel prices. Expected prices for coal, natural gas and oil are derived using rational expectations, or 'perfect foresight.' In this approach, expectations for future years are defined by the realized solution values for these years in a prior run. The expectations for the world oil price and natural gas wellhead price are set using the resulting prices from a prior run. The markups to the delivered fuel prices are calculated based on the markups from the previous year within a NEMS run. Coal prices are determined using the same coal supply curves developed in the Coal Market Module. The supply curves produce prices at different levels of coal production, as a function of labor productivity, and costs and utilization of mines. Expectations for each supply curve are developed in the EMM based on the actual demand changes from the prior run throughout the projection horizon, resulting in updated mining utilization and different supply curves.

The perfect foresight approach generates an internally consistent scenario for which the formation of expectations is consistent with the projections realized in the model. The NEMS model involves iterative cycling of runs until the expected values and realized values for variables converge between cycles.

Nuclear fuel prices

Nuclear fuel prices are calculated through an offline analysis which determines the delivered price to generators in mills per kilowatthour. To produce reactor grade uranium, the uranium (U_3O_8) must first be mined, and then sent through a conversion process to prepare for enrichment. The enrichment process takes the fuel to a given purity of U-235, typically 3-5 percent for commercial reactors in the United States. Finally, the fabrication process prepares the enriched uranium for use in a specific type of reactor core. The price of each of the processes is determined, and the prices are summed to get the final price of the delivered fuel. The one mill per kilowatthour charge that is assessed on nuclear generation to go to the DOE's Nuclear Waste Fund is also included in the final nuclear price. The analysis uses forecasts from Energy Resources International for the underlying uranium prices.

Legislation and regulations

Clean Air Act Amendments of 1990 (CAAA90) and Cross-State Air Pollution Rule (CSAPR)

The Cross-State Air Pollution Rule (CSAPR) was released by EPA in July 2011 and was created to regulate SO_2 and NO_x emissions from coal, oil, and natural gas steam power plants. CSAPR is intended to help States meet their National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. CSAPR implementation has been delayed because of a stay issued by the U.S. Court of Appeals for the D.C. Circuit. However, it is included in *AEO2012* despite the stay, because the Court of Appeals had not made a final ruling at the time *AEO2012* was completed.

CSAPR puts limits on annual emissions of SO2 and NOx, as well as seasonal NOx limits to address ground-level ozone. Twenty-three States are subject to the annual limits, and 25 States are subject to the seasonal limits. CSAPR consists of four individual cap and trade programs, covering two different SO2 groups, the Annual NOx group and the Seasonal NOx group (Figure 7). Each program was scheduled to begin in January 2012 with an initial annual cap, and for the Group 1 SO2 program, the cap is reduced further in 2014.

As specified in the CAAA90, EPA has developed a two-phase nitrogen oxide (NO_x) program, with the first set of standards for existing coal plants applied in 1996 while the second set was implemented in 2000. Dry bottom wall-fired, and tangential-fired boilers, the most common boiler types, referred to as Group 1 Boilers, were required to make significant reductions beginning in 1996 and further reductions in 2000. Relative to their uncontrolled emission rates, which range roughly between 0.6 and 1.0 pounds per million Btu, they are required to make reductions between 25 and 50 percent to meet the Phase I limits and further reductions to meet the Phase II limits. The EPA did not impose limits on existing oil and gas plants, but some states have additional NO_x regulations. All new fossil units are required to meet standards. In pounds per million Btu, these limits are 0.11 for conventional coal, 0.02 for advanced coal, 0.02 for combined cycle, and 0.08 for combustion turbines. These NO_x limits are incorporated in EMM.

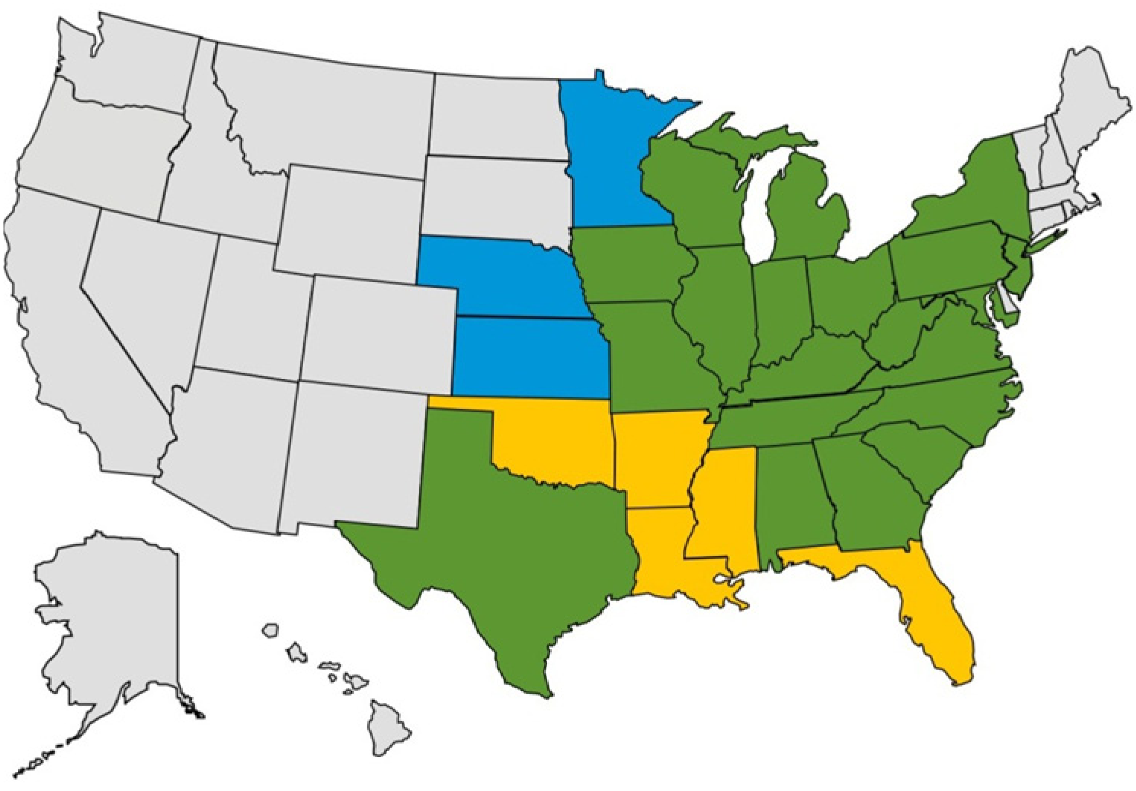
Figure 7. States covered by CSAPR limits on sulfur dioxide and nitrogen oxide emissions

States controlled for both fine particles (annual SO_2 and NO_x) and ozone (ozone season NO_x) (20 States)

States controlled for fine particles only (annual SO_2 and NO_x) (3 States)

States controlled for ozone only (ozone season NO_x) (5 States)

States not covered by the Cross-State Air Pollution Rule



Source: U.S. Energy Information Administration.

Sample costs of adding flue gas desulfurization equipment (FGD) to remove sulfur dioxide (SO_2) and selective catalytic reduction (SCR) equipment to remove nitrogen oxides (NOx) are given below for 100, 300, 500, and 700-megawatt coal plants. In the EMM, plant-specific costs are calculated based on the size of the unit and other operating characteristics. FGD units are assumed to remove 95 percent of the SO_2, while SCR units are assumed to remove 90 percent of the NOx. For *AEO2012*, the EMM also includes an option to install a dry sorbent injection (DSI) system, which is assumed to remove 70 percent of the SO_2. However, the DSI option is only available under the mercury and air toxics rule discussed in the next section, as its primary benefit is for reducing hydrogen chloride (HCl). The costs per megawatt of capacity decline with plant size and are shown in Table 8.7.

Table 8.7. Coal plant retrofit costs
2010 dollars

Coal Plant Size (MW)	FGD Capital Costs ($/kw)	SCR Capital Costs ($/kw)	DSI Capital Costs ($/kw)
100	642	222	125
300	497	187	57
500	432	174	40
700	360	155	31

Documentation for EPA Base Case v4.10 using the Integrated Planning Model, August 2010, EPA Contract EP-W-08-018.

Mercury regulation

The Mercury and Air Toxics Standards (MATS) rule was finalized in December 2011 to fulfill EPA's requirement to regulate mercury emissions from power plants. MATS also regulates other hazardous air pollutants (HAPS) such as hydrogen chloride (HCl) and fine particulate matter (PM2.5). The rule applies to coal- and oil-fired power plants with a nameplate capacity greater than 25 megawatts. The standards are scheduled to take effect in 2015 and require that all qualifying units achieve the maximum achievable control technology (MACT) for each of the three covered pollutants. For *AEO2012*, EIA assumes that all coal-fired generating units with a capacity greater than 25 megawatts will comply with the rule beginning in 2015. All power plants are required to reduce their mercury emissions to 90 percent below their uncontrolled emissions levels.

Because the EMM does not explicitly model HCl or PM2.5, specific control technologies are assumed to be used to achieve compliance. In order to meet the HCl requirement, units must have either flue gas desulfurization (FGD) scrubbers or dry sorbent injection (DSI) systems in order to continue operating. A full fabric filter is also required to meet the PM2.5 limits and to improve the effectiveness of the DSI technology. For mercury reductions, the EMM allows plants to alter their configuration by adding equipment, such as an SCR to remove NO_x or an SO_2 scrubber. They can also add activated carbon injection systems specifically designed to remove mercury. Activated carbon can be injected in front of existing particulate control devices or a supplemental fabric filter can be added with activated carbon injection capability.

The equipment to inject activated carbon in front of an existing particulate control device is assumed to cost approximately $6 (2010 dollars) per kilowatt of capacity, while the cost of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) is approximately $150 (2010 dollars) per kilowatt of capacity [2]. The amount of activated carbon required to meet a given percentage removal target is given by the following equations [3].

For a unit with a CSE, using subbituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 65 - (65.286 / (ACI + 1.026))

For a unit with a CSE, using bituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 100 - (469.379 / (ACI + 7.169))

For a unit with a CSE, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 - (28.049 / (ACI + 0.428))

For a unit with a HSE/Other, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 - (43.068 / (ACI + 0.421))

ACI = activated carbon injected in pounds per million actual cubic feet.

Power plant mercury emissions assumptions

The EMM represents 35 coal plant configurations and assigns a mercury emissions modification factor (EMF) to each configuration. Each configuration represents different combinations of boiler types, particulate control devices, sulfur dioxide (SO_2) control devices, nitrogen oxide (NO_x) control devices, and mercury control devices. An EMF represents the amount of mercury that was in the fuel that remains after passing through all the plant's systems. For example, an EMF of 0.60 means that 40 percent of the mercury that was in the fuel is removed by various parts of the plant. Table 8.8 provides the assumed EMFs for existing coal plant configurations without mercury-specific controls.

Table 8.8. Mercury emission modification factors

Configuration			EIA EMFs			EPA EMFs		
SO_2 Control	Particulate Control	NOx Control	Bit Coal	Sub Coal	Lignite Coal	Bit Coal	Sub Coal	Lignite Coal
None	BH	--	0.11	0.27	0.27	0.11	0.26	1.00
Wet	BH	None	0.05	0.27	0.27	0.03	0.27	1.00
Wet	BH	SCR	0.10	0.27	0.27	0.10	0.15	0.56
Dry	BH	--	0.05	0.75	0.75	0.50	0.75	1.00
None	CSE	--	0.64	0.97	0.97	0.64	0.97	1.00
Wet	CSE	None	0.34	0.73	0.73	0.34	0.84	0.56
Wet	CSE	SCR	0.10	0.73	0.73	0.10	0.34	0.56
Dry	CSE	--	0.64	0.65	0.65	0.64	0.65	1.00
None	HSE/Oth	--	0.90	0.94	0.94	0.90	0.94	1.00
Wet	HSE/Oth	None	0.58	0.80	0.80	0.58	0.80	1.00
Wet	HSE/Oth	SCR	0.42	0.76	0.76	0.10	0.75	1.00
Dry	HSE/Oth	--	0.60	0.85	0.85	0.60	0.85	1.00

Notes: SO_2 Controls - Wet = Wet Scrubber and Dry = Dry Scrubber, Particulate Controls, BH - fabric filter/baghouse. CSE = cold side electrostatic precipitator, HSE = hot side electrostatic precipitator, NO_x Controls, SCR = selective catalytic reduction,
— = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NO_x control system is not assumed to enhance mercury removal unless a wet scrubber is present, so it is left blank in such configurations. Sources: EPA, EMFs. www.epa.gov/clearskies/technical.html. EIA EMFs not from EPA: Lignite EMFs, Mercury Control Technologies for Coal-Fired Power Plants, presented by the Office of Fossil Energy on July 8, 2003. Bituminous coal mercury removal for a Wet/HSE/Oth/SCR configured plant, Table EMF1, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, U.S. Department of Energy, January 2003, Washington, DC.

Planned SO_2 Scrubber and NO_x control equipment additions

EIA assumes that all planned retrofits, as reported on the Form EIA-860, will occur as currently scheduled. For *AEO2012*, this includes 10.8 gigawatts of planned SO_2 scrubbers (Table 8.9) and 4.5 gigawatts of planned selective catalytic reduction (SCR).

Carbon capture and sequestration retrofits

Although a Federal greenhouse gas program is not assumed in the *AEO2012* Reference case, the EMM includes the option of retrofitting existing coal plants for carbon capture and sequestration (CCS). This option is important when considering alternate scenarios that do constrain carbon emissions. The modeling structure for CCS retrofits within the EMM was developed by the National Energy Technology Laboratory[4] and uses a generic model of retrofit costs as a function of basic plant characteristics (such as heatrate). The costs have been adjusted to be consistent with costs of new CCS technologies. The CCS retrofits are assumed to remove 90 percent of the carbon input. The addition of the CCS equipment results in a capacity derate of around 30 percent and reduced efficiency of 43 percent at the existing coal plant. The costs depend on the size and efficiency of the plant, with the capital costs ranging from $1,110 to $1,620 per kilowatt. It was assumed that only plants greater than 500 megawatts and with heat rates below 12,000 BTU per kilowatthour would be considered for CCS retrofits.

State Air Emissions Regulation

AEO2012 continues to model the Northeast Regional Greenhouse Gas Initiative (RGGI), which applies to fossil-fuel powered plants over 25 megawatts in the Northeastern United States. The State of New Jersey withdrew from the program at the end of 2011, leaving nine States in the accord. The rule caps CO_2 emissions from covered electricity generating facilities and requires that they account for each ton of CO_2 emitted with an allowance purchased at auction. Because the baseline and projected emissions were calculated before the economic recession that began in 2008, the actual emissions in the first years of the program have been less than the cap, leading to excess allowances and allowance prices at the floor price.

The California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, authorized the California Air Resources Board (CARB) to set California's GHG reduction goals for 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California. As one of the major initiatives for AB 32, CARB designed a cap-and-trade program that started on January 1, 2012, with the enforceable compliance obligations beginning in 2013. Although the cap-and-trade program applies to multiple economic sectors, for *AEO2012* it is only assumed to be implemented in the electric power sector. The electric power sector represented 25 percent of the State's GHG emissions in 2008, and therefore the EMM modeled the power sector cap at 25 percent of the limits specified in the bill for all sectors.

Table 8.9. Planned SO_2 scrubber additions by EMM region
gigawatts

Texas Reliability Entity	0.0
Florida Reliability Coordinating Council	0.0
Midwest Reliability Council - East	0.0
Midwest Reliability Council - West	0.0
Northeast Power Coordinating Council/New England	0.0
Northeast Power Coordinating Council/NYC-Westchester	0.0
Northeast Power Coordinating Council/Long Island	0.0
Northeast Power Coordinating Council/Upstate	1.0
ReliabilityFirst Corporation/East	1.2
ReliabilityFirst Corporation/Michigan	0.0
ReliabilityFirst Corporation/West	4.4
SERC Reliability Corporation/Delta	0.0
SERC Reliability Corporation/Gateway	0.0
SERC Reliability Corporation/Southeastern	4.1
SERC Reliability Corporation/Central	0.2
SERC Reliability Corporation/Virginia-Carolina	0.0
Southwest Power Pool/North	0.0
Southwest Power Pool/South	0.0
Western Electricity Coordinating Council/Southwest	0.0
Western Electricity Coordinating Council/California	0.0
Western Electricity Coordinating Council/Northwest Power Pool Area	0.0
Western Electricity Coordinating Council/Rockies	0.0
Total	10.8

Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Energy Policy Acts of 1992 (EPACT92) and 2005 (EPACT05)

The provisions of the EPACT92 include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs). The EPACT05 provides a 20-percent investment tax credit for Integrated Coal-Gasification Combined Cycle capacity and a 15-percent investment tax credit for other advanced coal technologies. These credits are limited to 3 gigawatts in both cases. It also contains a production tax credit (PTC) of 1.8 cents (nominal) per kilowatthour for new nuclear capacity beginning operation by 2020. This PTC is specified for the first 8 years of operation, is limited to $125 million (per gigawatt) annually, and is limited to 6 gigawatts of new capacity. However, this credit may be shared to additional units if more than 6 gigawatts are under construction by January 1, 2014. EPACT05 extended the PTC for qualifying renewable facilities by 2 years, or December 31, 2007. It also repealed the Public Utility Holding Company Act (PUHCA).

Energy Improvement and Extension Act 2008 (EIEA2008)

EIEA2008 extended the investment tax credit of 30 percent through 2016 for solar and fuel cell facilities.

American Recovery and Reinvestment Act (ARRA)

Updated tax credits for Renewables

ARRA extended the expiration date for the PTC to January 1, 2013, for wind and January 1, 2014, for all other eligible renewable resources. In addition, ARRA allows companies to choose an investment tax credit (ITC) of 30 percent in lieu of the PTC and allows for a grant in lieu of this credit to be funded by the U.S. Treasury. For some technologies, such as wind, the full PTC would appear to be more valuable than the 30 percent ITC; however, the difference can be small. Qualitative factors, such as the lack of partners with sufficient tax liability, may cause companies to favor the ITC grant option. *AEO2012* generally assumes that renewable electricity projects will claim the more favorable tax credit or grant option available to them.

Loan guarantees for renewables

ARRA provided $6 billion to pay the cost of guarantees for loans authorized by the Energy Policy Act of 2005. While most renewable projects which start construction prior to September 30, 2011 are potentially eligible for these loan guarantees, the application and approval of guarantees for specific projects is a highly discretionary process, and has thus far been limited. While *AEO2012* includes projects that have received loan guarantees under this authority, it does not assume automatic award of the loans to potentially eligible technologies.

Support for CCS

ARRA provided $3.4 billion for additional research and development on fossil energy technologies. A portion of this funding is expected to be used to fund projects under the Clean Coal Power Initiative program, focusing on projects that capture and sequester greenhouse gases. To reflect the impact of this provision, *AEO2012* Reference case assumes that an additional 1 gigawatt of coal capacity with CCS will be stimulated by 2017.

Smart grid expenditures

ARRA provides $4.5 billion for smart grid demonstration projects. While somewhat difficult to define, smart grid technologies generally include a wide array of measurement, communications, and control equipment employed throughout the transmission and distribution system that will enable real-time monitoring of the production, flow, and use of power from generator to consumer. Among other things, these smart grid technologies are expected to enable more efficient use of the transmission and distribution grid, lower line losses, facilitate greater use of renewables, and provide information to utilities and their customers that will lead to greater investment in energy efficiency and reduced peak load demands. The funds provided will not fund a widespread implementation of smart grid technologies, but could stimulate more rapid investment than would otherwise occur.

Several changes were made throughout the NEMS to represent the impacts of the smart grid funding provided in ARRA. In the electricity module, it was assumed that line losses would fall slightly, peak loads would fall as customers shifted their usage patterns, and customers would be more responsive to pricing signals. Historically, line losses, expressed as the percentage of electricity lost, have been falling for many years as utilities make investments to replace aging or failing equipment.

Smart grid technologies also have the potential to reduce peak demand through the increased deployment of demand response programs. In *AEO2012*, it is assumed that the Federal expenditures on smart grid technologies will stimulate efforts that reduce peak demand in 2035 by 3 percent from what they otherwise would be. Load is shifted to offpeak hours, so net energy consumed remains largely constant.

FERC Orders 888 and 889

FERC has issued two related rules (Orders 888 and 889) designed to bring low-cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and an Open Access Same-Time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. Consequently, utilities are expected to functionally or physically unbundle their marketing functions from their transmission functions.

These orders are represented in EMM by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make such transactions economical.

Electricity alternative cases

Integrated Technology cases

The Integrated High Technology Cost case combines assumptions from the end-use High Technology cases with assumptions on lower costs of new power plants, including renewables, nuclear and fossil. Assumptions for the other sectors appear in the respective chapters. This case assumes that the capital and operating costs for new fossil and nuclear plants will start 20 percent lower than in the Reference case, and will be 40 percent lower than Reference case levels in 2035.

The Integrated 2011 technology case combines assumptions from the end-use 2011 Technology cases and higher costs for new power plants. In the EMM it is assumed that the base costs of all nuclear and fossil generating technologies will remain at current costs during the projection period, with no reductions due to learning. The annual commodity cost adjustment factor is still applied as in the Reference case.

Table 8.10 shows the costs assumed for new fossil technologies across the Integrated Technology cases, while Table 8.11 shows the costs for new nuclear plants in the same cases.

Table 8.10. Cost and performance characteristics for fossil-fueled generating technologies: three cases

		Total Overnight Cost[1]		
	Total Overnight Cost in 2012 (Reference) (2010$/kW)	Reference (2010$/kW)	Low Integrated Technology (2010$/kW)	High Integrated Technology (2010$/kW)
Pulverized Coal	2844			
2015		2985	3005	2311
2020		2784	2830	2034
2025		2597	2666	1784
2030		2354	2449	1515
2035		2115	2229	1269
Advanced Coal	3220			
2015		3366	3403	2604
2020		3100	3204	2265
2025		2865	3019	1968
2030		2565	2773	1651
2035		2281	2524	1368
Advanced Coal with Sequestration	5348			
2015		5564	5650	4306
2020		5094	5321	3721
2025		4673	5013	3209
2030		4155	4605	2674
2035		3662	4191	2197
Conventional Combined Cycle	977			
2015		1026	1033	794
2020		956	972	698
2025		892	916	614
2030		809	841	520
2035		727	766	436
Advanced Gas	1003			
2015		1050	1060	813
2020		963	998	703
2025		890	940	611
2030		795	864	511
2035		706	786	424
Advanced Gas with Sequestration	2060			
2015		2141	2177	1657
2020		1949	2050	1423
2025		1782	1931	1224
2030		1576	1774	1014
2035		1383	1614	829
Conventional Combustion Turbine	974			
2015		1022	1029	790
2020		953	969	696
2025		889	913	610
2030		806	838	518
2035		724	763	434
Advanced Combustion Turbine	666			
2015		695	704	538
2020		631	663	461
2025		579	624	398
2030		512	573	329
2035		451	522	270

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.
Source: U.S. Energy Information Administration. *AEO2012* National Energy Modeling System runs: REF2012.D020112C, LTRKITEN.D031312A, HTRKITEN.D032812A

Table 8.11. Cost characteristics for advanced nuclear technology: three cases

	Overnight Cost in 2012 (Reference) (2010$/kW)	Total Overnight Cost[1] Reference (2010$/kW)	Low Integrated Technology (2010$/kW)	High Integrated Technology (2010$/kW)
Advanced Nuclear	5335			
2015		5466	5638	4231
2020		4733	5309	3456
2025		4302	5002	2954
2030		3850	4594	2477
2035		3414	4181	2049

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.
Source: U.S. Energy Information Administration. *AEO2012* National Energy Modeling System runs: REF2012.D020112C, LTRKITEN.D031312A, HTRKITEN.D032812A.

Electricity Environmental Regulation cases

Over the next few years electricity generators will have to begin steps to comply with a number of new environmental-Regulations, primarily through adding environmental controls at existing coal power plants. The additional cases examine the impacts of shorter economic recovery periods for the environmental controls, both with natural gas prices similar to the *AEO2012* reference case and with lower natural gas prices.

- The Reference 5 case assumes that the economic recovery period for investments in new environmental controls is reduced from 20 years to 5 years.
- The Low Gas Price 5 case uses more optimistic assumptions about future volumes of shale gas production, leading to lower natural gas prices, combined with the five-year recovery period for new environmental controls. The domestic shale gas resource assumption comes from the Low Tight Oil and Shale Gas Resource case.

Nuclear Alternative cases

For *AEO2012*, two alternate cases were run for nuclear power plants to address uncertainties about the operating lives of existing reactors, the potential for new nuclear capacity, and capacity uprates at existing plants. These scenarios are discussed in the Issues in Focus article, "Nuclear Power in *AEO2012*" in the full *AEO2012* report.

- The Low Nuclear case assumes that all existing nuclear plants are retired after 60 years of operation. In the Reference case, existing plants are assumed to run as long as they continue to be economic, implicitly assuming that a second 20-year license renewal will be obtained for most plants reaching 60 years before 2035. This case was run to analyze the impact of additional nuclear retirements, which could occur if the oldest plants do not receive a second license extension. In this case, 31 gigawatts of nuclear capacity are assumed to be retired by 2035. his case assumes that no new nuclear capacity will be added throughout the projection, excluding the capacity already planned and under construction. The case also assumes that only those capacity uprates reported to EIA will be completed. The Reference case assumes additional uprates based on Nuclear Regulatory Commission (NRC) surveys and industry reports.
- The High Nuclear case assumes that all existing nuclear units will receive a second license renewal and operate beyond 60 years (excluding one announced retirement). In the Reference case, beyond the announced retirement of Oyster Creek, an additional 5.5 gigawatts of nuclear capacity is assumed to be retired through 2035, reflecting uncertainty surrounding future aging impacts and/or costs. This case was run to provide a more optimistic outlook where all licenses are renewed and all plants are assumed to find it economic to continue operating beyond 60 years. The High Nuclear case also assumes additional planned nuclear capacity is completed based on combined license (COL) applications with the NRC. The Reference case assumes 6.8 gigawatts of planned capacity are added, while the High Nuclear case includes 13.5 gigawatts of planned capacity additions.

Notes and sources

[1] Updated Capital Cost Estimates for Electricity Generation Plants, EIA, November 2010.

[2] These costs were developed using the National Energy Technology Laboratory Mercury Control Performance and Cost Model, 1998.

[3] U.S. Department of Energy, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, January 2003.

[4] Retrofitting Coal-Fired Power Plants for Carbon Dioxide Capture and Sequestration - Exploratory Testing of NEMS for Integrated Assessments, DOE/NETL-2008/1309, P.A. Geisbrecht, January 18, 2009.

SURREBUTTAL EXHIBIT JIF-5

COST REPORT

COST AND PERFORMANCE DATA FOR POWER GENERATION TECHNOLOGIES

Prepared for the
National Renewable Energy Laboratory

FEBRUARY 2012

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Building a world of difference.

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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$

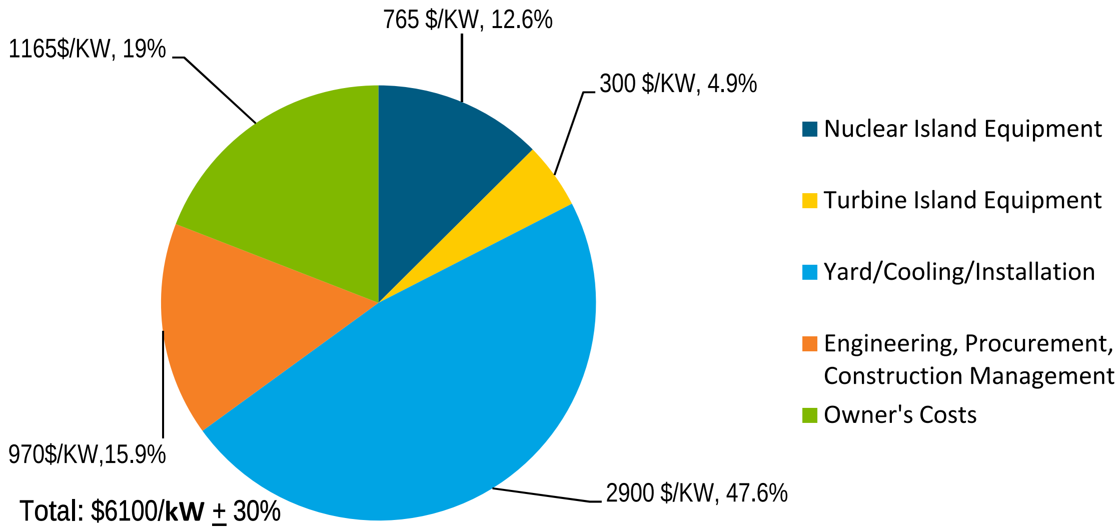

Figure 1. Capital cost breakdown for a nuclear power plant

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

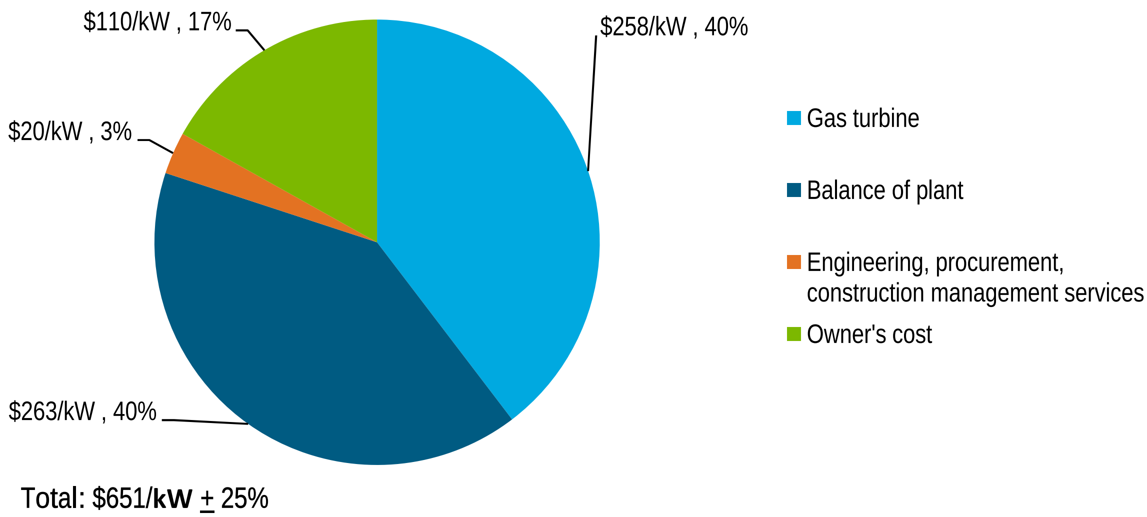

Figure 2. Capital cost breakdown for a gas turbine power plant

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

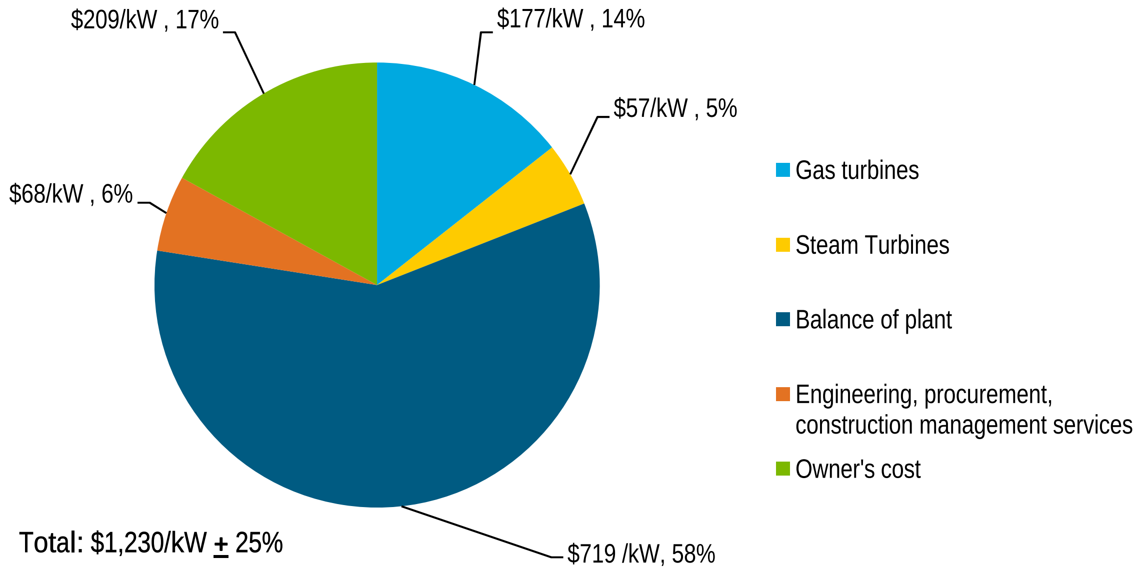

Figure 3. Capital cost breakdown for a combined-cycle power plant

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

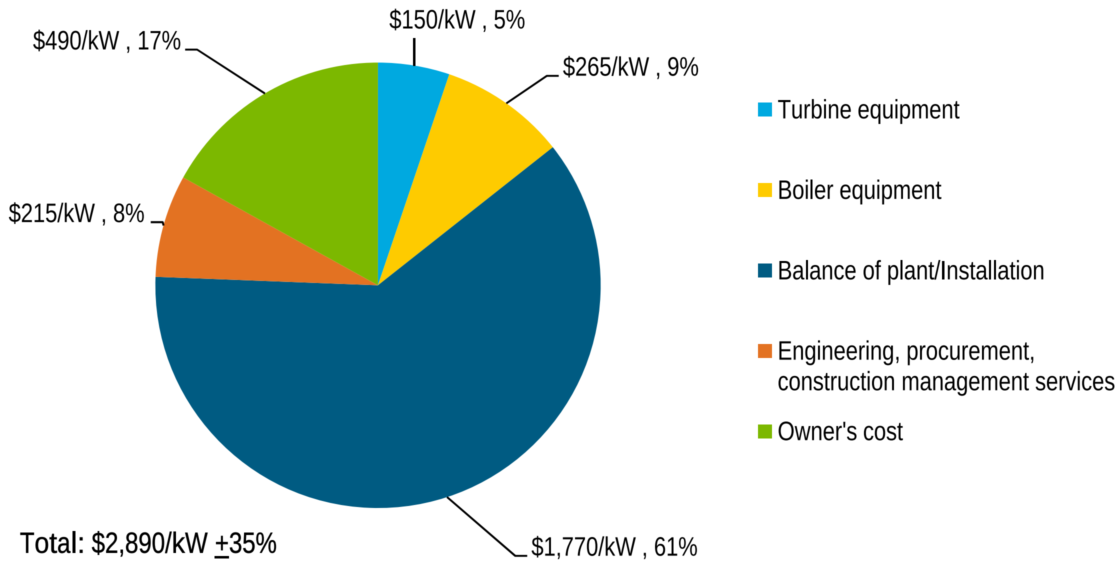

Figure 4. Capital cost breakdown for a pulverized coal-fired power plant

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 only[3]. 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

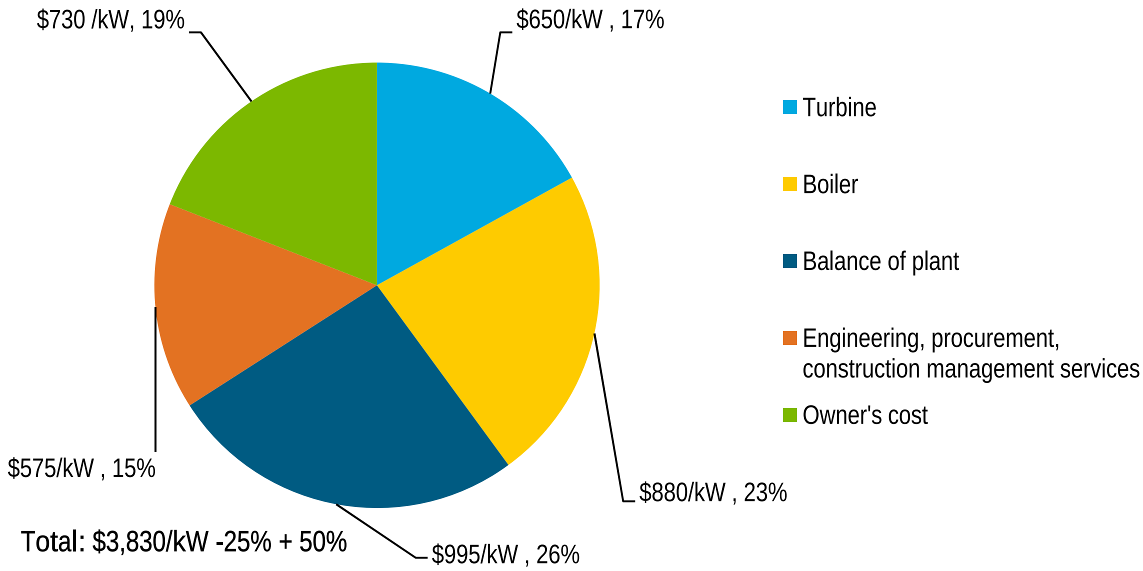

Figure 5. Capital cost breakdown for a standalone biomass power plant

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.

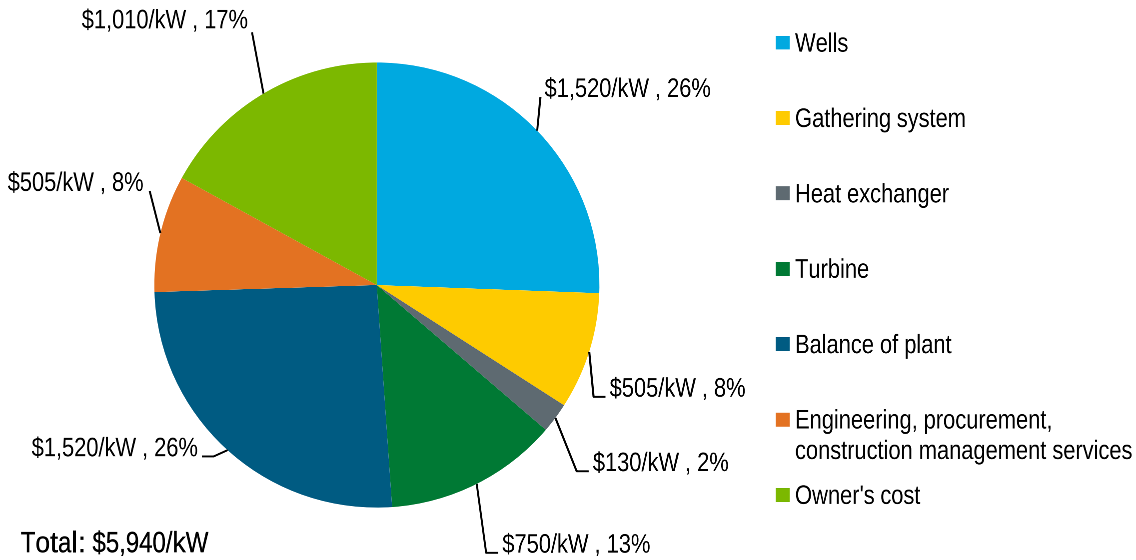

Figure 6. Capital cost breakdown for a hydrothermal geothermal power plant

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

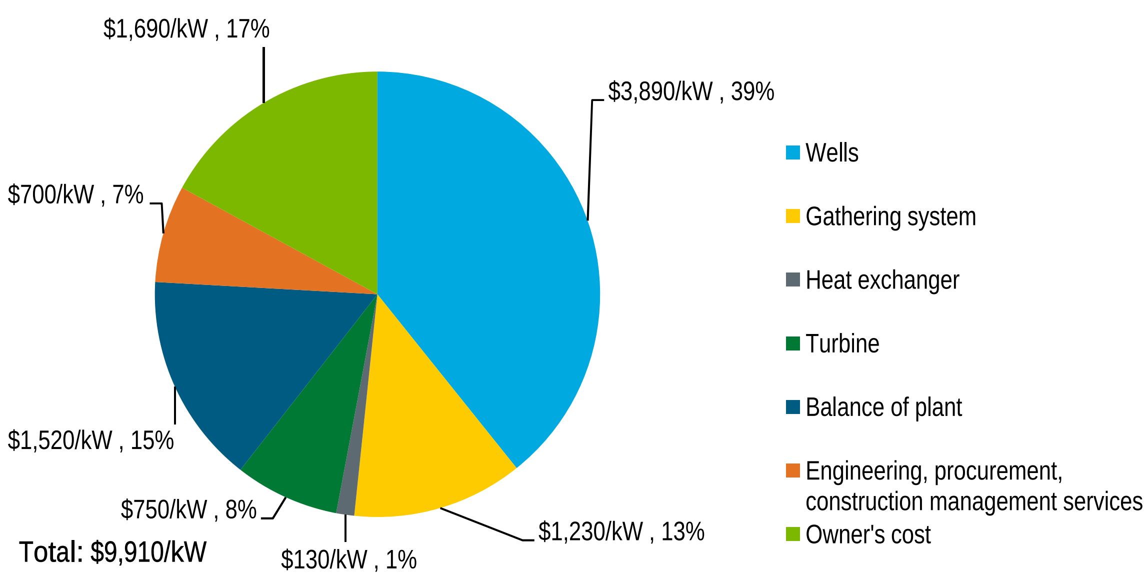

Figure 7. Capital cost breakdown for an enhanced geothermal system power plant

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.

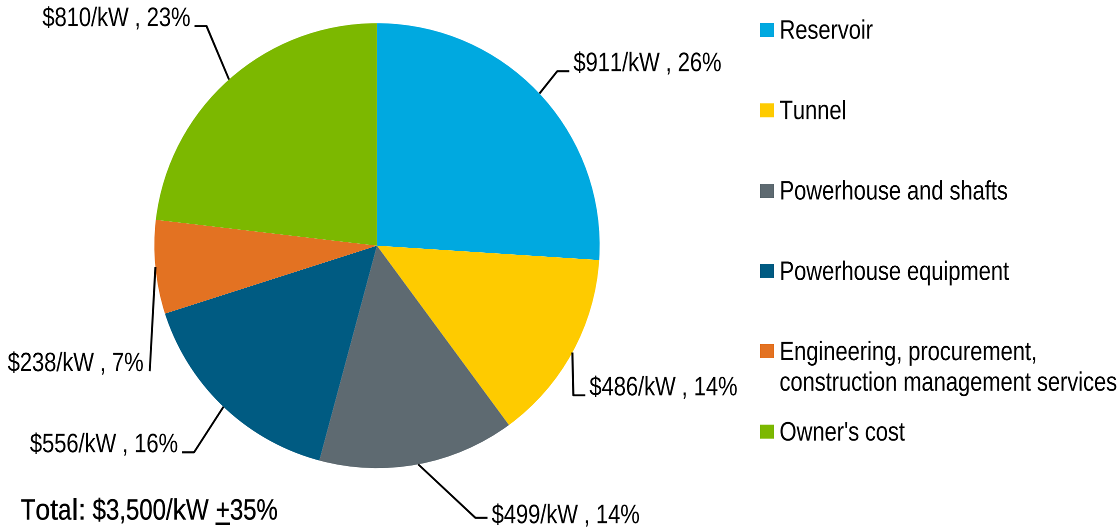

Figure 8. Capital cost breakdown for a hydroelectric power plant

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

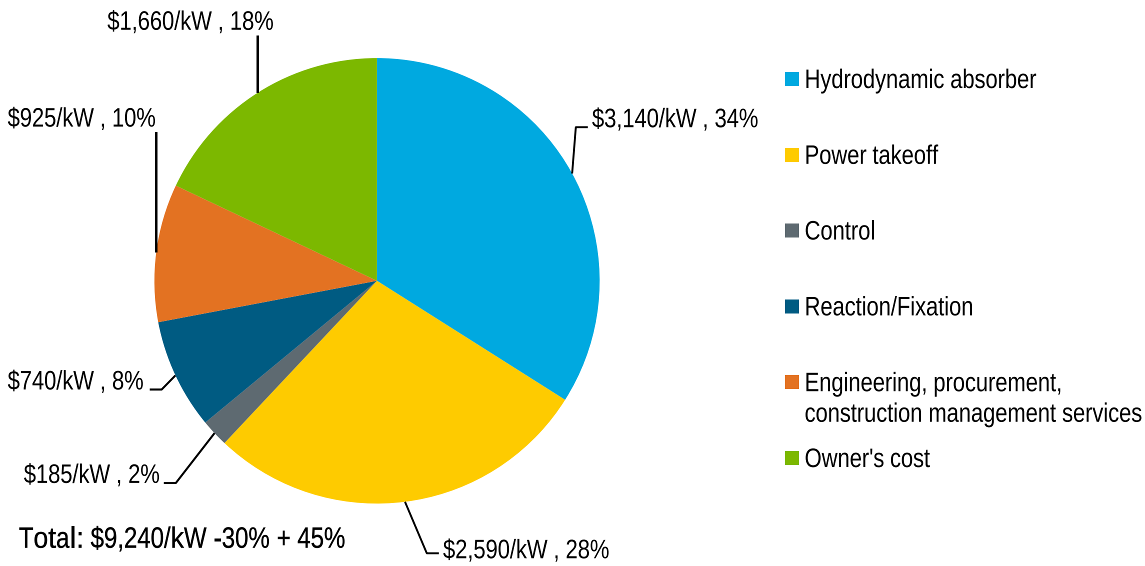

Figure 9. Capital cost breakdown for an ocean wave power plant

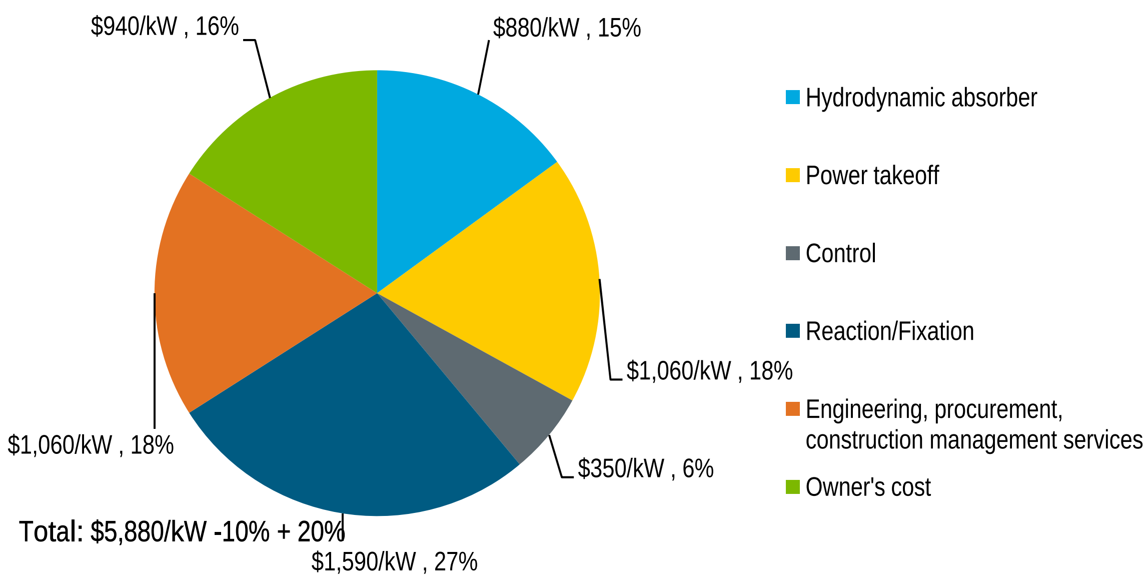

Figure 10. Capital cost breakdown for an ocean tidal power plant

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

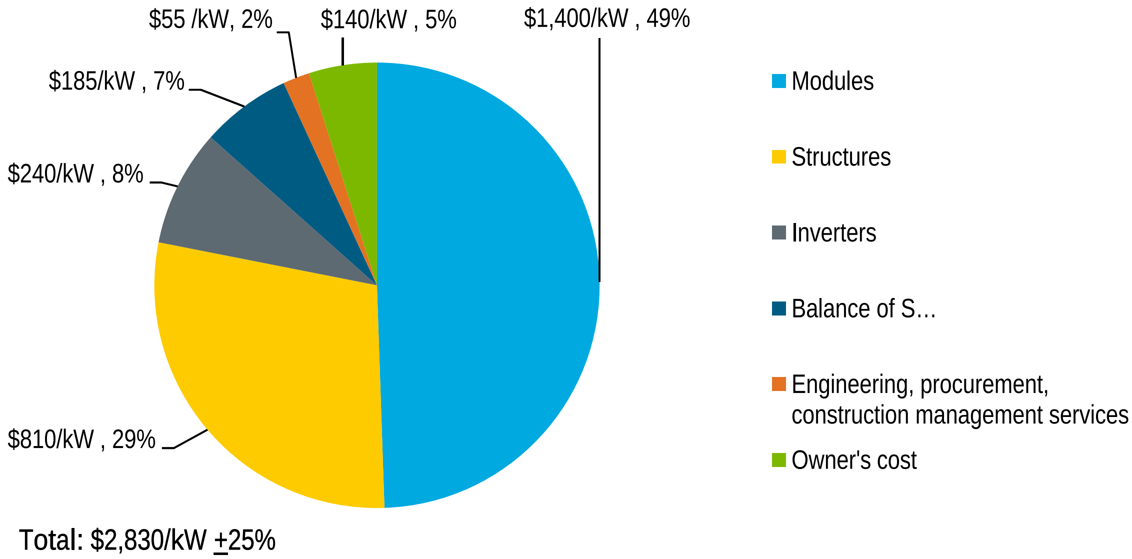

Figure 11. Capital cost breakdown for a solar photovoltaic power plant

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.

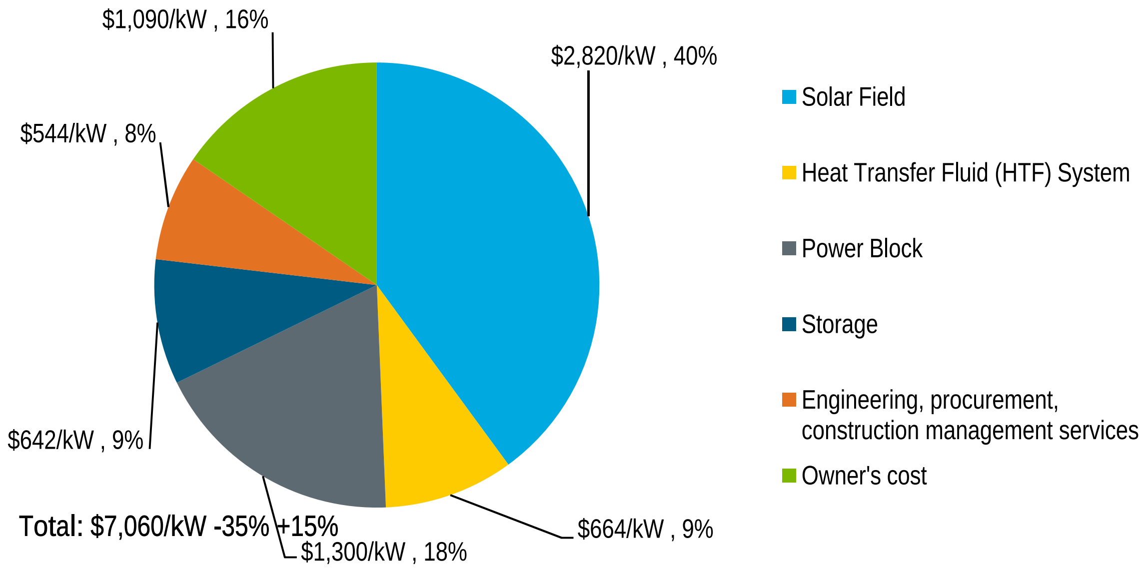

Figure 12. Capital cost breakdown for a trough concentrating solar power plant with storage

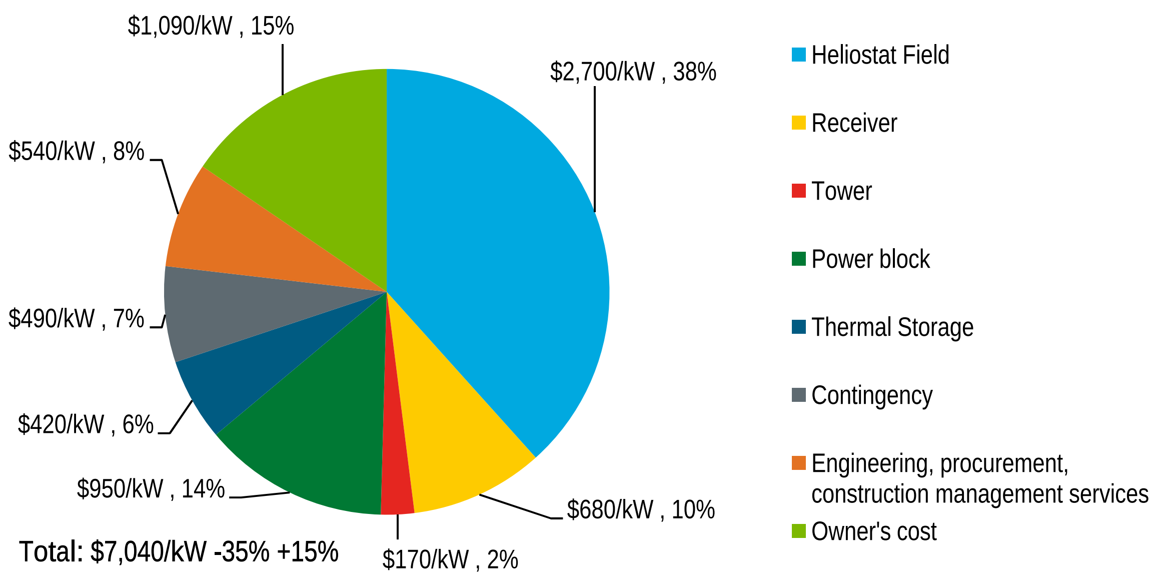

Figure 13. Capital cost breakdown for a tower concentrating solar power plant with storage

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

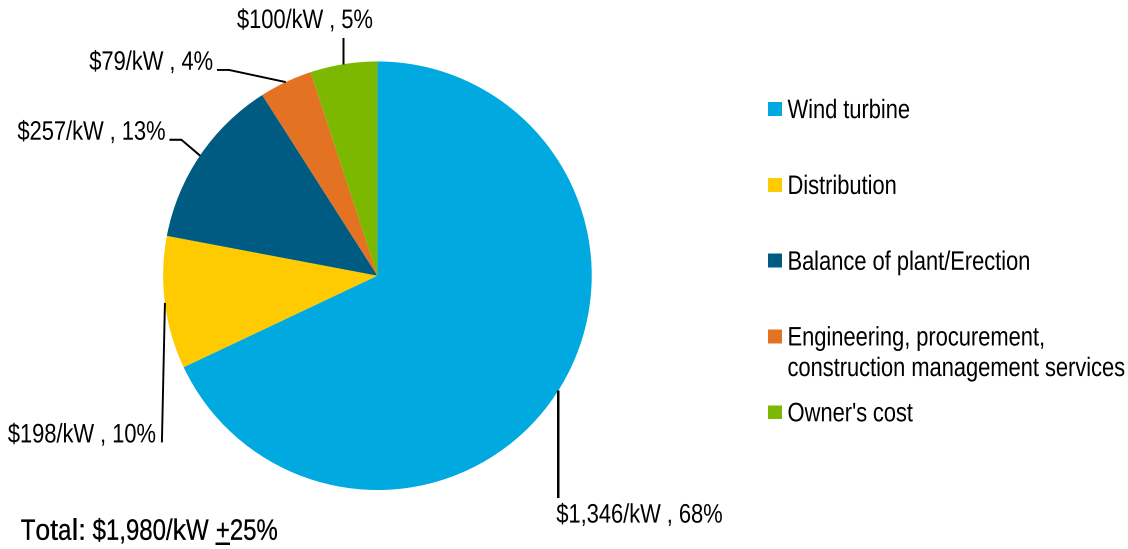

Figure 14. Capital cost breakdown for an onshore wind power plant

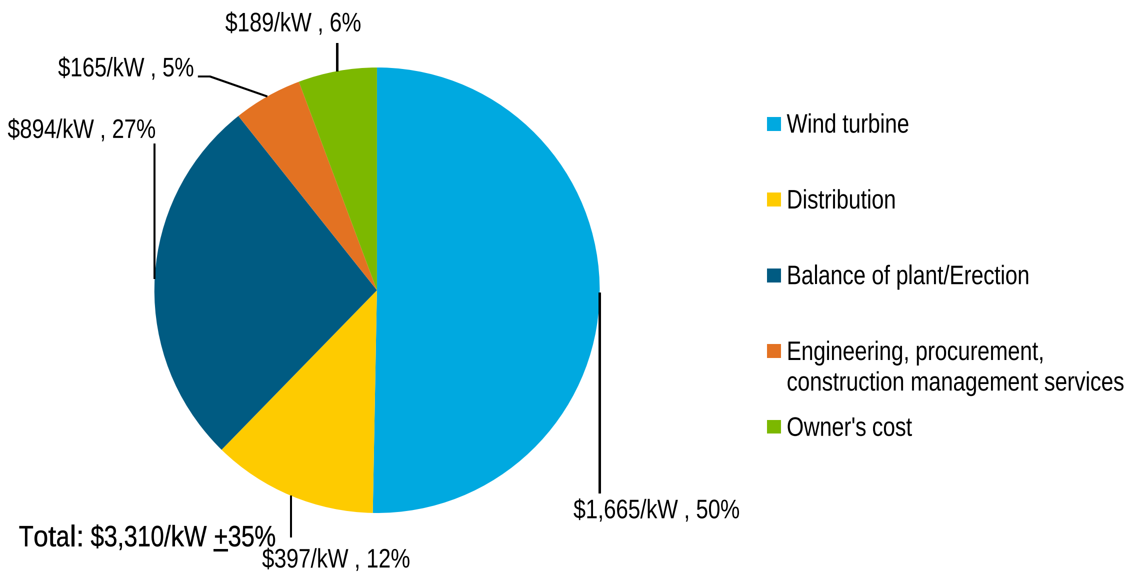

Figure 15. Capital cost breakdown for a fixed-bottom offshore wind power plant

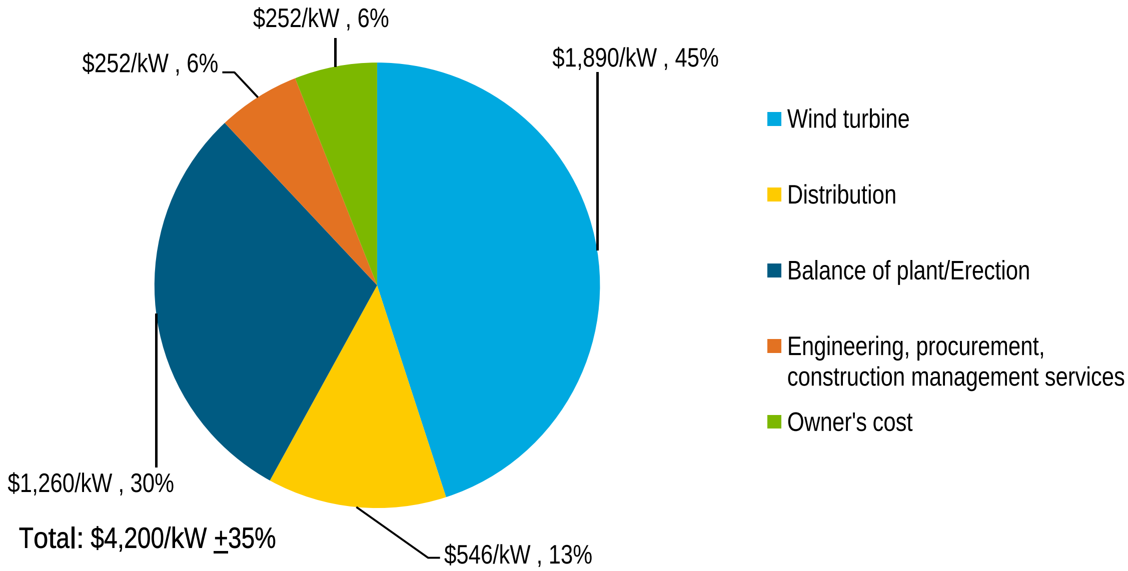

Figure 16. Capital cost breakdown for a floating-platform offshore wind power plant

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.

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[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.

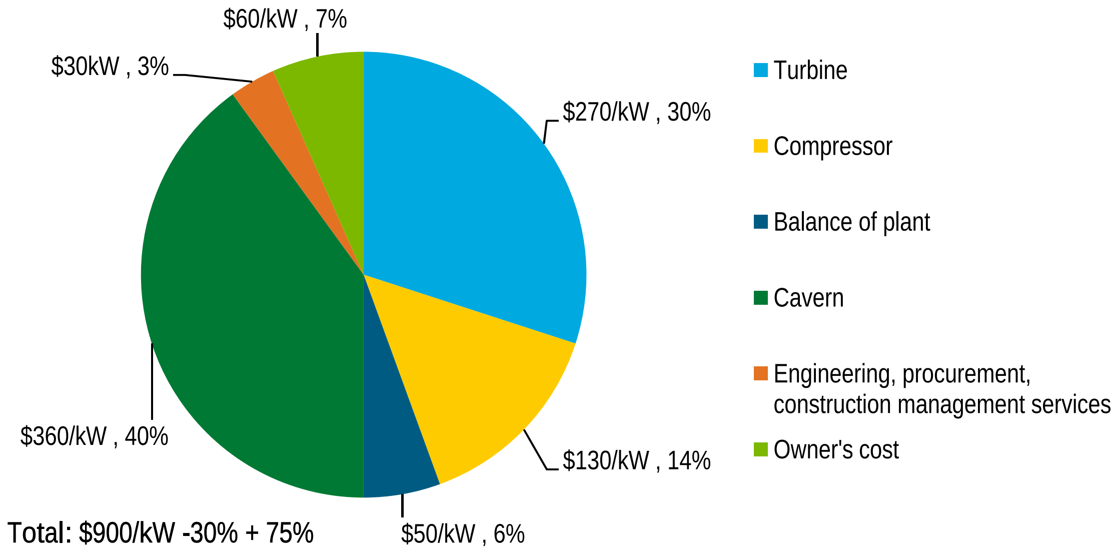

Figure 17. Capital cost breakdown for a compressed air energy storage power plant

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.

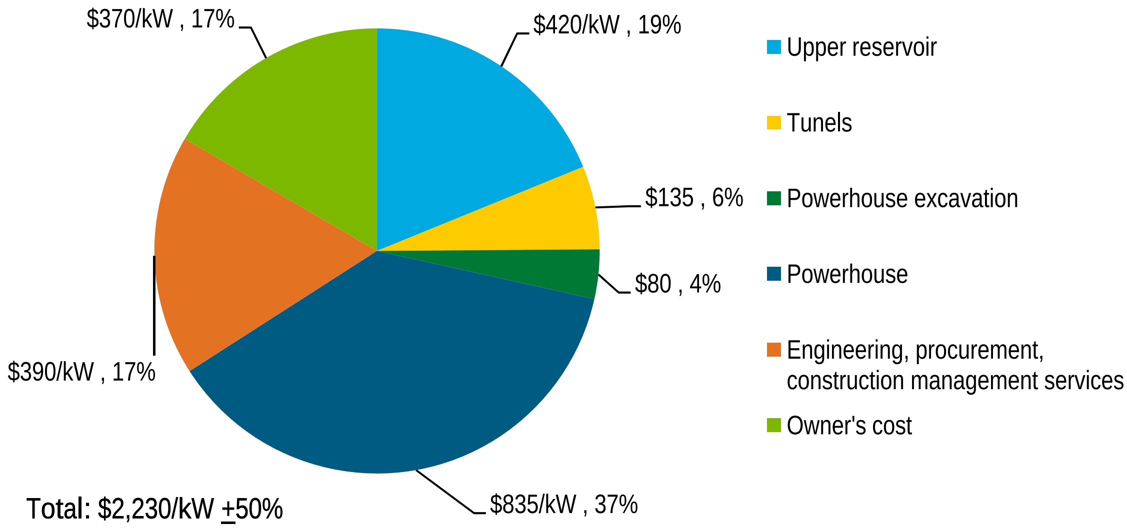

Figure 18. Capital Cost breakdown for a pumped-storage hydropower plant

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.

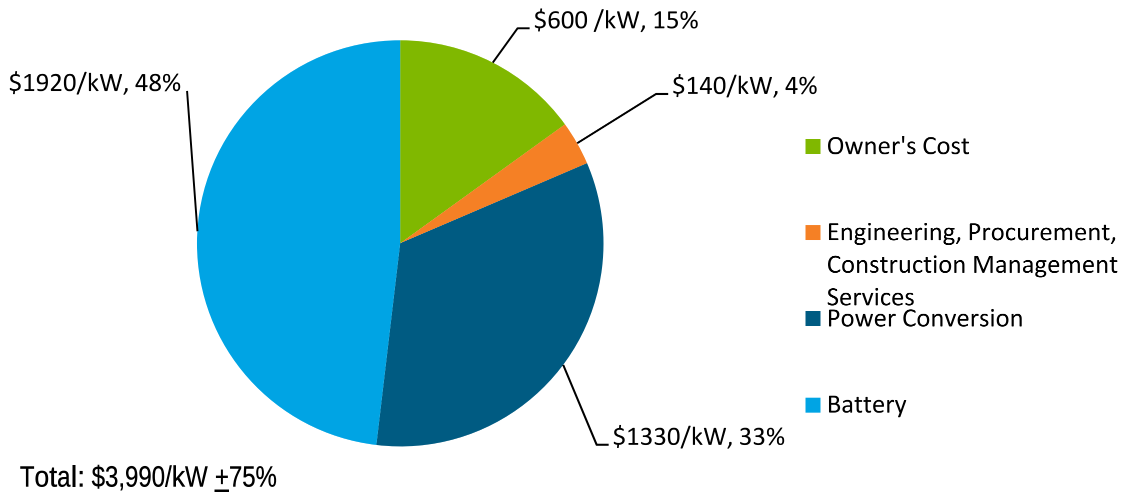

Figure 19. Capital Cost Breakdown for a Battery Energy Storage Plant

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.

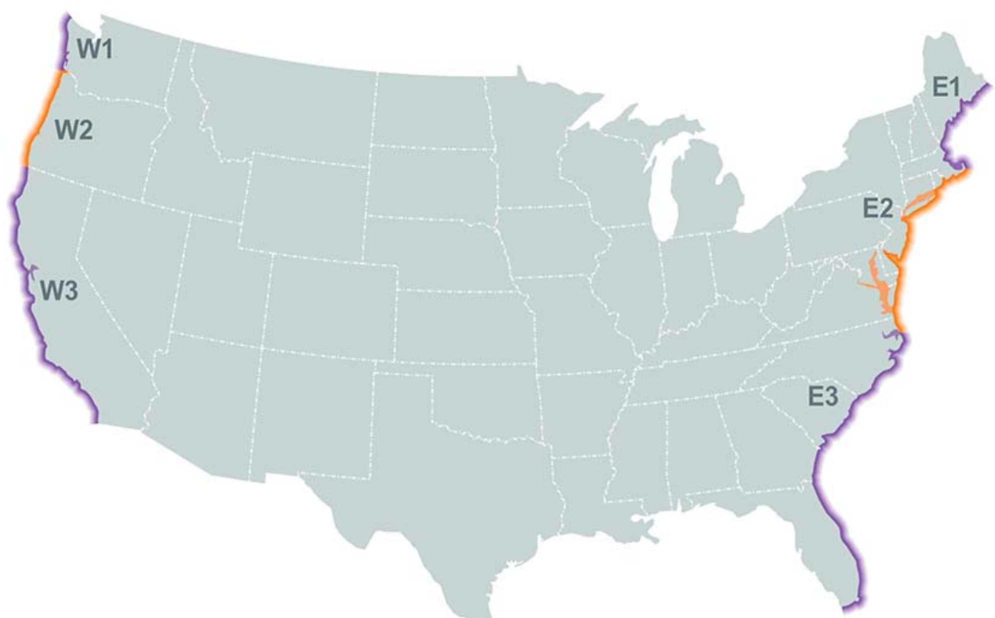


Figure A-1. Designated Coastal Segments

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)

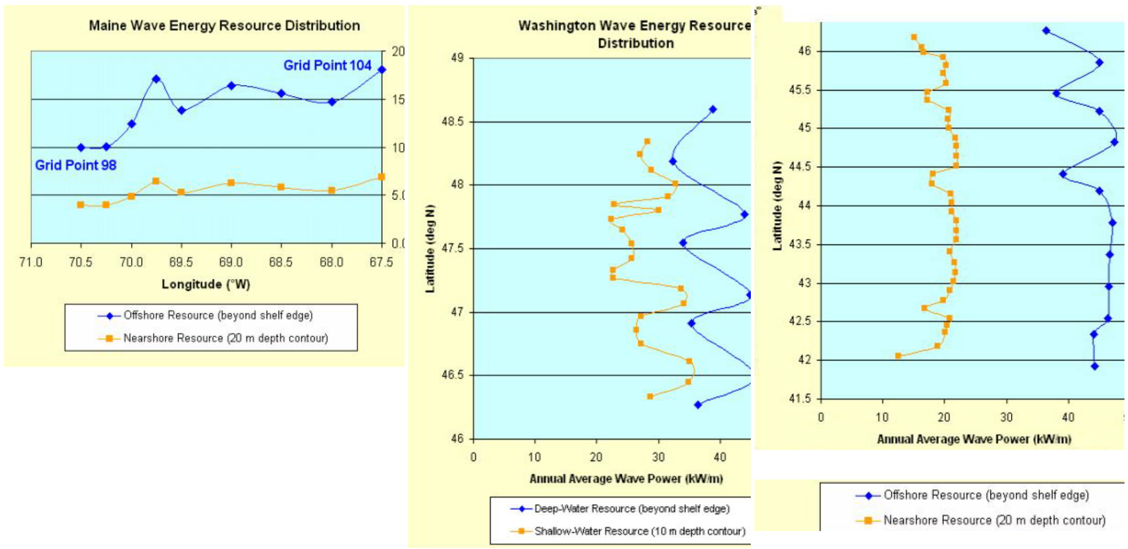
Table A-1. Length of Coastlines in United States

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).

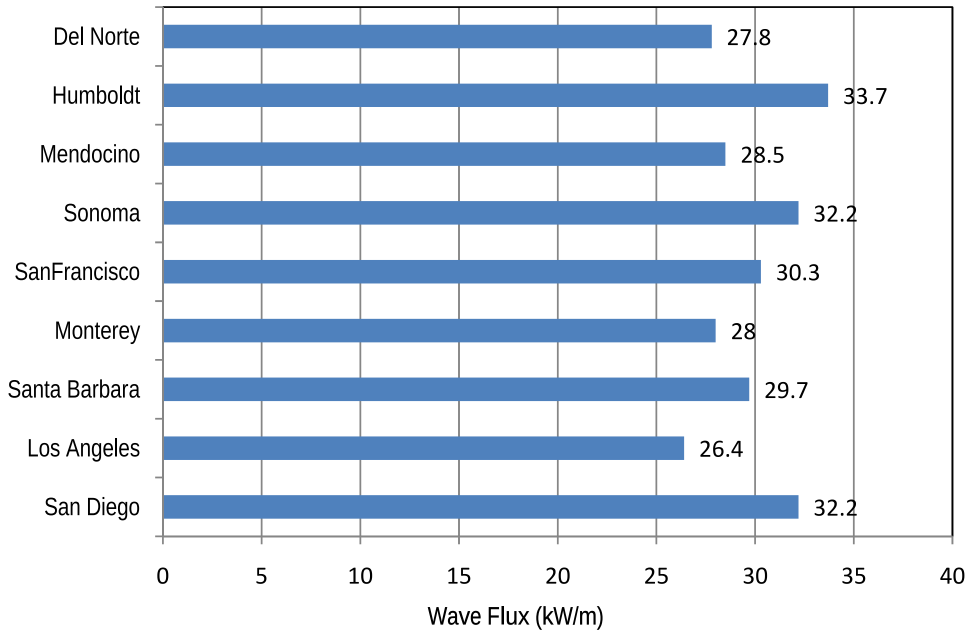


Figure A-3. Wave Flux for California

(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.

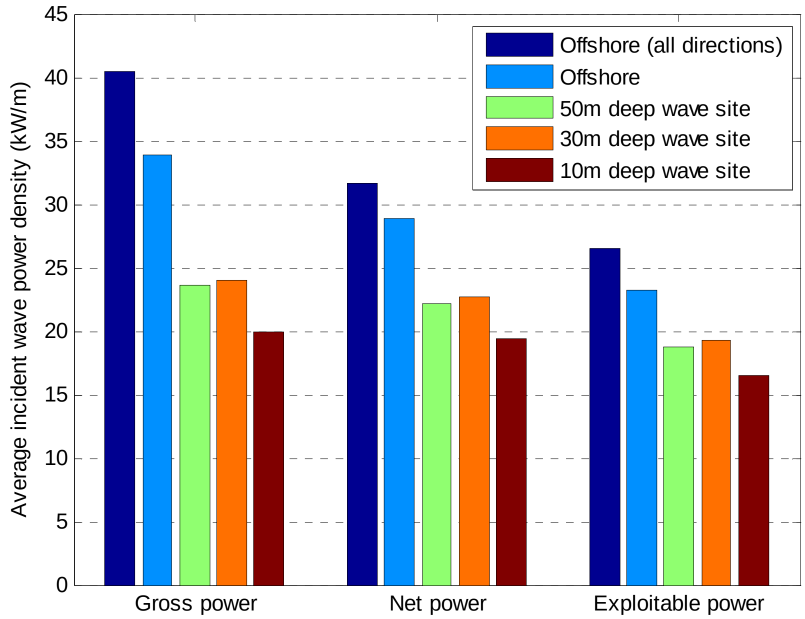


Figure A-4. Gross v. Exploitable Power at Varying Sea Depths

(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.

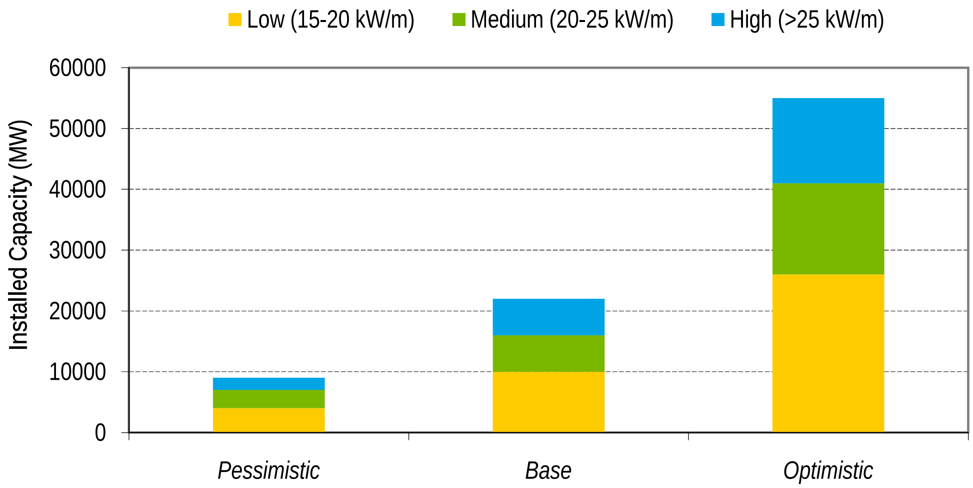


Figure A-5

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

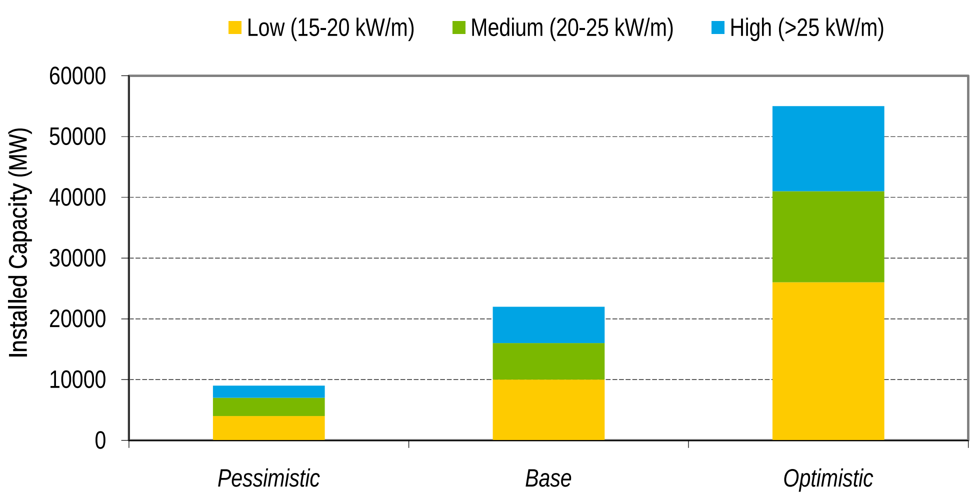


Figure A-5. Wave resource estimate for different scenarios

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.

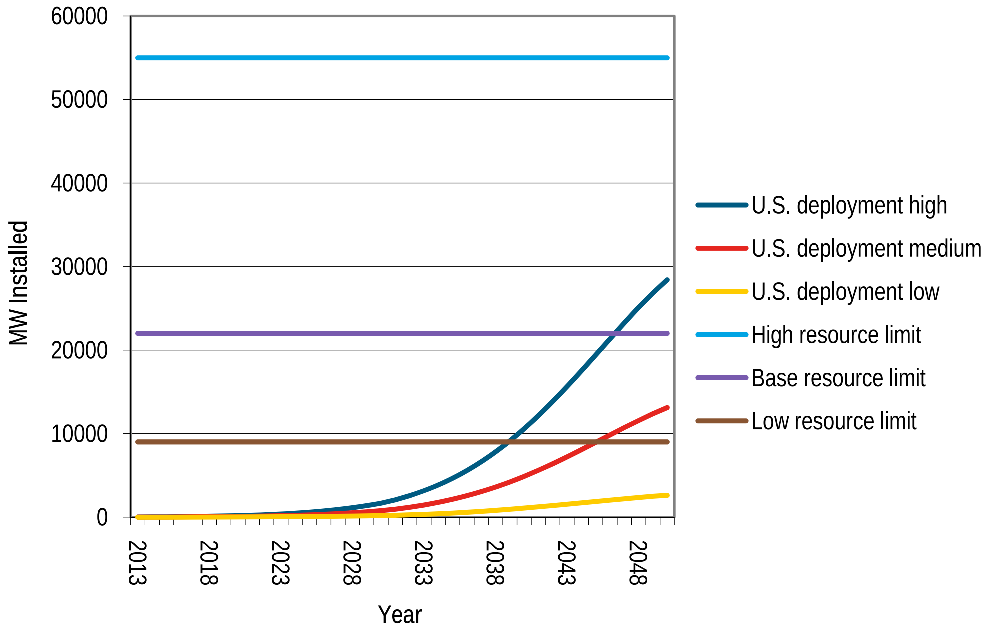


Figure A-6. Deployment Scenarios for Wave Power in the United States to 2050

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.

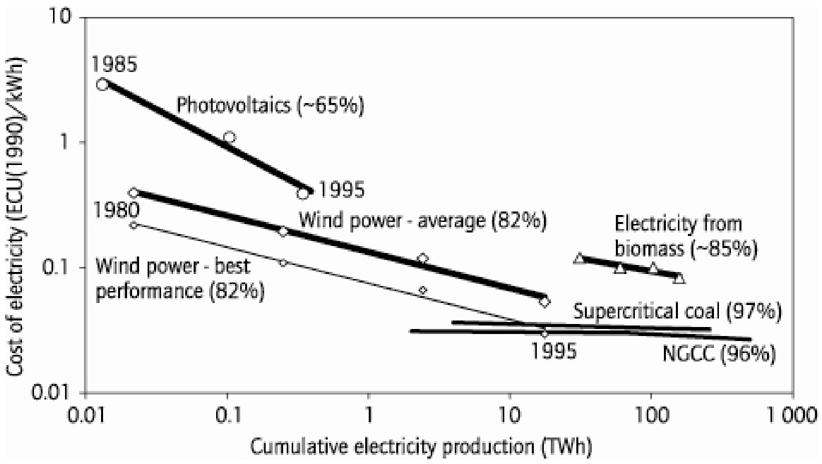


Figure A-7. Learning in Renewable Energy Technologies

(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.

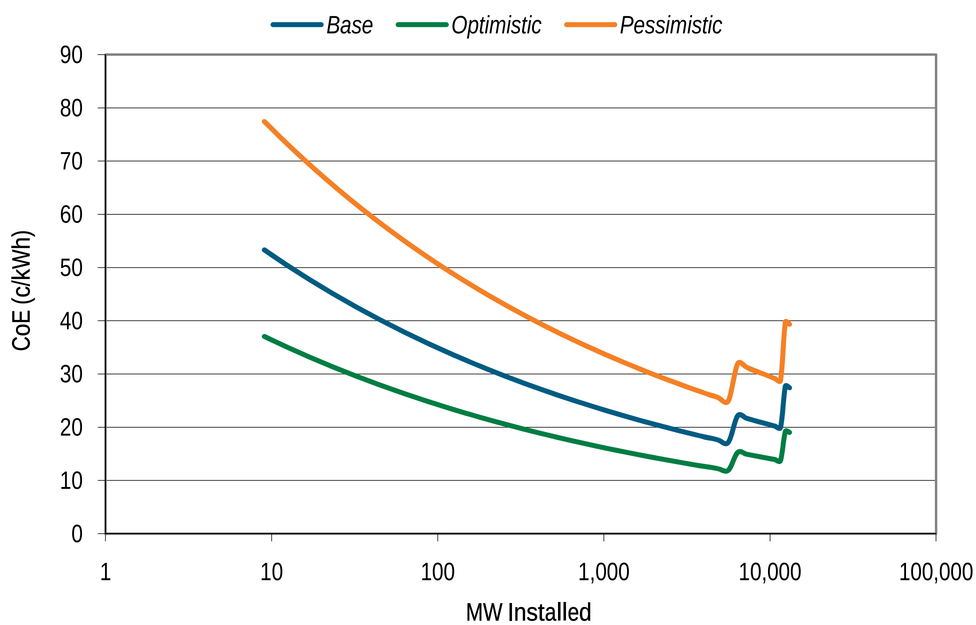


Figure A-8. Cost of energy projection with installed capacity for *Base Case* deployment and learning rates

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.

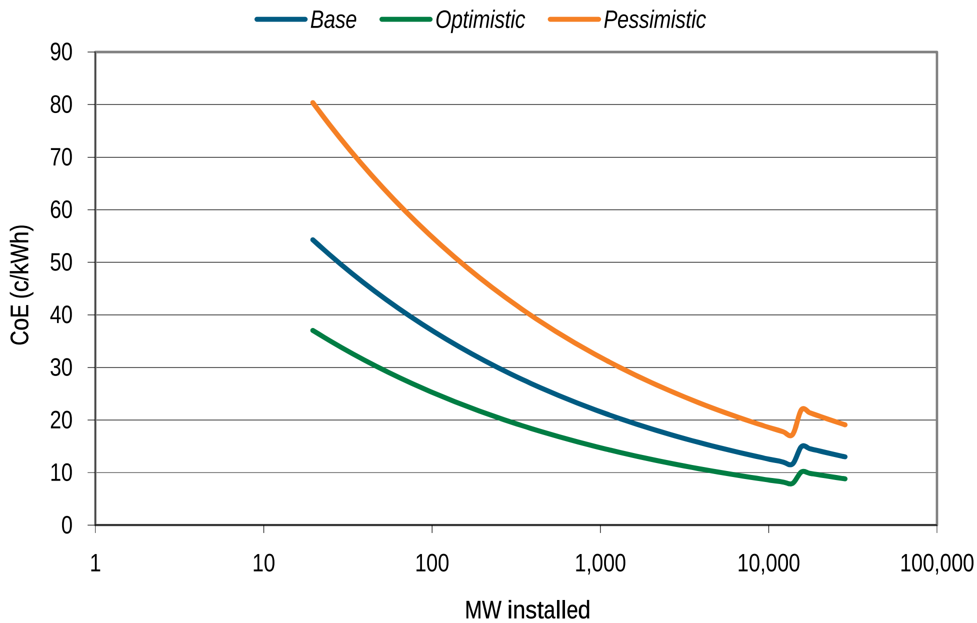


Figure A-9. Cost of energy (projection with installed capacity for *Optimistic* deployment and learning rates

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.

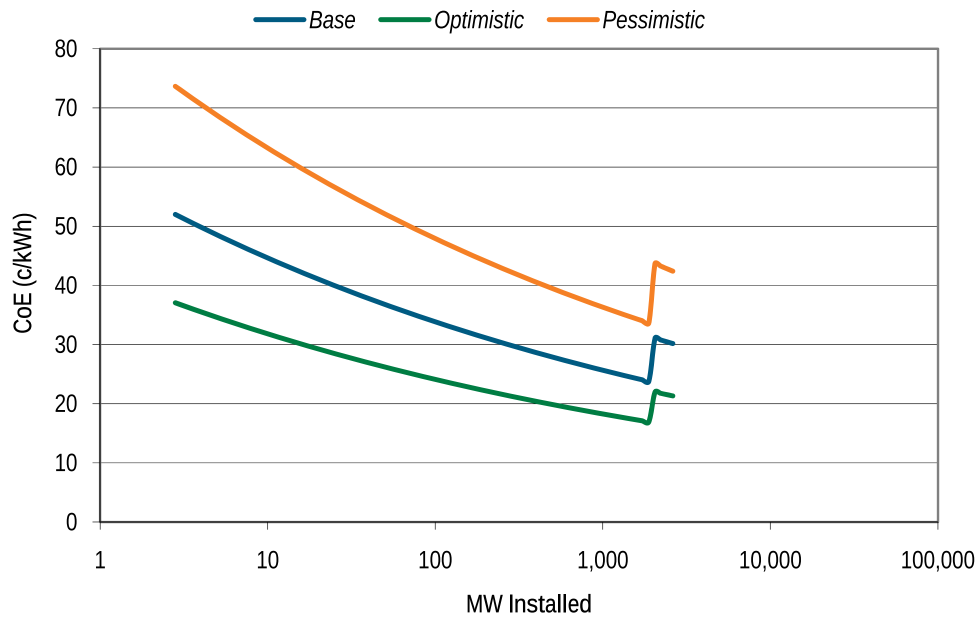


Figure A-10. Cost of energy (c/kWh) over projection with installed capacity for *Pessimistic* deployment and learning rates

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.

[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.

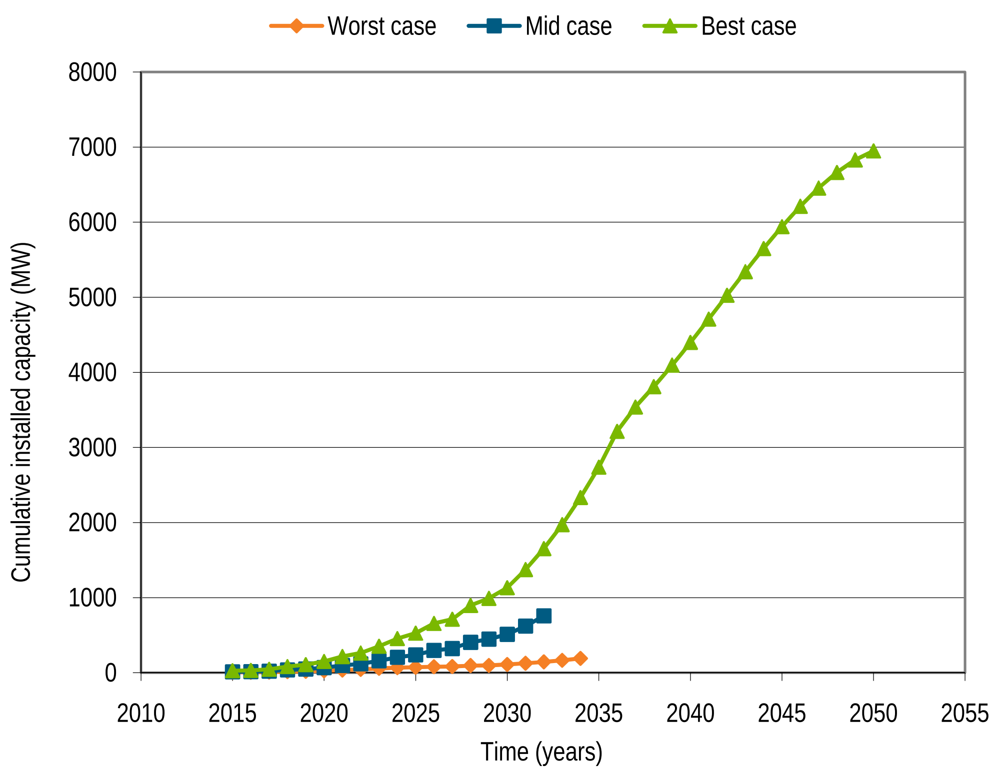


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Figure B-1. Deployment scenarios for tidal stream power (continental waters) in the United States to 2050

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).

[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.

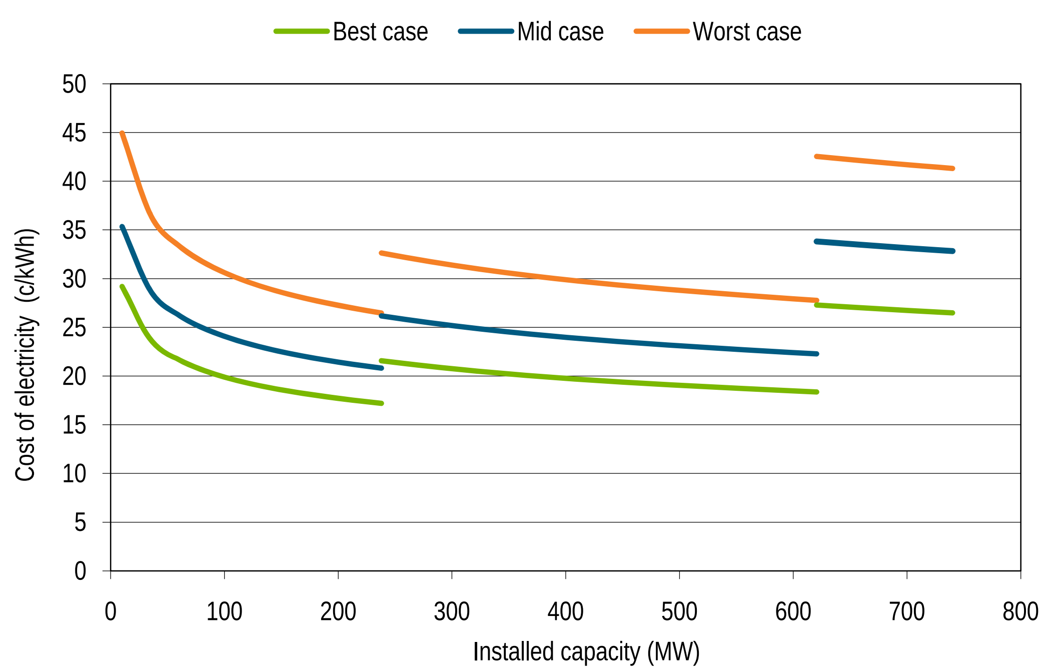

Figure B-2. Supply curve for a *Base Case* resource ceiling and an 11% learning rate

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*).

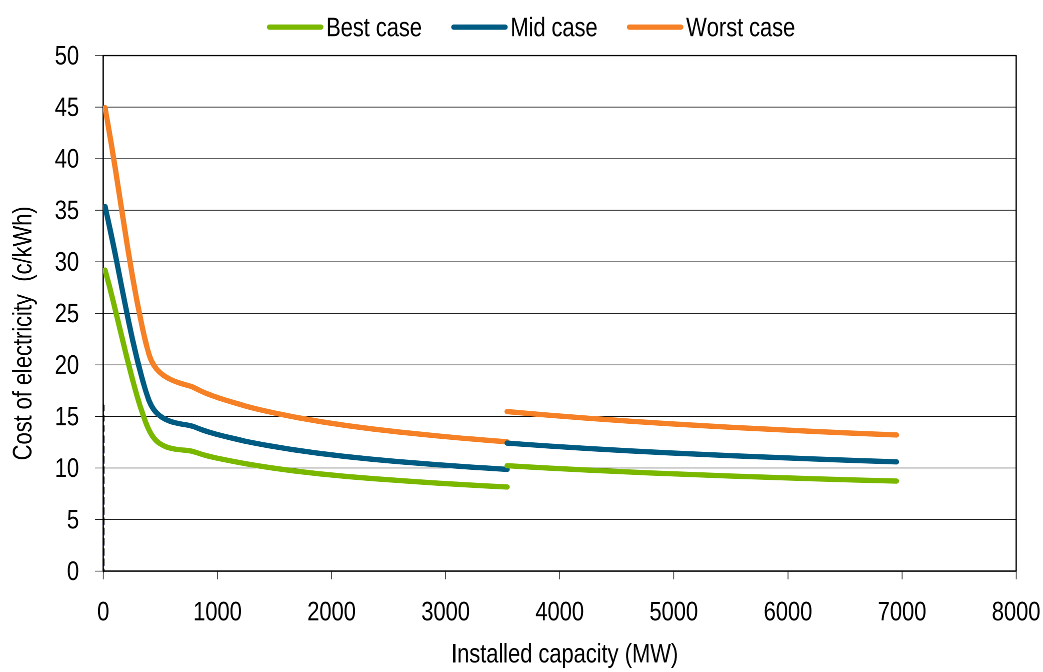

Figure B-3. Supply curve for an *Optimistic* resource ceiling and a 15% learning rate

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.

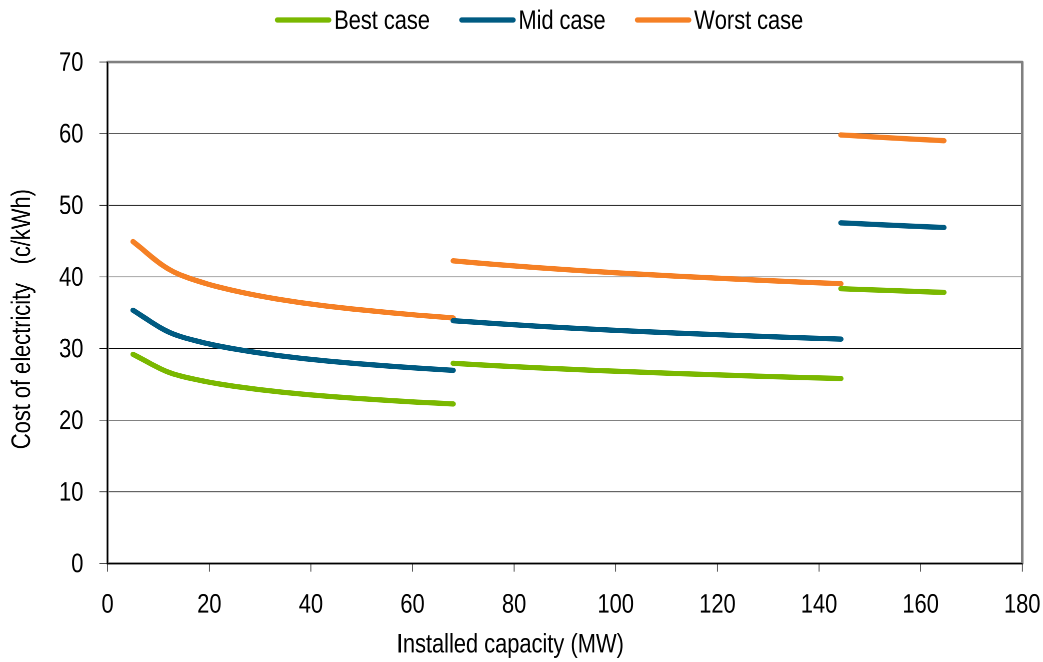

Figure B-4. Supply curve for a *Pessimistic* resource ceiling and a 7% learning rate

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.

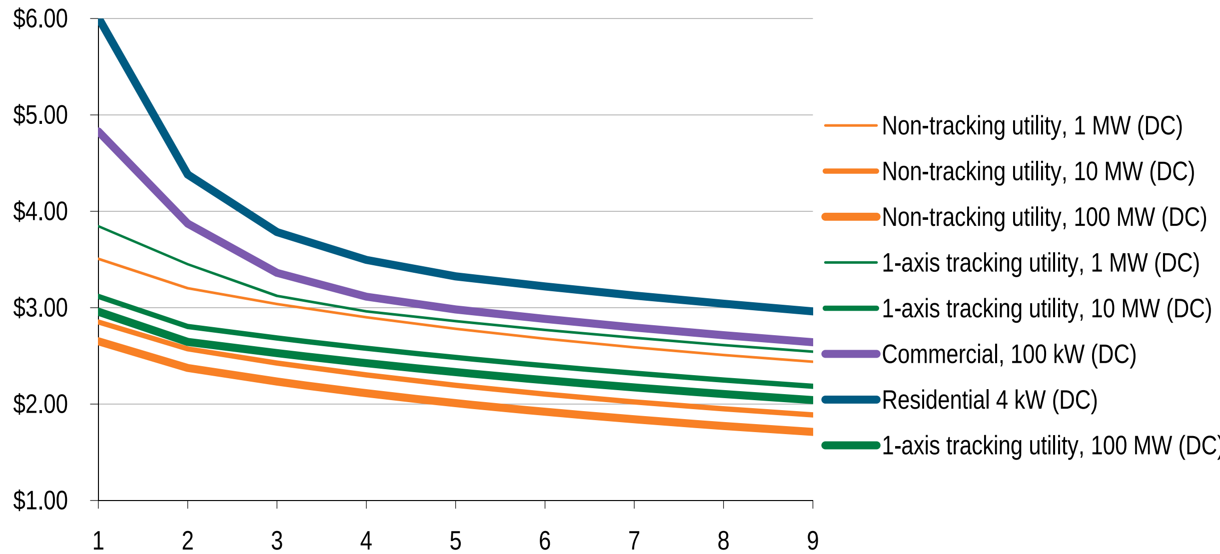

Figure C-1. Capital cost projection for solar photovoltaic technology

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.

SURREBUTTAL EXHIBIT JIF-6

Exhibit JIF-6

The Brattle Group

Cost of New Entry Estimates For Combustion-Turbine and Combined-Cycle Plants in PJM

August 24, 2011

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PJM Interconnection, L.L.C.

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Acknowledgements

The authors would like to thank David Cheever, Rod Gartner, and others at CH2M HILL for providing their rigorous analysis of engineering costs and for contributing their expertise in generation development to numerous other aspects of our analysis. We would also like to thank the PJM staff and Wood Group for their cooperation and responsiveness to our many questions and requests. Opinions expressed in this report, as well as any errors or omissions, are the authors' alone.

EXECUTIVE SUMMARY

This report documents our study of the gross Cost of New Entry ("CONE") for combustion turbine ("CT") and combined-cycle ("CC") power plants with a target online date of June 1, 2015, consistent with the 2015/16 delivery year in PJM's capacity market. We prepared this study in cooperation with CH2M HILL, a major engineering procurement, and construction company with extensive experience in the design and construction of power plants, and Wood Group, a power plant operation and maintenance ("O&M") service provider.

Gross CONE includes both the capital and ongoing fixed operating costs required to build and operate a new plant. We present these estimates for consideration by PJM Interconnection and stakeholders as they update the administrative CONE parameters for PJM's capacity market, the Reliability Pricing Model ("RPM"). The CT CONE parameter is used to define points of the Variable Resource Requirement (VRR) curve; both CC and CT CONE parameters are used for calculating offer price screens under the Minimum Offer Price Rule ("MOPR") for new generation offering capacity into RPM. We provide separate CT and CC CONE estimates for each of the five administrative CONE Areas in PJM.

Table 1 shows our recommended CONE for gas CT plants in each CONE Area based on levelized plant capital costs and annual fixed operation and maintenance ("FOM") costs for the 2015/16 delivery year. The table shows the major components of the CONE calculation including overnight costs, plant net summer installed capacity ("ICAP"), annual ongoing fixed O&M costs, and the after-tax weighted-average cost of capital ("ATWACC"). Our CONE estimates are presented on a "level nominal" basis (*i.e.*, equal payments over the plant's economic life) as well as on a "level real" basis (*i.e.*, payments that start lower but increase with inflation over time). As we explain in our concurrent report, Second Performance Assessment of PJM's Reliability Pricing Model, August 26, 2011 ("2011 RPM Report"), we recommend transitioning toward using a level-real CONE for MOPR purposes; for defining the VRR curve, we also recommend transitioning to level-real contingent on the implementation of several other recommendations.

Our estimates differ by CONE area due to differences in plant configuration assumptions, differences in labor rates, and other locational differences in capital and fixed costs. In each CONE area, except for the Rest of RTO area, all plants are configured with dual fuel. In addition, the CT plants are fitted with Selective Catalytic Reduction ("SCR") in each location except in Dominion, where the current Ozone attainment status does not yet require an SCR. We also provide costs for plants with dual-fuel capability and SCRs in each Area in case future developments necessitate such investments.

The Eastern Mid-Atlantic Area Council ("Eastern MAAC" or "EMAAC") and Western MAAC regions have the highest CONE estimates at \$112/kW-year (\$307/MW-day) and \$109/kW-year (\$298/MW-day) respectively on a level real basis. The Southwest MAAC and Rest of RTO areas are somewhat lower, both at \$103/kW-year (\$283/MW-day), primarily because of the non-union labor availability in Southwest MAAC and the lack of dual-fuel capability in the Rest of RTO region. The lowest CONE estimate is in Dominion at \$93/kW-year (\$254/MW-day), due to lower non-union labor rates and avoiding an SCR. Avoiding an SCR in Dominion reduces overnight capital costs by approximately $24 million, while avoiding dual-fuel capability in the Rest of RTO area reduces capital costs by approximately $19 million. These corresponding level-nominal costs are shown in Table 1.

Table 1 also shows the CONE estimates Power Project Management ("PPM") provided to PJM in 2008. PJM stakeholders agreed to use those estimates for setting points on the VRR curve by discounting them by 10 percent and then escalating them with the Handy-Whitman Index. To facilitate a more direct comparison of the PPM study to ours, we present the PPM results without discount, and inflation adjusted to 2015 dollars. As such, our level-nominal estimates are $19 to 23/kW-year ($53 to 62/MW-day) lower than the PPM estimates in the three CONE Areas reported. Our estimates are lower primarily due to reductions in equipment, materials, and labor costs since 2008 relative to inflation, as well as economies of scale associated with the larger size of the GE 7FA.05 turbine compared to the previously examined GE7FA.03 turbine model.

Finally, Table 1 also shows the CONE PJM has applied in its recent auction for the 2014/15 delivery year, escalated for one year of inflation to represent 2015/16 dollar values.

Table 1
Recommended Gas CT CONE for 2015/16

CONE Area	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M	After-Tax WACC	Levelized Gross CONE		PJM 2014/15 CT CONE
						Level Real	Level Nominal	
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$308.3	390	$791.2	$15.7	8.47%	$112.0	$134.0	$142.1
2 Southwest MAAC	$281.5	390	$722.6	$15.8	8.49%	$103.4	$123.7	$131.4
3 Rest of RTO	$287.3	390	$737.3	$15.2	8.46%	$103.1	$123.5	$135.0
4 Western MAAC	$299.3	390	$768.2	$15.1	8.44%	$108.6	$130.1	$131.4
5 Dominion	$254.7	392	$649.8	$14.7	8.54%	$92.8	$111.0	$131.5
Power Project Management, LLC 2008 Update								
June 1, 2008 Online Date (Escalated at CPI from 2008$ to 2015$)								
1 Eastern MAAC	$350.3	336	$1,042.2	$17.2	8.07%	n/a	$154.4	n/a
2 Southwest MAAC	$322.1	336	$958.4	$17.5	8.09%	n/a	$142.8	n/a
3 Rest of RTO	$332.5	336	$989.4	$15.3	8.11%	n/a	$146.1	n/a

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Dominion estimate excludes an SCR; with SCR CONE increases to $100.8/kW-year level real and $120.6/kW-year level nominal.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $110.7/kW-year level real and $132.5/kW-year level nominal.

PPM's estimates shown here were discounted by 10% in settlement and escalated at the Handy-Whitman Index for setting the administrative gross CONE parameters over the 2012/13 through 2014/15 delivery years PJM Interconnection, L.L.C. (2011d), p. 10; Power Project Management (2008).

PPM's numbers are escalated according to historical inflation over 2008-2011 and at 2.5% inflation rate over 2011-2015, see Federal Reserve Bank of St. Louis (2011) and Section VI.A.

Table 2 shows our recommended 2015/16 CONE for gas CC plants. These estimates are compared to the most recent estimates developed by Pasteris Energy for PJM in 2011. In each location, the gas CC plant is configured with an SCR. The plants have dual–fuel capability in all CONE Areas except in the Rest of RTO Area. Avoiding dual-fuel capability in the Rest of RTO Area reduces capital costs by approximately $18 million.

Eastern MAAC has the highest CC CONE at $141/kW-year ($385/MW-day) on a level real basis, while Rest of RTO and Western MAAC are a bit lower, both at $135/kW-year ($370/MW-day). Southwest MAAC and Dominion have the lowest CONE estimates at $123/kW-year ($338/MW-day) and $120/kW-year ($329/MW-day) respectively, primarily due to non-union labor rates in those locations. Our estimates are $6 to 12/kW-year ($17 to 32/MW-day) below the Pasteris Energy CONE estimates on a level-nominal basis primarily due to a higher ICAP rating. Our higher plant ICAP rating reflects the larger size of the GE 7FA.05 turbine relative to the GE7FA.04 turbine model examined by Pasteris, as well as the greater duct firing capability in the plant we examine. Table 2 also shows the CC CONE value PJM has utilized for the 2014/15 delivery year, inflation adjusted to 2015/16 dollar values.

Table 2
Recommended Gas CC CONE for 2015/16

CONE Area	Total Plant Capital Cost	Net Summer ICAP	Overnight Cost	Fixed O&M	After-Tax WACC	Levelized Gross CONE		PJM 2014/15 CC CONE
						Level Real	Level Nominal	
	($M)	*(MW)*	*($/kW)*	*($/kW-y)*	*(%)*	*($/kW-y)*	*($/kW-y)*	*($/kW-y)*
Brattle 2011 Estimate								*Escalated at CPI*
June 1, 2015 Online Date (2015$)								*for 1 Year*
1 Eastern MAAC	$621.4	656	$947.8	$16.7	8.47%	$140.5	$168.2	$179.6
2 Southwest MAAC	$537.4	656	$819.6	$16.6	8.49%	$123.3	$147.6	$158.7
3 Rest of RTO	$599.0	656	$913.7	$16.0	8.46%	$135.5	$162.2	$168.5
4 Western MAAC	$597.4	656	$911.2	$15.8	8.44%	$135.2	$161.8	$158.7
5 Dominion	$532.9	656	$812.8	$15.4	8.54%	$120.2	$143.8	$158.7
Pasteris 2011 Update								
June 1, 2014 Online Date (Escalated at CPI from 2014$ to 2015$)								
1 Eastern MAAC	$710.9	601	$1,183.1	$18.5	8.07%	n/a	$179.6	n/a
2 Southwest MAAC	$618.7	601	$1,029.5	$18.8	8.09%	n/a	$158.7	n/a
3 Rest of RTO	$678.0	601	$1,128.3	$16.9	8.11%	n/a	$168.5	n/a

Sources and Notes:

Overnight costs are the sum of nominal dollars expended over time and exclude interest during construction.

Rest of RTO CONE is for single fuel; dual-fuel CONE would be $138.9/kW-year level real and $136.3/kW-year level nominal.

Pasteris Energy's 2011 CONE estimates were used as the basis for the CC CONE estimate for the 2014/15 delivery year, see Pasteris Energy (2011), pg. 55.

Pasteris Energy's numbers are escalated at 2.5% inflation rate, see and Section VI.A.

SURREBUTTAL EXHIBIT JIF-7

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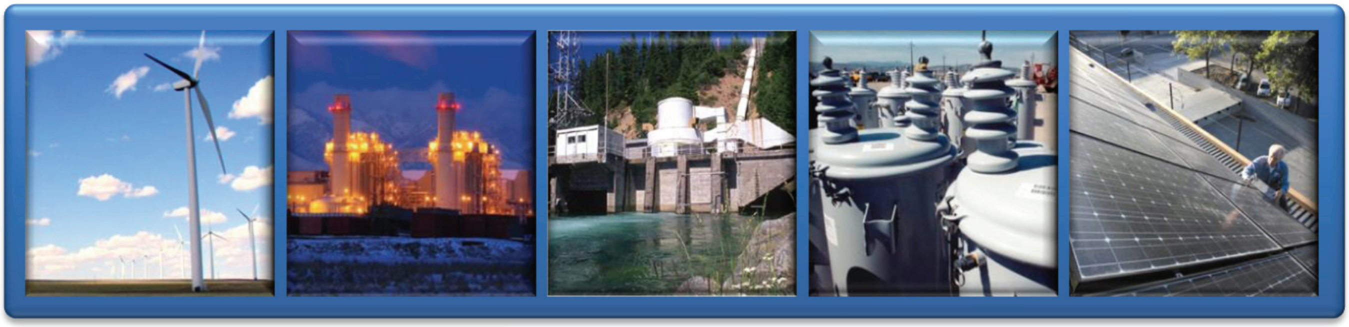
Volume I



Let's turn the answers on.

March 31, 2011

This 2011 Integrated Resource Plan (IRP) Report is based upon the best available information at the time of preparation. The IRP action plan will be implemented as described herein, but is subject to change as new information becomes available or as circumstances change. It is PacifiCorp's intention to revisit and refresh the IRP action plan no less frequently than annually. Any refreshed IRP action plan will be submitted to the State Commissions for their information.

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Cover Photos (Left to Right):
Wind: *McFadden Ridge I*
Thermal-Gas: *Lake Side Power Plant*
Hydroelectric: *Lemolo 1 on North Umpqua River*
Transmission: *Distribution Transformers*
Solar: *Salt Palace Convention Center Photovoltaic Solar Project*
Wind Turbine: *Dunlap I Wind Project*

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CHAPTER 6 – RESOURCE OPTIONS

Chapter Highlights

- *PacifiCorp developed resource attributes and costs for expansion resources that reflect updated information from project experience, public meeting comments, and studies. Capital cost uncertainty for many of the proposed generation options is high and is due to such factors as labor cost, commodity price, and resource demand volatility. Long-term resource pricing remains a challenge to predict.*
- *Resource costs have generally decreased from the previous IRP due to the economic slow-down in 2009 and 2010.*
- *Wind resources have been modeled using an approach that more closely aligns with Western Renewable Energy Zones and facilitates assignment of incremental transmission costs for the Energy Gateway transmission scenario analysis.*
- *Solar generation options (utility-scale photovoltaic systems and solar thermal with and without thermal storage) have been included in this IRP.*
- *In 2010, the Company commissioned a geothermal resource study performed by Black & Veatch and GeothermEx that identified eight sites meeting specific criteria for commercial viability. PacifiCorp used this resource data to develop geothermal resource capacity expansion options. Geothermal resource costs include development costs reflecting dry well risk, amounting to 35 percent of total project costs.*
- *Energy storage systems continue to be of interest with options included for advanced large batteries (one megawatt) as well as pumped hydro and compressed air energy storage.*
- *A 2010 resource potential study, conducted by The Cadmus Group, served as the basis for updated resource characterizations covering demand-side management (DSM) and distributed generation. The demand-side resource information was converted into supply curves by program/product type and competed against other resource alternatives in IRP modeling.*
- *PacifiCorp applied cost reduction credits for energy efficiency, reflecting risk mitigation benefits, transmission & distribution investment deferral benefits, and a 10% market price credit for Washington as required by the Northwest Power Act.*

Introduction

This chapter provides background information on the various resources considered in the IRP for meeting future capacity and energy needs. Organized by major category, these resources consist of supply-side generation (utility-scaled and distributed resources), DSM programs, transmission expansion projects, and market purchases. For each resource category, the chapter discusses the criteria for resource selection, presents the options and associated attributes, and describes the technologies. In addition, for supply-side resources, the chapter describes how PacifiCorp addressed long-term cost trends and uncertainty in deriving cost figures.

Supply-side Resources

Resource Selection Criteria

The list of supply-side resource options has been modified in relation to previous IRP resource lists to reflect the realities evidenced through permitting, public meeting comments, and studies undertaken to better understand the details of available generation resources. Capital costs, in general have decreased due to the slow-down of the economy in 2009 and 2010. Based on information, from outside sources, including proprietary data from Cambridge Energy Research Associates (CERA) and Gas Turbine World, as well as internal studies, the prices of single and combined-cycle gas turbine plants have declined in recent years but, are recovering slowly. Alternative energy resources continue to receive a greater emphasis. Specifically additional solar generation options and geothermal options have been included in the analysis compared to the previous IRP. Additional solar resources include utility-size photovoltaic systems (PV) as well as solar thermal with and without thermal storage. Energy storage systems continue to be of interest with options included for advanced large batteries (1 MW) as well as traditional pumped hydro and compressed air energy storage.

Derivation of Resource Attributes

The supply-side resource options were developed from a combination of resources. The process began with the list of major generating resources from the 2007 IRP. This resource list was reviewed and modified to reflect public input and permitting realities. Once the basic list of resources was determined, the cost and performance attributes for each resource were estimated. A number of information sources were used to identify parameters needed to model these resources. Supporting utility-scale resources were a number of engineering studies conducted by PacifiCorp to understand the cost of coal and gas resources in recent years. Additionally, experience with the construction of the 2x1 combined cycle plants at Currant Creek and Lake Side as well as other recent simple-cycle projects at Gadsby provided PacifiCorp with a detailed understanding of the cost of new power generating facilities. Preparation of benchmark submittals for PacifiCorp’s recent generation RFPs were also used to update actual project experience, while government studies were relied upon for characterizing future carbon capture costs.

Extensive new studies on the cost of the coal-fired options were not prepared in keeping with the reduced emphasis on these resources for new near-term generation.

The results of these estimating efforts were compared with other cost databases, such as the one supporting the Integrated Planning Model (IPM®) market model developed by ICF International, which the Company now uses for national emissions policy impact analysis among other uses. The IPM® cost estimates were used when cost agreement was close.

The Company made use of The WorleyParsons Group's renewable generation study completed in 2008 for solar, biomass and geothermal resources. As described below, a geothermal resource study was conducted for the Company by Black & Veatch/GeothermEx in 2010 to supplement geothermal information for the third expansion at Blundell and other potential resources.

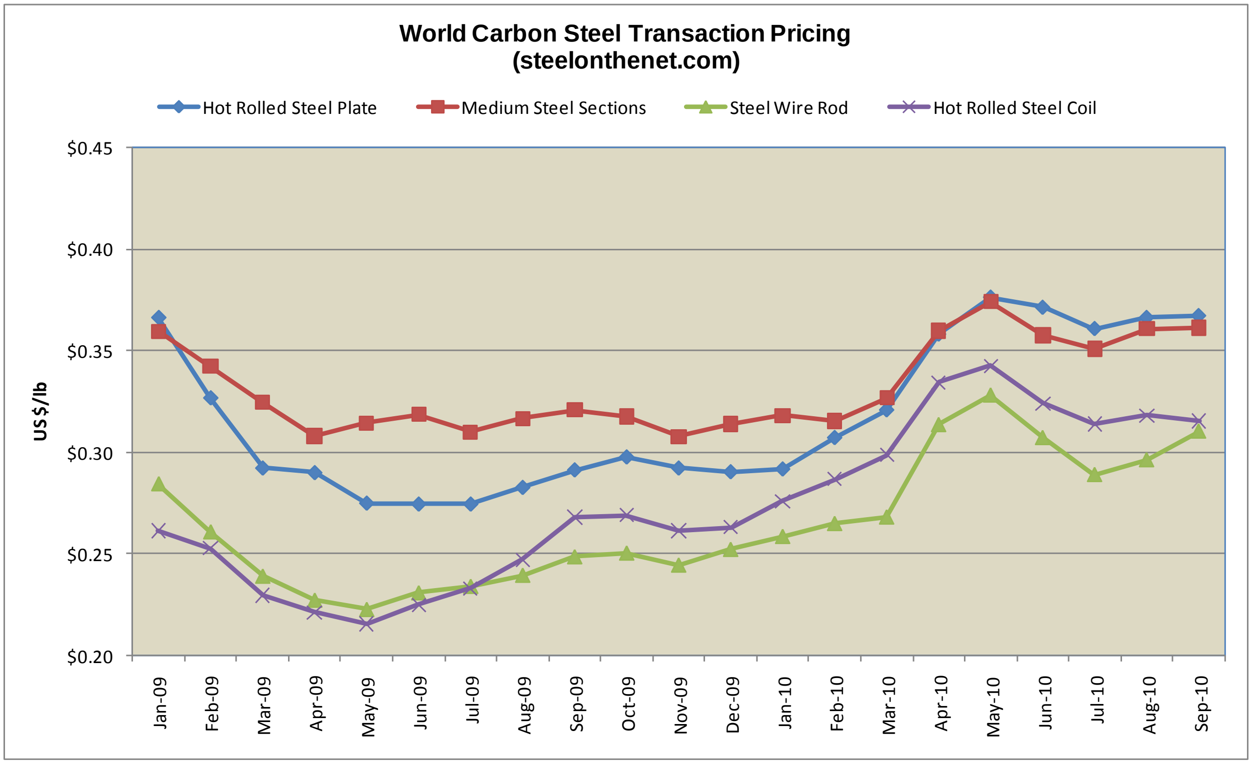
Wind costs are based on actual project experience in both the Pacific Northwest and Wyoming, as well as current projections. Nuclear costs are reflective of recent cost estimates associated with preliminary development activities as well as published estimates of new projects. Hydrokinetic, or wave power, has been added based on proposed projects in the Pacific Northwest. Other generation options, such as energy storage and fuel cells, were adopted from PacifiCorp's previous IRP. In some cases costs from the previous IRP were updated using cost increases for other studied resources.

Resource options also include a variety of small-scale generation resources, consisting of combined heat and power (CHP) and onsite solar supply-side resource options. Together these small resources are referred to as distributed generation. The Cadmus Group, Inc. (previously named Quantec LLC) provided the distributed generation costs and attributes as part of the DSM potential study update conducted for PacifiCorp in 2010. The DSM potential report identified the economic potential for distributed generation resources by state.

Handling of Technology Improvement Trends and Cost Uncertainties

The capital cost uncertainty for many of the proposed generation options is high. Various factors contribute to this uncertainty. Previously experienced shortages of skilled labor are not a problem in the current business climate but volatile commodity prices are still a large part of the uncertainty in being able to predict project costs for lump-sum contracting. For example, Figure 6.1 shows the trend in North American carbon steel sheet prices. The volatility trend is expected to continue, although prices have trended upward in the last year.

Figure 6.1 – World Carbon Steel Price Trends



Some technologies that have seen a decrease in demand, such as wind turbines and coal, have seen significant cost decreases since the 2008 IRP. As such, subsequent to completion of its 2008 IRP portfolio analysis in late 2008 and early 2009, the Company has witnessed price declines for wind turbines and certain other power plant equipment. Other technologies still in demand, such as gas turbines, have seen more stable prices. Thus, long-term resource pricing remains challenging to forecast.

Technologies, such as the integrated gasification combined cycle (IGCC) and certain renewables, like solar, have greater price and operational uncertainty because only a few units have been built and operated. As these technologies mature and more plants are built and operated the costs of such new technologies may decrease relative to more mature options such as pulverized coal and conventional natural gas-fired plants.

The supply-side resource options tables below do not consider the potential for such savings since the benefits are not expected to be realized until the next generation of new plants are built and operated for a period of time. Any such benefits for IGCC facilities are not expected to be available until after 2025 with commercial operation in 2030. As such, future IRPs will be better able to incorporate the potential benefits of future cost reductions. Given the current emphasis on renewable generation, the Company anticipates the cost benefits for these technologies to be available sooner. The estimated capital costs are displayed in the supply-side resource tables along with expected availability of each technology for commercial utilization.

Resource Options and Attributes

Tables 6.2 and 6.3 present cost and performance attributes for supply-side resource options designated for PacifiCorp's east and west control areas, respectively. Tables 6.4 through 6.7 present the total resource cost attributes for supply-side resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2010 dollars. The resource costs are presented for the modeled CO_2 tax levels in recognition of the uncertainty in characterizing these emission costs.

As mentioned previously, the attributes were mainly derived from PacifiCorp's recent cost studies and project experience. Cost and performance values reflect analysis concluded by June 2010. Additional explanatory notes for the tables are as follows:

- Capital costs are intended to be all-inclusive, and account for Allowance for Funds Used During Construction (AFUDC), land, EPC (Engineering, Procurement, and Construction) cost premiums, owner's costs, etc. Capital costs in Tables 6.3 and 6.4 reflect mid-2010 dollars, and do not include escalation from mid year to the year of commercial operation.
- Wind sites are modeled with location-specific peak load carrying capability levels and capacity factors.
- Certain resource names are listed as acronyms. These include:
  - *PC* – pulverized coal
  - *IGCC* – integrated gasification combined cycle
  - *SCCT* – simple cycle combustion turbine
  - *CCCT* – combined cycle combustion turbine
  - *CHP* – combined heat and power (cogeneration)
  - *CCS* – carbon capture and sequestration
- PacifiCorp's September 2010 forward price curves were used to calculate the levelized fuel costs reported in Tables 6.4 through 6.7.
- Utility-scale solar resources include federal production tax credits. Hybrid solar with natural gas backup is also treated this way.
- PacifiCorp assumes that wind, hydrokinetic, biomass, and geothermal resources are qualified for Production Tax Credits (PTC), depending on the installation date. The cost of these credits is included in the supply-side table.
- Gas backup for solar with a heat rate of 11,750 Btu/kWh is less efficient than for a standalone SCCT.
- Capital costs include transmission interconnection costs (switchyard and other upgrades needed to interconnect the resource to PacifiCorp's transmission network).
- For the nuclear resource, capital costs include the cost of storing spent fuel on-site during the life of the facility. Costs for ultimate off-site disposal of spent fuel is not included since there are no details regarding where, when or how that will be done. While the reported capital cost does not reflect the cost of transmission, PacifiCorp adjusted the modeled capital cost to include transmission assuming a plant location near Payette, Idaho. The transmission cost adder is $842/kW, and factors in transmission lines and termination points for connections to the Hemingway and Limber substations.

- The capacity degradation of retrofitting an existing 500 MW pulverized coal unit with a carbon capture and sequestration (CCS) system represents the net change to capacity. The heat rate is the total net heat rate after retrofitting an existing 10,000 Btu/kWh unit with a CCS system.
- The wind resources are representative generic resources included in the IRP models for planning purposes. Cost and performance attributes of specific resources are identified as part of the acquisition process. An estimate for wind integration costs, $9.70/MWh, has been added in Tables 6.3 through 6.6.
- State specific tax benefits are excluded from the IRP supply side table but would be considered in the evaluation of a specific project.

Table 6.1 – East Side Supply-Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2010 Dollars ($)	Location / Timing		Plant Details			Outage Information		Costs			Emissions			
Resource Description	Installation Location	Earliest In-Service Date (Middle of year)	Average Capacity MW - Not Incl. Degradation	Design Plant Life in Years	Annual Average Heat Rate HHV - Incl. Degradation	Maint. Outage Rate	Equivalent Forced Outage Rate	Base Capital Cost in $/kW	Var. O&M, $/MWh	Fixed O&M in $/kW-yr	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu
East Side Resource Options														
Coal														
Utah PC without Carbon Capture & Sequestration	Utah	2020	600	40	9,106	4.6%	4.0%	$3,077	$0.96	$38.80	0.100	0.070	0.40	205
Utah PC with Carbon Capture & Sequestration	Utah	2030	526	40	13,087	5.0%	5.0%	$5,563	$6.71	$66.07	0.050	0.020	0.20	20
Utah IGCC with Carbon Capture & Sequestration	Utah	2030	466	40	10,823	7.0%	8.0%	$5,386	$11.28	$53.24	0.050	0.011	0.04	20
Wyoming PC without Carbon Capture & Sequestration	Wyoming	2020	790	40	9,214	4.6%	4.0%	$3,484	$1.27	$36.00	0.100	0.070	0.60	205
Wyoming PC with Carbon Capture & Sequestration	Wyoming	2030	692	40	13,242	5.0%	5.0%	$6,299	$7.26	$61.37	0.050	0.020	0.30	20
Wyoming IGCC with Carbon Capture & Sequestration	Wyoming	2030	456	40	11,047	7.0%	8.0%	$6,099	$13.52	$58.00	0.050	0.011	0.06	20
Existing PC with Carbon Capture & Sequestration (500 MW)	Utah/Wyo	2030	(139)	20	14,372	5.0%	5.0%	$1,383	$6.71	$66.07	0.050	0.011	0.30	20
Natural Gas (4500 feet)														
Utility Cogeneration	Utah	2014	10	20	4,974	10.0%	8.0%	$4,250	$23.29	$1.86	0.0006	0.050	0.255	118
Fuel Cell - Large (solid oxide fuel cell)	Utah	2013	5	30	7,262	2.0%	3.0%	$1,593	$0.03	$8.40	0.0006	0.050	0.255	118
SCCT Aero	Utah	2014	118	30	9,773	3.8%	2.6%	$1,000	$5.63	$9.95	0.0006	0.011	0.255	118
Intercooled Aero SCCT (Utah, 186 MW)	Utah	2014	279	30	9,379	3.8%	2.9%	$1,174	$3.93	$7.01	0.0006	0.011	0.255	118
Intercooled Aero SCCT (Utah, 279 MW)	Utah	2014	279	30	9,379	3.8%	2.9%	$1,174	$3.93	$7.01	0.0006	0.011	0.255	118
Intercooled Aero SCCT (Wyoming, 257 MW)	Wyoming	2014	257	30	9,379	3.8%	2.9%	$1,273	$4.26	$7.60	0.0006	0.011	0.255	118
Internal Combustion Engines	Utah	2014	301	30	8,806	5.0%	1.0%	$1,150	$5.50	$6.49	0.0006	0.017	0.255	118
SCCT Frame (2 Frame "F")	Utah	2014	362	35	10,446	3.8%	2.7%	$991	$7.16	$5.41	0.0006	0.050	0.255	118
SCCT Frame (2 Frame "F")	Wyoming	2014	330	35	10446	3.8%	2.7%	$1,074	$7.76	$5.87	0.0006	0.050	0.255	118
CCCT (Wet "F" 1x1)	Utah	2014	270	40	7,302	3.8%	2.7%	$1,181	$2.98	$13.48	0.0006	0.011	0.255	118
CCCT Duct Firing (Wet "F" 1x1)	Utah	2014	43	40	8,869	3.8%	2.7%	$482	$0.55	$0.00	0.0006	0.011	0.255	118
CCCT (Wet "F" 2x1)	Utah	2014	539	40	6,885	3.8%	2.7%	$1,067	$2.98	$8.19	0.0006	0.011	0.255	118
CCCT Duct Firing (Wet "F" 2x1)	Utah	2014	86	40	8,681	3.8%	2.7%	$538	$0.55	$0.00	0.0006	0.011	0.255	118
CCCT (Dry "F" 2x1)	Utah	2015	512	40	6,963	3.8%	2.7%	$1,104	$3.35	$9.69	0.0006	0.011	0.255	118
CCCT Duct Firing (Dry "F" 2x1)	Utah	2015	85	40	8,934	3.8%	2.7%	$538	$0.55	$0.00	0.0006	0.011	0.255	118
CCCT (Wet "G" 1x1)	Utah	2015	333	40	6,751	3.8%	2.7%	$1,117	$4.56	$6.75	0.0006	0.011	0.255	118
CCCT Duct Firing (Wet "G" 1x1)	Utah	2015	72	40	9,021	3.8%	2.7%	$473	$0.36	$0.00	0.0006	0.011	0.255	118
CCCT Advanced (Wet "H" 1x1)	Utah	2018	400	40	6,602	3.8%	2.7%	$1,233	$4.56	$6.75	0.0006	0.011	0.255	118
CCCT Advanced Duct Firing (Wet "H" 1x1)	Utah	2018	75	40	9,021	3.8%	2.7%	$605	$0.36	$0.00	0.0006	0.011	0.255	118
Other - Renewables														
Wyoming Wind (35% CF)	Wyoming	2012	100	25	n/a	n/a	n/a	$2,239	$0.00	$31.43	0.000	0.000	0.000	0
Utah Wind (29% CF)	Utah	2012	100	25	n/a	n/a	n/a	$2,239	$0.00	$31.43	0.000	0.000	0.000	0
Blundell Geothermal (Dual Flash)	Utah	2015	35	40	n/a	5.0%	5.0%	$4,277	$5.94	$110.85	0.000	0.000	0.000	0
Greenfield Geothermal (Binary)	Utah	2017	45	40	n/a	5.0%	5.0%	$6,132	$5.94	$209.40	0.000	0.000	0.000	0
Advance Battery Storage	All	2015	5	30	11,000	1.9%	5.0%	$2,025	$10.00	$1.00	0.100	0.400	3.000	205
Pumped Storage	Nevada	2020	250	50	12,500	5.0%	5.0%	$1,723	$4.30	$4.30	0.100	0.400	3.000	205
Compressed Air Energy Storage (CAES)	Wyoming	2015	350	30	11,980	3.8%	2.7%	$1,307	$5.50	$3.80	0.001	0.011	0.255	118
Nuclear (Advance Fission)	Idaho	2030	1,600	40	10,710	7.3%	7.7%	$5,307	$1.63	$146.70	0.000	0.000	0.000	0
Solar (Thin Film PV) - 19% CF	Utah	2012	5	25	n/a	n/a	n/a	$4,191	$0.00	$59.50	0.000	0.000	0.000	0
Solar Concentrating (Thermal Trough, NG backup) - 25% solar	Utah	2014	250	30	n/a	n/a	n/a	$4,033	$0.00	$120.99	0.000	0.000	0.000	0
Solar Concentrating (Thermal Trough) - 30% solar	Utah	2014	250	30	n/a	n/a	n/a	$4,519	$0.00	$135.56	0.000	0.000	0.000	0

Table 6.2 – West Side Supply-Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2010 Dollars ($)	Location / Timing		Plant Details			Outage Information		Costs			Emissions			
Resource Description	Installation Location	Earliest In-Service Date (Middle of year)	Average Capacity MW - Not Incl. Degradation	Design Plant Life in Years	Annual Average Heat Rate HHV - Incl. Degradation	Maint. Outage Rate	Equivalent Forced Outage Rate	Base Capital Cost in $/kW	Var. O&M, $/MWh	Fixed O&M in $/kW-yr	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu
West Side Resource Options														
Natural Gas (4500 feet)														
CCCT (Wet "F" 2x1)	Northwest	2014	539	40	6,885	3.8%	2.7%	$1,067	$2.98	$8.19	0.0006	0.011	0.255	118
CCCT Duct Firing (Wet "F" 2x1)	Northwest	2014	86	40	8,681	3.8%	2.7%	$538	$0.55	$0.00	0.0006	0.011	0.255	118
CCCT (Wet "G" 1x1)	Northwest	2015	333	40	6,751	3.8%	2.7%	$1,117	$4.56	$6.75	0.0006	0.011	0.255	118
CCCT Duct Firing (Wet "G" 1x1)	Northwest	2015	72	40	9,021	3.8%	2.7%	$473	$0.36	$0.00	0.0006	0.011	0.255	118
CCCT Advanced (Wet "H" 1x1)	Northwest	2018	400	40	6,602	3.8%	2.7%	$1,233	$4.56	$6.75	0.0006	0.011	0.255	118
CCCT Advanced Duct Firing (Wet "H" 1x1)	Northwest	2018	75	40	9,021	3.8%	2.7%	$605	$0.36	$0.00	0.0006	0.011	0.255	118
Natural Gas (1500 feet)														
Fuel Cell - Large (solid oxide fuel cell)	Northwest	2013	5	30	7,262	2.0%	3.0%	$1,593	$0.03	$8.40	0.0006	0.050	0.255	118
SCCT Aero	Northwest	2014	130	30	9,773	3.85%	2.60%	$909	$5.12	$9.04	0.00060	0.01102	0.255	118
Intercooled Aero SCCT	Northwest	2014	307	30	9,379	3.85%	2.90%	$1,067	$3.57	$6.37	0.00060	0.01102	0.255	118
Internal Combustion Engines	Northwest	2014	331	30	8,806	5.00%	1.00%	$1,046	$5.50	$6.49	0.00060	0.01652	0.255	118
SCCT Frame (2 Frame "F")	Northwest	2014	405	35	10,446	3.85%	2.70%	$901	$6.51	$4.92	0.00060	0.04950	0.255	118
Other - Renewables														
Oregon / Washington Wind (29% CF)	Northwest	2012	50	25	n/a	n/a	5.00%	$2,383	$0.00	$31.43	0.00000	0.000	0.0	0
Greenfield Geothermal (Binary)	Northwest	2015	35	40	n/a	5.00%	5.00%	$6,132	$5.94	$209.40	0.00000	0.000	0.0	0
Biomass	Northwest	2015	50	30	10,979	4.60%	4.00%	$3,509	$0.96	$38.80	0.1000	0.3500	0.400	205
Hydrokinetic (Wave, Buoy) - 21% CF	Northwest	2020	100	20	n/a	n/a	n/a	$5,831	$0.00	174.92	0.0000	0.0000	0.000	0
Solar (Thin Film PV) - 19% CF	Northwest	2012	5	25	n/a	n/a	n/a	$4,191	0	$56.91	0	0	0	0
West Side Resource Options at ISO Conditions (Sea Level)														
Natural Gas														
CCCT (Wet "F" 2x1)	Northwest	2014	620	40	6,885	3.85%	2.70%	$928	$2.59	$7.12	0.00060	0.0110	0.255	118
CCCT Duct Firing (Wet "F" 2x1)	Northwest	2014	99	40	8,681	3.85%	2.70%	$468	$0.48	$0.00	0.00060	0.0110	0.255	118

Table 6.3 – Total Resource Cost for East Side Supply-Side Resource Options, \$0 CO_2 Tax

$0 CO2 Tax	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)					
Supply Side Resource Options Mid-Calendar Year 2010 Dollars ($)				Fixed O&M $/kW-Yr						Levelized Fuel							
Resource Description	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Other	Total	Total Fixed ($/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation or Wind Integration	Tax Credits	Environmental	Total Resource Cost with PTC (Mills/kWh)	Total Resource Cost without PTC (Mills/kWh)
East Side Resource Options																	
Coal																	
Utah PC without Carbon Capture & Sequestration	$ 3,077	8.18%	$ 251.66	$ 38.80	$ 6.00	$ 44.80	$ 296.46	91%	37.03	254.41	23.17	$ 0.96	-	-	0.00	61.15	[redacted]
Utah PC with Carbon Capture & Sequestration	$ 5,563	8.02%	$ 445.91	$ 66.07	$ 6.00	$ 72.07	$ 517.98	90%	65.70	254.41	33.29	$ 6.71	-	-	0.00	105.70	[redacted]
Utah IGCC with Carbon Capture & Sequestration	$ 5,386	7.90%	$ 425.60	$ 53.24	$ 6.00	$ 59.24	$ 484.84	85%	65.11	254.41	27.54	$ 11.28	-	-	0.00	103.93	[redacted]
Wyoming PC without Carbon Capture & Sequestration	$ 3,484	8.18%	$ 284.95	$ 36.00	$ 6.00	$ 42.00	$ 326.95	91%	40.84	247.56	22.81	$ 1.27	-	-	0.00	64.92	[redacted]
Wyoming PC with Carbon Capture & Sequestration	$ 6,299	8.02%	$ 504.90	$ 61.37	$ 6.00	$ 67.37	$ 572.27	90%	72.59	247.56	32.78	$ 7.26	-	-	0.00	112.63	[redacted]
Wyoming IGCC with Carbon Capture & Sequestration	$ 6,099	7.90%	$ 481.91	$ 58.00	$ 6.00	$ 64.00	$ 545.91	85%	73.32	247.56	27.35	$ 13.52	-	-	0.00	114.18	[redacted]
Existing PC with Carbon Capture & Sequestration (500 MW)	$ 1,383	10.50%	$ 145.16	$ 66.07	$ 6.00	$ 72.07	$ 217.23	90%	27.55	247.56	35.58	$ 6.71	-	-	0.00	69.84	[redacted]
Natural Gas (4500 feet)																	
Utility Cogeneration	$ 4,250	9.91%	$421.23	$ 1.86	$ 0.50	$ 2.36	$ 423.59	82%	58.97	539.00	26.81	$ 23.29	$ 3.33	-	0.00	112.40	[redacted]
Fuel Cell - Large (solid oxide fuel cell)	$ 1,593	8.55%	$136.15	$ 8.40	$ 0.50	$ 8.90	$ 145.05	95%	17.43	539.00	39.14	$ 0.03	$ 4.87	-	0.00	61.47	[redacted]
SCCT Aero	$ 1,000	8.88%	$88.77	$ 9.95	$ 0.50	$ 10.45	$ 99.22	21%	53.94	539.00	52.68	$ 5.63	$ 6.55	-	0.00	118.79	[redacted]
Intercooled Aero SCCT (Utah, 186 MW)	$ 1,174	8.88%	$104.25	$ 7.01	$ 0.50	$ 7.51	$ 111.76	21%	60.75	539.00	50.55	$ 3.93	$ 6.28	-	0.00	121.52	[redacted]
Intercooled Aero SCCT (Utah, 279 MW)	$ 1,174	8.88%	$104.25	$ 7.01	$ 0.50	$ 7.51	$ 111.76	21%	60.75	539.00	50.55	$ 3.93	$ 6.28	-	0.00	121.52	[redacted]
Intercooled Aero SCCT (Wyoming, 257 MW)	$ 1,273	8.88%	$113.04	$ 7.60	$ 0.50	$ 8.10	$ 121.14	21%	65.85	539.00	50.55	$ 4.26	$ 5.46	-	0.00	126.12	[redacted]
Internal Combustion Engines	$ 1,150	8.88%	$102.11	$ 6.49	$ 0.50	$ 6.99	$ 109.10	21%	59.30	539.00	47.46	$ 5.50	$ 5.90	-	0.00	118.17	[redacted]
SCCT Frame (2 Frame "F")	$ 991	8.41%	$83.36	$ 5.41	$ 0.50	$ 5.91	$ 89.27	21%	48.53	539.00	56.30	$ 7.16	$ 7.00	-	0.00	118.99	[redacted]
SCCT Frame (2 Frame "F")	$ 1,074	8.41%	$90.39	$ 5.87	$ 0.50	$ 6.37	$ 96.76	21%	52.60	539.00	56.30	$ 7.76	$ 6.08	-	0.00	122.75	[redacted]
CCCT (Wet "F" 1x1)	$ 1,181	8.37%	$98.92	$ 13.48	$ 0.50	$ 13.98	$ 112.90	56%	23.01	539.00	39.36	$ 2.98	$ 4.89	-	0.00	70.25	[redacted]
CCCT Duct Firing (Wet "F" 1x1)	$ 482	8.37%	$40.37	-	$ 0.50	$ 0.50	$ 40.87	16%	29.16	539.00	47.80	$ 0.55	$ 5.94	-	0.00	83.46	[redacted]
CCCT (Wet "F" 2x1)	$ 1,067	8.37%	$89.34	$ 8.19	$ 0.50	$ 8.69	$ 98.04	56%	19.98	539.00	37.11	$ 2.98	$ 4.61	-	0.00	64.69	[redacted]
CCCT Duct Firing (Wet "F" 2x1)	$ 538	8.37%	$45.08	-	$ 0.50	$ 0.50	$ 45.58	16%	32.52	539.00	46.79	$ 0.55	$ 5.82	-	0.00	85.68	[redacted]
CCCT (Dry "F" 2x1)	$ 1,104	8.37%	$92.48	$ 9.69	$ 0.50	$ 10.19	$ 102.67	56%	20.93	539.00	37.53	$ 3.35	$ 4.67	-	0.00	66.48	[redacted]
CCCT Duct Firing (Dry "F" 2x1)	$ 538	8.37%	$45.08	-	$ 0.50	$ 0.50	$ 45.58	16%	32.52	539.00	48.15	$ 0.55	$ 5.99	-	0.00	87.21	[redacted]
CCCT (Wet "G" 1x1)	$ 1,117	8.37%	$93.53	$ 6.75	$ 0.50	$ 7.25	$ 100.78	56%	20.54	539.00	36.39	$ 4.56	$ 4.52	-	0.00	66.01	[redacted]
CCCT Duct Firing (Wet "G" 1x1)	$ 473	8.37%	$39.60	-	$ 0.50	$ 0.50	$ 40.10	16%	28.61	539.00	48.62	$ 0.36	$ 6.04	-	0.00	83.63	[redacted]
CCCT Advanced (Wet "H" 1x1)	$ 1,233	8.37%	$103.28	$ 6.75	$ 0.50	$ 7.25	$ 110.53	56%	22.53	539.00	35.58	$ 4.56	$ 4.42	-	0.00	67.09	[redacted]
CCCT Advanced Duct Firing (Wet "H" 1x1)	$ 605	8.37%	$50.68	-	$ 0.50	$ 0.50	$ 51.18	16%	36.51	539.00	48.62	$ 0.36	$ 6.04	-	0.00	91.54	[redacted]
Other - Renewables																	
Wyoming Wind (35% CF)	$ 2,239	8.55%	$191.33	$ 31.43	$ 0.50	$ 31.93	$ 223.26	35%	72.82	-	-	-	$ 9.70	(20.69)	-	61.82	82.52
Utah Wind (29% CF)	$ 2,239	8.55%	$191.33	$ 31.43	$ 0.50	$ 31.93	$ 223.26	29%	87.88	-	-	-	$ 9.70	(20.69)	-	76.89	97.58
Blundell Geothermal (Dual Flash)	$ 4,277	7.24%	$309.68	$ 110.85	$ 0.50	$ 111.35	$ 421.03	90%	53.40	-	-	$ 5.94		(20.69)	-	38.65	59.34
Greenfield Geothermal (Binary)	$ 6,132	7.24%	$444.03	$ 209.40	$ 0.50	$ 209.90	$ 653.93	90%	82.94	-	-	$ 5.94		(20.69)	-	68.19	88.88
Advance Battery Storage	$ 2,025	8.11%	$164.34	$ 1.00	$ 0.50	$ 1.50	$ 165.84	21%	90.15	539.00	59.29	$ 10.00	$ 7.37	-	0.00	166.81	[redacted]
Pumped Storage	$ 1,723	7.97%	$137.25	$ 4.30	$ 1.35	$ 5.65	$ 142.90	20%	81.56	539.00	67.38	$ 4.30	$ 8.41	-	0.00	161.65	[redacted]
Compressed Air Energy Storage (CAES)	$ 1,307	8.11%	$106.02	$ 3.80	$ 1.35	$ 5.15	$ 111.17	47%	27.18	539.00	64.57	$ 5.50	$ 6.97	-	0.00	104.22	[redacted]
Nuclear (Advance Fission)	$ 5,307	8.09%	$429.48	$ 146.70	$ 6.00	$ 152.70	$ 582.18	85%	78.19	81.14	8.69	$ 1.63	-	-	-	88.50	88.50
Solar (Thin Film PV) - 19% CF	$ 4,191	8.55%	$358.24	$ 59.50	$ 6.00	$ 65.50	$ 423.74	19%	254.59	-	-	-	-	(20.69)	-	233.90	254.59
Solar Concentrating (Thermal Trough, NG backup) - 25% solar	$ 4,033	9.53%	$384.21	$ 120.99	$ 6.00	$ 126.99	$ 511.20	33%	176.84	539.00	14.62	-	$ 1.82	(20.69)	-	172.58	193.27
Solar Concentrating (Thermal Trough) - 30% solar	$ 4,519	7.93%	$358.43	$ 135.56	$ 6.00	$ 141.56	$ 499.99	30%	190.26	-	-	-	$ 1.82	(20.69)	-	171.38	192.07

Table 6.4 – Total Resource Cost for West Side Supply-Side Resource Options, $0 CO_2 Tax

$0 CO2 Tax	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)					
Supply Side Resource Options Mid-Calendar Year 2010 Dollars ($)				Fixed O&M $/kW-Yr						Levelized Fuel							
Resource Description	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Other	Total	Total Fixed ($/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation or Wind Integration	Tax Credits	Environmental	Total Resource Cost with PTC (Mills/kWh)	Total Resource Cost without PTC (Mills/kWh)
West Side Resource Options																	
Natural Gas (4500 feet)																	
CCCT (Wet "F" 2x1)	$ 1,067	8.37%	$89.34	$ 8.19	$ 0.50	$ 8.69	$ 98.04	56%	19.98	572.00	39.38	$ 2.98	$ 4.85	-	0.00	67.20	[redacted]
CCCT Duct Firing (Wet "F" 2x1)	$ 538	8.37%	$45.08	-	$ 0.50	$ 0.50	$ 45.58	16%	32.52	572.00	49.65	$ 0.55	$ 6.12	-	0.00	88.84	[redacted]
CCCT (Wet "G" 1x1)	$ 1,117	8.37%	$93.53	$ 6.75	$ 0.50	$ 7.25	$ 100.78	56%	20.54	572.00	38.62	$ 4.56	$ 4.76	-	0.00	68.48	[redacted]
CCCT Duct Firing (Wet "G" 1x1)	$ 473	8.37%	$39.60	-	$ 0.50	$ 0.50	$ 40.10	16%	28.61	572.00	51.60	$ 0.36	$ 6.36	-	0.00	86.93	[redacted]
CCCT Advanced (Wet "H" 1x1)	$ 1,233	8.37%	$103.28	$ 6.75	$ 0.50	$ 7.25	$ 110.53	56%	22.53	572.00	37.76	$ 4.56	$ 4.65	-	0.00	69.50	[redacted]
CCCT Advanced Duct Firing (Wet "H" 1x1)	$ 605	8.37%	$50.68	-	$ 0.50	$ 0.50	$ 51.18	16%	36.51	572.00	51.60	$ 0.36	$ 6.36	-	0.00	94.83	[redacted]
Natural Gas (1500 feet)																	
Fuel Cell - Large (solid oxide fuel cell)	$ 1,593	8.55%	$136.15	$ 8.40	$ 0.50	$ 8.90	$ 145.05	95%	17.43	572.00	41.54	$ 0.03	$ 5.12	-	0.00	64.12	[redacted]
SCCT Aero	$ 909	8.88%	$80.70	$ 9.04	$ 0.50	$ 9.54	$ 90.25	21%	49.06	572.00	55.90	$ 5.12	$ 6.89	-	0.00	116.97	[redacted]
Intercooled Aero SCCT	$ 1,067	8.88%	$94.77	$ 6.37	$ 0.50	$ 6.87	$ 101.64	21%	55.25	572.00	53.65	$ 3.57	$ 6.61	-	0.00	119.08	[redacted]
Internal Combustion Engines	$ 1,046	8.88%	$92.82	$ 6.49	$ 0.50	$ 6.99	$ 99.81	21%	54.26	572.00	50.37	$ 5.50	$ 6.21	-	0.00	116.34	[redacted]
SCCT Frame (2 Frame "F")	$ 901	8.41%	$75.78	$ 4.92	$ 0.50	$ 5.42	$ 81.20	21%	44.14	572.00	59.75	$ 6.51	$ 7.36	-	0.00	117.76	[redacted]
Other - Renewables																	
Oregon / Washington Wind (29% CF)	$ 2,383	8.55%	$203.69	$ 31.43	$ 0.50	$ 31.93	$ 235.62	29%	92.75	-	-	-	$ 9.70	(20.69)	-	81.75	102.45
Greenfield Geothermal (Binary)	$ 6,132	7.24%	$444.03	$ 209.40	$ 0.50	$ 209.90	$ 653.93	90%	82.94	-	-	$ 5.94	-	(20.69)	-	68.19	88.88
Biomass	$ 3,509	7.93%	$278.36	$ 38.80	$ 0.50	$ 39.30	$ 317.66	91%	39.67	483.58	53.09	$ 0.96	-	(20.69)	0.00	73.04	93.73
Hydrokinetic (Wave, Buoy) - 21% CF	$ 5,831	9.53%	$555.49	$ 174.92	$ 6.00	$ 180.92	$ 736.41	21%	400.31	-	-	-	-	(20.69)	-	379.61	400.31
Solar (Thin Film PV) - 19% CF	$ 4,191	8.55%	$358.24	$ 56.91	$ 6.00	$ 62.91	$ 421.16	19%	253.04	-	-	-	-	(20.69)	-	232.34	253.04
West Side Resource Options																	
Natural Gas																	
CCCT (Wet "F" 2x1)	$ 928	8.37%	$77.69	$ 7.12	$ 0.50	$ 7.62	$ 85.31	56%	17.39	572.00	39.38	$ 2.59	$ 4.85	-	0.00	64.22	[redacted]
CCCT Duct Firing (Wet "F" 2x1)	$ 468	8.37%	$39.20	-	$ 0.50	$ 0.50	$ 39.70	16%	28.32	572.00	49.65	$ 0.48	$ 6.12	-	0.00	84.58	[redacted]

Table 6.5 – Total Resource Cost for East Side Supply-Side Resource Options, \$19 CO_2 Tax

\$19 CO2 Tax	Capital Cost \$/kW			Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)					
Supply Side Resource Options Mid-Calendar Year 2010 Dollars (\$)				Fixed O&M \$/kW-Yr						Levelized Fuel							
Resource Description	Total Capital Cost	Payment Factor	Annual Payment (\$/kW-Yr)	O&M	Other	Total	Total Fixed (\$/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation or Wind Integration	Tax Credits	Environmental	Total Resource Cost with PTC (Mills/kWh)	Total Resource Cost without PTC (Mills/kWh)
East Side Resource Options																	
Coal																	
Utah PC without Carbon Capture & Sequestration	\$ 3,077	8.18%	\$ 251.66	\$ 38.80	\$ 6.00	\$ 44.80	\$ 296.46	91%	37.03	254.41	23.17	\$ 0.96	-	-	13.36	74.51	[redacted]
Utah PC with Carbon Capture & Sequestration	\$ 5,563	8.02%	\$ 445.91	\$ 66.07	\$ 6.00	\$ 72.07	\$ 517.98	90%	65.70	254.41	33.29	\$ 6.71	-	-	1.87	107.57	[redacted]
Utah IGCC with Carbon Capture & Sequestration	\$ 5,386	7.90%	\$ 425.60	\$ 53.24	\$ 6.00	\$ 59.24	\$ 484.84	85%	65.11	254.41	27.54	\$ 11.28	-	-	1.55	105.48	[redacted]
Wyoming PC without Carbon Capture & Sequestration	\$ 3,484	8.18%	\$ 284.95	\$ 36.00	\$ 6.00	\$ 42.00	\$ 326.95	91%	40.84	247.56	22.81	\$ 1.27	-	-	13.52	78.43	[redacted]
Wyoming PC with Carbon Capture & Sequestration	\$ 6,299	8.02%	\$ 504.90	\$ 61.37	\$ 6.00	\$ 67.37	\$ 572.27	90%	72.59	247.56	32.78	\$ 7.26	-	-	1.89	114.52	[redacted]
Wyoming IGCC with Carbon Capture & Sequestration	\$ 6,099	7.90%	\$ 481.91	\$ 58.00	\$ 6.00	\$ 64.00	\$ 545.91	85%	73.32	247.56	27.35	\$ 13.52	-	-	1.58	115.76	[redacted]
Existing PC with Carbon Capture & Sequestration (500 MW)	\$ 1,383	10.50%	\$ 145.16	\$ 66.07	\$ 6.00	\$ 72.07	\$ 217.23	90%	27.55	247.56	35.58	\$ 6.71	-	-	2.05	71.90	[redacted]
Natural Gas (4500 feet)																	
Utility Cogeneration	\$ 4,250	9.91%	\$421.23	\$ 1.86	\$ 0.50	\$ 2.36	\$ 423.59	82%	58.97	539.00	26.81	\$ 23.29	\$ 3.33	-	4.19	116.59	[redacted]
Fuel Cell - Large (solid oxide fuel cell)	\$ 1,593	8.55%	\$136.15	\$ 8.40	\$ 0.50	\$ 8.90	\$ 145.05	95%	17.43	539.00	39.14	\$ 0.03	\$ 4.87	-	6.12	67.59	[redacted]
SCCT Aero	\$ 1,000	8.88%	\$88.77	\$ 9.95	\$ 0.50	\$ 10.45	\$ 99.22	21%	53.94	539.00	52.68	\$ 5.63	\$ 6.55	-	8.24	127.03	[redacted]
Intercooled Aero SCCT (Utah, 186 MW)	\$ 1,174	8.88%	\$104.25	\$ 7.01	\$ 0.50	\$ 7.51	\$ 111.76	21%	60.75	539.00	50.55	\$ 3.93	\$ 6.28	-	7.91	129.42	[redacted]
Intercooled Aero SCCT (Utah, 279 MW)	\$ 1,174	8.88%	\$104.25	\$ 7.01	\$ 0.50	\$ 7.51	\$ 111.76	21%	60.75	539.00	50.55	\$ 3.93	\$ 6.28	-	7.91	129.42	[redacted]
Intercooled Aero SCCT (Wyoming, 257 MW)	\$ 1,273	8.88%	\$113.04	\$ 7.60	\$ 0.50	\$ 8.10	\$ 121.14	21%	65.85	539.00	50.55	\$ 4.26	\$ 5.46	-	7.91	134.03	[redacted]
Internal Combustion Engines	\$ 1,150	8.88%	\$102.11	\$ 6.49	\$ 0.50	\$ 6.99	\$ 109.10	21%	59.30	539.00	47.46	\$ 5.50	\$ 5.90	-	7.42	125.59	[redacted]
SCCT Frame (2 Frame "F")	\$ 991	8.41%	\$83.36	\$ 5.41	\$ 0.50	\$ 5.91	\$ 89.27	21%	48.53	539.00	56.30	\$ 7.16	\$ 7.00	-	8.81	127.80	[redacted]
SCCT Frame (2 Frame "F")	\$ 1,074	8.41%	\$90.39	\$ 5.87	\$ 0.50	\$ 6.37	\$ 96.76	21%	52.60	539.00	56.30	\$ 7.76	\$ 6.08	-	8.81	131.55	[redacted]
CCCT (Wet "F" 1x1)	\$ 1,181	8.37%	\$98.92	\$ 13.48	\$ 0.50	\$ 13.98	\$ 112.90	56%	23.01	539.00	39.36	\$ 2.98	\$ 4.89	-	6.16	76.40	[redacted]
CCCT Duct Firing (Wet "F" 1x1)	\$ 482	8.37%	\$40.37	-	\$ 0.50	\$ 0.50	\$ 40.87	16%	29.16	539.00	47.80	\$ 0.55	\$ 5.94	-	7.48	90.94	[redacted]
CCCT (Wet "F" 2x1)	\$ 1,067	8.37%	\$89.34	\$ 8.19	\$ 0.50	\$ 8.69	\$ 98.04	56%	19.98	539.00	37.11	\$ 2.98	\$ 4.61	-	5.80	70.50	[redacted]
CCCT Duct Firing (Wet "F" 2x1)	\$ 538	8.37%	\$45.08	-	\$ 0.50	\$ 0.50	\$ 45.58	16%	32.52	539.00	46.79	\$ 0.55	\$ 5.82	-	7.32	93.00	[redacted]
CCCT (Dry "F" 2x1)	\$ 1,104	8.37%	\$92.48	\$ 9.69	\$ 0.50	\$ 10.19	\$ 102.67	56%	20.93	539.00	37.53	\$ 3.35	\$ 4.67	-	5.87	72.35	[redacted]
CCCT Duct Firing (Dry "F" 2x1)	\$ 538	8.37%	\$45.08	-	\$ 0.50	\$ 0.50	\$ 45.58	16%	32.52	539.00	48.15	\$ 0.55	\$ 5.99	-	7.53	94.74	[redacted]
CCCT (Wet "G" 1x1)	\$ 1,117	8.37%	\$93.53	\$ 6.75	\$ 0.50	\$ 7.25	\$ 100.78	56%	20.54	539.00	36.39	\$ 4.56	\$ 4.52	-	5.69	71.70	[redacted]
CCCT Duct Firing (Wet "G" 1x1)	\$ 473	8.37%	\$39.60	-	\$ 0.50	\$ 0.50	\$ 40.10	16%	28.61	539.00	48.62	\$ 0.36	\$ 6.04	-	7.61	91.24	[redacted]
CCCT Advanced (Wet "H" 1x1)	\$ 1,233	8.37%	\$103.28	\$ 6.75	\$ 0.50	\$ 7.25	\$ 110.53	56%	22.53	539.00	35.58	\$ 4.56	\$ 4.42	-	5.57	72.66	[redacted]
CCCT Advanced Duct Firing (Wet "H" 1x1)	\$ 605	8.37%	\$50.68	-	\$ 0.50	\$ 0.50	\$ 51.18	16%	36.51	539.00	48.62	\$ 0.36	\$ 6.04	-	7.61	99.15	[redacted]
Other - Renewables																	
Wyoming Wind (35% CF)	\$ 2,239	8.55%	\$191.33	\$ 31.43	\$ 0.50	\$ 31.93	\$ 223.26	35%	72.82	-	-	-	\$ 9.70	(20.69)	-	61.82	82.52
Utah Wind (29% CF)	\$ 2,239	8.55%	\$191.33	\$ 31.43	\$ 0.50	\$ 31.93	\$ 223.26	29%	87.88	-	-	-	\$ 9.70	(20.69)	-	76.89	97.58
Blundell Geothermal (Dual Flash)	\$ 4,277	7.24%	\$309.68	\$ 110.85	\$ 0.50	\$ 111.35	\$ 421.03	90%	53.40	-	-	\$ 5.94		(20.69)	-	38.65	59.34
Greenfield Geothermal (Binary)	\$ 6,132	7.24%	\$444.03	\$ 209.40	\$ 0.50	\$ 209.90	\$ 653.93	90%	82.94	-	-	\$ 5.94		(20.69)	-	68.19	88.88
Advance Battery Storage	\$ 2,025	8.11%	\$164.34	\$ 1.00	\$ 0.50	\$ 1.50	\$ 165.84	21%	90.15	539.00	59.29	\$ 10.00	\$ 7.37	-	16.14	182.95	[redacted]
Pumped Storage	\$ 1,723	7.97%	\$137.25	\$ 4.30	\$ 1.35	\$ 5.65	\$ 142.90	20%	81.56	539.00	67.38	\$ 4.30	\$ 8.41	-	18.34	179.99	[redacted]
Compressed Air Energy Storage (CAES)	\$ 1,307	8.11%	\$106.02	\$ 3.80	\$ 1.35	\$ 5.15	\$ 111.17	47%	27.18	539.00	64.57	\$ 5.50	\$ 6.97	-	10.10	114.32	[redacted]
Nuclear (Advance Fission)	\$ 5,307	8.09%	\$429.48	\$ 146.70	\$ 6.00	\$ 152.70	\$ 582.18	85%	78.19	81.14	8.69	\$ 1.63	-	-	-	88.50	88.50
Solar (Thin Film PV) - 19% CF	\$ 4,191	8.55%	\$358.24	\$ 59.50	\$ 6.00	\$ 65.50	\$ 423.74	19%	254.59	-	-	-	-	(20.69)	-	233.90	254.59
Solar Concentrating (Thermal Trough, NG backup) - 25% solar	\$ 4,033	9.53%	\$384.21	\$ 120.99	\$ 6.00	\$ 126.99	\$ 511.20	33%	176.84	539.00	14.62	-	\$ 1.82	(20.69)	-	172.58	193.27
Solar Concentrating (Thermal Trough) - 30% solar	\$ 4,519	7.93%	\$358.43	\$ 135.56	\$ 6.00	\$ 141.56	\$ 499.99	30%	190.26	-	-	-	\$ 1.82	(20.69)	-	171.38	192.07

Table 6.6 – Total Resource Cost for West Side Supply-Side Resource Options, \$19 CO_2 Tax

$19 CO2 Tax	Capital Cost $/kW			Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)					
Supply Side Resource Options Mid-Calendar Year 2010 Dollars ($)				Fixed O&M $/kW-Yr						Levelized Fuel							
Resource Description	Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Other	Total	Total Fixed ($/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation or Wind Integration	Tax Credits	Environmental	Total Resource Cost with PTC (Mills/kWh)	Total Resource Cost without PTC (Mills/kWh)
West Side Resource Options																	
Natural Gas (4500 feet)																	
CCCT (Wet "F" 2x1)	$ 1,067	8.37%	$89.34	$ 8.19	$ 0.50	$ 8.69	$ 98.04	56%	19.98	572.00	39.38	$ 2.98	$ 4.85	-	5.80	73.01	[redacted]
CCCT Duct Firing (Wet "F" 2x1)	$ 538	8.37%	$45.08	-	$ 0.50	$ 0.50	$ 45.58	16%	32.52	572.00	49.65	$ 0.55	$ 6.12	-	7.32	96.16	[redacted]
CCCT (Wet "G" 1x1)	$ 1,117	8.37%	$93.53	$ 6.75	$ 0.50	$ 7.25	$ 100.78	56%	20.54	572.00	38.62	$ 4.56	$ 4.76	-	5.69	74.17	[redacted]
CCCT Duct Firing (Wet "G" 1x1)	$ 473	8.37%	$39.60	-	$ 0.50	$ 0.50	$ 40.10	16%	28.61	572.00	51.60	$ 0.36	$ 6.36	-	7.61	94.53	[redacted]
CCCT Advanced (Wet "H" 1x1)	$ 1,233	8.37%	$103.28	$ 6.75	$ 0.50	$ 7.25	$ 110.53	56%	22.53	572.00	37.76	$ 4.56	$ 4.65	-	5.57	75.07	[redacted]
CCCT Advanced Duct Firing (Wet "H" 1x1)	$ 605	8.37%	$50.68	-	$ 0.50	$ 0.50	$ 51.18	16%	36.51	572.00	51.60	$ 0.36	$ 6.36	-	7.61	102.44	[redacted]
Natural Gas (1500 feet)																	
Fuel Cell - Large (solid oxide fuel cell)	$ 1,593	8.55%	$136.15	$ 8.40	$ 0.50	$ 8.90	$ 145.05	95%	17.43	572.00	41.54	$ 0.03	$ 5.12	-	6.12	70.24	[redacted]
SCCT Aero	$ 909	8.88%	$80.70	$ 9.04	$ 0.50	$ 9.54	$ 90.25	21%	49.06	572.00	55.90	$ 5.12	$ 6.89	-	8.24	125.21	[redacted]
Intercooled Aero SCCT	$ 1,067	8.88%	$94.77	$ 6.37	$ 0.50	$ 6.87	$ 101.64	21%	55.25	572.00	53.65	$ 3.57	$ 6.61	-	7.91	126.99	[redacted]
Internal Combustion Engines	$ 1,046	8.88%	$92.82	$ 6.49	$ 0.50	$ 6.99	$ 99.81	21%	54.26	572.00	50.37	$ 5.50	$ 6.21	-	7.42	123.76	[redacted]
SCCT Frame (2 Frame "F")	$ 901	8.41%	$75.78	$ 4.92	$ 0.50	$ 5.42	$ 81.20	21%	44.14	572.00	59.75	$ 6.51	$ 7.36	-	8.81	126.57	[redacted]
Other - Renewables																	
Oregon / Washington Wind (29% CF)	$ 2,383	8.55%	$203.69	$ 31.43	$ 0.50	$ 31.93	$ 235.62	29%	92.75	-	-	-	$ 9.70	(20.69)	-	81.75	102.45
Greenfield Geothermal (Binary)	$ 6,132	7.24%	$444.03	$ 209.40	$ 0.50	$ 209.90	$ 653.93	90%	82.94	-	-	$ 5.94	-	(20.69)	-	68.19	88.88
Biomass	$ 3,509	7.93%	$278.36	$ 38.80	$ 0.50	$ 39.30	$ 317.66	91%	39.67	483.58	53.09	$ 0.96	-	(20.69)	16.11	89.15	109.84
Hydrokinetic (Wave, Buoy) - 21% CF	$ 5,831	9.53%	$555.49	$ 174.92	$ 6.00	$ 180.92	$ 736.41	21%	400.31	-	-	-	-	(20.69)	-	379.61	400.31
Solar (Thin Film PV) - 19% CF	$ 4,191	8.55%	$358.24	$ 56.91	$ 6.00	$ 62.91	$ 421.16	19%	253.04	-	-	-	-	(20.69)	-	232.34	253.04
West Side Resource Options																	
Natural Gas																	
CCCT (Wet "F" 2x1)	$ 928	8.37%	$77.69	$ 7.12	$ 0.50	$ 7.62	$ 85.31	56%	17.39	572.00	39.38	$ 2.59	$ 4.85	-	5.80	70.03	[redacted]
CCCT Duct Firing (Wet "F" 2x1)	$ 468	8.37%	$39.20	-	$ 0.50	$ 0.50	$ 39.70	16%	28.32	572.00	49.65	$ 0.48	$ 6.12	-	7.32	91.90	[redacted]

Distributed Generation

Tables 6.7 and 6.8 present the total resource cost attributes for these resource options, and are based on estimates of the first-year real levelized cost per megawatt-hour of resources, stated in June 2010 dollars. The resource costs are presented for both the $0 and $19 CO_2 tax levels in recognition of the uncertainty in characterizing emission costs. Additional explanatory notes for the tables are as follows:

- A 14-percent administrative cost (for fixed operation and maintenance) is included in the overall cost of the resources. This cost level is in line with the administration costs of the Utah State Energy Program's Renewable Energy Rebate Program, which was 14 percent of total program costs[39] as well as PacifiCorp's program administrative cost experience.
- Federal tax benefits are included for the following resources based on a percent of capital cost.
    - Reciprocating Engine 10 percent
    - Microturbine 10 percent
    - Fuel Cell 30 percent
    - Gas Turbine 10 percent
    - Industrial Biomass 10 percent
    - Anaerobic Digesters 10 percent
- The resource cost for Industrial Biomass is based on The Cadmus Group data. The fuel is assumed to be provided by the project owner at no cost, a conservative assumption. In reality, the cost to the Company would be each state's filed avoided cost rate; and
- Installation costs for on-site ("micro") solar generation technologies are treated on a total resource cost basis; that is, customer installation costs are included. However, capital costs are adjusted downward to reflect federal benefits of 30 percent of installed system costs. The state tax incentives are not included as the Total Resource Cost test sees the incentive as a benefit to customers who install the systems, but is a cost to the state's tax payers, making the net effect zero.

[39] See the Utah Geological Survey's comments on Rocky Mountain Power's solar incentive program, Docket No. 07-035-T14. The comments can be downloaded at: http://www.psc.state.ut.us/utilities/electric/07docs/07035T14/66677Comments%20from%20State%20of%20Utah%20DNR.pdf

Table 6.7 – Distributed Generation Resource Supply-Side Options

Supply-side Resource Options Mid-Calendar Year 2010 Dollars ($)	Location / Timing		Plant Details				Outage Information		Costs			Emissions			
Resource Description	Installation Location	Earliest In-Service Date (Middle of year)	Average Capacity MW	Fuel	Design Plant Life in Years	Annual Average Heat Rate HHV BTU/kWh	Maint. Outage Rate	Equivalent Forced Outage Rate	Base Capital Cost in $/kW	Var. O&M, $/MWh	Fixed O&M in $/kW-yr	SO2 in lbs/MMBtu	NOx in lbs/MMBtu	Hg in lbs/trillion Btu	CO2 in lbs/mmBtu
Small Combined Heat & Power															
Reciprocating Engine	Utah	2011	0.75	Natural Gas	20	8,000	2%	3%	$ 1,880	-	$ 56.94	0.001	0.101	0.255	118.00
Reciprocating Engine	Oregon / California	2011	0.33	Natural Gas	20	8,000	2%	3%	$ 1,880	-	$ 56.94	0.001	0.101	0.255	118.00
Reciprocating Engine	Washington	2011	0.01	Natural Gas	20	8,000	2%	3%	$ 1,880	-	$ 56.94	0.001	0.101	0.255	118.00
Reciprocating Engine	Wyoming	2011	0.30	Natural Gas	20	8,000	2%	3%	$ 1,880	-	$ 56.94	0.001	0.101	0.255	118.00
Gas Turbine	Not Modeled	2011	0.06	Natural Gas	20	6,300	2%	3%	$ 1,755	-	$ 56.94	0.001	0.050	0.255	118.00
Microturbine	Not Modeled	2011	0.09	Natural Gas	15	8,000	2%	3%	$ 2,595	-	$ 54.02	0.001	0.101	0.255	118.00
Fuel Cell	Not Modeled	2011	0.05	Natural Gas	10	6,300	2%	3%	$ 4,583	-	$ 35.04	0.001	0.003	0.255	118.00
Commercial Biomass, Anaerobic Digester	Not Modeled	2011	0.05	Biomass	20	-	10%	10%	$ 3,293	-	$ 52.97	-	-	-	-
Industrial Biomass, Waste	Utah	2011	3.78	Biomass	15	-	5%	5%	$ 1,752	-	$ 31.54	-	-	-	-
Industrial Biomass, Waste	Oregon / California	2011	3.20	Biomass	15	-	5%	5%	$ 1,752	-	$ 31.54	-	-	-	-
Industrial Biomass, Waste	Idaho	2011	1.22	Biomass	15	-	5%	5%	$ 1,752	-	$ 31.54	-	-	-	-
Industrial Biomass, Waste	Washington	2011	0.99	Biomass	15	-	5%	5%	$ 1,752	-	$ 31.54	-	-	-	-
Industrial Biomass, Waste	Wyoming	2011	1.48	Biomass	15	-	5%	5%	$ 1,752	-	$ 31.54	-	-	-	-
Solar															
Rooftop Photovoltaic	Utah	2011	1.300	Solar	30	-			$ 5,691	-	$ 23.83	-	-	-	-
Rooftop Photovoltaic	Wyoming	2011	0.105	Solar	30	-			$ 5,691	-	$ 23.83	-	-	-	-
Rooftop Photovoltaic	Oregon / California	2011	1.172	Solar	30	-			$ 5,691	-	$ 23.83	-	-	-	-
Rooftop Photovoltaic	Idaho	2011	0.050	Solar	30	-			$ 5,691	-	$ 23.83	-	-	-	-
Rooftop Photovoltaic	Washington	2011	0.172	Solar	30	-			$ 5,691	-	$ 23.83	-	-	-	-
Water Heaters	Utah	2011	2.372	Solar	20	-			$ 1,420	-	$ 11.18	-	-	-	-
Water Heaters	Wyoming	2011	0.466	Solar	20	-			$ 1,420	-	$ 11.18	-	-	-	-
Water Heaters	Oregon / California	2011	0.516	Solar	20	-			$ 1,420	-	$ 11.18	-	-	-	-
Water Heaters	Idaho	2011	0.265	Solar	20	-			$ 1,420	-	$ 11.18	-	-	-	-
Water Heaters	Washington	2011	1.290	Solar	20	-			$ 1,420	-	$ 11.18	-	-	-	-
Attic Fans	Utah	2011	0.35	Solar	10	-			$ 16,939	-	-	-	-	-	-

Table 6.8 – Distributed Generation Total Resource Cost, $0 CO_2 Tax

$0 CO2 Tax	Capital Cost $/kW					Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)			
Supply-side Resource Options Mid-Calendar Year 2010 Dollars ($)						Fixed O&M $/kW-Yr						Levelized Fuel					
Resource Description	Capital Cost	Rebate and Administrative Costs	Net Capital Costs	Payment Factor	Annual Payment ($/kW-Yr)	O&M	Other	Total	Total Fixed ($/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation	Environmental	Total Resource Cost (Mills/kWh)
Small Combined Heat & Power																	
Reciprocating Engine		$ 141.50	$ 1,879.96	11.06%	$ 207.98	$ 56.94	-	$ 56.94	$ 264.92	56%	54.00	539.00	43.12	-	$ 5.36	0.00	$ 102.48
Reciprocating Engine		$ 141.50	$ 1,879.96	11.06%	$ 207.98	$ 56.94	-	$ 56.94	$ 264.92	56%	54.00	572.00	45.76	-	$ 5.64	0.00	$ 105.40
Reciprocating Engine		$ 141.50	$ 1,879.96	11.06%	$ 207.98	$ 56.94	-	$ 56.94	$ 264.92	56%	54.00	572.00	45.76	-	$ 5.64	0.00	$ 105.40
Reciprocating Engine		$ 141.50	$ 1,879.96	11.06%	$ 207.98	$ 56.94	-	$ 56.94	$ 264.92	56%	54.00	539.00	43.12	-	$ 4.66	0.00	$ 101.78
Gas Turbine		$ 132.11	$ 1,755.19	11.06%	$ 194.18	$ 56.94	-	$ 56.94	$ 251.12	95%	30.18	539.00	33.96	-	$ 4.22	0.00	$ 68.35
Microturbine		$ 195.35	$ 2,595.35	11.24%	$ 291.74	$ 54.02	-	$ 54.02	$ 345.76	56%	70.48	539.00	43.12	-	$ 5.36	0.00	$ 118.96
Fuel Cell		$ 344.93	$ 4,582.62	14.79%	$ 677.95	$ 35.04	-	$ 35.04	$ 712.99	95%	85.68	539.00	33.96	-	$ 4.22	0.00	$ 123.85
Commercial Biomass, Anaerobic Digester		$ 247.84	$ 3,292.74	9.53%	$ 313.70	$ 52.97	-	$ 52.97	$ 366.67	80%	52.32	-	-	-		-	$ 52.32
Industrial Biomass, Waste		$ 131.86	$ 1,751.86	11.24%	$ 196.93	$ 31.54	-	$ 31.54	$ 228.46	90%	28.98	-	-	-		-	$ 28.98
Industrial Biomass, Waste		$ 131.86	$ 1,751.86	11.24%	$ 196.93	$ 31.54	-	$ 31.54	$ 228.46	90%	28.98	-	-	-		-	$ 28.98
Industrial Biomass, Waste		$ 131.86	$ 1,751.86	11.24%	$ 196.93	$ 31.54	-	$ 31.54	$ 228.46	90%	28.98	-	-	-		-	$ 28.98
Industrial Biomass, Waste		$ 131.86	$ 1,751.86	11.24%	$ 196.93	$ 31.54	-	$ 31.54	$ 228.46	90%	28.98	-	-	-		-	$ 28.98
Industrial Biomass, Waste		$ 131.86	$ 1,751.86	11.24%	$ 196.93	$ 31.54	-	$ 31.54	$ 228.46	90%	28.98	-	-	-		-	$ 28.98
Solar																	
Rooftop Photovoltaic		$ 325.58	$ 5,691.13	7.93%	$ 451.42	$ 23.83	-	$ 23.83	$ 475.25	17%	311.80	-	-	-		-	$ 311.80
Rooftop Photovoltaic		$ 325.58	$ 5,691.13	7.93%	$ 451.42	$ 23.83	-	$ 23.83	$ 475.25	16%	339.08	-	-	-		-	$ 339.08
Rooftop Photovoltaic		$ 325.58	$ 5,691.13	7.93%	$ 451.42	$ 23.83	-	$ 23.83	$ 475.25	12%	467.70	-	-	-		-	$ 467.70
Rooftop Photovoltaic		$ 325.58	$ 5,691.13	7.93%	$ 451.42	$ 23.83	-	$ 23.83	$ 475.25	15%	354.59	-	-	-		-	$ 354.59
Rooftop Photovoltaic		$ 325.58	$ 5,691.13	7.93%	$ 451.42	$ 23.83	-	$ 23.83	$ 475.25	14%	379.39	-	-	-		-	$ 379.39
Water Heaters		$ 106.88	$ 1,419.92	9.53%	$ 135.28	$ 11.18	-	$ 11.18	$ 146.45	17%	96.08	-	-	-		-	$ 96.08
Water Heaters		$ 106.88	$ 1,419.92	9.53%	$ 135.28	$ 11.18	-	$ 11.18	$ 146.45	16%	104.49	-	-	-		-	$ 104.49
Water Heaters		$ 106.88	$ 1,419.92	9.53%	$ 135.28	$ 11.18	-	$ 11.18	$ 146.45	12%	144.12	-	-	-		-	$ 144.12
Water Heaters		$ 106.88	$ 1,419.92	9.53%	$ 135.28	$ 11.18	-	$ 11.18	$ 146.45	15%	109.27	-	-	-		-	$ 109.27
Water Heaters		$ 106.88	$ 1,419.92	9.53%	$ 135.28	$ 11.18	-	$ 11.18	$ 146.45	14%	116.91	-	-	-		-	$ 116.91
Attic Fans		$ 325.58	$ 16,938.68	14.79%	$ 2,505.91	-	-	-	$ 2,505.91	17%	1,644.04	-	-	-		-	$ 1,644.04

Table 6.8a – Distributed Generation Total Resource Cost, \$19 CO_2 Tax

\$19 CO2 Tax	Capital Cost \$/kW					Fixed Cost				Convert to Mills				Variable Costs (mills/kWh)			
Supply-side Resource Options Mid-Calendar Year 2010 Dollars (\$)						Fixed O&M \$/kW-Yr						Levelized Fuel					
Resource Description	Total Capital Cost	Rebate and Administrative Costs	Net Capital Costs	Payment Factor	Annual Payment (\$/kW-Yr)	O&M	Other	Total	Total Fixed (\$/kW-Yr)	Capacity Factor	Total Fixed (Mills/kWh)	¢/mmBtu	Mills/kWh	O&M	Gas Transportation or Wind Integration	Environmental	Total Resource Cost (Mills/kWh)
Small Combined Heat & Power																	
Reciprocating Engine		\$ 141.50	\$ 1,879.96	11.06%	\$ 207.98	\$ 56.94	-	\$ 56.94	\$ 264.92	56%	54.00	550.00	44.00	-	\$ 5.36	6.74	\$ 110.11
Reciprocating Engine		\$ 141.50	\$ 1,879.96	11.06%	\$ 207.98	\$ 56.94	-	\$ 56.94	\$ 264.92	56%	54.00	583.50	46.68	-	\$ 5.64	6.74	\$ 113.07
Reciprocating Engine		\$ 141.50	\$ 1,879.96	11.06%	\$ 207.98	\$ 56.94	-	\$ 56.94	\$ 264.92	56%	54.00	583.50	46.68	-	\$ 5.64	6.74	\$ 113.07
Reciprocating Engine		\$ 141.50	\$ 1,879.96	11.06%	\$ 207.98	\$ 56.94	-	\$ 56.94	\$ 264.92	56%	54.00	550.00	44.00	-	\$ 4.66	6.74	\$ 109.41
Gas Turbine		\$ 132.11	\$ 1,755.19	11.06%	\$ 194.18	\$ 56.94	-	\$ 56.94	\$ 251.12	95%	30.18	550.00	34.65	-	\$ 4.22	5.31	\$ 74.36
Microturbine		\$ 195.35	\$ 2,595.35	11.24%	\$ 291.74	\$ 54.02	-	\$ 54.02	\$ 345.76	56%	70.48	550.00	44.00	-	\$ 5.36	6.74	\$ 126.59
Fuel Cell		\$ 344.93	\$ 4,582.62	14.79%	\$ 677.95	\$ 35.04	-	\$ 35.04	\$ 712.99	95%	85.68	550.00	34.65	-	\$ 4.22	5.31	\$ 129.86
Commercial Biomass, Anaerobic Digester		\$ 247.84	\$ 3,292.74	9.53%	\$ 313.70	\$ 52.97	-	\$ 52.97	\$ 366.67	80%	52.32	-	-	-		-	\$ 52.32
Industrial Biomass, Waste		\$ 131.86	\$ 1,751.86	11.24%	\$ 196.93	\$ 31.54	-	\$ 31.54	\$ 228.46	90%	28.98	-	-	-		-	\$ 28.98
Industrial Biomass, Waste		\$ 131.86	\$ 1,751.86	11.24%	\$ 196.93	\$ 31.54	-	\$ 31.54	\$ 228.46	90%	28.98	-	-	-		-	\$ 28.98
Industrial Biomass, Waste		\$ 131.86	\$ 1,751.86	11.24%	\$ 196.93	\$ 31.54	-	\$ 31.54	\$ 228.46	90%	28.98	-	-	-		-	\$ 28.98
Industrial Biomass, Waste		\$ 131.86	\$ 1,751.86	11.24%	\$ 196.93	\$ 31.54	-	\$ 31.54	\$ 228.46	90%	28.98	-	-	-		-	\$ 28.98
Industrial Biomass, Waste		\$ 131.86	\$ 1,751.86	11.24%	\$ 196.93	\$ 31.54	-	\$ 31.54	\$ 228.46	90%	28.98	-	-	-		-	\$ 28.98
Solar																	
Rooftop Photovoltaic		\$ 325.58	\$ 5,691.13	7.93%	\$ 451.42	\$ 23.83	-	\$ 23.83	\$ 475.25	17%	311.80	-	-	-		-	\$ 311.80
Rooftop Photovoltaic		\$ 325.58	\$ 5,691.13	7.93%	\$ 451.42	\$ 23.83	-	\$ 23.83	\$ 475.25	16%	339.08	-	-	-		-	\$ 339.08
Rooftop Photovoltaic		\$ 325.58	\$ 5,691.13	7.93%	\$ 451.42	\$ 23.83	-	\$ 23.83	\$ 475.25	12%	467.70	-	-	-		-	\$ 467.70
Rooftop Photovoltaic		\$ 325.58	\$ 5,691.13	7.93%	\$ 451.42	\$ 23.83	-	\$ 23.83	\$ 475.25	15%	354.59	-	-	-		-	\$ 354.59
Rooftop Photovoltaic		\$ 325.58	\$ 5,691.13	7.93%	\$ 451.42	\$ 23.83	-	\$ 23.83	\$ 475.25	14%	379.39	-	-	-		-	\$ 379.39
Water Heaters		\$ 106.88	\$ 1,419.92	9.53%	\$ 135.28	\$ 11.18	-	\$ 11.18	\$ 146.45	17%	96.08	-	-	-		-	\$ 96.08
Water Heaters		\$ 106.88	\$ 1,419.92	9.53%	\$ 135.28	\$ 11.18	-	\$ 11.18	\$ 146.45	16%	104.49	-	-	-		-	\$ 104.49
Water Heaters		\$ 106.88	\$ 1,419.92	9.53%	\$ 135.28	\$ 11.18	-	\$ 11.18	\$ 146.45	12%	144.12	-	-	-		-	\$ 144.12
Water Heaters		\$ 106.88	\$ 1,419.92	9.53%	\$ 135.28	\$ 11.18	-	\$ 11.18	\$ 146.45	15%	109.27	-	-	-		-	\$ 109.27
Water Heaters		\$ 106.88	\$ 1,419.92	9.53%	\$ 135.28	\$ 11.18	-	\$ 11.18	\$ 146.45	14%	116.91	-	-	-		-	\$ 116.91
Attic Fans		\$ 325.58	\$ 16,938.68	14.79%	\$ 2,505.91	-	-	-	\$ 2,505.91	17%	1,644.04	-	-	-		-	\$ 1,644.04

Resource Option Description

Coal

Potential coal resources are shown in the supply-side resource options tables as supercritical PC boilers (PC) and IGCC in Utah and Wyoming. Costs for large coal-fired boilers, since the 2007 IRP, have risen by approximately 50 to 60 percent due to many factors involving material shortages, labor shortages, and the risk of fixed price contracting. The recent downturn in the economy has mitigated many of these concerns and prices for coal generation have declined from the previous IRP. Despite these cost decreases the uncertainty of future carbon regulations and difficulty in obtaining construction and environmental permits for coal based generation continues to encourage the Company to postpone the selection of coal as a resource before 2020.

Supercritical technology was chosen over subcritical technology for pulverized coal for a number of reasons. Increasing coal costs are making the added efficiency of the supercritical technology cost-effective for long-term operation. Additionally, there is a greater competitive marketplace for large supercritical boilers than for large subcritical boilers. Increasingly, large boiler manufacturers only offer supercritical boilers in the 500-plus MW sizes. Due to the increased efficiency of supercritical boilers, overall emission quantities are smaller than for a similarly sized subcritical unit. Compared to subcritical boilers, supercritical boilers can follow loads better, ramp to full load faster, use less water, and require less steel for construction. The smaller steel requirements have also leveled the construction cost estimates for the two coal technologies. The costs for a supercritical PC facility reflect the cost of adding a new unit at an existing site. PacifiCorp does not expect a significant difference in cost for a multiple unit at a new site versus the cost of a single unit addition at an existing site.

CO_2 capture and sequestration technology represents a potential cost for new and existing coal plants if future regulations require it. Research projects are underway to develop more cost-effective methods of capturing carbon dioxide from the flue gas of conventional boilers. The costs included in the supply side resource tables utilize amine based solvent systems for carbon capture. Sequestration would store the CO_2 underground for long-term storage and monitoring.

PacifiCorp and MidAmerican Energy Holdings Company are monitoring CO_2 capture technologies for possible retrofit opportunities at its existing coal-fired fleet, as well as applicability for future coal plants that could serve as cost-effective alternatives to IGCC plants if CO_2 removal becomes necessary in the future. An option to capture CO_2 at an existing coal-fired unit has been included in the supply side resource tables. Currently there are only a couple of large-scale sequestration projects in operation around the world and a number of these are in conjunction with enhanced oil recovery. CCS is not considered a viable option before 2025 due to risk issues associated with technological maturity and underground sequestration liability.

An alternative to supercritical pulverized-coal technology for coal-based generation would be the use of IGCC technology. A significant advantage for IGCC when compared to conventional pulverized coal with amine-based carbon capture is the reduced cost of capturing CO_2 from the process. Gasification plants have been built and demonstrated around the world, primarily as a means of producing chemicals from coal. Only a limited number of IGCC plants have been constructed specifically for power generation. In the U.S., these facilities have been demonstration projects and cost significantly more than conventional coal plants in both capital and operating costs. These projects have been constructed with significant funding from the federal government. A number of IGCC technology suppliers have teamed up with large constructor to form consortia who are now offering to build IGCC plants. A few years ago, these consortia were willing to provide IGCC plants on a lump-sum, turn-key basis. However, in today's market, the willingness of these consortia to design and construct IGCC plants on lump-sum turnkey basis is in question. The costs presented in the supply-side resource options tables reflect recent studies of IGCC costs associated with efforts to partner PacifiCorp with the Wyoming Infrastructure Authority (WIA) to investigate the acquisition of federal grant money to demonstrate western IGCC projects.

PacifiCorp was selected by the WIA to participate in joint project development activities for an IGCC facility in Wyoming. The ultimate goal was to develop a Section 413 project under the 2005 Energy Policy Act. PacifiCorp commissioned and managed feasibility studies with one or more technology suppliers/consortia for an IGCC facility at its Jim Bridger plant with some level of carbon capture. Based on the results of initial feasibility studies, PacifiCorp declined to submit a proposal to the federal agencies involved in the Section 413 solicitation.

PacifiCorp is a member of the Gasification User's Association. In addition, PacifiCorp communicates regularly with the primary gasification technology suppliers, constructors, and other utilities. The results of all these contacts were used to help develop the coal-based generation projects in the supply side resource tables. Over the last two years PacifiCorp has help a series of public meetings as a part of an IGCC Working Group to help provide a broader level of understanding for this technology.

Coal Plant Efficiency Improvements

Fuel efficiency gains for existing coal plants (which are manifested in lower plant heat rates) are realized by (1) emphasizing continuous improvement in operations, and (2) upgrading components if economically justified. Such fuel efficiency improvements can result in a smaller emission footprint for a given level of plant capacity, or the same footprint when plant capacity is increased.

The efficiency of generating units degrades gradually as components wear out over time. During operation, controllable process parameters are adjusted to optimize unit output and efficiency. Typical overhaul work that contributes to improved efficiency includes (1) steam turbine overhauls, (2) cleaning and repairing condensers, feed water heaters, and cooling towers and (3) cleaning boiler heat transfer surfaces.

When economically justified, efficiency improvements are obtained through major component upgrades. Examples include turbine upgrades using new blade and sealing technology, improved seals and heat exchange elements for boiler air heaters, cooling tower fill upgrades, and the addition of cooling tower cells. Such upgrade opportunities are analyzed on a case-by-case basis, and are tied to a unit's major overhaul cycle. PacifiCorp is taking advantage of improved upgrade technology through its "dense pack" coal plant turbine upgrade initiative where justified.

Natural Gas

Natural gas generation options are numerous and a limited number of representative technologies are included in the supply-side resource options table. SCCT and CCCT are included. As with other generation technologies, the cost of natural gas generation has increased substantially from previous IRPs. Costs for gas generation have not decreased since the 2008 IRP, depending on the option, due not only to general utility cost issues mentioned earlier, but also due to the decrease in coal-based projects thereby putting an increased demand on natural gas options that can be more easily permitted.

Combustion turbine options include both simple cycle and combined cycle configurations. The simple cycle options include traditional frame machines as well as aero-derivative combustion turbines. Two aero-derivative machine options were chosen. The General Electric LM6000 machines are flexible, high efficiency machines and can be installed with high temperature SCR systems, which allow them to be located in areas with air emissions concerns. These types of gas turbines are identical to those installed at Gadsby. LM6000 gas turbines have quick-start capability (less than ten minutes to full load) and higher heating value heat rates near 10,000 Btu/kWh. Also selected for the supply-side resource options table is General Electric's new LMS-100 gas turbine. This machine was recently installed for the first time in a commercial venture. It is a cross between a simple-cycle aero-derivative gas turbine and a frame machine with significant amount of compressor intercooling to improve efficiency. The machines have higher heating value heat rates of less than 9,500 Btu/kWh and similar starting capabilities as the LM6000 with significant load following capability (up to 50 MW per minute).

Frame simple cycle machines are represented by the "F" class technology. These machines are about 150 MW at western elevations, and can deliver good simple cycle efficiencies.

Other natural gas-fired generation options include internal combustion engines and fuel cells. Internal combustion engines are represented by a large power plant consisting of 14 machines at 10.9 MW. These machines are spark-ignited and have the advantages of a relatively attractive heat rate, a low emissions profile, and a high level of availability and reliability due to the number of machines. At present, fuel cells hold less promise due to high capital cost, partly attributable to the lack of production capability and continued development. Fuel cells are not ready for large scale deployment and are not considered available as a supply-side option until after 2013.

Combined cycle power plants options have been limited to 1x1 and 2x1 applications of "F" class combustion turbines and a "G" 1x1 facility. The "F" class machine options would allow an expansion of the Lake Side facility. Both the 1x1 and 2x1 configurations are included to give some flexibility to the portfolio planning. Similarly, the "G" machine has been added to take advantage of the improved heat rate available from these more advanced gas turbines. The "G" machine is only presented as a 1x1 option to keep the size of the facility reasonable for selection as a portfolio option. These natural gas technologies are considered mature and installation lead times and capital costs are well known.

Wind

Resource Supply, Location, and Incremental Transmission Costs

PacifiCorp revised its approach for locating wind resources to more closely align with Western Renewable Energy Zones (WREZ), facilitate assignment of incremental transmission costs for the Energy Gateway transmission scenario analysis, and allow the System Optimizer model to more easily select wind resources outside of transmission-constrained areas in Wyoming. Resources are now grouped into a number of wind-generation-only bubbles as well as certain conventional topology bubbles. Wind generation bubbles are intended to enable assignment of incremental transmission costs. Table 6.9 shows the relationship between the topology bubbles and corresponding WREZ.

Table 6.9 – Representation of Wind in the Model Topology

Topology Area	Bubble Type	Topology Bubble Linkage	Corresponding Western Renewable Energy Zone(s)
Wyoming	Wind Generation Only	Linked to *Aeolus*	Wyoming East Central (WY_EC) Wyoming North (WY_NO) Wyoming East (WY_EA) Wyoming South (WY_SO)
Utah	Wind Generation Only	Linked to *Utah South*	Utah West (UT_WE)
Oregon/Washington	Wind Generation Only	Linked to *BPA*	Washington South (WA_SO) Oregon Northeast (OR_NE) Oregon West (OR_WE)
Brady, Idaho	Conventional	N/A	Idaho East (ID_EA)
Walla Walla, WA	Conventional	N/A	Oregon Northeast (OR_NE)
Yakima, WA	Conventional	N/A	Washington South (WA_SO)

Incremental transmission costs are expressed as dollars-per-kW values that are applied to costs of wind resources added in wind-generation-only bubbles.[40] The only exception is for the Oregon/Washington bubble. PacifiCorp's transmission investment analysis indicated that supporting incremental wind additions of over 500 MW in the PacifiCorp west control area would require on the order of $1.5 billion in new transmission facilities (several new 500/230 kV segments would be needed). Since the model cannot automatically apply the transmission cost based on a given megawatt threshold, the incremental transmission cost was removed from this bubble for the base Energy Gateway scenario (which excludes the Wyoming transmission segment) and added as a manual fixed cost adjustment to the portfolio's reported cost if the west side wind additions exceed the 500 MW threshold. *It is important to note that the west-side transmission cost adjustment is only applicable to the Energy Gateway scenario analysis, and not core case portfolio development, which is based on the full Energy Gateway footprint. Only if a core case portfolio included at least 500 MW of west-side wind would PacifiCorp apply an out-of-model transmission cost adjustment. None of the core case portfolios reached this wind capacity threshold.*

[40] Incremental transmission costs also could have been added directly to the wind capital costs. However, assigning a cost to a wind generation bubble avoids the need to individually adjust costs for many wind resources.

In the case of east-side wind resources, the only resource location-dependent transmission cost was $71/kW assigned to Wyoming resources based on an estimated incremental expansion of at least 1,500 MW.

As noted above, the model can also locate wind resources in conventional bubbles. No incremental transmission costs are associated with conventional bubbles, other than wheeling charges where applicable. Transmission interconnection costs—direct and network upgrade costs for connecting a wind facility to PacifiCorp's transmission system (230 kV step-up)—are included in the wind capital costs. It should be noted that primary drivers of wind resource selection are the requirements of renewable portfolio standards and the availability of production tax credits.

Capital Costs

PacifiCorp started with a base set of wind capital costs. The source of these costs is the database of the IPM®, a proprietary modeling system licensed to PacifiCorp by ICF International. These wind capital costs are divided into levels that differentiate costs by site development conditions. PacifiCorp then applied adjustments to the base capital costs to account for federal tax credits, wind integration costs, fixed O&M costs, and wheeling costs as appropriate. (The cost adjustments are converted into discounted values and added to the base capital cost.) These adjusted capital cost values are used only in the System Optimizer model. Table 6.10 shows cost values, WREZ resource potentials, and resource unit limits.

To specify the number of discrete wind resources for a topology bubble, PacifiCorp divided the WREZ resource limit (or depth) by the number of cost levels, rounding to the nearest multiple of 100, and then divided by a 100 MW unit size. (Table 6.10) This formula does not apply to the 200 MW of Washington South and Oregon Northeast wind resources that are available without incremental transmission in the Yakima and Walla Walla bubbles. All wind resources are specified in 100 MW blocks, but the model can choose a fractional amount of a block.

Wind Resource Capacity Factors and Energy Shapes

All resource options in a topology bubble are assigned a single capacity factor. Wyoming resource options are assigned a capacity factor value of 35 percent, while wind resources in other states are assigned a value of 29 percent. Capacity factor is a separate modeled parameter from the capital cost, and is used to scale wind energy shapes used by both the System Optimizer and Planning and Risk (PaR) models. The hourly generation shape reflects average hourly wind variability. The hourly generation shape is repeated for each year of the simulation.

Wind Integration Costs

To capture the costs of integrating wind into the system, PacifiCorp applied a value of $9.70/MWh (in 2010 dollars) for portfolio modeling. The source of this value was the Company's 2010 wind integration study, which is included as Appendix H. Integration costs were incorporated into wind capital costs based on a 25-year project life expectancy and generation performance.

Annual Wind Selection Limits

To reflect realistic system resource addition limits tied to such factors as transmission availability, operational integration, rate impact, resource market availability, and procurement constraints, System Optimizer was constrained to select wind up to certain annual limits. The limit is 200 MW per year with the exception of the hard CO_2 emission cap cases, where the annual limit was specified as 500 MW. These limits apply on a system basis. Note that the effect of the annual limits is to spread wind additions across multiple years rather than cap the cumulative total wind added to a portfolio.

Table 6.10 – Wind Resource Characteristics by Topology Bubble

***Utah South* wind-only bubble**

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Utah	2016	29%	1	3,059	1,516	5
			2	3,508		5
			3	4,180		5

***BPA* wind-only bubble**

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Washington South (Yakima)	2016	29%	1	3,454	2,566	9
			2	3,927		9
			3	4,633		9
Oregon Northeast (Walla Walla)	2016	29%	1	3,597	1,464	5
			2	4,074		5
			3	4,788		5
Oregon West	2016	29%	1	3,597	196	1
			2	4,074		1
			3	4,788		1

Wyoming wind resources in *Aeolus* wind-only bubble

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Wyoming South	2018	35%	1	3,147	1,324	13
Wyoming North	2018	35%	1	3,147	3,063	31
Wyoming East Central	2018	35%	1	3,147	2,594	26
Wyoming East	2018	35%	1	3,147	7,257	73

Idaho (Goshen) wind resources in *Brady* bubble

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Idaho East	2016	29%	1	3,339	618	2
			2	3,788		2
			3	4,460		2

Oregon/Washington wind resources that do not require new incremental transmission *

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Washington South (Yakima)	2013	29%	1	2,393	n/a	1
Oregon Northeast (Walla Walla)	2013	29%	1	2,393	n/a	1

* This section includes only the 200 MW of Oregon and Washington wind resources that do not require incremental transmission. Wind resources in these areas that require additional transmission are modeled with the parameters shown in the "*BPA* wind only bubble" section above.

Other Renewable Resources

Other renewable generation resources included in the supply-side resource options table include geothermal, biomass, landfill gas, waste heat and solar. The financial attributes of these renewable options are based on EPRI's TAG® database and have been adjusted based on PacifiCorp's recent construction and study experience.[41]

Geothermal

In response to the 2008 IRP Update, comments from the Utah stakeholders requested a geothermal resources study to review the geothermal resources in PacifiCorp's service territory. A geothermal resources study was commissioned by PacifiCorp in 2010 and performed by Black & Veatch in conjunction with GeothermEx. The study established criteria for the commercial viability for a geothermal resource as a resource with at least 25 percent of the geothermal resource capacity drilled and operated in the past. While over 80 potential projects were identified within 100 miles of an interconnection to the PacifiCorp grid only eight resources met the commercial criteria. Figure 6.2 and Table 6.11, which come from the report, identify the eight resources and compares their capacity and cost attributes, including the levelized cost of energy (LCOE).[42] All resources, except Roosevelt hot springs (Blundell) because of moderate fluid temperatures, would use binary technology and are inherently more costly and less efficient than the flash design suitable for the higher temperature brine at Blundell. For the supply side table, two types of geothermal resources are defined. East side geothermal refers to the Roosevelt Hot Springs resource (Blundell) and utilizes a cost estimate equivalent to the study conclusion and the current expectation for the cost of a third unit at the Blundell plant. Other geothermal resources are designated Greenfield geothermal and utilize a cost equal to the average of the binary geothermal costs from the geothermal study. These additional geothermal resources are considered western resources for modeling purposes.

PacifiCorp has committed to conduct additional geothermal studies in 2011 to further define and quantify the geothermal opportunities uncovered in the 2010 geothermal study. The 2011 study will also look and the other identified geothermal options and determine which, if any, merits additional development work. The 2011 study will identify new geothermal opportunities sufficient to allow a request for approval of development funds for recovery from the various state commissions.

[41] Technical Assessment Guide, Electric Power Research Institute, Palo Alto, CA.

[42] The levelized cost of energy is the constant dollar cost of the energy generated over the life of the project, and includes operation and maintenance costs, investment costs, and taxes/tax benefits.

Figure 6.2 – Commercially Viable Geothermal Resources Near PacifiCorp's Service Territory

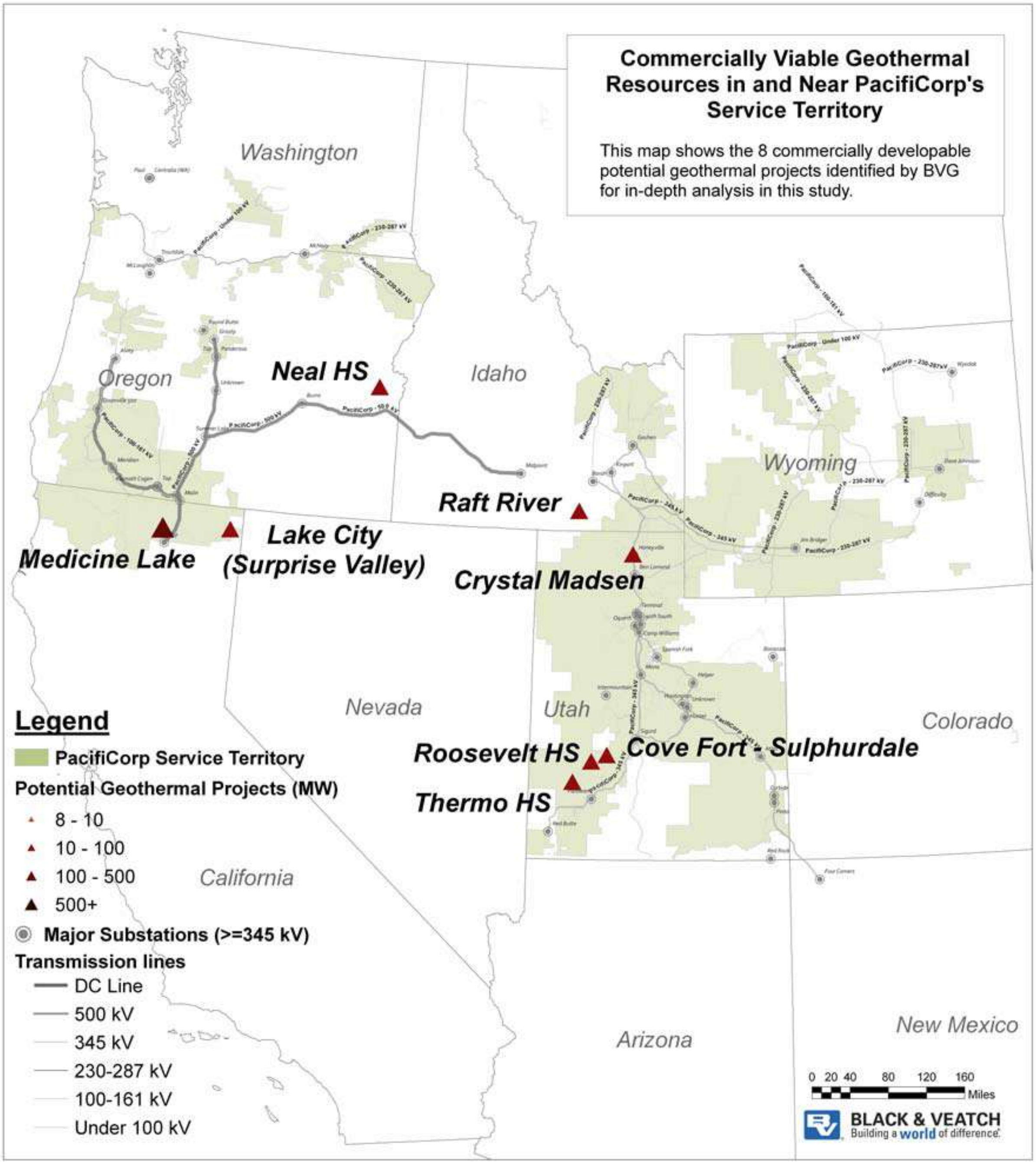


Table 6.11 – 2010 Geothermal Study Results

Table 1-1. Sites Selected for In-Depth Review.

Field Name	State	Additional Capacity Available (Gross MW)	Additional Capacity Available (Net MW)	Additional Capacity Available to PacifiCorp (Net MW)[a]	Anticipated Plant Type for Additonal Capacity	LCOE (Low, $/MWh)[b,c]	LCOE (High, $/MWh)[b,c]
Lake City	CA	30	24	24	Binary	$83	$90
Medicine Lake	CA	480	384	384	Binary	$91	$98
Raft River	ID	90	72	43	Binary	$93	$100
Neal Hot Springs	OR	30	24	0	Binary	$80	$87
Cove Fort	UT	100	80	60 to 63	Binary	$68	$75
Crystal-Madsen	UT	30	24	0	Binary	$93	$100
Roosevelt Hot Springs	UT	90	81[d]	81[d]	Flash/Binary Hybrid	$46	$51
Thermo Hot Springs	UT	118	94	0	Binary	$91	$98
Totals		***968***	***783***	***592 to 595***			

Source: BVG analysis for PacifiCorp.
Note:
[a] Calculated by subtracting the amount of resource under contract to or in contract negotiations with other parties from the estimated net capacity available.
[b] Net basis
[c] These screening level cost estimates are based on available public information. More detailed estimates based on proprietary information and calculated on a consistent basis might yield different comparisons.
[d] While 81 MW net are estimated to be available, the resource should be developed in smaller increments to verify resource sustainability

Biomass

The biomass project option would involve the combustion of whole trees grown in a plantation setting, presumably in the Pacific Northwest.

Solar

Three solar resources were defined. A concentrating PV system represents a utility scale PV resource. Optimistic performance and cost figures were used equivalent to the best reported PV efficiencies. Solar thermal projects are represented by both a solar concentrating design trough system with natural gas backup and a solar concentrating design thermal tower arrangement with six hours of thermal storage. The system parameters for these systems were suggested by the WorleyParsons Group study and reflect current proposed projects in the desert southwest. Efforts are being undertaken in 2011 to verify this data. A two-megawatt solar project will be built in Oregon as a part of the Oregon solar initiative. Development of PV resources in Utah will be studied with Sandia National Laboratories.

Combined Heat and Power and Other Distributed Generation Alternatives

Combined heat and power (CHP) plants are small (ten megawatts or less) gas compressor heat recovery systems using a binary cycle. PacifiCorp evaluated both larger systems that would be contracted at the customer site (labeled as utility cogeneration in Tables 6.1, 6.3, and 6.5) and smaller distributed generation systems.

A large CHP (40 to 120 megawatts) combustion turbine with significant steam based heat recovery from the flue gas has not been included in PacifiCorp's supply-side table for the eastern service territory due to a lack of large potential industrial applications. These CHP opportunities are site-specific, and the generic options presented in the supply-side resource options table are not intended to represent any particular project or opportunity.

Small distributed generation resources are unique in that they reside at the customer load. The generation can either be used to reduce the customer load, such as net metering, or sold to the utility. Small CHP resources generate electricity and utilize waste heat for space and water heating requirements. Fuel is either natural gas or renewable biogas. On-site solar resources, also referred to as "micro solar", include electric generation and energy-efficiency measures that use solar energy. The DG resources are up to 4.8 MW in size.

Table 6.12 shows modeling attributes for the distributed generation resources reflected in The Cadmus Group's 2010 potentials study. Rather than using the year-by-year resource potentials for 2011-2030 from The Cadmus Group, PacifiCorp calculated the average annual values based on the 2030 cumulative resource totals.[43] PacifiCorp also applied a three-megawatt threshold for the average annual capacity values to designate resources to include in the IRP models.

Table 6.12 – Distributed Generation Resource Attributes

Technology Type	Available MW Capacity each Year by Topology Bubble 1/ South/Central Oregon plus California	Walla Walla, WA	Yakima, WA	Goshen, ID	Utah North	Wyoming Southwest	Annual Fixed O&M Costs ($/kW)	Measure Life (Yrs)	Heat Rate (Ave. Btu/kWh)	Admin Cost (% of total program cost)	Capital Cost ($/kW), Total Resource Cost basis	Technology Cost Change
Reciprocating Engine	0.33	0.01	-	-	0.75	0.30	56.94	20	8,000	14%	1,880	1%
MicroTurbine	-	-	-	-	-	-	54.02	15	8,000	14%	2,595	-1%
Fuel Cell	-	-	-	-	-	-	35.04	10	6,300	14%	4,583	-3%
Gas Turbine	-	-	-	-	-	-	56.94	20	6,300	14%	1,755	1%
Industrial Biomass	3.20	0.36	0.63	1.22	3.78	1.48	31.54	15	N/A	14%	1,752	1%
Anaerobic Digesters	-	-	-	-	-	-	52.97	20	N/A	14%	3,293	-1%
PV	1.17	0.08	0.09	0.05	1.30	0.11	23.83	30	N/A	14%	5,691	-2%
Solar Water Heaters	0.52	0.32	0.97	0.27	2.37	0.47	11.18	20	N/A	14%	1,420	2%
Solar Attic Fans	-	-	-	-	0.35	-	0.00	10	N/A	14%	16,939	2%

1/ Technologies with no capacities listed indicate that the average annual capacity for 2011-2030 is less than the 3 MW threshold for inclusion in the IRP models.

Introduction of many new distributed generation technologies designed to fill the needs of niche markets has helped spur reductions in capital and operating costs.

More details on the distributed generation resources can be found in the Cadmus potentials study report available for download on PacifiCorp's demand-side management Web page, http://www.pacificorp.com/es/dsm.html.

[43] Many of the annual capacity potentials are a small fraction of a megawatt. This resource set-up approach enabled one resource with multiple units to be defined for each technology as opposed to an individual resource having to be defined for each year. The number of resource options is one of the key factors that establish model run-time.

As in past IRPs, a number of energy storage technologies are included, such as compressed energy storage (CAES), pumped hydroelectric, and advanced batteries. There are a number of potential CAES sites—specifically solution-mined sites associated with gas storage in southwest Wyoming—that could be developed in areas of existing gas transmission. CAES may be an attractive alternative for high elevation sites since the gas compression could compensate for the higher elevation. Thermal energy storage is also included as a load control (Class 1 DSM) resource. Although not included in this IRP, flywheel energy storage systems show promise for such applications as frequency regulation, and will be investigated for the next IRP as PacifiCorp gathers data from other utility test projects and assesses resource potential for its own system.

Nuclear

An emissions-free nuclear plant has been included in the supply-side resource options table. This option is based recent internal studies, press reports and information from a paper prepared by the Uranium Information Centre Ltd., "The Economics of Nuclear Power," May 2008. A 1,600 MW plant is characterized utilizing advanced nuclear plant designs with an assumed location in Idaho. Modeled capital costs include incremental transmission costs to deliver energy into PacifiCorp's system. Nuclear power is not considered a viable option in the PacifiCorp service territory before 2030.

Demand-side Resources

Resource Options and Attributes

Source of Demand-side Management Resource Data

DSM resource opportunity estimates used in the development of the 2011 IRP were derived from an update to the "Assessment of Long-Term, System-Wide Potential for Demand-Side and Other Supplemental Resources" study completed in June 2007 (DSM potential study). The 2010 DSM potential study, conducted by The Cadmus Group, provided a broad estimate of the size, type, location and cost of demand-side resources.[44] The demand-side resource information was converted into supply-curves by type of DSM; e.g. capacity-based Classes 1 and 3 DSM and energy-based Class 2 DSM for modeling against competing supply-side alternatives.

Demand-side Management Supply Curves

Resource supply curves are a compilation of point estimates showing the relationship between the cumulative quantity and costs of resources. Supply curves incorporate a linear relationship between quantities and costs (at least up to the maximum quantity available) to help identify at any particular cost how much of a particular resource can be acquired. Resource modeling utilizing supply curves allows utilities to sort out and select the least-cost resources (products and quantities) based on each resource's cost versus quantity in comparison to the supply curves of alternative and competing resource types.

[44] The Cadmus DSM potentials report is available on PacifiCorp's demand-side management Web page. http://www.pacificorp.com/es/dsm.html.

As with supply-side resources, the development of demand-side resource supply curves requires specification of quantity, availability, and cost attributes. Attributes specific to demand-side supply curves include:

- resource quantities available in year one—either megawatts or megawatt-hours—recognizing that some resources may come from stock additions not yet built, and that elective resources cannot all be acquired in the first year
- resource quantities available over time; for example, Class 2 DSM energy-based resource measure lives
- seasonal availability and hours available (Classes 1 and 3 DSM capacity resources)
- the shape or hourly contribution of the resource (load shape of the Class 2 DSM energy resource); and
- levelized resource costs (dollars per megawatt per year for Classes 1 and 3 DSM capacity resources, or dollars per megawatt-hour for Class 2 DSM energy resources).

Once developed, DSM supply curves are treated like any other discrete supply-side resource in the IRP modeling environment. A complicating factor for modeling is that the DSM supply curves must be configured to meet the input specifications for two models: the System Optimizer capacity expansion optimization model, and the Planning and Risk production cost simulation model.

Class 1 DSM Capacity Supply Curves

Supply curves were created for five discrete Class 1 DSM products:

1) residential air conditioning
2) residential electric water heating
3) irrigation load curtailment
4) commercial/industrial curtailment; and
5) commercial/industrial thermal energy storage

The potentials and costs for each product were provided at the state level resulting in five products across six states, or thirty supply curves before accounting for system load areas (some states cover more than one load area). After accounting for load areas, a total of fifty Class 1 DSM supply curves were used in the 2011 IRP modeling process.

Class 1 DSM resource price differences between west and east control areas for similar resources were driven by resource differences in each market, such as irrigation pump size and hours of operation as well as product performance differences. For instance, residential air conditioning load control in the west is more expensive on a unitized or dollar per kilowatt-year basis due to climatic differences that result in less contribution or load available per installed switch.

The combination residential air conditioning and electric water heating dispatchable load control product was not provided to the System Optimizer model as a resource option for either control area. In the west, electric water heating control wasn't included as it adds little additional load for the cost, and electric water heating market share continues to decline each year as a result of conversions to gas. In the east, electric water heating control wasn't included because (1) the market potential is very small. (It is predominantly a gas water heating market), (2) an established program already exists that doesn't include a water heater control component, and (3) the potential identified is assumed to be located in areas where gas is not available; such as more rural and mountainous areas where direct load control paging signals are less reliable.

The assessment of potential for distributed standby generation was combined with an assessment of commercial/industrial energy management system controls in the development of the resource opportunity and costs of the commercial/industrial curtailment product. The costs for this product are constant across all jurisdictions under the pay-for-performance delivery model assumed.

Tables 6.13 and 6.14 show the summary level Class 1 DSM program information, by control area, used in the development of the Class 1 resources supply curves. As previously noted, the products were further broken down by quantity available by state and load area in order to provide the model with location-specific details.

Table 6.13 – Class 1 DSM Program Attributes West Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)	Year Available
Residential and Small Commercial Air Conditioning	Yes, with residential time-of-use	50 hours, not to exceed 6 hours per day	Summer	14	$116-159	2013
Residential Electric Water Heating	Yes, with residential time-of-use	50 hours	Summer	5	$88	2013
Irrigation Direct Load Control	Yes, with irrigation time-of-use	50 hours, not to exceed 6 hours per day	Summer	27	$74	2013
Commercial/Industrial Curtailment (includes distributed stand-by generation)	Yes, with Thermal Energy Storage, demand buyback, and commercial Class 3 time related price products	80 hours, not to exceed 6 hours per day	Summer and Winter	40	$82	2013
Commercial/industrial Thermal Energy Storage	Yes, with commercial Class 3 time related price products	480 hours	Summer	1	$253	2013

Table 6.14 – Class 1 DSM Program Attributes East Control Area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)	Year Available
Residential and Small Commercial Air Conditioning	Yes, with residential time-of-use	50 hours, not to exceed 6 hours per day	Summer	89	$116	2012
Residential Electric Water Heating	Yes, with residential time-of-use	50 hours	Summer	5	$88	2013
Irrigation Direct Load Control	Yes, with irrigation time-of-use	50 hours, not to exceed 6 hours per day	Summer	28	$50-$74	2012
Commercial/Industrial Curtailment (includes distributed stand-by generation)	Yes, with Thermal Energy Storage, demand buyback, and commercial Class 3 time related price products	80 hours, not to exceed 6 hours per day	Summer and Winter	95	$82	2012
Commercial/industrial Thermal Energy Storage	Yes, with commercial Class 3 time related price products	480 hours	Summer	6	$253	2013

To configure the supply curves for use in the System Optimizer model, there are a number of data conversions and resource attributes that are required by the System Optimizer model. All programs are defined to operate within a 5x8 hourly window and are priced in $/kW-month. The following are the primary model attributes required by the model:

- **The Capacity Planning Factor (CPF):** This is the percentage of the program size (capacity) that is expected to be available at the time of system peak. For Classes 1 and 3 DSM programs, this parameter is set to 1 (100 percent)
- **Additional reserves:** This parameter indicates whether additional reserves are required for the resource. Firm resources, such as dispatchable load control, do not require additional reserves.
- **Daily and annual energy limits:** These parameters, expressed in Gigawatt-hours, are used to implement hourly limits on the programs. They are obtained by multiplying the hours available by the program size.
- **Nameplate capacity (MW) and service life (years)**

- **Maximum Annual Units:** This parameter, specified as a pointer to a vector of values, indicates the maximum number of resource units available in the year for which the resource is designated.
- **First year and month available / last year available**
- **Fractional Units First Year:** For resources that are specified such that the model can select fractions of megawatts, this parameter tells the model the first year in which a fractional quantity of the resource can be selected. Year 2011 is entered in order to make these DSM resource options available in all years.

After the model has selected DSM resources, a program converts the resource attributes and quantities into a data format suitable for direct import into the Planning and Risk model.

Class 3 DSM Capacity Supply Curves

Supply curves were created for five discrete Class 3 DSM products, which are capacity-based resources like Class 1 DSM products:

1) residential time-of-use rates;
2) commercial critical peak pricing;
3) commercial and industrial demand buyback;
4) commercial and industrial real-time pricing; and
5) mandatory Irrigation time-of-use[45]

The potentials and costs for each product were provided at the state level resulting in five products across six states, or thirty supply curves before accounting for system load areas (some states cover more than one load area). After accounting for load areas, a total of fifty Class 3 DSM supply curves were used in the 2011 IRP modeling process.

In providing the data for the construction of Class 3 DSM supply curves, the Company did not net out one product's resource potential against a competing product. As Class 3 DSM resource selections are not included as base resources for planning purposes, not taking product interactions into consideration poised no risk of over-reliance (or double counting the potential) of these resources in the final resource plan. For instance, in the development of the supply curves for residential time-of-use the program's market potential was not adjusted by the market potential or quantity available of a lesser-cost alternative, residential critical peak pricing.

Market potentials and costs for each of the five Class 3 DSM programs modeled were taken from the estimates provided in the Updated DSM potential study and evaluated independently as if it were the only resource available targeting a particular customer segment.

Modest product price differences between west and east control areas were driven by resource opportunity differences. The DSM potential study assumed the same fixed costs in each state in

[45] This rate design is an alternative product to the voluntary Class 1 irrigation load management product and assumes regulators and interested parties would support mandatory participation with sufficiently high rates to enable realization of peak energy reduction potential.

which it is offered regardless of quantify available. Therefore, states with lower resource availability for a particular product have a higher cost per kilowatt-year for that product.

Tables 6.15 and 6.16 show the summary level Class 3 DSM program information, by control area, used in the development of the Class 3 DSM resources supply curves. As previously noted, the products were further broken down by quantity available by state and load bubble in order to provide the model with location specific information.

Table 6.15 – Class 3 DSM Program Attributes West Control area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)	Year Available
Residential Time-of-Use	Yes, with Res A/C and water heater DLC	480/600 hours	Summer and Winter	7	$13	2013
Commercial Critical Peak Pricing	Yes, with C&I curtailment, demand buyback and other Class 3 time related price products	40 hours	Summer	17	$13	2013
Commercial/Industrial Demand Buyback	Yes, with C&I curtailment and Class 3 time related price products	87 hours	Summer and Winter	6	$18	2011
Commercial/Industrial Real Time Pricing	Yes, with C&I curtailment, demand buyback and other Class 3 time related price products	87 hours	Summer and Winter	2	$8	2013
Mandatory Irrigation Time-of-Use	Yes, with irrigation DLC	480 hours	Summer	125	$9	2013

Table 6.16 – Class 3 DSM Program Attributes East Control area

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)	Year Available
Residential Time-of-Use	Yes, with Res A/C and Water Heater DLC	480/600 hours	Summer and Winter	12	$13	2013
Commercial Critical Peak Pricing	Yes, with C&I curtailment, demand buyback and other Class 3 time related price products	40 hours	Summer	100	$13	2013
Commercial/Industrial Demand Buyback	Yes, with C&I curtailment and Class 3 time related price products	87 hours	Summer and Winter	40	$18	2013

Products	Competing Strategy	Hours Available	Season	Potential (MW)	Cost ($/kW-yr)	Year Available
Commercial/Industrial Real Time Pricing	Yes, with C&I curtailment, demand buyback and other Class 3 time related price products	87 hours	Summer and Winter	23	$6	2013
Mandatory Irrigation Time-of-Use	Yes, with irrigation DLC	480 hours	Summer	182	$4-9	2013

System Optimizer data formats and parameters for Class 3 DSM programs are similar to those defined for the Class 1 DSM programs. The data export program converts the Class 3 DSM programs selected by the model into a data format for import into the Planning and Risk model.

Class 2 DSM, Capacity Supply Curves

The 2011 IRP represents the second time the Company has utilized the supply curve methodology in the evaluation and selection of Class 2 DSM energy products. The Updated DSM potential study provided the information to fully assess the contribution of Class 2 DSM resources over the IRP planning horizon and adjusted resource potentials and costs taking into consideration changes in codes and standards, emerging technologies, resource cost changes, and state specific modeling conventions and resource evaluation considerations (Washington and Utah). Class 2 DSM resource data was provided by state down to the individual measure and facility levels; e.g., specific appliances, motors, air compressors for residential buildings, small offices, etc. When compared to the 2007 DSM potential study, the number of measures in the Updated DSM potential study increased, primarily due to utilizing the relevant measure level data developed in support of the Northwest Power and Conservation Council's 6th Power Plan. In all, the Updated DSM potential study provided Class 2 DSM resource information at the following granularity level:

- **State:** Washington, California, Idaho, Utah, Wyoming
- **Measure:**
  - 126 residential measures
  - 133 commercial measures
  - 67 industrial measures
  - Three irrigation measures
  - 12 street lighting measures
- **Facility type[46]:**
  - Six residential facility types
  - 24 commercial facility types
  - 14 industrial facility types
  - One irrigation facility type
  - One street lighting type

[46] Facility type includes such attributes as existing or new construction, single or multi-family, etc. Facility types are more fully described in the Updated DSM potential study.

The DSM potential study also provided total resource costs, which included both measure cost and a 15 percent adder for administrative costs levelized over measure life at PacifiCorp's cost of capital, consistent with the treatment of supply-side resource costs. Utah resource costs were levelized using utility costs instead of total costs and an adder for administration.

The technical potential for all Class 2 DSM resources across five states over the twenty-year DSM potential study horizon totaled 12.3 million MWh. The technical potential represents the total universe of possible savings before adjustments for what is likely to be realized (achievable). When the achievable assumptions described below are considered the technical potential is reduced to a technical achievable potential for modeling consideration of 10.1 million MWh.

Despite the granularity of Class 2 DSM resource information available, it was impractical to use this much information in the development of Class 2 DSM resource supply curves. The combination of measures by facility type and state generated over 18,000 separate permutations or distinct measures that could be modeled using the supply curve methodology.[47] This many supply curves is impossible to handle with PacifiCorp's IRP models. To reduce the resource options for consideration, while not losing the overall resource quantity available, the decision was made to consolidate like measures into bundles using levelized costs to reduce the number of combinations to a more manageable number. The result was the creation of nine cost bundles; three more cost bundles than were developed for the 2008 IRP.

The bundles were developed based on the Class 2 DSM Update potential study's technical potentials. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure type was adjusted to reflect the achievable acquisitions over the 20 year planning horizon. Consistent with regional planning assumptions in the Northwest, 85 percent of the technical potential for discretionary (retrofit) resources was assumed to be achievable over the twenty year planning period. For lost-opportunity (new construction or equipment failure) the achievable potential is 65 percent of the technical over the twenty year planning period. This assumption is also consistent with planning assumptions in the Pacific Northwest. During the planning period, the aggregate (both discretionary and lost opportunity) achievable potential is 82 percent of the technical potential.

The application of ramp rates in the current Class 2 DSM is a change from the 2007 DSM Potential Study in which the technical achievable potential was assumed to be equally available in increments that were 1/20th of the total. In the updated DSM Potential Study, the technical achievable potential for each measure by state is assigned a ramp rate that reflects the relative state of technology and state programs. New technologies and states with newer programs were

[47] Not all energy efficiency measures analyzed are applicable to all market segments. The two most common reasons for this are (1) differences in existing and new construction and (2) some end-uses do not exist in all building types. For example, a measure may look at the savings associated with increasing an existing home's insulation up to current code levels. However, this level of insulation would already be required in new construction, and thus, would not be analyzed for the new construction segment. Similarly, certain measures, such as those affecting commercial refrigeration would not be applicable to all commercial building types, depending on the building's primary business function; for example, office buildings would not typically have commercial refrigeration.

assumed to take more time to ramp up than states and technologies with more extensive track records. Use of ramp rate assumptions is also consistent with regional planning assumptions in the Northwest.

Nine cost bundles across five states (excluding Oregon), and over twenty years, equates to 900 supply curves before allocating across the Company load areas shown in Table 6.17. In addition, there are compact florescent lamp (CFL) bundles for 2011 and 2012, which are discussed later in this section.

Table 6.17 – Load Area Energy Distribution by State

State	Goshen, ID	Utah	Walla Walla, Washington	South/Central Oregon and California	Wyoming	Yakima, Washington
CA				100%		
OR			4%	96%		
ID	42%	58%				
UT		100%				
WA			25%			75%
WY		18%			82%	

After the load areas are accounted for (with some states served in more than one load area as noted in table 6.17), the number of supply curves grew to 1,440, excluding Oregon.

Figures 6.3 through 6.9 show the changes in Class 2 DSM resource potential (adjusted for achievable acquisitions) by state relative to the last update conducted in 2009.

Figure 6.3 – PacifiCorp Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

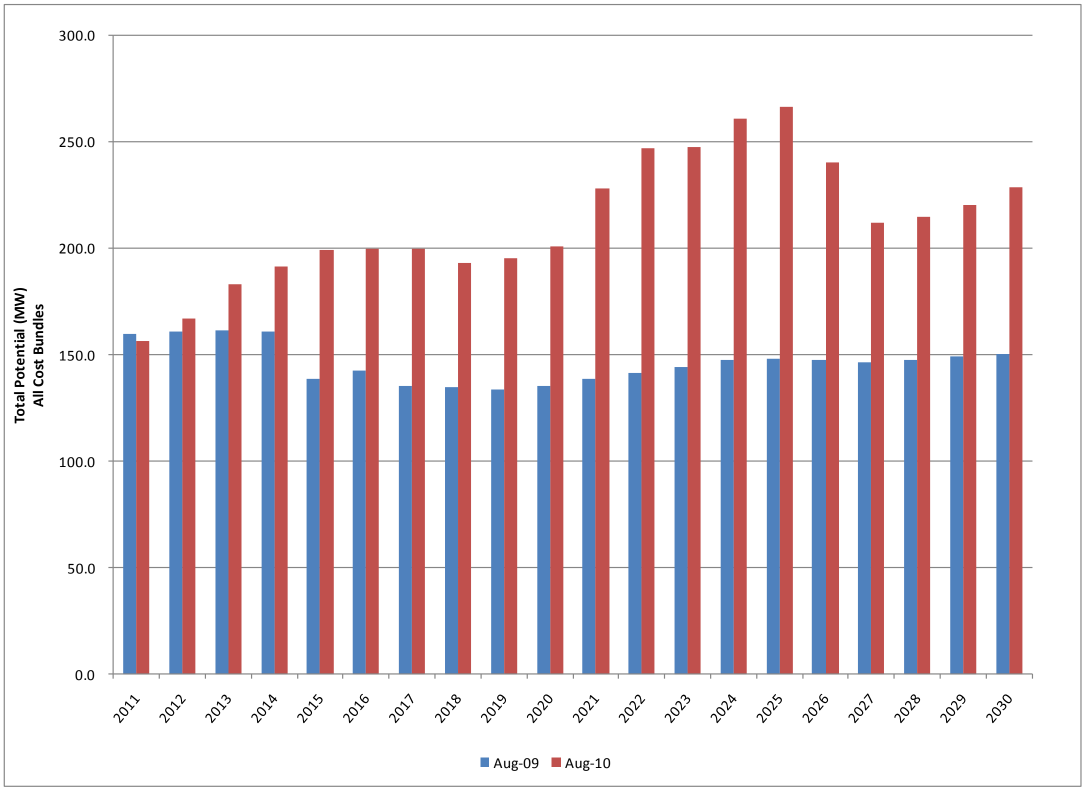


Figure 6.4 – California Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

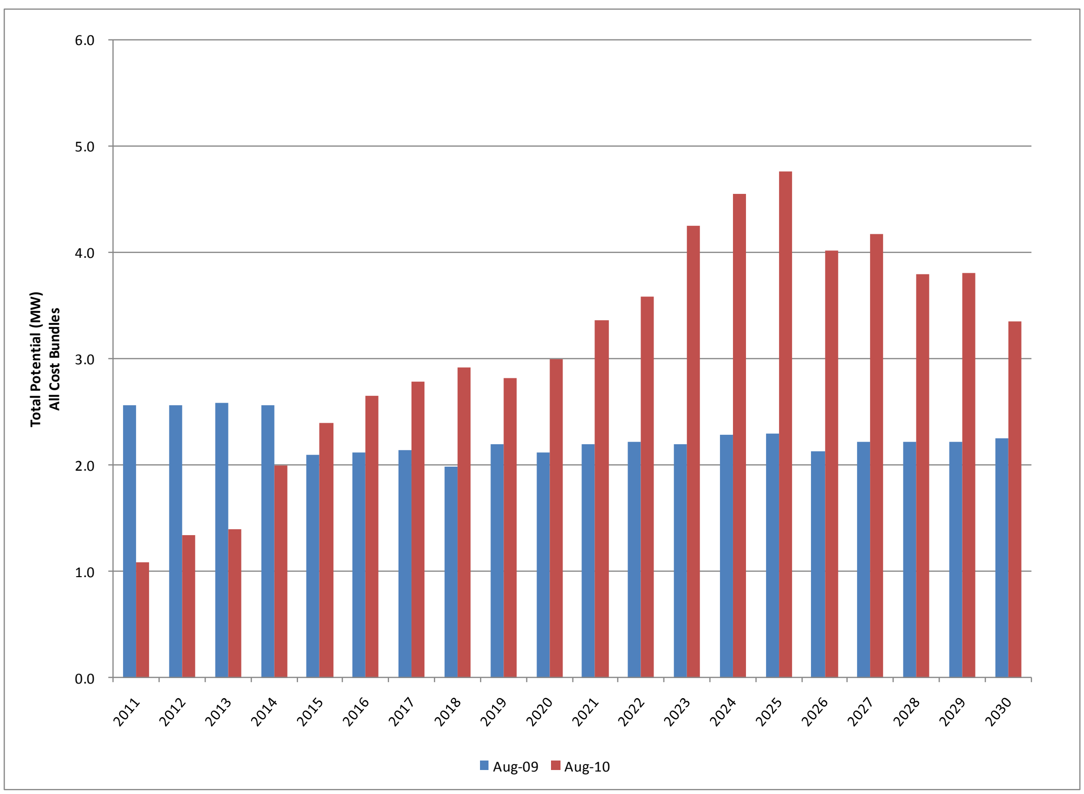


Figure 6.5 – Oregon Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

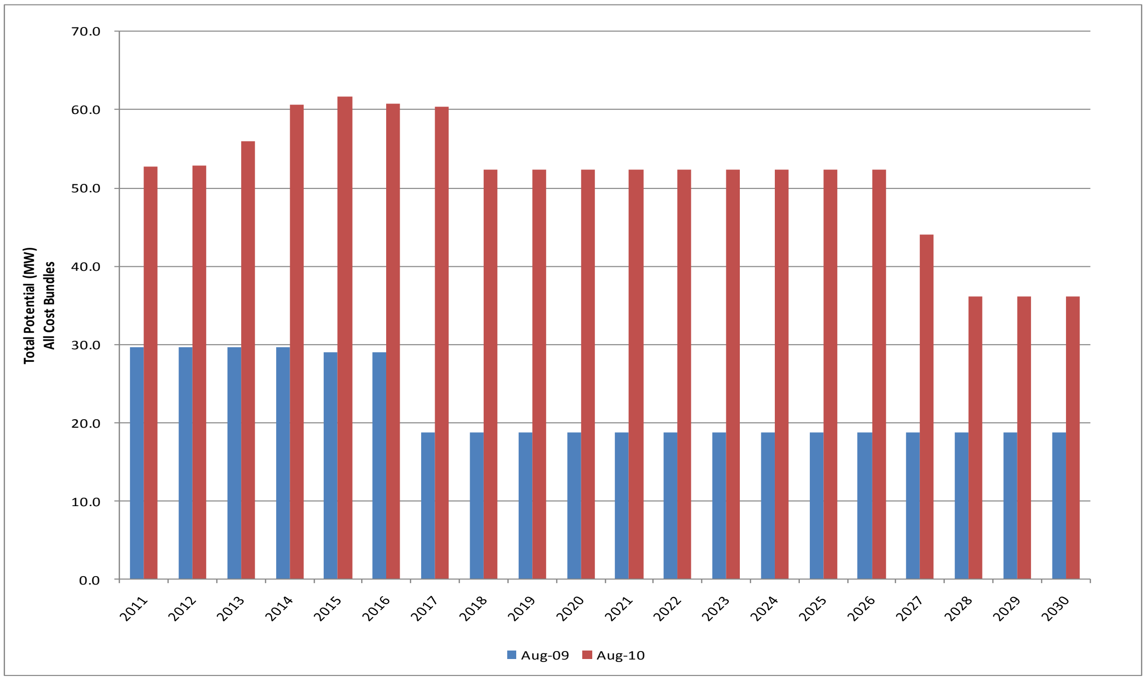


Figure 6.6 – Washington Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

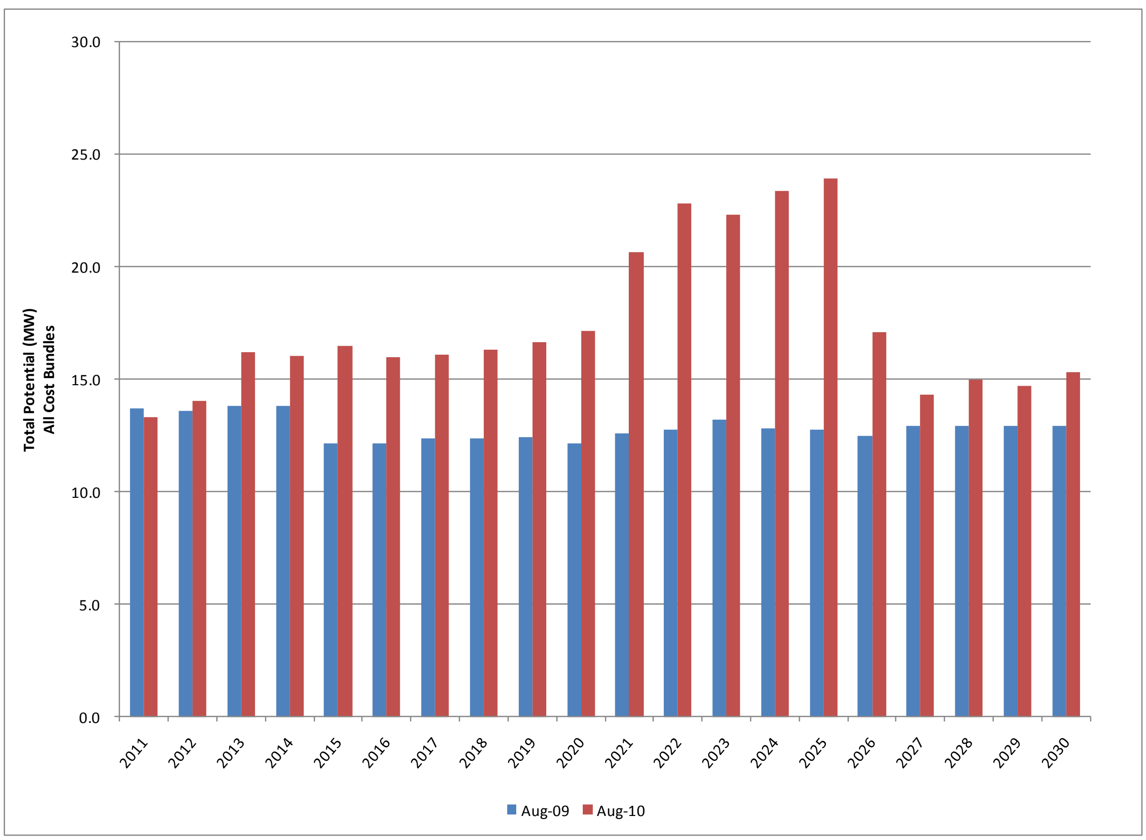


Figure 6.7 – Utah Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

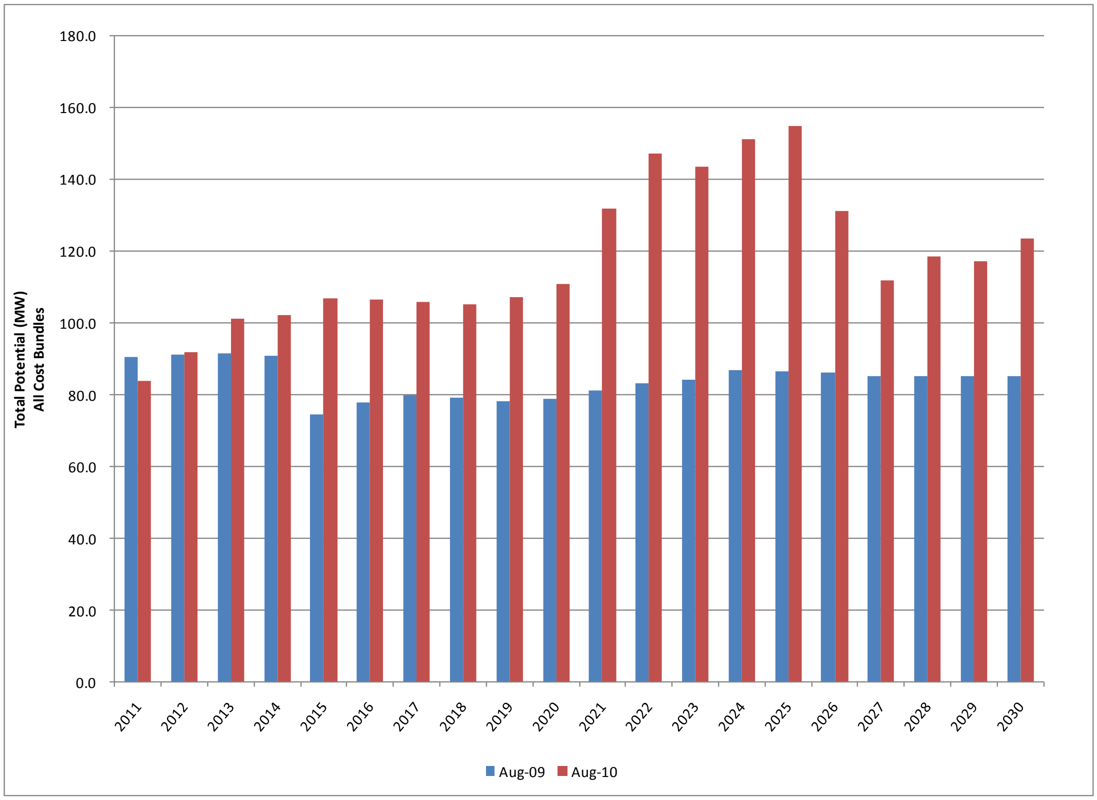


Figure 6.8 – Idaho Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

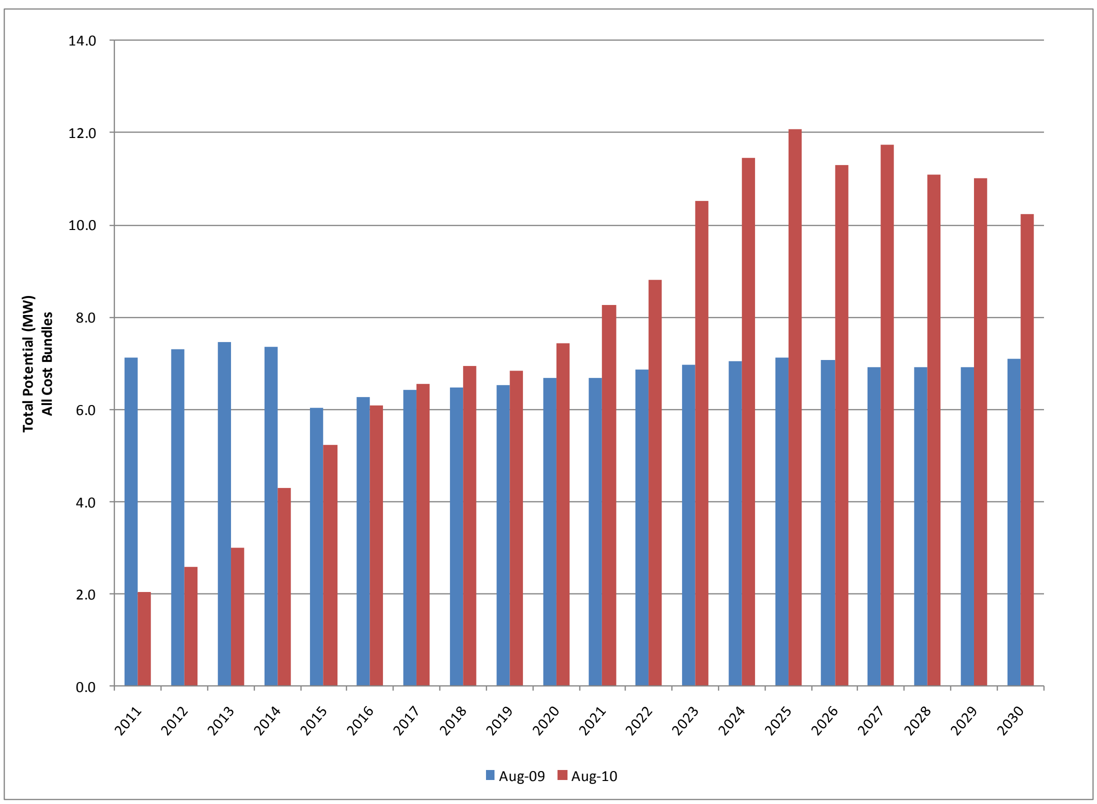


Figure 6.9 – Wyoming Class 2 DSM Potential, Aug-2009 vs. Aug-2010 Curves

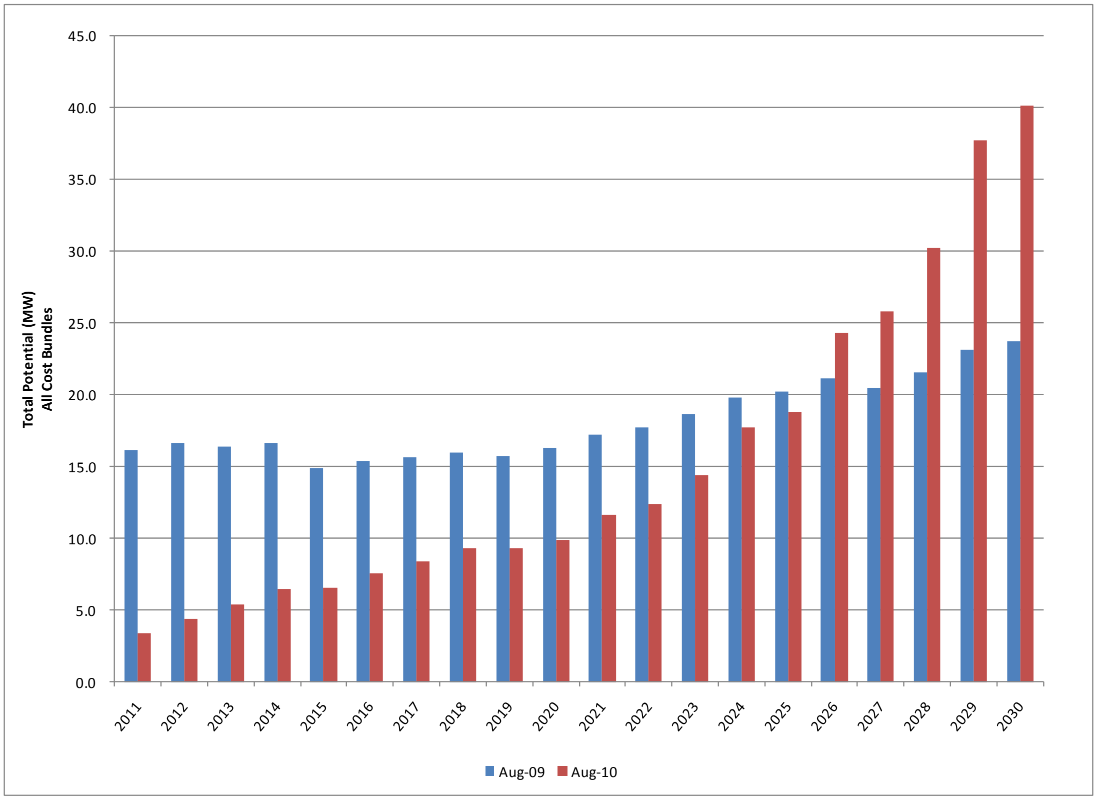


Figure 6.10 shows the Class 2 DSM cost bundles, designated by $/kWh cost breakpoints (e.g., $0.00/kWh to $0.07/kWh) and the associated bundle price after applying cost credits. These cost credits include the following:

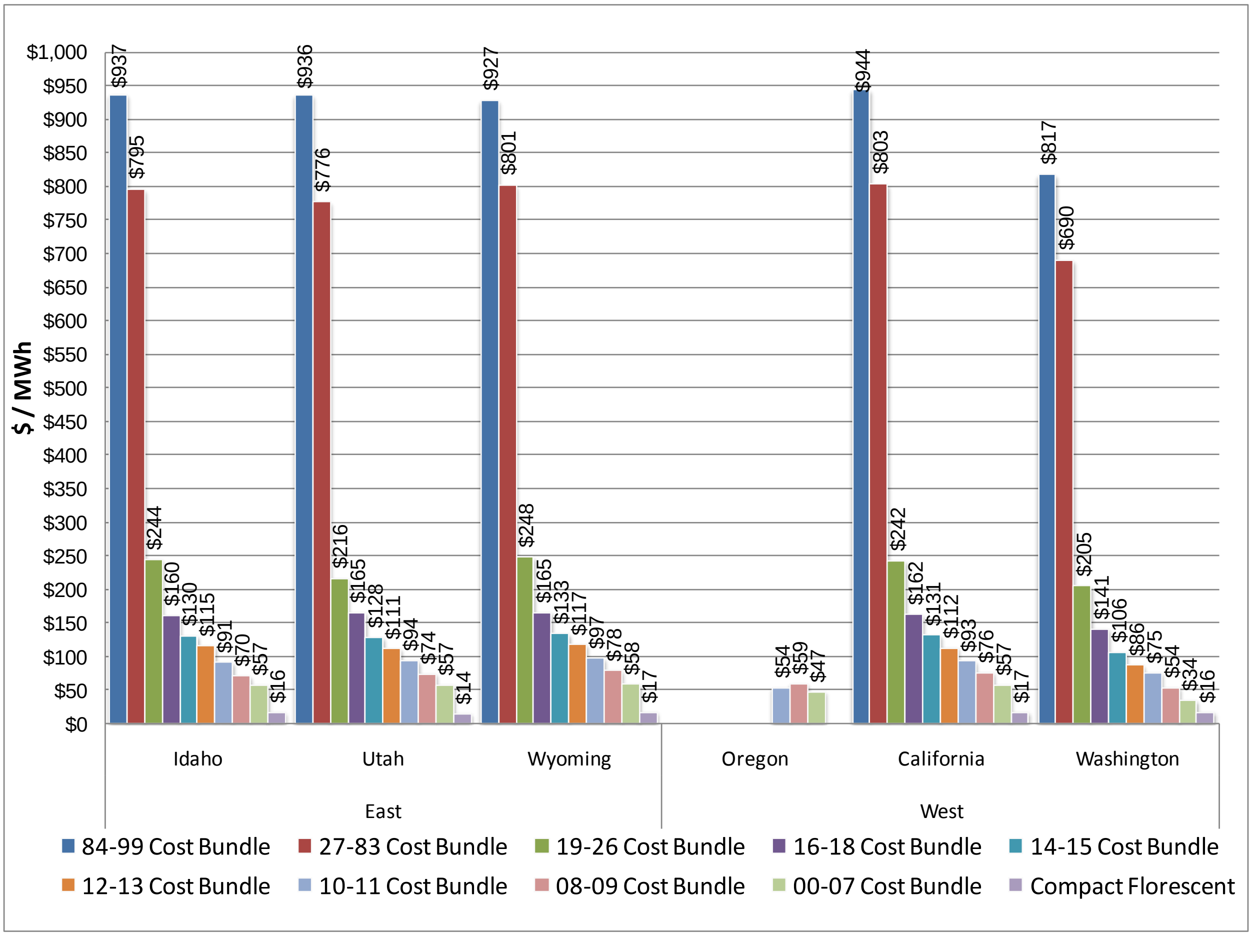
- A transmission and distribution investment deferral credit of $54/kW-year
- Stochastic risk reduction credit of $14.98/MWh[48]
- Northwest Power Act 10-percent credit (Washington resources only)[49]

The bundle price can be interpreted as the average levelized cost for the group of measures in the cost range. In specifying the bundle cost breakpoints, narrower cost ranges were defined for the lower-cost resources to improve the cost accuracy for the bundles expected to be selected by the System Optimizer model most frequently. In contrast, the highest-cost bundles were specified with the widest cost breakpoints.

[48] PacifiCorp developed this credit by assessing the upper-tail cost of 2008 IRP portfolios that included large amounts of clean resources (wind and DSM) relative to the upper-tail cost of the 2008 IRP preferred portfolio.

[49] The formula for calculating the $/MWh credit is: (Bundle price - ((First year MWh savings x market value x 10%) + (First year MWh savings x T&D deferral x 10%))/First year MWh savings. The levelized forward electricity price for the Mid-Columbia market is used as the proxy market value.

Figure 6.10 – Class 2 DSM Cost Bundles and Bundle Prices



As shown in Figure 6.10 the potential associated with standard or spiral "twister" CFLs for 2011 and 2012 were provided as separate bundles for two years. Each of the bundles utilized a $0.02/kWh levelized cost and represents the technical and achievable potentials available from this technology prior to the impact of the pending federal lighting standards. Energy savings potentials from these measures are not included in any other years during the planning horizon. However, potential from specialty CFLs and light emitting diode ("LED") measures not directly impacted by the pending lighting standard change are included in lighting resource potentials in all years.

Class 2 DSM resources in Oregon are acquired on behalf of the Company through ETO programs. The ETO provided the Company three cost bundles, weighted and shaped by the end-use measure potential for each year over a twenty-year horizon. Allocating these resources over two load areas in Oregon for consistency with other modeling efforts generated an additional 120 Class 2 DSM supply curves (three cost bundles multiplied by two load areas multiplied by twenty years).

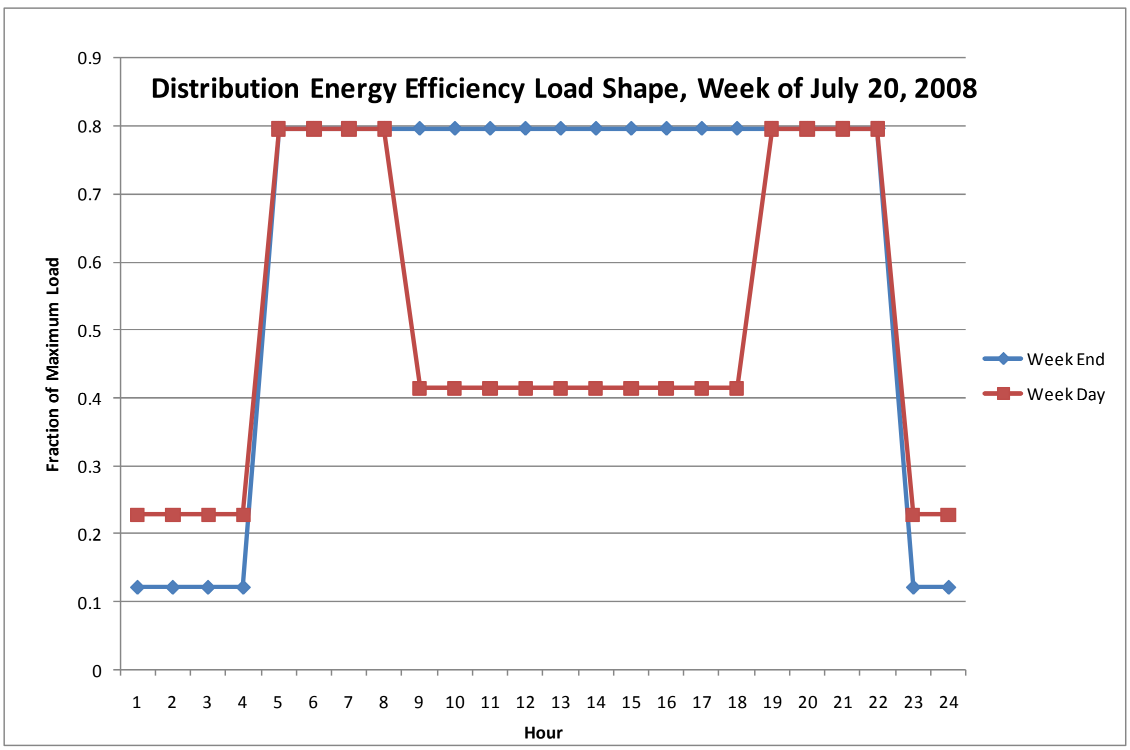
In addition to the program attributes described for the Classes 1 and 3 DSM resources, the Class 2 DSM supply curves also have load shapes describing the available energy savings on an hourly basis. For System Optimizer, each supply curve is associated with an annual hourly ("8760") load shape configured to the 2008 calendar year. These load shapes are used by the model for each simulation year. In contrast, the Planning and Risk model requires for each supply curve a load shape that covers all 20 years of the simulation.

The load shape is composed of fractional values that represent each hour's demand divided by the maximum demand in any hour for that shape. For example, the hour with maximum demand would have a value of 1.00 (100 percent), while an hour with half the maximum demand would have a value of 0.50 (50 percent). Summing the fractional values for all of the hours, and then multiplying this result by peak-hour demand, produces the annual energy savings represented by the supply curve.

Distribution Energy Efficiency

The two resource options, consisting of megawatt capacity potentials (based on six feeders for Walla Walla and 13 feeders for Yakima/Sunnyside), levelized dollars/MWh costs, and daily load shapes, were based on preliminary data provided by the consultant performing the Washington distribution efficiency study. The resource potential is small, totaling only 0.191 MW for Walla Walla and 0.403 MW for Yakima/Sunnyside. The associated levelized resource costs were \$63/MWh and \$64/MWh, respectively. The load shapes use a representative day pattern for weekdays and weekends. Figure 6.11 shows a sample load shape for the week of July 20, 2008. These load shapes are repeated for each year of the 20-year simulation. The resources are assumed to be available beginning in 2013, and the model can select a fractional amount of the total potential.

Figure 6.11 – Sample Distribution Energy Efficiency Load Shape



Transmission Resources

For this IRP, PacifiCorp investigated seven Energy Gateway scenarios, consisting of various combinations of transmission segments. Preliminary evaluation of the seven scenarios using the System Optimizer model resulted in the selection of four scenarios for portfolio modeling. Detailed information on the scenarios and associated modeling approach and findings are provided in Chapter 4.

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). Front office transactions are proxy resources, assumed to be firm, that represent procurement activity made on an annual forward basis to help the Company cover short positions.

As proxy resources, front office transactions represent a range of purchase transaction types. They are usually standard products, such as heavy load hour (HLH), light load hour (LLH), and/or daily HLH call options (the right to buy or "call" energy at a "strike" price) and typically rely on standard enabling agreements as a contracting vehicle. Front office transaction prices are determined at the time of the transaction, usually via a third party broker and based on the view of each respective party regarding the then-current forward market price for power. An optimal mix of these purchases would include a range in terms for these transactions.

Solicitations for front office transactions can be made years, quarters or months in advance. Annual transactions can be available up to as much as three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

Two front office transaction types were included for portfolio analysis: an annual flat product, and a HLH third quarter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. Third-quarter HLH transactions represent purchases received 16 hours per day, six days per week from July through September. Because these are firm products the counterparties back the full purchase. For example, a 100 MW front office purchase requires the seller to deliver 100 MW to PacifiCorp regardless of circumstance.[50] Thus, to insure delivery, the seller must hold whatever level of reserves as warranted by its system to insure firmness. For this reason, PacifiCorp does not need to hold additional reserves on its 100 MW firm front office purchase. Table 6.18 shows the front office transaction resources included in the IRP models, identifying the market hub, product type, annual megawatt capacity limit, and availability.

[50] Typically, the only exception would be under force majeure. Otherwise, the seller is required to deliver the full amount even if the seller has to acquire it at an exorbitant price.

Table 6.18 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual (“7x24”) and 3rd Quarter Heavy Load Hour (“6x16”)	400 MW + 375 MW with 10% price premium, 2011-2030
California Oregon Border (COB) Flat Annual (“7x24”) and 3rd Quarter Heavy Load Hour (“6x16”)	400 MW, 2011-2030
Southern Oregon / Northern California 3rd Quarter Heavy Load Hour (“6x16”)	50 MW, 2011-2030
Mead 3rd Quarter, Heavy Load Hour (6x16)	190 MW, 2011-2012 264 MW, 2013-2014 100 MW, 2015-2016 0 MW, 2017+
Mona 3rd Quarter, Heavy Load Hour (6x16)	200 MW, 2011-2012 300 MW, 2013+
Utah North 3rd Quarter, Heavy Load Hour (6x16)	250 MW, 2011-2030

To arrive at these maximum quantities, PacifiCorp considered the following:

- Historical operational data and institutional experience with transactions at the market hubs.
- The Company’s forward market view, including an assessment of expected physical delivery constraints and market liquidity and depth.
- Financial and risk management consequences associated with acquiring purchases at higher levels, such as additional credit and liquidity costs.

Prices for front office transaction purchases are associated with specific market hubs and are set to the relevant forward market prices, time period, and location, plus appropriate wheeling charges.

For this IRP, the Public Utility Commission of Oregon directed PacifiCorp to evaluate intermediate-term market purchases as resource options and assess associated costs and risks.[51] In formulating market purchase options for the IRP models, the Company lacked cost and quantity information with which to discriminate such purchases from the proxy FOT resources already modeled in this IRP. Lacking such information, the Company anticipated using bid information from the All-Source RFP reactivated in December 2009, if applicable, to inform the development of intermediate-term market purchase resources for modeling purposes. The Company received no intermediate-term market purchase bids; therefore, such resources were not modeled for this IRP.

[51] Public Utility Commission of Oregon, In the Matter of PacifiCorp, dba Pacific Power 2007 Integrated Resource Plan, Docket No. LC 42, Order No. 08-232, April 4, 2008, p. 36.