An Expanded Analysis of the Costs and Benefits of Base Case and Carbon Reduction Scenarios in the EIPC Process

Preliminary Results

Prepared for The Sustainable FERC Project

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1. EXECUTIVE SUMMARY

President Obama's recent announcement of a plan to regulate carbon emissions from existing power plants underscores the escalating need to plan for an electric system subject to carbon and other pollution constraints. Over the last three years, the American Recovery and Reinvestment Act-funded Eastern Interconnection Planning Collaborative (EIPC) conducted an assessment of future power sector infrastructure needs (generation and transmission) for three different energy future scenarios across the Eastern Interconnection:

- Scenario 1 (S1), a "Carbon reduction" future[1] with nationally implemented federal carbon constraints and increased energy efficiency and demand response;
- Scenario 2 (S2), a future with a regionally implemented national renewable portfolio standard; and
- Scenario 3 (S3), a business-as-usual future.

While the EIPC produced two reports describing certain costs, emissions profiles, and electricity resource shares for each of the scenarios, it did not include a comparison of total study period costs between the scenarios. EIPC did not analyze year-over-year investment requirements and annual production costs for the 2015-2040 study period. In this report, Synapse Energy Economics has done that.

This analysis underscores the need and ability to pursue the CO_2 reduction future aggressively.

Synapse has taken the modeling data available from the completed EIPC process[2] and created a framework to analyze the results for Scenarios 1 and 3 more comprehensively—over time and from a total cost perspective. **Our key findings** include:

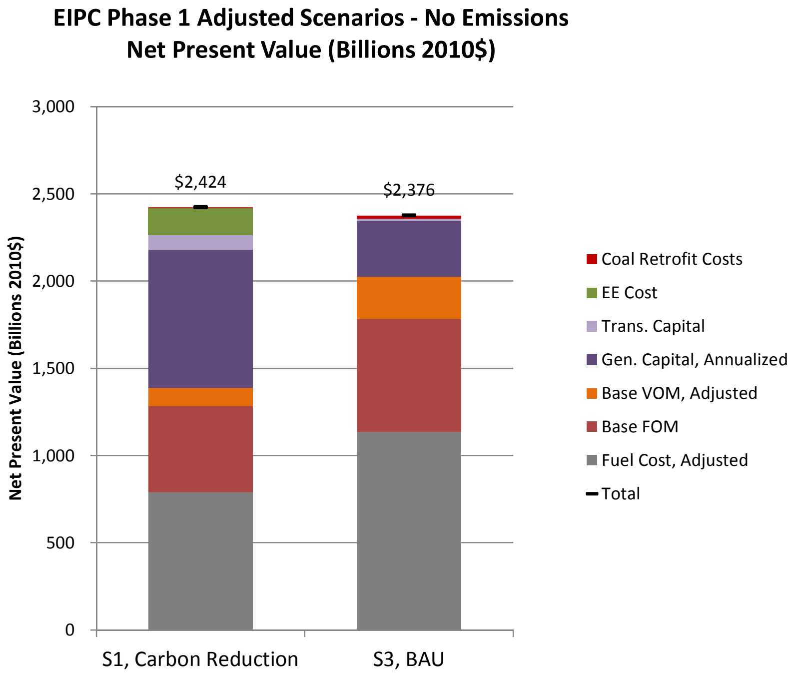
1. Excluding emissions costs, the Carbon reduction future (S1) would have nearly the same cost over time as the business-as-usual future (S3). The overall net present value of costs for each future during the 2015-2040 study period is approximately $2.4 trillion ($2.424 trillion vs. $2.376 trillion). The Carbon reduction scenario (S1) is the only scenario in which a CO2 cost is actually accounted for by EIPC, which initially appears to result in a higher total net present value of costs

[1] In Phase I of EIPC, the Carbon reduction policy (Scenario 1) was called the "Combined Federal Climate and Energy Policy" future, which was defined as follows: "Reduce economy-wide carbon emissions by 50% from 2005 levels in 2030 and 80% in 2050 combined with meeting 30% of the nation's electricity requirements from renewable resources by 2030 and significant deployment of energy efficiency measures, demand response, distributed generation, smart grid and other low-carbon technologies; achieved by utilizing a nation-wide/eastern interconnection-wide implementation strategy." See EIPC Phase I Report at ix.

[2] We note there are a number of ways in which future planning processes can leverage the work initiated by EIPC, building upon that effort to develop robust and refined regional and interregional plans to expand and upgrade U.S. power system infrastructure. Synapse's recommendations for further analyses—including additional production cost modeling, analysis of investment streams to finance different scenarios and analysis of energy efficiency resource costs—are presented in section 5 of this report.

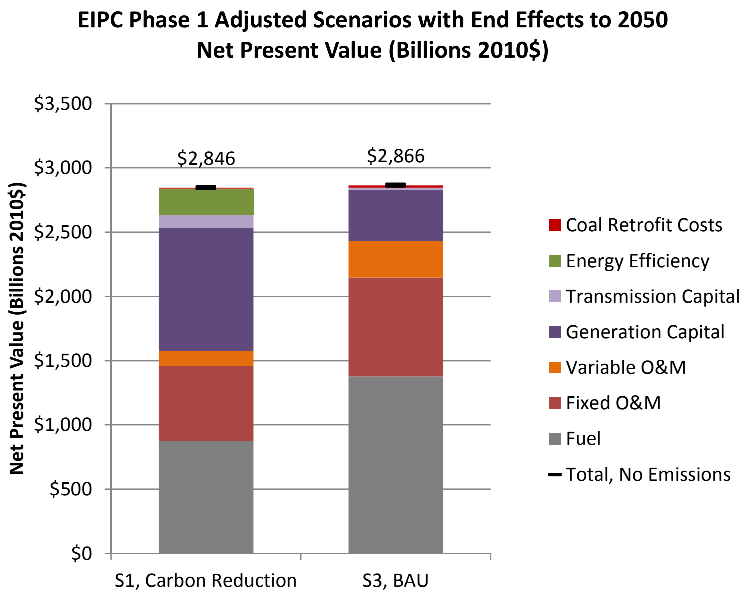
relative to S3 business-as-usual costs. However, if the costs of the increased CO2 emissions in the business-as-usual case (S3) are factored into the analysis (see discussion in paragraph 3 below), then the business-as-usual case is much more expensive. And if the CO2 price is treated either as a cost that is recycled back into the provision of new resources, energy efficiency, or directly back to customers— or if a commensurate CO2 cap instead of a CO2 price is used to achieve comparable CO2 reductions in the S1 case—then (as the chart below shows) the Carbon reduction future is only 2 percent more costly than the business-as-usual future.

Figure 1. Net present value of revenue requirements of S1 and S3—excluding CO_2 emissions cost



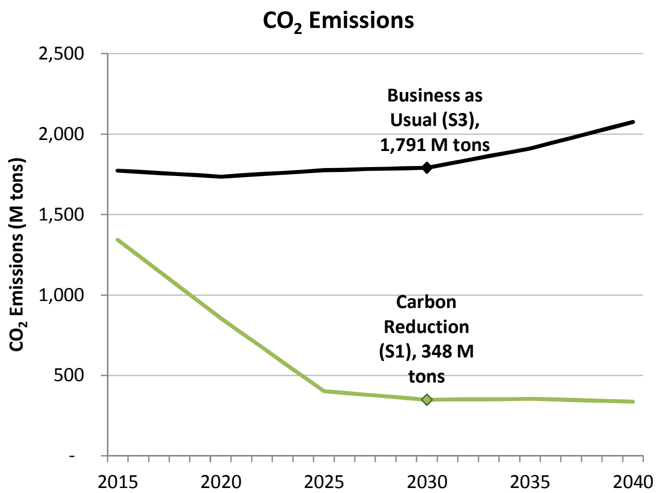
2. In addition, the further out one looks, the more attractive a low-fuel economy/carbon reduction future becomes. Although the business-as-usual scenario (S3) appears to have a marginally lower overall cost through 2040 (if emissions reductions are not factored into the analysis), the present value cost trajectories of S1 and S3 actually cross just a few years later. Despite the fact that these two scenarios have different goals and create very different electric systems by 2040, the present value differences between the two scenarios are easily within a margin of error (2%); and, as Figure 2 below shows, the net present value of revenue requirements for S1 would be $20 billion lower than for S3 if the period of analysis was extended to 2050 from 2040 (even without factoring in emissions reductions).

Figure 2. Net present value of revenue requirements of S1 and S3, including extension period to 2050



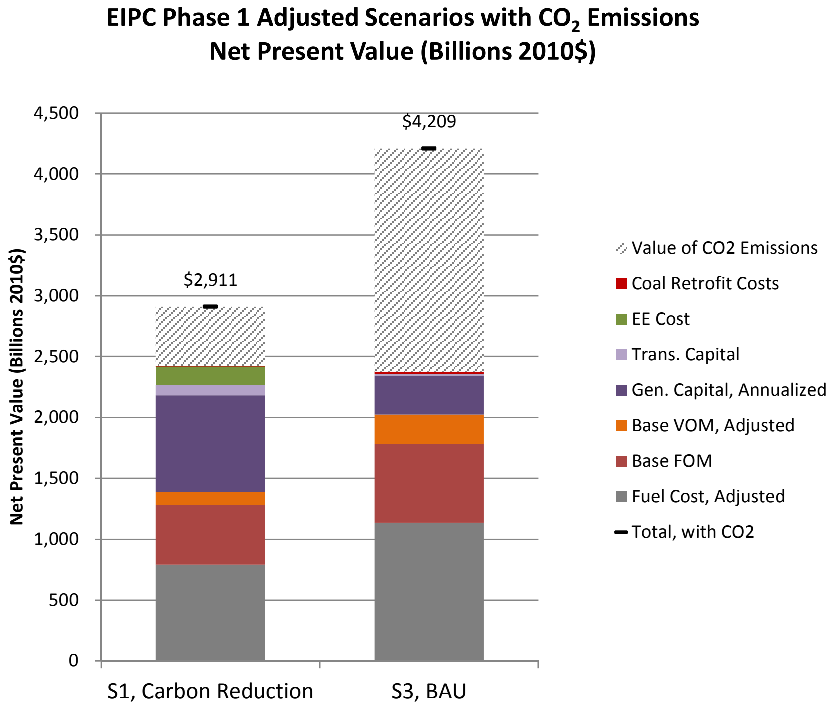
3. Unlike the business-as-usual future, the Carbon reduction future **reduces more than 30 billion tons of CO_2** by 2040, equivalent to five years' worth of U.S. national emissions. Any difference in present value revenue requirements between these two futures (see discussion in paragraphs 1 and 2 above) is completely overshadowed by the significant benefits of the carbon reductions seen in the Carbon reduction future (S1). As designed, the Carbon reduction scenario's carbon emissions rapidly fall as coal resources are retired out of the system – dropping 51 percent by 2020 and 80 percent by 2030 on an annual basis compared to S3. In contrast, the CO_2 emissions of the business-as-usual future rise by 17 percent over the analysis period, creating a wide gap. See Figure 3 below.

Figure 3. Carbon emissions profile, 2015-2040, Scenarios 1 and 3



Over the full analysis period, the Carbon reduction future (S1) results in nearly 33 *billion* fewer tons of CO_2 in the atmosphere than business-as-usual (S3), all from within the electric sector. As Figure 4 below demonstrates, if the carbon emitted in the business-as-usual future (S3) were assigned the same value as the price charged for carbon emissions in the Carbon reduction future (S1), the business-as-usual (S3) cost increase would be significant – making the Carbon reduction future the much more attractive alternative.

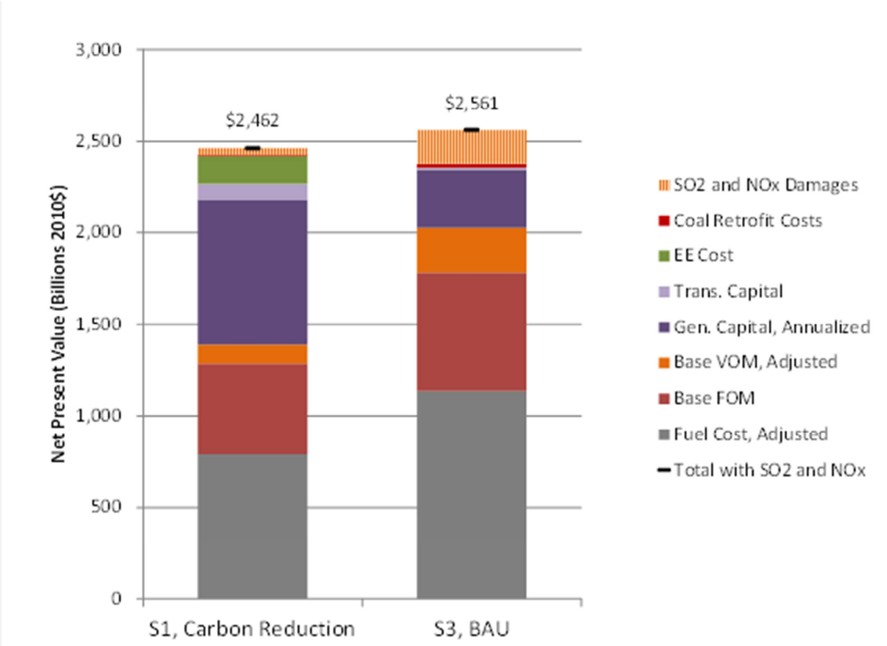
Figure 4. Net present value of revenue requirements of S1 and S3 with consistent valuation of CO_2 emissions



4. In addition, tens of millions of tons of SO_2 and NO_x are also reduced in the Carbon reduction scenario. If these emissions benefits were monetized, the Carbon reduction future would clearly be superior to the business-as-usual future (even without considering the significant CO2 reductions in S1 discussed in paragraph 3 above). From a public health standpoint, such avoided SO_2 and NO_x emissions could be very significant. Applying a National Academies of Science valuation method,[3] weighted average damage per ton, for the value of NO_x and SO_2 avoided emissions, the S1 future would avoid the premature mortality of approximately 36,000 statistical individuals just from improving poor air quality. This translates into a value for avoided mortality of about $146 billion, and this difference may be seen in Figure 5 below, which does not include the costs or valuation of carbon dioxide.

[3] In 2010, the National Academies of Science (NAS) produced a report that provided estimated damages per ton of NOx and SO2 emissions released from mid- to large coal and gas generators, where damages were "monetized statistical lives" (i.e., premature mortality).

Figure 5. Net present value of revenue requirements of S1 and S3 with valuation of health damages from SO_2 and NO_x



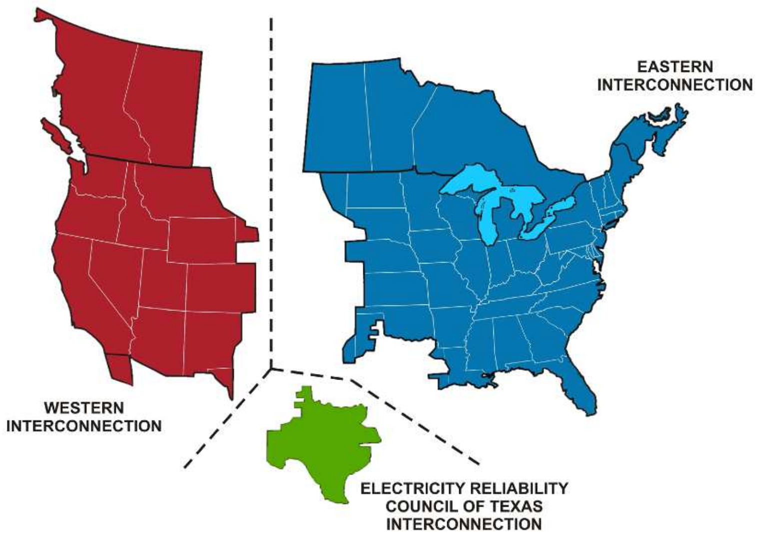
Our study also examined expanded analyses of EIPC scenarios, focusing on production costs, capital expenditure assumptions, and the costs of energy efficiency, as well as sensitivities related to wind resource impacts. These analyses are described in Sections 3 and 4 of our report.

This analysis underscores the need *and ability* to aggressively pursue a Carbon reduction future.

2. BACKGROUND

The Eastern Interconnection is the largest interconnected electrical grid in the United States, connecting 39 states, the District of Columbia, and much of Canada.

Figure 6. North American Electric Reliability Corporation Interconnections



In 2009, 23 of the electrical transmission planning authorities (planners for approximately 95 percent of the peak customer demand in the Eastern Interconnection) created the Eastern Interconnection Planning Collaborative (EIPC). The Department of Energy awarded the EIPC a $16 million, 3-year grant to fund an assessment of electrical transmission expansion options to support a range of possible energy futures over the next 20 years.

The DOE funding promoted collaborative, open, and transparent long-term electrical planning analyses by a range of stakeholders including state and federal policymakers, consumer and environmental interest organizations, transmission planners, and entities generating, transmitting, or consuming electricity within the Eastern Interconnection.

The EIPC analyzed in detail the electrical demand and supply, as well as the transmission resource implications, of three different electric sector energy futures. Those resource scenarios, selected through an intensive and collaborative stakeholder process during Phase I of the EIPC process, included the following:

- Scenario 1 (S1), a "combined policies" or "Carbon reduction" future with nationally implemented federal carbon constraints and increased energy efficiency/demand response;
- Scenario 2 (S2), a future with a regionally implemented national renewable portfolio standard; and

- Scenario 3 (S3), a business-as-usual future.

The EIPC process produced two reports delivered to the US DOE, one for each of the two main phases of the project, Phase I and Phase II.

2.1. EIPC Phase I

Phase I of the EIPC process integrated all existing transmission plans into one working power flow model for the entire Eastern Interconnection, and used the proprietary Charles River Associates "MRN-NEEM" model to select the most cost-effective set of resources to support various policy-driven futures for the planning period 2015-2040.[4] The NEEM model automatically added or removed different types of generation based on economics, generation characteristics, and multiple input assumptions, selecting the most economic (i.e., lowest cost) generation additions and retirements within specific regions to fulfill the requirements of each resource future, and produced specific expansion results for each five-year interval of the overall planning period. A total of roughly 80 NEEM model runs were executed, and the stakeholders participating in EIPC chose the three specific scenarios listed above (S1, S2, and S3) from these runs for further study in Phase II.

2.2. EIPC Phase II

The purpose of Phase II was: (1) to develop and assess transmission grid expansion plans that would reliably support each of the S1, S2, and S3 energy futures, (2) to evaluate the estimated costs of overall power production and supply in each of the three futures for the year 2030, and (3) to estimate generation, transmission, and various "other" costs for the three scenarios.

To achieve these goals, Phase II developed transmission expansion "buildouts" and then ran detailed production cost modeling for the three selected scenarios. To develop the transmission expansion needs for each of the three selected scenarios, the EIPC stakeholders used a traditional transmission planning tool (power flow modeling). The generation builds and retirements for each of the three chosen scenarios were integrated into the power flow model, and then the model was used to evaluate potential future grid reliability problems (using standard industry reliability tests). The transmission planners and stakeholders participating in EIPC then developed transmission expansion plans designed to support reliably the different needs of the three futures, adding transmission upgrade solutions to the power flow model until the reliability issues were resolved. The transmission expansion analysis framework consisted primarily of two components: generation interconnection requirements and

[4] A power flow model is a sophisticated mathematical computer modeling tool used to examine the power flows on the electric power transmission network for specific load, resource, and transmission asset scenarios. It is the primary tool used in industry to assess the reliability of the electric power grid under many different operating circumstances. The MRN-NEEM model is a combined resource expansion and simplified dispatch/production cost analysis tool. It is sometimes referred to as just the "NEEM" model, reflecting the use of just the electric power sector portion of the model. The NEEM model uses a more rudimentary representation of transmission than the power flow model.

transmission constraint relief. Each of the three different resource futures resulted in distinct transmission grid buildouts to support their electrical needs.

Charles River Associates ("CRA") then used the GE MAPS hourly production cost platform, which incorporates a fairly detailed representation of the transmission system, for the production cost analyses. This model simulates a security-constrained economic dispatch and security-constrained unit commitment to approximate the actual operation of the electric power grid. This production cost model was run on each of the three futures, using the generation mix identified in Phase I and the newly enhanced transmission systems developed in Phase II. The production cost modeling was conducted for a single year–2030.

The Phase II EIPC report summarizes the costs and benefits of the three modeled scenarios with a summary table containing two groups of data: 1) the 2030 operations and maintenance ("O&M") costs of each scenario, mainly fuel and variable O&M costs (from the GE MAPS production cost modeling results), and 2) a snapshot of the "overnight capital costs" (literally, the cost to build something if it could be built overnight, exclusive of carrying costs, expressed in the report in constant or "real" 2010$ currency) required for the supply and demand resource expansions, as well as for the transmission buildouts that accompanied the three scenarios. This scenario-based listing also included projected costs associated with fixed O&M, energy efficiency, demand response, integration of variable resource output, CO_2 costs (if and to the extent modeled), pollution retrofit costs, and nuclear uprate costs. These costs were reflected either as annual operating costs in 2030 or as capital investment requirements accumulated over the 2015-2030 period. This table is reproduced below.

Table 1. EIPC Scenario Results as Presented in the Phase II Report

2030 O&M Costs - ($2010 Billions)			
Costs	Scnenario 1: Combined Policy	Scenario 2: RPS Implimented Regionally	Scenario 3: Business as Usual
Production Costs - Fuel	$ 40.8	$ 73.8	$ 85.1
Production Costs - Variable O&M	$ 6.4	$ 15.5	$ 18.4
CO2 Costs	$ 45.3	$ 0.1	$ 0.2
Policy Driven Energy Efficiency	$ 8.9	$ 1.5	$ 1.5
CO2 Price Driven Energy Efficiency	$ 10.0	$ -	$ -
Demand Response O&M	$ 0.6	$ 0.3	$ 0.3
Variable Resource Integration	$ 2.9	$ 2.5	$ 1.0
Fixed O&M	$ 34.7	$ 52.1	$ 48.1
Total O&M Costs	$ 149.6	$ 145.8	$ 154.6
Total O&M Costs without CO2	$ 104.3	$ 145.7	$ 154.4

Overnight Capital Costs for Capital through 2030 ($2010 Billions)			
Costs	Scnenario 1: Combined Policy	Scenario 2: RPS Implimented Regionally	Scenario 3: Business as Usual
Transmission -Generation Interconnection	$ 49.6	$ 54.3	$ 7.3
Transmission - Constraint Relief	$ 48.4	$ 13.0	$ 7.9
Transmission - Voltage Support	$ 0.5	$ 0.1	$ 0.2
Generation	$ 868.1	$ 679.4	$ 242.3
Nuclear Uprates	$ 4.9	$ 4.9	$ 4.9
Pollution Retrofit Costs	$ 6.8	$ 20.2	$ 22.0
Distributed Generation	$ -	$ -	$ -
Total Capital Costs	$ 978.3	$ 771.9	$ 284.6

Source: "Phase 2 Report: DOE Draft - Part 1 Interregional Transmission Development and Analysis for Three Stakeholder Selected Scenarios," page 6. This report is listed on the EIPC website as "Final Version Submitted to DOE," though the title contains the reference "DRAFT." Available at: *http://www.eipconline.com/uploads/20130103_Phase2Report_Part1_Final.pdf*.

While the EIPC Phase II report describes how these costs were determined, it does not attempt to rationalize or apportion the capital investment costs across the time periods up to and beyond 2030. The report also did not attempt to project, extrapolate, or interpolate the modeling results from either Phase I or Phase II to determine an expected pattern of operating costs for any year other than 2030. Thus, the results as presented do not provide a comprehensive assessment of the relative values of the three scenarios. In particular, without further analysis of the EIPC results there is no way to directly compare the net present value impacts of (S1) the Carbon reduction case to (S3) the business-as-usual case - due to the limited temporal information. This analysis attempts to provide the data for such a direct comparison.

2.3. Synapse Analysis

In this analysis, Synapse takes the next step of placing EIPC results into an appropriate temporal context – i.e., annualizing all production and investment costs – and using a "present value" framework, (sometimes referred to as a "present value revenue requirements" (PVRR) framework) to compare the energy resource futures.[5] Synapse placed the EIPC results into the "appropriate temporal context" by evaluating the costs and benefits associated with each of the modeled scenarios for each year of the time period 2015-2040, thereby permitting the underlying economics of each scenario's costs and benefits to be compared in greater detail than by using only a one-year (2030) snapshot.[6] We then computed the present value of annual total cost streams inclusive of both production costs and capital investment required for each scenario.

We focus primarily on the cost-effectiveness of (S1) the carbon reduction case, as compared with (S3) the business-as-usual case.[7] The analysis we provide takes all of the relevant data from EIPC modeling results, both Phase I and Phase II, and constructs a temporal framework in which one can make rational comparisons between the scenarios. Our construct is one that is often utilized in Integrated Resource Planning – i.e., it determines the present value of the revenue requirements for a number of different alternatives, including the common components studied in the EIPC process (resource supply, demand, and transmission). The revenue requirements in this analysis are determined for each of the years 2015 through 2040 (and through 2050 for an "end effects" assessment, as described in Section 4.2), and then a present value computation is performed to arrive at comparative present value revenue requirements for each of the scenarios.

To provide a reasonable estimate of the total present value revenue requirements of each scenario examined in Phase II, we needed an annual estimate of both the production costs of energy (i.e., fuel, operations and maintenance, and emissions), capital expenditures for new and uprated existing

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[5] Present value revenue requirements analysis is a standard industry method for comparing resource expansion plans.

[6] We based our analysis on an understanding of the different models used in Phase I and Phase II, using the data available in Phase I to help assess patterns of expected production costs that can be aligned with the information available for just one year (2030) in Phase II. Once the analytical framework was in place, we undertook a PVRR analysis designed to place the scenarios on an appropriate economic footing for comparison, and then evaluated the effect of modifying some of the input parameters. Finally, Synapse considered the value of emissions reductions, which are important because the emissions profiles of the scenarios differ dramatically, so that an overall "apples to apples" comparison of the scenarios could be made. Synapse includes these additional analyses in this report.

[7] Our focus does not imply that some form of national RPS policy (Scenario 2) cannot also be cost-effective. Instead, as discussed in this report, our analysis indicates that Scenario 2 as modeled, with restricted input assumptions and modeling limitations defined in the EIPC process, was unable to take advantage of (and thus represent) the benefits of the broad array of high quality wind resources modeled in Scenario 1 and the full capabilities of an expanded transmission system. Thus, to be more cost effective, a national RPS policy would likely need to be modeled and implemented in a different manner than was modeled at EIPC.

generation, environmental control project costs, transmission expansion costs, and costs for energy efficiency. We analyzed all of the same cost components as were included in the EIPC process.

EIPC's Phase I provided production costs and levelized capital expenditures for every five years, and these costs could be annualized, but Phase II required the addition of costs that were not considered in Phase I (e.g., energy efficiency costs), adjustments to account for changes in dispatch that resulted from more detailed production cost modeling in Phase II, and a clear set of capital expense trajectories. The following section describes how production costs and capital spending results from Phase I and Phase II were merged, reconciled and annualized.

The following steps were executed to estimate annual bulk power costs:

- Compare Phase I and II production costs;
- Reconcile Phase I production costs with Phase II production costs for the year 2030;
- Extend adjustments for Phase I production costs through all other years (2015-2040);[8]
- Annualize capital expenditures for new build generation;
- Annualize capital expenditures for new transmission and environmental retrofits; and
- Estimate the annual cost of energy efficiency for S1, reconciled with the single-year 2030 costs presented in Table 1 (the EIPC Phase II report results).

3. Expanded Analysis of EIPC Scenarios

3.1. Production Costs

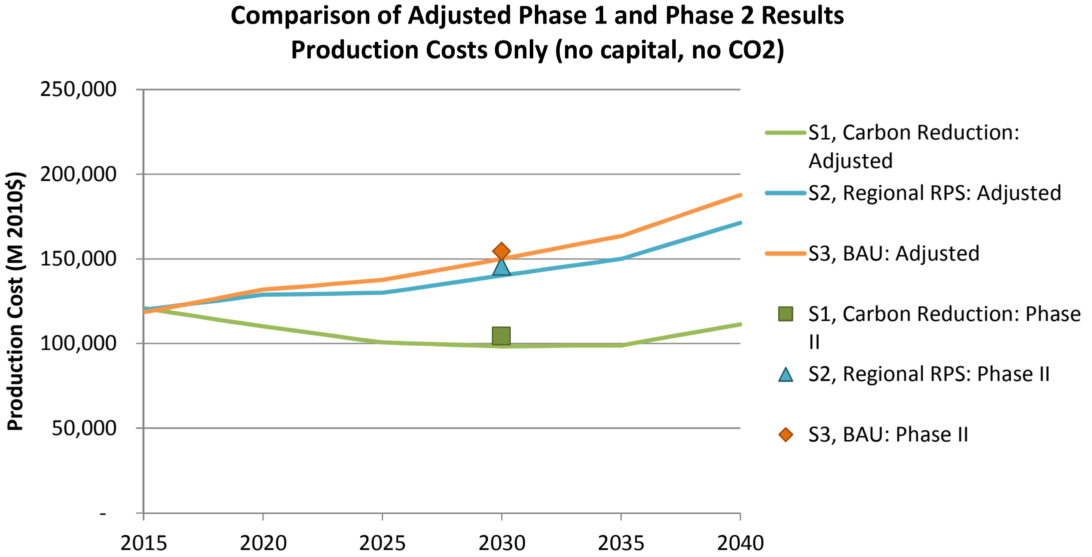
Comparison of Phase I and II production cost estimates

Phase I production costs were provided for every five-year period between 2015 and 2040, while the much more detailed Phase II production cost estimates were only provided for the year 2030.We can compare total Eastern Interconnection production costs from Phase I and Phase II for the year 2030 (see Figure 7, below). In aggregate, the production costs of (S3) business-as-usual and (S2) regional RPS implementation were captured by the Phase I model (MRN-NEEM) in a manner that provided results consistent with the Phase II model (GE MAPS) results for the year 2030. However, S1 production cost

[8] The result of all of these adjustments (discussed in greater detail in Section 3 below) is that – for purposes of this report and analysis – the total aggregate Phase I production costs associated with the Carbon reduction future (S1) are increased substantially, especially from 2030 forward, and the Phase I production costs for the business-as-usual (S3) and RPS future (S2) are adjusted downwards slightly for those same years. See Figure 14, and discussion in Section 3 below.

results from Phase I for the year 2030 are significantly lower than in Phase II—about $30 billion (nearly 40 percent)—suggesting that Phase I fails to capture all of the production costs for S1 in the year 2030.

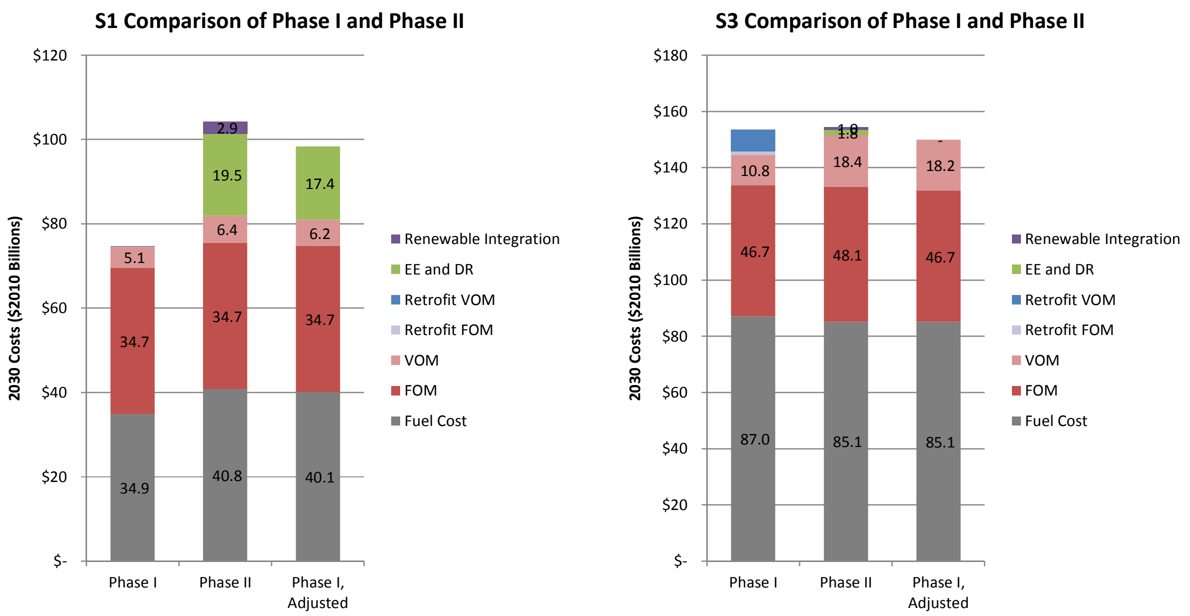
Figure 7. Comparison of Phase I and II adjusted production costs (no capital investments, no emissions costs)



There are a number of reasons that the Carbon reduction scenario (S1) production cost results are not consistent between Phase I and Phase II, requiring the adjustments discussed in this section (the final results of which are shown in Figure 7 above). Much of the difference can be attributed to the simple fact that energy efficiency (EE) and demand response (DR) were not assigned an explicit cost in Phase I (66 percent of the difference between Phase I and Phase II for 2030). Other important factors include significantly higher fuel and variable O&M costs in Phase II (24 percent of the difference), and the absence of renewable energy integration costs in Phase I (10 percent of the difference). Fixed O&M was not modeled explicitly in the Phase II production cost modeling, and thus it is not markedly different between Phase I and II for any scenario. See Figure 8.

In contrast, S3 (business-as-usual) has almost identical production costs in 2030 for Phase I and Phase II – different by only half of a percent. There are only minor differences in fuel use and the O&M expense differences are split between O&M for generating units and O&M specifically associated with environmental controls ("retrofit VOM/FOM"), but, in aggregate, the production costs for the business-as-usual case in Phase I and Phase II are quite similar.

Figure 8. Comparison of production cost components in Phase I and II for (S1) Carbon reduction future, left and (S3) business-as-usual, right



In contrast, (S3) business-as-usual has almost an identical production costs in 2030 for Phase I and Phase II – different by only half of a percent. There are only minor differences in fuel use, and the O&M expense differences are split between O&M for generating units and O&M specifically associated with environmental controls ("retrofit VOM/FOM"), but, in aggregate, the production costs for the business-as-usual case in Phase I and Phase II are quite similar.

In sum, the business-as-usual case has similar production costs between Phase I and Phase II for 2030, whereas the Carbon reduction future has more significant differences in production costs for 2030, because the business-as-usual case did not add as much energy efficiency or demand response as the Carbon reduction future, and also did not have the renewable energy integration costs that were added to the CO_2 reduction future in Phase II. Also, the fuel and variable O&M costs for S1 were notably higher in Phase II (compared to Phase I) because hourly production cost modeling (used in Phase II) captures the increased fuel use seen when gas-fired units ramp and cycle more frequently to balance the system. This was not captured with the much more simplified production cost modeling used in Phase I. This effect is not seen in S3 because it has relatively lower ramping and cycling of gas-fired units compared to S1 (because S3 has much less wind on the system); thus in Phase II, balancing the hour-to-hour energy needs of S3 does not require as much ramping and cycling of gas-fired units as is needed with S1.

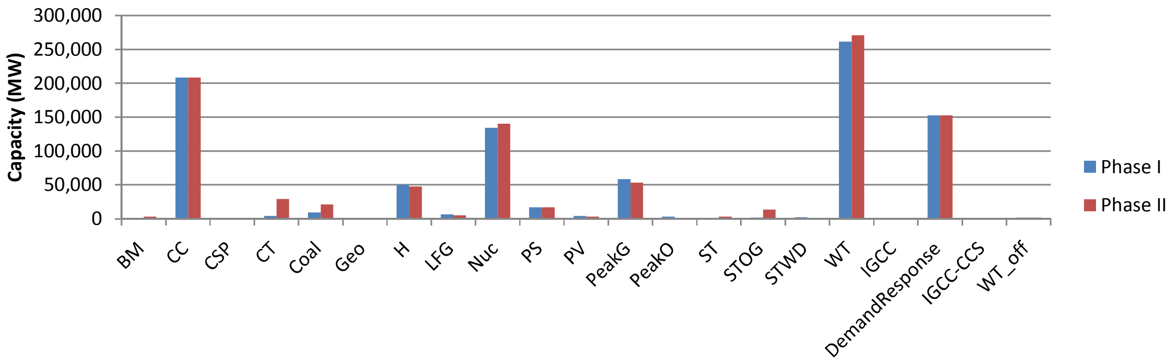
To create a reasonable annual stream of costs for comparison purposes, it became critical to adjust the Phase I production cost numbers from S1 upwards so that they incorporated the cost of EE and DR, and renewable energy integration costs, and also properly reflected fuel and O&M costs similar to those projected in Phase II.

Reconcile Phase I production costs for consistency with Phase II, 2030

The first task was to recognize the differences between the model outputs from Phase I and Phase II that led to specific production cost differences in the year 2030, and then to create a logical and consistent adjustment mechanism that allowed changes at a very fine scale of granularity. This step was necessary to reconcile the Phase I production costs (from the MRN NEEM model) for consistency with the more rigorous production cost modeling in Phase II for the year 2030 (from GE MAPS). Both of these EIPC models reported capacity, generation, total fuel costs, O&M costs, and emissions costs for 2030 for various fuel or resource types (e.g., coal, natural gas combined cycle, wind, etc.) for each of 24 Eastern Interconnection regions. Accordingly, multiple variables were required to adjust fuel and O&M costs across the interconnection and, as a result, there were minor differences in capacity from Phase I to Phase II, minor to significant differences in capacity factors, and even differences in fuel costs ($/megawatt hour or MWh).

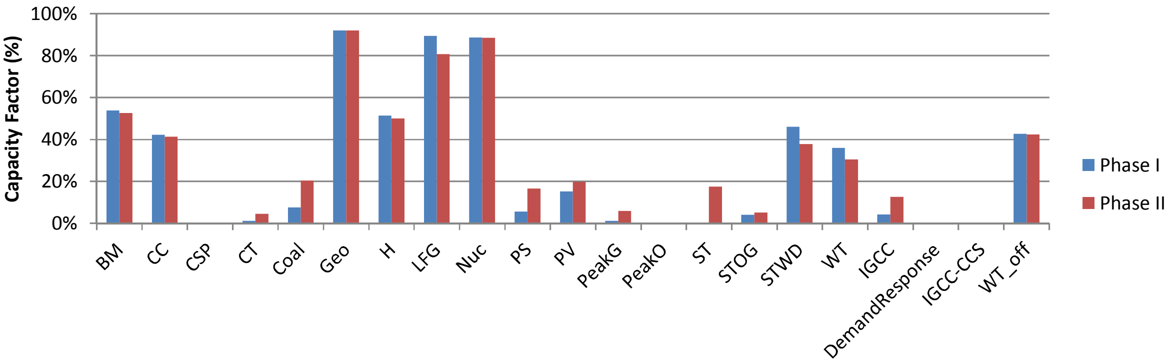
For example, in S1 there is over twice as much coal online in Phase II as in Phase I (21.6 GW versus 9.5 GW, respectively) and almost seven times more Combustion Turbines (or CTs) (29.3 GW versus 4.2 GW). See Figure 9, below. These capacity differences are not spread out over all regions, but occur in specific locations.

Figure 9. Differences in capacity (MW) from Phase I to Phase II in 2030 in S1



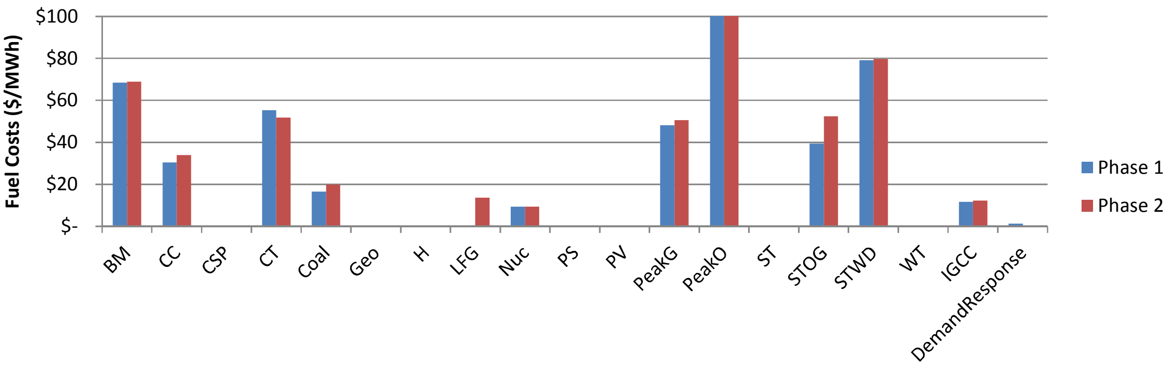
The amount of generation output by units of different types also changes significantly from Phase I to Phase II (as would be expected from a more refined dispatch model like the GE MAPS model used in Phase II). Some resources have significant step increases in expected output (such as CTs, increasing their capacity factors from 1.2 percent to 4.5 percent; and coal, which increases its capacity factors from 7.7 percent to 20 percent). Other units are stepped down, including wind (from 36 percent to 30.4 percent capacity factor).

Figure 10. Differences in capacity factor (%) from Phase I to Phase II in 2030 in S1



Finally, in S1, the actual fuel price (in $/MWh) is changed from Phase I to Phase II, with some units seeing significant changes (see Figure 11, below). For example, natural gas combined cycle unit fuel costs increase by 11 percent, and landfill gas (LFG) is stepped up from effectively free at 10 cents to $13.7/MWh. With the exception of LFG costs, the underlying input fuel costs (in $/one million British thermal units (MMBTu)) are unchanged from Phase I to Phase II, indicating that the shifts in realized fuel costs are likely a function of heat rate changes.

Figure 11. Differences in unit fuel costs ($/MWh) from Phase I to Phase II in 2030 in S1



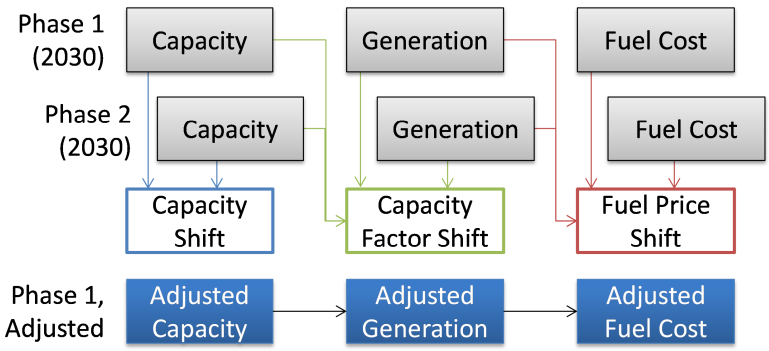
The (S1) Carbon reduction case reflects a much more dramatic change in underlying fuel costs between Phases I and II than the (S3) business-as-usual case, and the root cause can be traced back to higher effective heat rates in S1 under Phase II than under Phase I. It is likely that in the Phase II production cost modeling the natural gas combined-cycle units, the remaining coal units, and steam gas units in 2030 all experience significantly more ramping in S1 than in the other two scenarios, and the effects of this ramping are reflected in the effective heat rate as modeled by GE MAPS – an effect that could not be captured in Phase I with MRN NEEM. Overall, Phase I modeling could not fully reflect the fuel and variable O&M cost changes would result from using a more detailed chronological dispatch tool with more granular representation of the heat rate across different segments of capacity. Therefore, to capture the effective heat rate degradation properly, as well as the changes in capacity and capacity factors, we developed an adjustment mechanism for the Phase I results.

To adjust for all of these variables (capacity, capacity factors, per unit emissions rates, and per unit cost of fuel and O&M) for the year 2030, we created a series of adjustment factors that sequentially modify Phase I capacity to match Phase II 2030 capacity, then shifted capacity factors to match Phase II generation, then shifted per unit emissions rates and costs for fuel and O&M to match Phase II production costs. Where capacity exists in both Phase I and Phase II, the adjustment factors shifted total capacity, capacity factor, and emissions and costs specifically for the fuel type and region. Where Phase I had no capacity for a particular generation type in a certain region, the adjustment algorithm creates the correct amount of capacity and then adjusts its generation and emissions and costs using more generic factors. Where Phase II has no capacity for a particular generation type in a certain region, the algorithm zeros out the capacity.

Capacity factors for each generation type in each region are derived from Phase II results for 2030. Fuel costs, variable O&M expenses, and emissions are all shifted with an adjustment algorithm derived from Phase II results from 2030. These adjustors are applied to fuel and O&M prices and emissions rates on a per MWh basis, and then applied to the adjusted generation capacity.

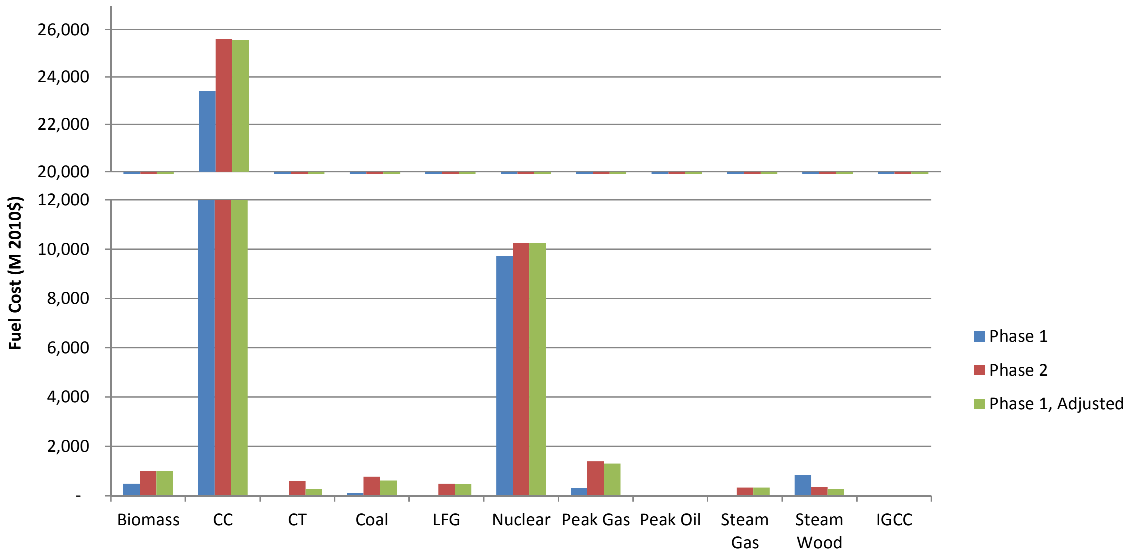
A schematic of this process for fuel costs is shown in Figure 12, below: (1) capacity is compared between the two phases and adjusted; (2) generation and capacity are used to derive a capacity factor shift factor, and an adjusted amount of generation is derived; and (3) fuel costs and generation from Phase I and II are used to derive fuel prices, and a fuel price shift factor. This factor is then applied to fuel prices from Phase I, and multiplied by generation to estimate total adjusted fuel cost.

Figure 12. Representative schematic for fuel cost adjustment to correct from Phase I to Phase II results



Overall, this process resulted in adjusted production cost elements for the Carbon reduction future (S1) in the year 2030, making the production costs from Phase I consistent with the Phase II production costs for 2030. Figure 13 below shows the output of the fuel adjustment for 2030 applied across all fuel types and aggregated across the regions (only fuel types with a fuel cost in S1 are shown here). The adjustment mechanism fixes total fuel costs – from an under-prediction of 14.5 percent in Phase I costs relative to Phase II to cost levels that are within 1.5 percent of the Phase II costs in the adjusted Phase I results.

Figure 13. Differences in total fuel costs for S1 as modeled in Phase I and Phase II, and as adjusted for Phase I to be consistent with Phase II outputs



The same type of mechanism shown in Figure 13 was also replicated for variable O&M and emissions. Emissions costs are then applied to emissions in S1 to derive total emissions costs.

Using this mechanism, we can—and did—correct Phase I production costs for the year 2030 for all of the scenarios (including S3, business-as-usual). However, a similar mechanism should be—and was—applied to all of the other Phase I years. The following section describes this mechanism.

Reconcile Phase I production costs for consistency with Phase II, all other years

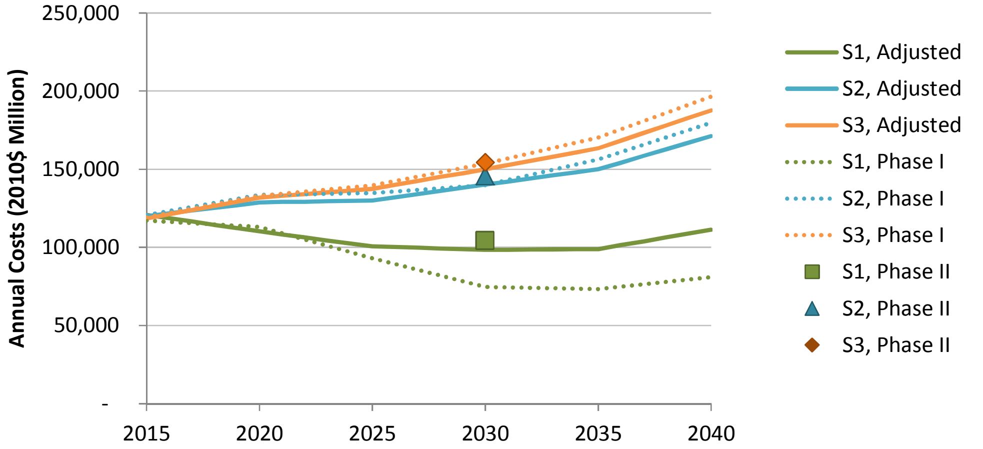
We applied a mechanism similar to the one used for 2030 across all other years, with one critical exception: the adjustment was not used at all for the year 2015, when possible average heat rate increases for gas-fired balancing resources (due to the high penetration of intermittent wind resources deployed in later years) would not yet be expected. In fact, Figure 7 suggests that the production costs of all three scenarios are very similar in 2015; further, the production costs for S2 and S3 in 2030 are almost identical from Phase I to Phase II, suggesting that MRN NEEM does capture aggregate production costs reasonably well at lower penetrations of renewable energy.

We hypothesized that the average heat rate discrepancy in S1 is a result of the high levels of renewable energy installed in the scenario. As the penetration of wind increases over time, there would be a shift towards somewhat higher average heat rates as gas-fired balancing units cycle more frequently. We further assume that other differences (such as minor changes in capacity) also scale with the penetration of wind. Therefore, for 2015, we use Phase I results as presented, but as wind penetration increases towards 2030 levels, we increasingly shifted production costs to correspond more closely to Phase II results using the mechanisms described above. Each year was assigned a weighting variable that represents how much new wind has come online after 2015 relative to the amount finally online in

2030. This weighting factor was then applied to adjust for capacity, capacity factor, fuel price, variable O&M price, and emissions rate changes.

Adjusted production costs were interpolated on an annual basis between the five-year increments.

Figure 14. Comparison of Phase I and II annual production costs, and Adjusted Phase I production costs (no capital investments or emissions costs)



The result of all of these adjustments is that–for purposes of this report and analysis–the total aggregate production costs for the (S1) CO_2 reduction future are *increased* substantially, especially from 2030 forward, and the production costs for the (S2) RPS future (S3) business-as-usual are adjusted *downwards* slightly for those same years. See Figure 14 above.

3.2. Capital Spending

Capital for new build generation

One of the largest cost components considered in this process is the capital cost of new generation. In particular, significant capital is spent in S1 to support large new blocks of wind generation. Neither Phase I nor Phase II results provide detailed capital expenditures sufficient to break down *annual* capital revenue requirements.[9]

Phase I provides estimated new capacity online for every five-year period. For simplicity, we assumed that new capacity is put in service on each five-year mark.[10] Phase I provided estimated overnight

[9] Phase I results provide aggregate levelized costs for each five-year block, but the mechanism of levelization is not provided. Phase II results provide total aggregate new generation spending (in real dollars) by 2030.

[10] For the purposes of this analysis, and with the exception of the wind cost sensitivity addressed in Section 4.5, Synapse did not make any changes to overnight capital costs or the effects that might be seen if resource development delays increase the effective costs of financing, e.g. for long-lead time nuclear or transmission resource additions.

capital costs (in $/kW) for each five-year period, and it also provided regional escalators to differentiate between the costs of building new types of capacity in different regions.

The amount of new capacity brought online was multiplied by the overnight cost and the regional escalator to derive a total capital cost for each type of unit, aggregated across all regions.

For each type of unit, we assumed a book life of between 5 years (demand response) and 50 years (hydroelectric), with most generator types having an assumed 30-year book life. We used an 8 percent (real) all inclusive weighted average cost of capital (WACC) to estimate a flat levelized carrying charge commensurate with the book life, as shown in Table 2, below.

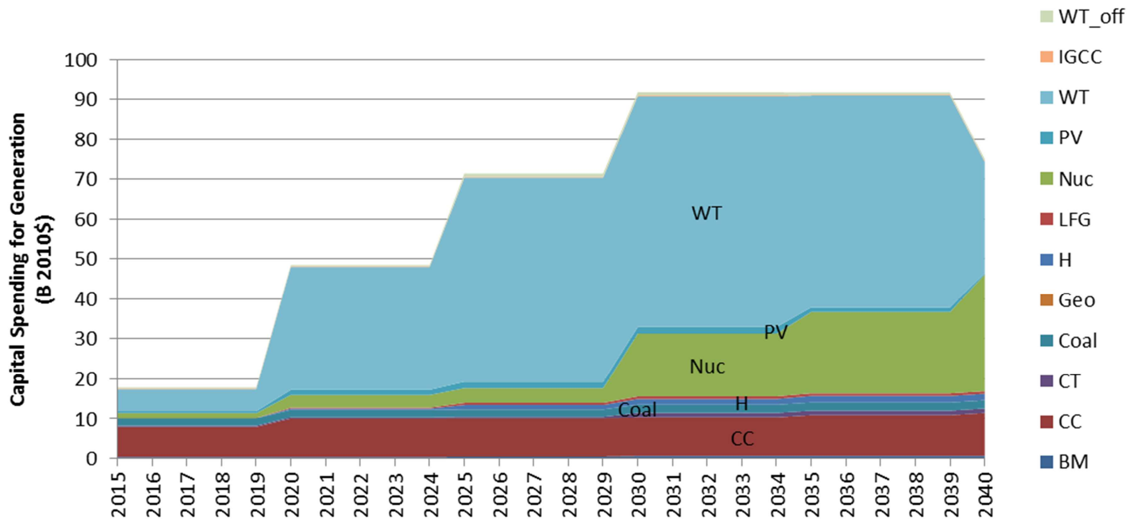
Table 2. Book life and carrying charge for new generation

Unit Type	Book Life	WACC	Carrying Charge
Biomass	30	8%	8.9%
CC	30	8%	8.9%
CSP	30	8%	8.9%
CT	30	8%	8.9%
Coal	40	8%	8.4%
Geo	30	8%	8.9%
Hydroelectric	50	8%	8.2%
LFG	30	8%	8.9%
Nuclear	40	8%	8.4%
PS	30	8%	8.9%
PV	20	8%	10.2%
Peak Gas	30	8%	8.9%
Peak Oil	30	8%	8.9%
ST	40	8%	8.4%
Steam Oil/Gas	30	8%	8.9%
Steam Wood	30	8%	8.9%
Wind	20	8%	10.2%
IGCC	30	8%	8.9%
Demand Response	5	8%	25.0%
IGCC-CCS	30	8%	8.9%
Offshore Wind	20	8%	10.2%

The carrying charge was used to estimate annual expenditures through the book life of each generator built in each of the five-year intervals. This resulted in an annual cost of capital, which is illustrated for the Carbon reduction future (S1) in Figure 15, below. This same process was replicated for each of the scenarios.

The annual levelized cost in the five-year increment periods was verified against the Phase I levelized capital expense estimates, and we found it generally to be within 2-5 percent of those values with no systematic bias.

Figure 15. New build generation capital expenses per year, S1



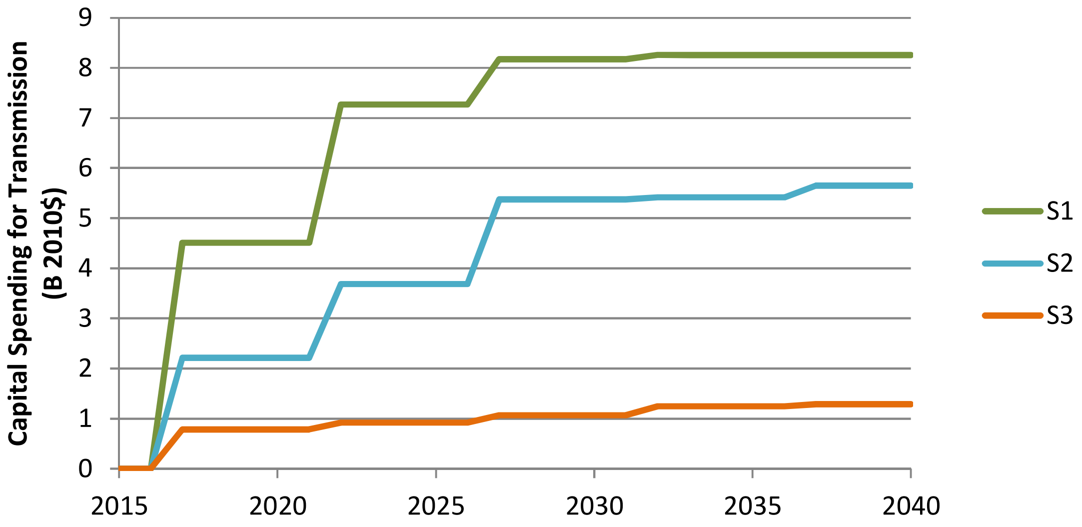
Capital for new build transmission

Annual transmission capital expenses were derived from total Phase II transmission costs. Specifically, Table 5-9 in the Phase II report indicates high and low estimates of total transmission spending by 2030. We used the average of the high and the low estimates provided in the report.

In our analysis, it was assumed that most new transmission built in the (S1) Carbon reduction future was built for the purposes of transporting wind, and, thus, the transmission capital costs were spread from 2015 to 2030 in line with the wind buildout (i.e., as more wind was built, more transmission was brought online). We also assumed that transmission lines were brought into service three years in advance of their wind load. Thus, if a large block of new wind capacity was scheduled to come online in 2020, new transmission would be assumed to be built for modeling purposes in 2017.

Costs for new transmission were annualized in the same manner as new build generation costs, assuming a 40-year book life, and a carrying charge of 8.4 percent. New transmission capital expenses per year are shown in Figure 16.

Figure 16. New transmission capital expenses per year, all scenarios



Capital for environmental retrofits

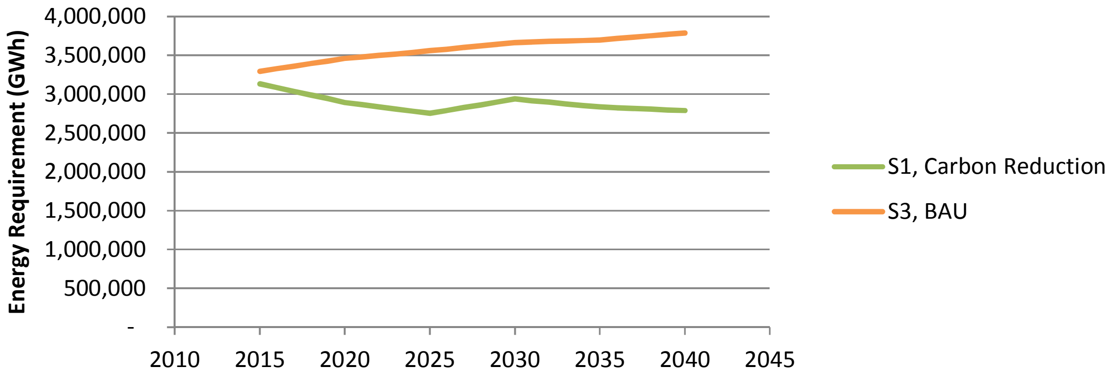
Coal retrofit capital costs (for environmental retrofits) were derived from total Phase II reported capital expenditures through 2030. Spending was spread across years following a pattern established from Phase I output.

The costs for coal retrofits were annualized in the same manner as new build generation and transmission costs, assuming a 15-year book life, and a carrying charge of 11.7 percent.

3.3. Energy Efficiency

Neither the Phase I nor the Phase II report or supporting materials supplied sufficient information to estimate the annual cost of energy efficiency for each year over the study period, 2015-2040. To estimate a reasonable annual cost of energy efficiency, we reviewed the difference between energy demand (using generation as a proxy) in S1 and S3 (as shown in Figure 17, below). We assumed that the (S3) business-as-usual case had minimal to no additional energy efficiency spending, and thus used this scenario as a baseline. We assigned a lifetime cost of saved energy in $/KWh that would result in the correct level of spending in the year 2030 according to the Phase II report summary data for that year's energy efficiency costs. This chart indicates that the Carbon reduction scenario (S1) saved 657 TWh in 2030 relative to the business-as-usual. To reach the $17.4 billion differential cost of efficiency shown in the Phase II report for the year 2030, we found that the lifetime cost of efficiency must be about 2.6¢/kWh. This same cost was then applied across all years, reflecting in this chart the energy savings in the (S1) Carbon reduction future relative to (S3) business-as-usual.

Figure 17. Energy requirement (generation) by scenario, GWh

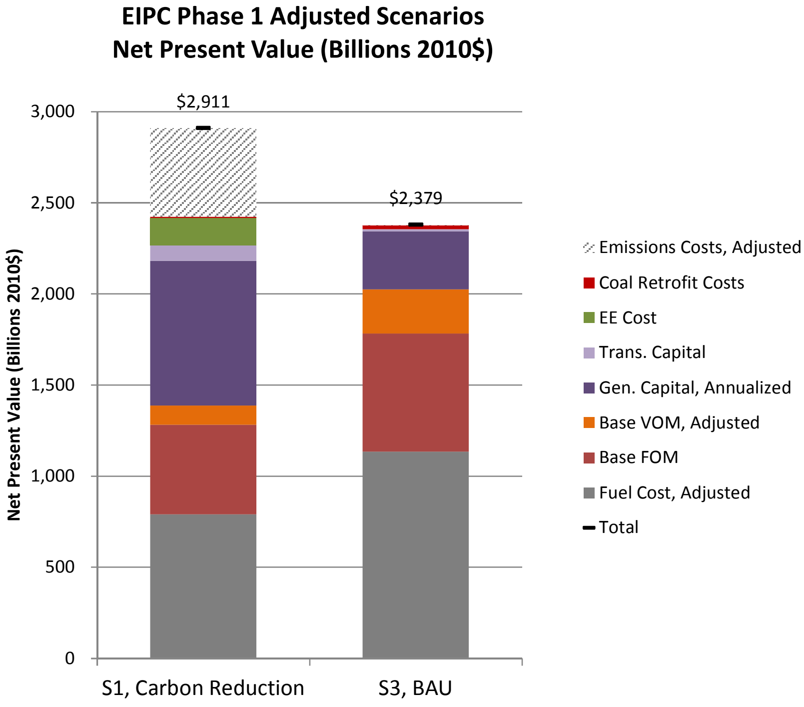


4. RESULTS

4.1. Present Value of Revenue Requirements for Scenarios 1 and 3

Once annual cost streams were derived for production costs, capital expenditures, and the cost of energy efficiency, we could readily derive a present value of revenue requirements for scenarios 1 and 3 (for the EIPC study period of 2015-2040). The first chart showing the results of this analysis is provided in Figure 18 below.

Figure 18. Net present value of revenue requirements of S1 and S3— includes CO2 emissions cost



In the EIPC study, the primary purpose of using a carbon price was to achieve the desired CO_2 reductions of the Carbon reduction future (S1).[11] The S1 "carbon price" assumed for Phase I of the EIPC process resulted in retiring uneconomic coal-fired generation and preferring non-carbon or lower carbon emitting resources such as wind (and some natural gas) in the resource expansion process.

Because S1 is the only scenario in which a CO_2 cost is actually accounted for in the EIPC analyses, this scenario, at first glance, seems to show higher total net present value costs relative to the business-as-usual (S3) scenario. However, in order to properly compare the cost/value of emissions between the Carbon reduction (S1) and business-as-usual (S3) scenarios, it is important to evaluate the costs of the much higher emissions in the business-as-usual case (see section 4.3 below, which includes a comparison of the cost/value of CO2 and other emissions for both scenarios).

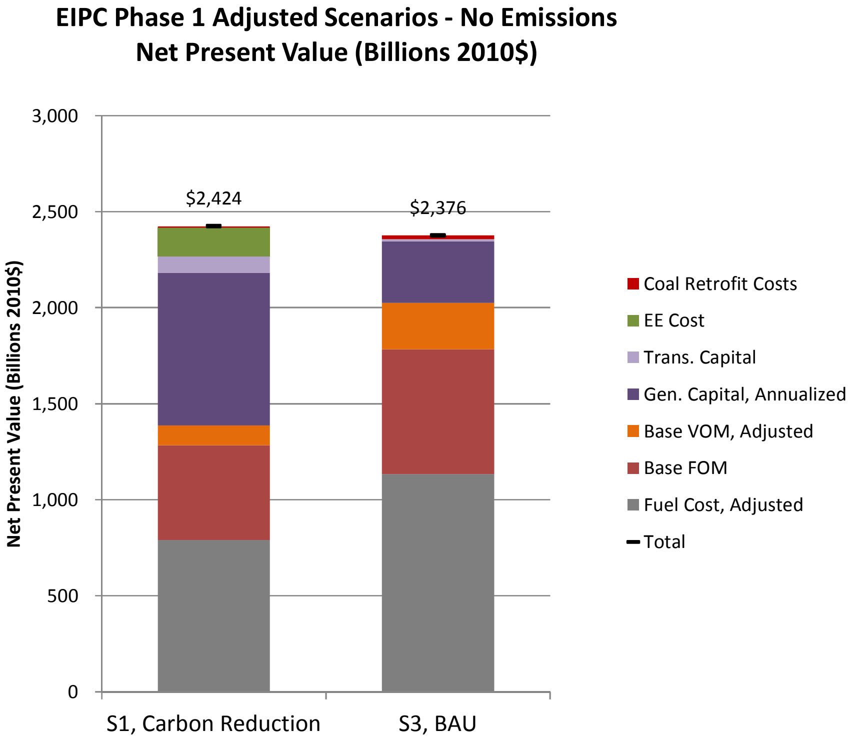
The CO_2 reductions in the Carbon reduction scenario (S1) could also have been achieved by using a carbon cap[12], which would not have imposed a direct CO_2 price. If the CO_2 price is treated either as a cost that is recycled back into the provision of new resources[13], energy efficiency, or directly back to customers— or if a commensurate CO_2 cap is used to achieve the desired CO_2 reductions, instead of a CO_2 price — then the Carbon reduction future is only about 2% more costly than the business-as-usual future over the 2015-2040 study period.

[11] It is our understanding that Charles River Associates ran multiple iterations of the MRN NEEM model, using different carbon prices, until the desired Carbon reductions were achieved – in line with the future's target carbon reductions.

[12] Indeed, it is our understanding that the intent of the carbon future was to cap carbon emissions; and that the use of a carbon price in the NEEM MRN modeling process was an easier modeling task to implement than a direct cap used in the modeling. As noted, CRA used an iterative modeling process to determine the carbon price that resulted in the desired "capped" level of carbon for that scenario.

[13] Unlike any of the other cost components, carbon price revenues are available for recycling, offsetting other system costs.

Figure 19. Present value of revenue requirements of S1 and S3— excludes CO_2 emissions cost



Reviewing the graphics in Figure 19, it is clear that S1 results in combined lower production costs (fuel, fixed, and variable O&M) than S3 business-as-usual, but has a larger capital requirement for generation and transmission, and requires additional energy efficiency expenditures. As shown in Figure 19 above and Table 3 below, even if one does not factor in the value of the greatly reduced pollution emissions in S1 (discussed in Section 4.3), the Carbon reduction future is nearly the same cost over the EIPC study period of 2015-2040 as the business-as-usual future (about 2 percent more costly).

Table 3. Present value of revenue requirements for Scenarios 1 and 3

Net Present Value (B 2010$)	Scenario 1	Scenario 3
Fuel Cost, Adjusted	790	1,134
Base FOM	494	648
Base VOM, Adjusted	104	243
Emissions Costs, Adjusted	487	3
Gen. Capital, Annualized	794	319
Trans. Capital	85	12
EE Cost	150	0
Coal Retrofit Costs	7	20
Total	2,911	2,379
Total Without CO_2 Price	2,424	2,376

Table 3 indicates that, even without factoring in the cost savings from the significant reduction in emissions from the Carbon reduction future or lower capital costs for wind, or "end effects" from later years beyond 2040 (all discussed below), if a commensurate CO_2 cap is used to reduce emissions or revenue raised from a CO_2 price is used to help pay for some of the costs of the Carbon reduction future, the Carbon reduction future is cost competitive with the business-as-usual future[14].

4.2. End Effects – Costs and Savings after 2040

The (S1) Carbon reduction future shows an aggressive buildout of renewable energy through 2040, increasingly shifting the Eastern Interconnection away from fossil energy and towards low fuel cost and low emissions resources. One of the tradeoffs of such a scenario is that it incurs significant capital expenses upfront to build renewable resources, but provides long-term benefits in low fuel costs and emission reduction savings/benefits through the lifetime of those resources. Many of these resources would last beyond the 2040 analysis period, and the savings (or costs) incurred beyond that period are captured in an extension analysis.

"End effects" are distortions in long-range planning analyses caused by reviewing costs and benefits in limited arbitrary time periods. These effects generally refer to outcomes that would or could appear significantly different if the analysis period were extended or shortened, thereby minimizing the effect of imposing an end-date on an analysis. Because it is not practical or reasonable to extend an analysis through an infinite time period, long-range planning analyses use a variety of methods to estimate how an analytical outcome could change if the analysis were extended through a longer period.

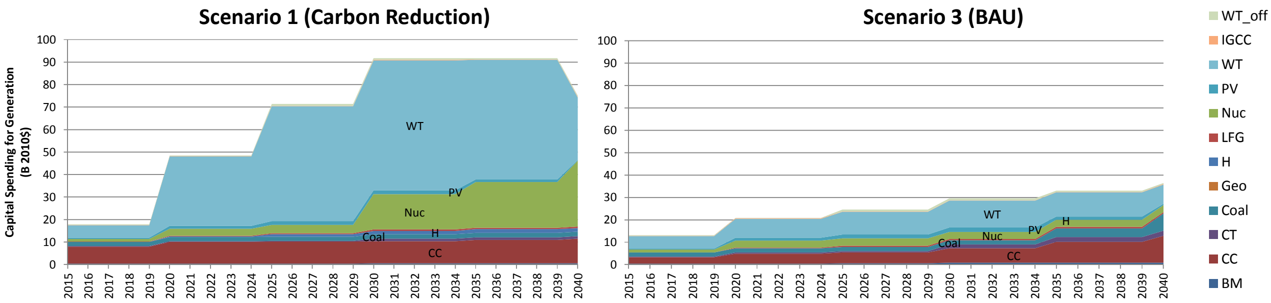
In power system planning or economic modeling, "extension periods" can be used to capture the extended depreciation period of long-lived resources, as well as allow for the comparison of resource plans with a variety of capital spending plans and production costs. One method of applying an extension period is simply to assume that the last year of the analysis is extended through a later year. For this type of extension, production costs (i.e., fuel, O&M, and emissions costs) are simply held

[14] Although not discussed in great detail in this report, the EIPC process also evaluated a "Regionally Implemented National RPS Scenario", also known as Scenario 2. The net present value revenue requirements for Scenario 2, the Regionally Implemented National RPS scenario, total $2,677 billion (with CO2 price included) and $2,673 billion (with CO2 price excluded, or recycled back to cover the costs of the scenario). This indicates that Scenario 2, with the restricted input assumptions and modeling limitations that were defined as agreed in the EIPC process, was unable to take advantage of (and thus represent) the benefits of the broad array of high quality wind resources and expanded transmission modeled in Scenario 1. In other words, the way the scenario was restricted – including the fact that the RPS mandates could only be satisfied within certain pre-defined regions within the Eastern Interconnection – prevented the load from being able to access the best (highest capacity factor) wind resources. Our analysis does not imply that some form of national RPS policy (Scenario 2) would not also be cost-effective, but a national RPS policy may need to be modeled and/or implemented in a different manner than was modeled at EIPC.

constant.[15] For capital costs, some analyses will assume that existing infrastructure is simply replaced in-kind through the extension period.

In the EIPC analysis, S1 incurs significant capital costs to build wind and new nuclear facilities, with much of the spending occurring from 2025-2030 (see Figure 20 below, left side). In contrast, (S3) business-as-usual entails far less capital spending, but incurs far higher production costs in the out-years (for capital costs see Figure 20 below, right side; for production costs, see Figure 14). By ending the analysis in 2040, the EIPC analysis may distort some of the long-term benefits of maintaining a high capital, low fuel/O&M economy.

Figure 20. Capital spending for generation in S1 and S3 (Billions 2010$)



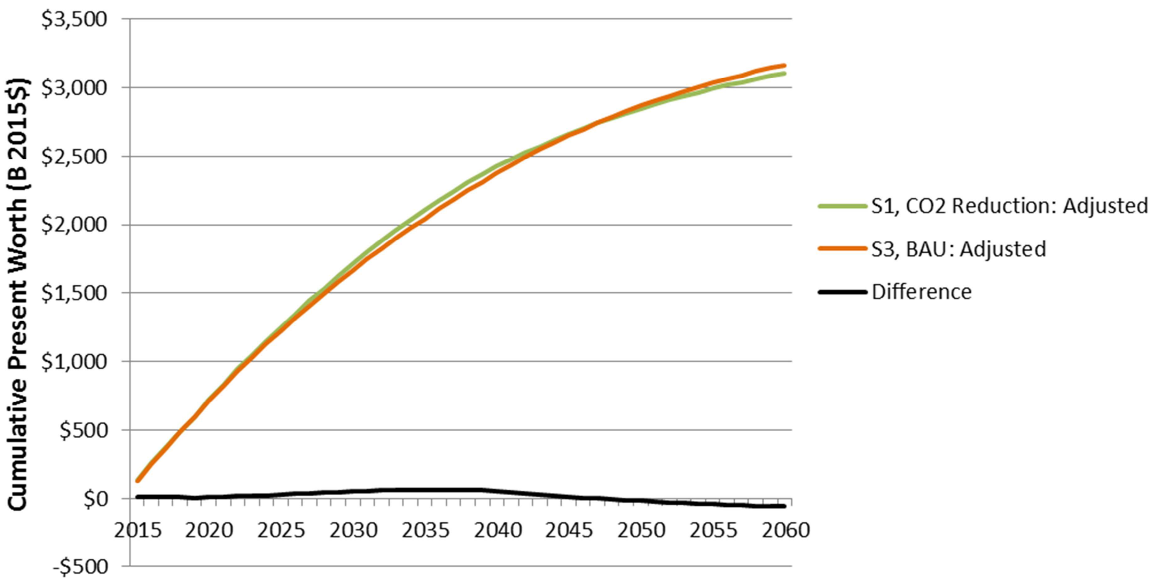
To correct for the end effects, we simply continue the last year's real levelized capital spending for an extended period. All costs incurred in the last year, including capital, are simply held at 2040 values through an extended time period. The net present value of the scenario can therefore be reviewed through 2040 or any year thereafter.

In the EIPC analysis, the definition of the analysis period matters – especially because investment in low-fuel or no-fuel resources late in the study period (closer to 2040) pays significant dividends beyond 2040. Thus it is analytically critical to consider the period post-2040 in any comprehensive analysis. Although (S3) the business-as-usual case appears to be marginally lower overall cost through 2040, the two cost trajectories actually cross just a few years later in 2047 (see Figure 21, below). After 2047, the cumulative present worth[16] of S1 becomes lower than S3, and it continues to fall relative to Scenario 3. Figure 21 shows that, even without factoring in the value of emissions reductions in the Carbon reduction scenario, the total costs of Scenarios 1 and 3 are *extremely* similar over time, deviating by less than 5 percent in any given year. The black line near the axis is the difference (S1 minus S3): when this line crosses the zero line in 2047, S1 is less expensive.

[15] In some cases, extension period adjustments will account for expected escalation of some terms above and beyond core inflation.

[16] Cumulative present worth is the accumulation of present value to any specified year.

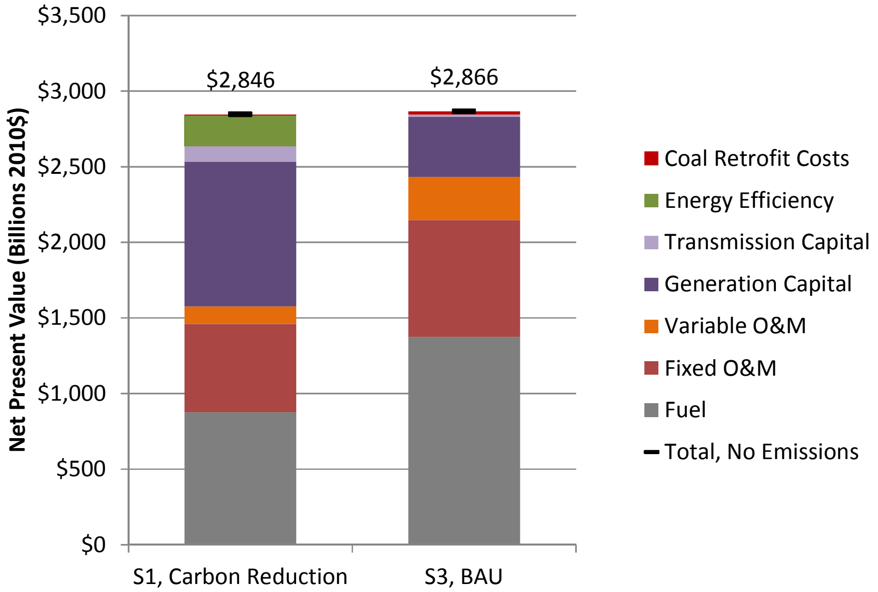
Figure 21. Cumulative present worth (CPW) from 2015 through any given year of the analysis (plus 20-year extension period to 2060)



Correcting for end effects in the EIPC analysis is an important consideration, because the EIPC approach partially distorts the scenario results by analyzing the most expensive period of S1, while ignoring some of the long-term benefits of low production costs.

The long-range cost of S1 compared with S3 is extremely close (until one looks at emissions costs, discussed in section 4.3 below). Despite the fact that these two scenarios have different goals and create very different systems by 2040, the present value differences between the two scenarios are easily within a margin of error (2 percent). Indicating that S3 is significantly less expensive than S1 over the period 2014-2040, or that S1 is significantly less expensive over a longer period, is misleading – these scenarios are essentially equivalent from a pure cost perspective (see Figure 22 below), which shows the present value of revenue requirement for S1 and S3 with a 10-year extension period (i.e. to 2050). When the period is extended by 10 years, the present value revenue requirements of Scenario 1 are $20 billion lower than S3.

Figure 22. Net present value of revenue requirements of S1 and S3, including extension period to 2050



The assessments in the charts above do not attribute net social costs or benefits to the vastly different emissions profiles of the modeled scenarios. Assigning any of a range of social costs to the emissions profiles of the scenarios results in S1 demonstrating a much higher net value to society than S3. The emissions reductions benefits are discussed in sections 4.3 and 4.4.

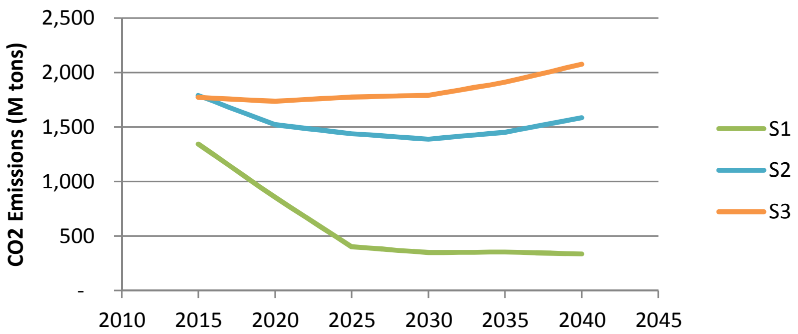
4.3. CO_2 Reduction Benefits of Scenario 1

Even if one ignores the "end effects" discussed in Section 4.2 above, the relatively minor difference in present value revenue requirements between the (S1) CO_2 reduction future and the (S3) business-as-usual scenario through 2040 (see e.g., Table 3 of section 4.1 of this report) are completely overshadowed by the value of the CO_2 emissions reductions in the Carbon reduction policy scenario (S1). As designed, in the Carbon reduction future carbon emissions rapidly fall as coal resources are retired out of the system – with CO_2 emissions from the electric power sector dropping 51 percent by 2020 and 80 percent by 2030 (see Figure 23 below).[17] In contrast, the CO_2 emissions of the (S3) business-as-usual rise by 17 percent over the analysis period, creating a wide gap. By 2030, the business-as-usual scenario emits over 1.4 billion more tons of carbon than S1. Over the full analysis period, S1 results in nearly 33 *billion* fewer tons of CO_2 in the atmosphere than the business-as-usual. For comparative purposes, the EPA estimates that the US, as a whole, emitted approximately 7.4 billion tons of CO_2 equivalent in 2011 from all sources, including transportation, electricity, industry, and agriculture.

[17] Note that CO2 emissions here start at a lower level in 2015 due to assumed pre-2015 coal retirements that are not assumed in S2 and S3.

By this measure, S1 would be the equivalent of the US producing no emissions at all for nearly five years – a significant reduction in carbon emissions.

Figure 23. CO_2 emissions in S1, S2, and S3



While Phase II did not price carbon emissions explicitly, these emissions still have a social value – i.e., there is significant value in reducing greenhouse gasses, regardless of whether legislation or regulation has assigned a specific market price to these emissions. If the carbon emitted in S3 were assigned the same value as carbon emitted in S1, the cost increase would be significant: the net present value (i.e., the cost) of emissions in S1 would be approximately $490 billion, or close to 17 percent of the scenario's cost.

Figure 24. Cost of CO_2 emissions in S1 and S3, at S1 CO_2 prices

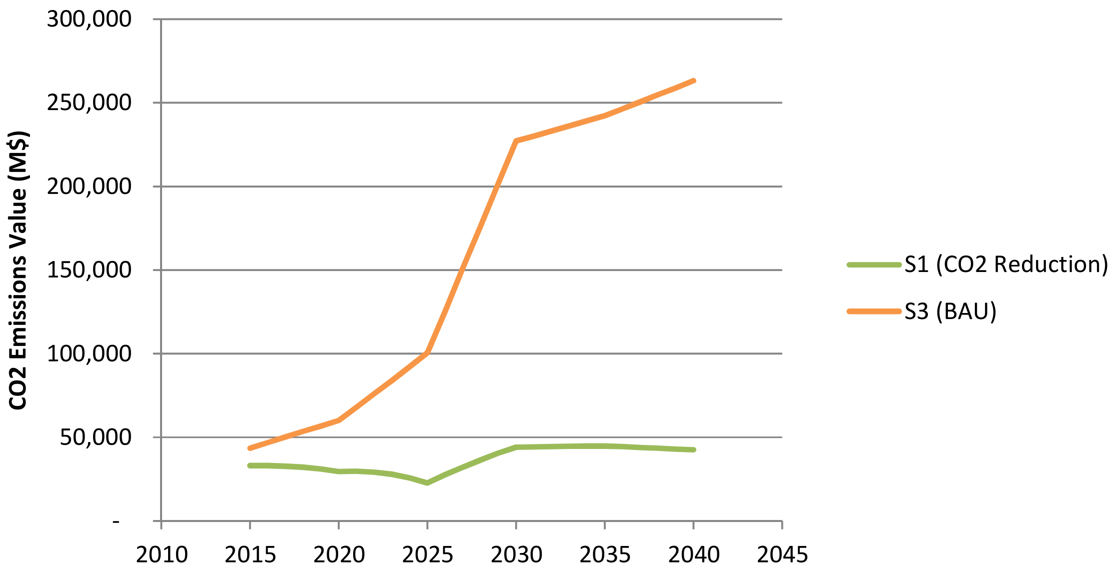
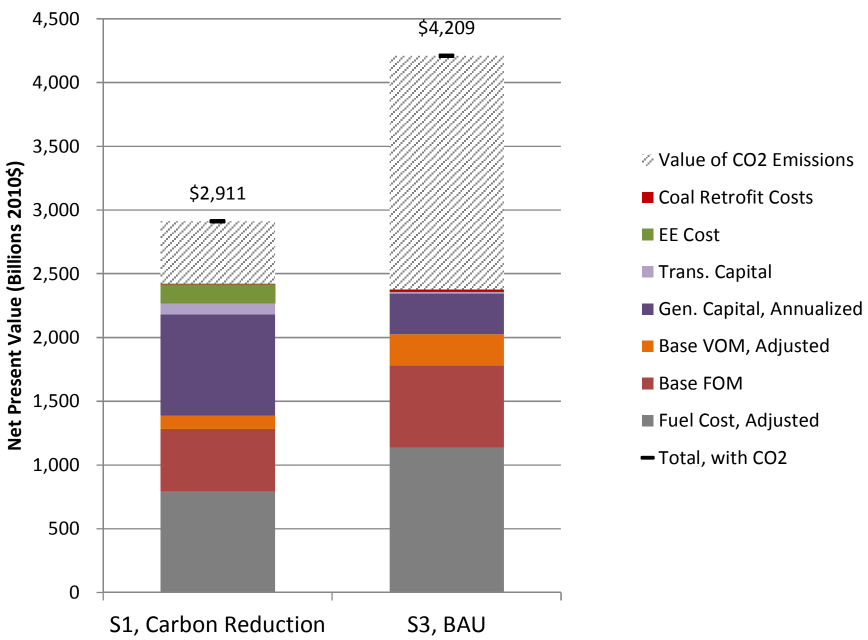


Figure 24 above, shows the annual costs of CO_2 emissions in scenarios 1 and 3, with the cost per ton of CO_2 calculated using the same price for emissions assumed in Scenario 1. In other words, the chart above in Figure 24 shows the costs of carbon if the CO_2 pricing used to force the model to reduce emissions in S1 was also used to "cost out" the emissions in S3. While Scenario 1 reduces emissions significantly and maintains an annual cost below $50 billion per year, the business-as-usual, with uncontrolled emissions, increases the cost of CO_2 emissions rapidly past 2025 to $150-$250 billion per year. The present value revenue requirement value of CO_2 emissions from Scenario 3 is close to $1.8 trillion, or $1.3 trillion more expensive than the Scenario 1 emissions cost (Figure 25, below). Overall, if these emissions costs were consistently tallied for both of the scenarios, the business-as-usual (S3) would have a total present value revenue requirement of over $4.1 trillion – or about 44 percent more expensive than the all-in costs of Scenario 1.

Figure 25. Present value of revenue requirements of S1 and S3 with consistent valuation of CO_2 emissions



Note: Emissions cost from S1 as per adjustments. Emissions costs for S2 from total CO_2 emissions multiplied by imputed annual CO_2 cost.

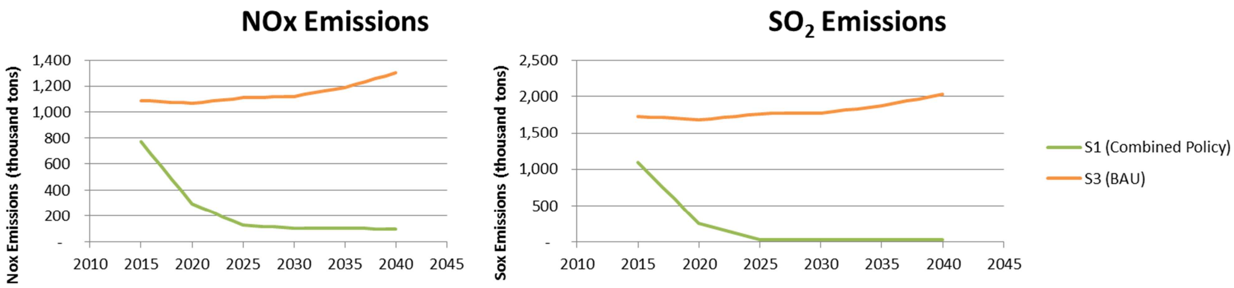
4.4. Other Emissions Reduction Benefits of Scenario 1

By virtue of the rapid retirement of coal resources in S1, the Carbon reduction scenario, S1 is able to offset significant emissions of criteria pollutants, including oxides of nitrogen (NO_x) and sulfur dioxide (SO_2), pollutants responsible for ground-level ozone, acid rain, and the formation of fine particulates. While gas-fired units produce NO_x, the amount of this pollutant is significantly lower in S1 relative to the business-as-usual scenario (which maintains a much larger coal fleet). Emissions of SO_2 all but disappear with the retirement of essentially the entire coal fleet in S1. Overall, by 2025, the S1 scenario avoids 983,000 tons of NO_x emissions and 1,731,000 tons of SO_2 emissions each year.[18] Over the full course of

[18] Exclusively for the purpose of quantifying and valuing NOX and SO2 emissions, emissions rates for all years for all generating types (i.e., in tons/MWh generated) in both S1 and S3 are derived from Phase II S3 results in the year

the study period, S1 avoids 24 million tons of NO_x and 42 million tons of SO_2, and this would have significant societal benefits.

Figure 26. NO_x and SO_2 emissions in S1, S2, and S3



From a public health standpoint, such avoided emissions could be very significant in terms of cost savings. In 2010, the National Academies of Science (NAS) produced a report entitled "Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use." Work papers for this report provided estimated damages per ton of NO_x and SO_2 emissions released from mid- to large-sized coal and gas generators, where damages were monetized statistical lives (i.e., premature mortality). Different power plants can cause different levels of damage per ton of emissions released depending on their proximity to population centers, prevailing wind patterns, and seasonal patterns of emissions. While we cannot break the study down into individual units because such information was not included in the EIPC process, we can use a weighted average damage multiplier, weighted by the generation of all resources considered in the NAS study (gas and coal). Overall, applying the weighted average damage per ton for NO_x and SO_2 avoided emissions in S1 (relative to business-as-usual scenario) suggests that the S1 future would avoid the premature mortality of about 36,000 statistical individuals,[19] just from improving poor air quality. Applying a value of statistical life (VSL) recommended by the EPA in recent regulatory analyses[20] ($6.3 million), and using the EPA's discount rate of 3 percent on future mortality, the value of the avoided mortality is approximately $146 billion – readily clearing the apparent $48 billion gap relative to the business-as-usual scenario shown in Table 3 (Section 4.1) above.[21]

2030. This may underestimate NOX and SO2 emissions for both scenarios in the early years when there are fewer assumed controls in place.

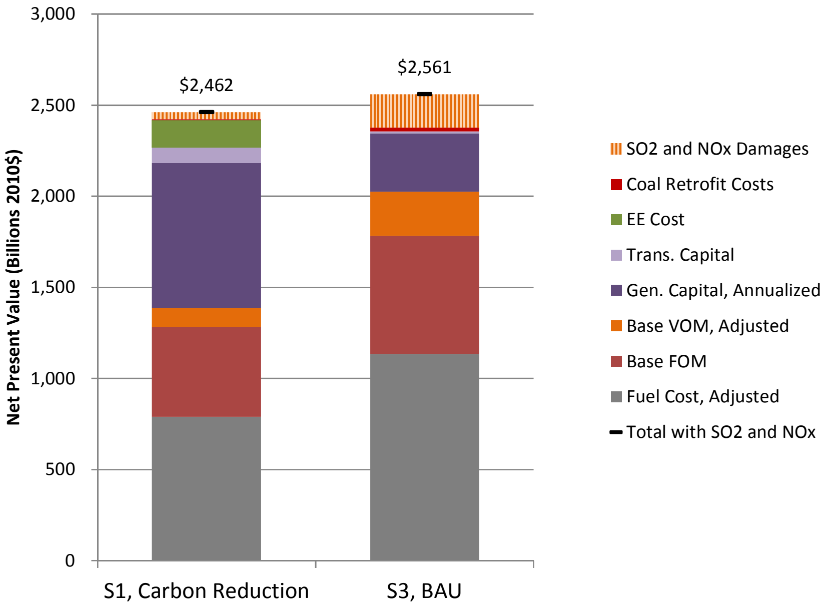
[19] Public health studies that examine the connection between premature mortality and air quality identify a risk of mortality associated with poor air quality. This risk, multiplied by the population, results in an estimated number of lives that would have premature mortality due to poor air quality. This type of epidemiological study does not identify specific individuals that would be expected to suffer health consequences from poor air quality.

[20] Regulatory Impact Assessment for MATS, Section 5.4.4.1 http://www.epa.gov/mats/pdfs/20111221MATSfinalRIA.pdf

[21] The EPA suggests that VSL estimates range from $1.0 to $10 million per statistical life. At this range, the NPV of saved lives is between $23 and $232 billion.

The results of this analysis can be seen in Figure 27 below. This graphic does not include the costs or valuation of carbon dioxide discussed in Section 4.3 or the "end effects" discussed in Section 4.2 above.

Figure 27. Present value of revenue requirements of S1 and S3 with valuation of health damages from SO_2 and NO_x



4.5. Sensitivities

Sensitivity: Reduced wind

The EIPC Phase II report describes a series of alternative sensitivities tested in the EIPC production cost analyses (Section 6.1 of the Phase II report) to examine the causes of excessive wind curtailment in S1. The wind curtailment issue was alarming because a significant portion of the newly installed wind generation was "curtailed" (i.e., it was not used). The excessive wind curtailment suggested that there was a problem either with the transmission buildout developed by the planners (not enough transmission to get the wind generation to the load) or the amounts or locations of wind generation. It would be uneconomic to build as much wind generation, or locate it where it was located on the grid, if there was insufficient transmission available to make use of it.

To try and improve the wind capacity factors and reduce the wind curtailment, one of the EIPC sensitivities simply reduced the amount of wind built in specific regions. Synapse produced adjusted production costs and revised capital investment estimates in line with this sensitivity, assuming that natural gas combined-cycle units were on the margin when wind energy was increased (if and when increased). Thus, if more wind could reach the grid, less gas CC energy would be needed.

First, the total amount of new wind built in four regions (MISO West, Nebraska, Southwest Power Pool North, and MISO Missouri/Illinois) was reduced in the EIPC sensitivity by the amount shown in the Phase

II report (that sensitivity scaled the new wind capacity to 61-85 percent of the amounts that were initially-installed). To accomplish this, the EIPC modeling sensitivity run assumed that in every year that new wind was assumed to be built (as reported in the Phase I results), only a fraction of that new wind was actually procured – in other words, the reduction was scaled across all years equitably. Wind capacity factors as reported in the Phase II report were then adjusted by the reduced curtailment values shown in Table 6-4 of the Phase II report, resulting in slightly-to-significantly higher capacity factors. The changed capacity factors, along with the reduced wind capacity in 2030, produced 65.5 TWh less energy in 2030 than in the base version of Scenario 1. During the EIPC sensitivity run, the model filled this 65.5 TWh energy gap with natural gas, or it increased capacity factors, to make up 65.5 TWh. This type of calculation was repeated across all years.

Ultimately, this sensitivity resulted in *increased* emissions for the Carbon reduction future (so that the emissions goals of the S1 Carbon reduction scenario were not fully achieved). However, it also reduced the present value revenue requirements of wind capital costs by $61 billion and increased fuel costs (i.e. gas) by $26 billion. In total, it reduced the present value revenue requirements of Scenario 1 by $33 billion, bringing the total cost of the scenario down to $2,391 billion from $2,424 billion (which would make the overall costs of this sensitivity/scenario essentially the same as business-as-usual, S3, with its PVRR of $2,376 billion - without factoring in the extremely high value of the reduced emissions of this sensitivity as compared to S3).

Sensitivity: Improved transmission leads to reduced curtailment

An alternative sensitivity was developed by Synapse to test the effect of reducing wind curtailment to 5 percent, which was to be accomplished by assuming that sufficient additional "economic"[22] transmission would be developed that would avoid the heavily curtailment of wind in the Midwest. This transmission would consist of reinforcement of the weakest links remaining on the grid after the major generation interconnection, constraint relief, and interregional transmission path buildouts from EIPC Tasks 7 and 8 were completed. Annual wind curtailment in 2030 was set at a maximum of 5 percent (reduced from up to 40 percent curtailment in Nebraska), but no changes were made to the amount of wind capacity on the system. As a result, in 2030, wind was calculated to provide 94 TWh (or 13 percent) more energy than estimated in Phase II for Scenario 1. To reduce the wind curtailments to 5 percent, this sensitivity assumes increased transmission investments of $10 billion (real), spread over the same timeline as other transmission investments. This $10 billion transmission investment estimate was based on improvements to underlying 345 kV and 230 kV system elements that were key "choke points" or flowgates on the system, as revealed in the Phase II production cost analyses and sensitivities.[23] We

[22] As compared to reliability-required transmission.

[23] The $10 billion estimate was derived by making an allowance for 100 reinforcement projects costing $100 million each, to supplement the specified buildout for S1. In reality, the reinforcement projects will vary in size, with many under $100 million and some over $100 million. This estimate is based on the range of costs typically seen for upgrades of 230 kV and 345 kV circuits, and transformer additions. This allowance will allow for upgrades to "flowgate" elements that were the cause of binding congestion in the GE MAPS production cost runs for S1.

note that the overall capital investment for transmission is relatively small compared to supply-side investments for new resources and production costs over the life of the investments, and thus even with higher levels of incremental transmission to mitigate the effect of choke points, the magnitude of the overall results would be roughly the same as is seen here.

This sensitivity reduced fuel costs by $38 billion (present value revenue requirements), and increased total transmission costs by $10 billion. In total, it reduced the present value revenue requirements of S1 by $31 billion, bringing the total present value cost to $2,393 billion from $2,424 billion (which would make the overall costs of this sensitivity/scenario essentially the same as the business-as-usual, S3, with its PVRR of $2,376 billion – without factoring in the extremely high value of the related emissions of this sensitivity as compared to S3).

Sensitivity: Wind capital cost adjustment

A final sensitivity was applied to both of the other sensitivities discussed above: an improved learning curve for wind capital costs. Materials supplied with Phase II show an assumption of about 10 percent improvement in the overnight capital cost of wind from 2015 to 2025. We assumed that the unit capital cost of wind could be improved by 1 percent per year through the full analysis period, or 15.5 percent by 2025 and 30 percent by 2040.[24] However, since the vast majority of new wind is assumed to be brought online through 2025, the full impact of this assumption is an improvement in overnight capital costs of about 3.5 percent in 2020 and 5 percent in 2025. The real overnight cost was reduced in 2025 from $2,216/kW to $2,091/kW.

This assumption impacts only the capital spending assumption. For the first sensitivity ("Reduced Wind"), this assumption reduces the present value revenue requirements of new build wind capital costs by about $19 billion, to a total of $2,372. This assumption reduces the second sensitivity by $22 billion, for a total present value revenue requirement of $2,371 billion (which would make the overall costs of this sensitivity/scenario essentially the same as the business-as-usual, S3, with its PVRR of $2,376 billion – without factoring in the extremely high value of the related emissions of this sensitivity as compared to S3).

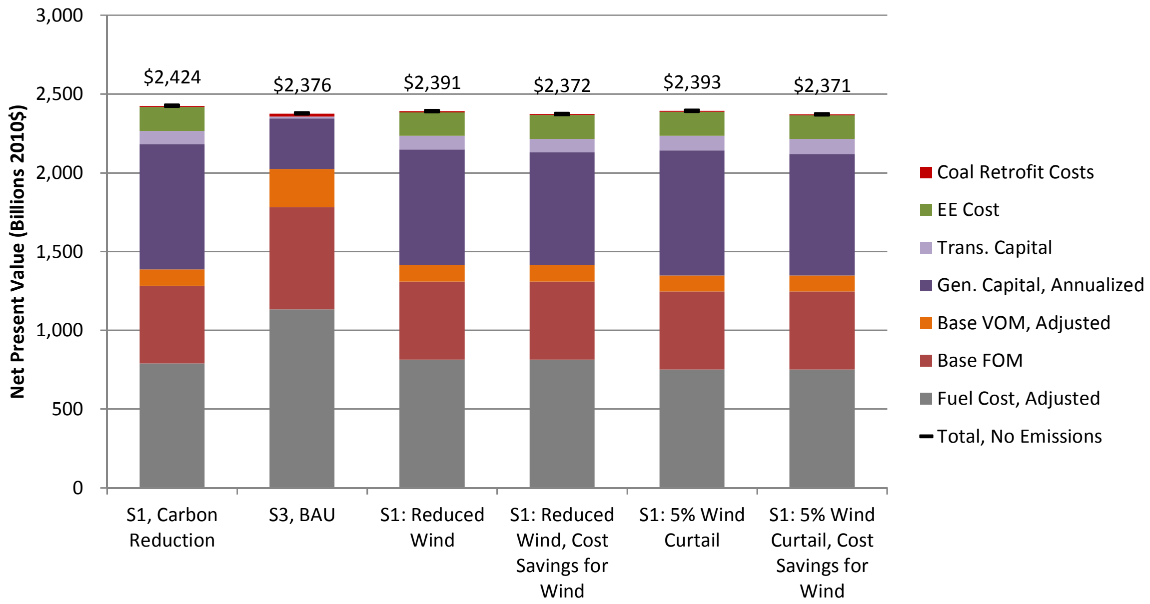
Present value of revenue requirements for Scenarios 1 and 3 and sensitivities

Overall, the present value revenue requirements of the scenarios and additional sensitivities shows that (without factoring in the costs of emissions) Scenario 1 can be achieved at approximately the same cost of the (S3) business-as-usual, provided that a CO_2 cap is used instead of a CO_2 price, or costs incurred for

[24] See e.g. IEA Wind Task 26: The Past And Future Cost Of Wind Energy, Work Package 2. Lead Authors: Eric Lantz: National Renewable Energy Laboratory, Ryan Wiser: Lawrence Berkeley National Laboratory, Maureen Hand: National Renewable Energy Laboratory. Contributing Authors: Athanasia Arapogianni: European Wind Energy Association, Alberto Ceña: Spanish Wind Energy Association, Emilien Simonot: Spanish Wind Energy Association, Edward James-Smith: Ea Energy Analyses. NREL Technical Report NREL/TP-6A20-53510, May 2012. Available at: http://www.ieawind.org/index_page_postings/WP2_task26.pdf. See Figure ES-3.

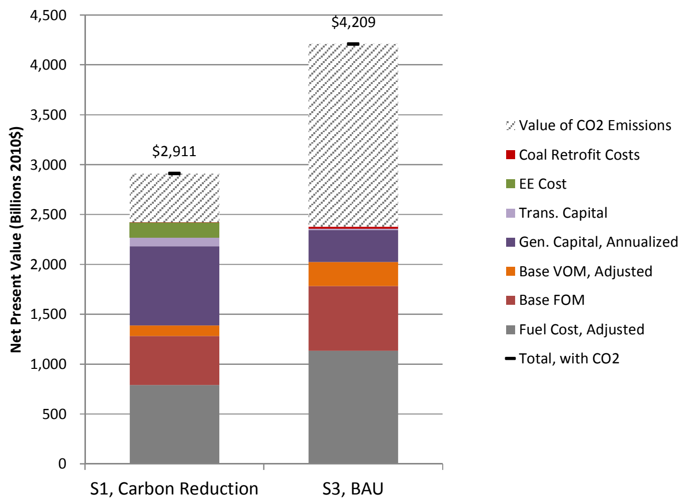
CO_2 emissions are recycled back as clean energy investments or returned to customers (see Figure 28, below). Options to reduce wind curtailment provide value and reduce costs. Ultimately, if the cost of wind turbines drops in accordance with the assumptions in our sensitivities here (1 percent per year), a reduced wind scenario or an improved transmission and reduced curtailment scenario would provide cost savings relative to a business-as-usual trajectory.

Figure 28. Net present value of revenue requirements of S1 and S3 and Sensitivities, excluding emissions costs



Of course, when emissions are factored into the analysis, the carbon reduction future is the clear economic winner, seen below (also shown in Figure 4)

Figure 29. Net present value of revenue requirements of S1 and S3 with consistent valuation of CO_2 emissions



5. RECOMMENDATIONS FOR FURTHER ANALYSIS

Based on our analyses of EIPC data and reports, and the additional analyses discussed in this report, we recommend further analyses of how best to achieve the Carbon reduction future studied at EIPC (i.e., how best to reduce economy-wide carbon emissions by 50% from 2005 levels in 2030, and by 80% in 2050). Even without considering emissions reduction benefits, a Carbon reduction future is remarkably similar (or even lower) in cost when compared to "business-as-usual". But the extremely high value of the emissions reductions in a Carbon reduction future makes it a clear winner for the US and its economy. We should study how to best achieve such a future, at the lowest cost possible, optimizing the use of installed resources (i.e., reducing "wind curtailment" to 5% or lower), investing in energy efficiency, building enough transmission to get the best wind and other resources to the customers who need power, and adding the right amount of new (low emission) generation at the right locations, etc.

We also recommend that ongoing analysis of resource expansion scenarios for the Eastern Interconnection include at least the following enhancements, which we categorize as either "modeling methods" or "input assumptions" additions. Importantly, the results of our analyses suggest that planners should utilize modeling tools and analytical approaches that permit apples-to-apples comparisons of various resource futures over the long term.

Modeling Methods

- Thoughtful and iterative use of the two key types of modeling tools currently used by and of value to resource planners -- power flow and production cost models – is essential. Notably, it is likely that more detailed production cost models capable of providing hourly granularity are required to adequately capture the unit commitment and dispatch variations that occur for any high wind scenarios.
- Thoughtful use of a capacity expansion model (such as, for example, MRN NEEM, which was used at EIPC and is a proprietary model), or development of a new capacity expansion model that is not proprietary would be valuable. The capacity expansion model should be used iteratively with the two models discussed in the previous bullet – power flow and production cost models - to try and reduce costs and optimize the futures studied.
- Planning studies should include enough iteration among the various models to ensure that installed resources are able to be properly used (e.g., to minimize uneconomic "wind curtailment"), that there is enough transmission to best get generation to the customers who need power, and that new generation additions and locations are optimized.
- Inclusion of detailed production cost modeling for more than just a single year will also be important. To capture overall trends related to infrastructure improvements that last more than 20 years, and in some cases at least 40 years (e.g., transmission), it is imperative that the benefits accruing to scenarios be estimated for more than a single year. Extending the

production cost analyses to cover even one or two additional years – and more years if possible -- would help to define the endpoints of multi-decade investments and operational savings.

- Careful construction of the streams of investment costs needed to finance any resource expansion scenarios is critical. In our analysis, initial investment costs for required resources were placed at five-year intervals. Estimates of investment costs by year, rather than by five-year interval, would help refine the cost estimating process.
- Examination of non-electric power sector interactions would also be valuable. In particular, the interrelationship between the electric and transportation sectors should be analyzed in greater detail than was possible during EIPC.

Input Assumptions

- Use of current data on resource expansion costs and resource performance, capturing the most recent trends - especially for renewable resources that exhibit, or are projected to exhibit, significant cost declines and/or performance improvements – will be important. For example, onshore and offshore wind cost projections are critical to any analysis that attempts to determine the economics of different electricity futures for the US over the next few decades. In the EIPC process, parties agreed to use AEO data that reflected the upturn in wind capital costs seen over the 2006-2010 timeframe and not the downward turn in costs that was just beginning, which some stakeholders thought overstated the costs of new wind resources in the scenarios. All efforts must be used to thoroughly vet projected wind (as well as other) resource costs.
- The EIPC process showed that energy efficiency and demand response resources should be properly evaluated in resource and transmission planning because they can often be the most cost-effective ways to help reduce infrastructure needs, minimize emissions, and lower system costs. Thus, energy efficiency and (clean) demand response resources should be aggressively pursued, as well as properly evaluated in resource and transmission planning.
- Detailed analysis of the costs and benefits of energy efficiency resources must be included in the evaluation of alternative resource scenarios. The interrelationship between the stream of investment costs for energy efficiency, the resulting stream of energy efficiency savings, and the baseline load forecast must be carefully analyzed and considered.