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File No. EO-2015-0055

SURREBUTTAL TESTIMONY

OF

S. HANDE BERK

ON

BEHALF OF

UNION ELECTRIC COMPANY
d/b/a Ameren Missouri

St. Louis, Missouri
April 2015

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I. INTRODUCTION

Q. Please state your name and business address.

A. S. Hande Berk, One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. By whom and in what capacity are you employed?

A. I am employed by Ameren Services Company ("Ameren Services") as Senior Corporate Planning Analyst.

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science degree in Economics from Orta Doğu Teknik Üniversitesi in Ankara, Turkey in June of 2000 and a Master of Science degree in Economics and Finance from Southern Illinois University Edwardsville in August of 2002. I joined Ameren Services Corporate Planning Department as a Forecasting and Load Research Specialist in July of 2003. I was responsible for electricity and gas sales and peak demand forecasts, weather normalization, load research data management and analysis to support cost of service studies and electric rate design, and monthly economic outlook reports for senior management. In September of 2008, I became a Corporate Planning Analyst. My responsibilities included fuel budgeting for Ameren Missouri's generating fleet, benchmarking and calibrating the MIDAS tool used for long-term resource planning analysis to the Company's official fuel budget, and modeling and analyzing the alternative resource plans in the Company's 2011 Integrated Resource Plan ("IRP") filing. I was promoted to Senior Corporate Planning Analyst in October of 2011, and I led the efforts for the Company's 2012 IRP Annual Update in that capacity. I became a Senior Corporate Model Specialist in December of 2011. My duties included financial forecasting, monthly margin analysis, analysis support for the divestiture of Ameren Energy Resources and project evaluation. I was transferred back to the Corporate Analysis group in June of 2013 as a Senior Corporate Planning Analyst. I was the project lead on Ameren Missouri's 2014 IRP filing. I developed the revenue requirements model that replaced MIDAS in addition to overseeing all of the assumptions and analyses used in the filing. I am currently working in that same capacity and am responsible for long-term resource planning related analyses.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of my testimony is to 1) respond to the rebuttal testimony of the Missouri Public Service Commission ("Commission") Staff's ("Staff") witness John Rogers regarding his concerns on whether Ameren Missouri's ("Company") proposed energy efficiency plan benefits all customers, and 2) respond to the rebuttal testimony of Sierra Club's witness Tim Woolf regarding Ameren Missouri's decision to choose the Realistic Achievable Potential ("RAP") demand-side management ("DSM") portfolio over the Maximum Achievable Potential ("MAP") DSM portfolio and the Company's treatment of greenhouse gas ("GHG") regulations in its 2014 Integrated Resource Plan ("IRP") filing.

Q. Please summarize the rebuttal testimony of Mr. Rogers regarding benefits of DSM programs as it relates to the IRP and your conclusions.

A. In his rebuttal testimony, Mr. Rogers uses three comparable plans from the IRP, with no additional DSM after MEEIA Cycle 1, RAP DSM or MAP DSM. He adjusts the average annual rate increases of these three plans to include performance incentive awards similar to those requested by the Company in this case. He estimates the average increase in average rates over the 2016-2035 period for the plan with RAP DSM to be 0.3% higher than average increase for the plan with no further DSM and concludes that, "the RAP DSM strategy contained in the 2014 IRP and proposed in MEEIA Cycle 2 application is expected to result in no overall long-term benefits for all customers of Ameren Missouri."[1]

My conclusion is that the RAP portfolio benefits all customers whether or not they participate in the programs. I suggest two changes for the evaluation of rate impacts: 1) Levelized average rates should be used to account for time value of money as opposed to average increase in average rates; and 2) Comparisons should be made over the entire span of the IRP analysis period and not just 2016-2035, since the latter would lead to biased conclusions by disregarding the benefits of programs assumed to be implemented in the later years of the planning horizon.

In addition to reduced levelized rates relative to the no DSM plan, the RAP portfolio also provides flexibility in long-term planning and helps mitigate risks, and therefore provides other benefits to all customers. For these reasons, Mr. Rogers' assertion that not all customers benefit from the programs should be rejected.

Q. Please summarize the rebuttal testimony of Mr. Woolf regarding the Company's decision to choose RAP over MAP and its treatment of GHG regulations in its 2014 IRP filing.

[1] John Rogers Rebuttal, p. 30, l. 15-17.

A. Mr. Woolf criticizes Ameren Missouri's decision to choose RAP instead of MAP DSM in its preferred resource plan because he alleges that MAP would reduce electricity costs and average bills by significantly more than the RAP portfolio. He also alleges that by assuming very low probabilities, there will be any federal GHG emission regulations and by assuming relatively low estimates for carbon dioxide ("CO_2") allowance prices, the Company significantly understates additional cost that could be avoided by energy efficiency programs.

I explain in detail why Mr. Woolf's allegations have no basis. As part of the IRP analysis, we have concluded that the RAP portfolio most appropriately balances the achievement of cost-effective energy efficiency savings with the risks and rate impacts to all customers. The MAP portfolio does not because it 1) results in higher levelized rates over the IRP study period, which means it does not reduce average bills 2) requires much higher incremental spending for each additional kWh saved, and 3) does not result in net savings to all customers until 2034.

Ameren Missouri has appropriately considered GHG regulations as part of its IRP analysis and has properly evaluated the potential impacts of the Environmental Protection Agency's ("EPA") proposed Clean Power Plan ("CPP"). All of the scenarios in the IRP analysis do, in fact, include federal GHG regulation assumptions in either direct or indirect form. The direct CO_2 emissions price scenarios have a combined probability of 15%. The high probability (85%) assigned by Ameren Missouri's subject matter experts to regulations that impose indirect costs on CO_2 emissions is appropriate in light of the EPA's proposed CPP, which does not impose an explicit price on CO_2 emissions. The retirement of existing coal-fired plants, including some owned by Ameren Missouri, and replacement of these plants with resources that produce lower (or no) CO_2 emissions fully account for the indirect costs of such regulations. As a result, there is no need to also impose an explicit price for CO_2 emissions. The CO_2 prices assumed by the Company are exactly equal to those produced by Synapse in its last study prior to the filing of the Company's IRP and are similar to those produced by Synapse in its updated study released last month. For these reasons, Mr. Woolf's assertions regarding Ameren Missouri's selection of the RAP portfolio and the Company's treatment of GHG regulations in arriving at its decision should be rejected.

III. THE COMPANY'S RAP PORTFOLIO BENEFITS ALL CUSTOMERS

Q. Please explain Mr. Rogers' analysis regarding the DSM plans evaluated in the Company's 2014 IRP.

A. Mr. Rogers analyzed three alternative resource plans that were evaluated in the Company's 2014 IRP: "RAP-Plan I" (includes RAP DSM), also the Company's preferred resource plan, "MAP-Plan R" (includes MAP DSM) and "No DSM Plan K" (includes no further DSM after MEEIA Cycle 1, the current 2013-2015 three-year DSM plan). He compared the average annual rate increases, after adjusting for the requested performance incentive in this case, and found that average annual rate impacts for MAP-Plan R and RAP-Plan I were 1.10% and 0.3% higher, respectively, than the No DSM Plan K rate impacts for the 2016-2035 time frame. He concluded that the "RAP DSM strategy contained in the 2014 IRP and proposed in MEEIA Cycle 2 application is expected to result in no overall long-term benefits for all customers of Ameren Missouri" since RAP-Plan I shows a 0.3% higher "average annual average rate impact" than No DSM-Plan K for the 2016-2035 planning horizon.

Q. Do you agree with Mr. Rogers' conclusion?

A. No, I do not.

Q. Why not?

A. I disagree for three reasons, in addition to the flaws in Mr. Rogers' analyses addressed in Company witness Steve Wills' surrebuttal testimony: 1) the time frame Mr. Rogers is using should not end in 2035, but should be expanded to include results through 2044 to capture end effects of decisions made during the 20-year period; 2) instead of using the average percent increase in average rates over that time period, <u>levelized rates</u> should be used in evaluating whether or not all customers benefit from the programs; and 3) including energy efficiency provides flexibility in planning for the future and helps Ameren Missouri in adapting to changing conditions, resulting in continued risk mitigation benefits to customers.

Q. Please explain your first reason. Why should results be evaluated through 2044 instead of 2035?

A. While Ameren Missouri develops its resource plans looking at a 20-year period, it is important to include ten additional years in the analysis to capture longer-term financial and operational "end-effects" resulting from decisions reflected in the 20-year planning horizon.

Q. Why is it important to capture end-effects?

A. Simply put, leaving out the end-effects will cause biased comparisons between different resource plans because you may underestimate the costs and benefits of a resource decision. For example, assume the Company adds a new supply-side resource in the last year of the planning horizon. If the analysis ends there, the costs of adding this new resource will be vastly underestimated as the analysis will include only one year of return on equity, depreciation expense, etc. This will lead to erroneous conclusions about the relative cost of that resource. The opposite is true in the case of energy efficiency. As is evident from the Company's proposed DSM plan, the expenditure must be made first and most of the benefits are realized in the subsequent years. If the assumption is that there will be continuous energy efficiency expenditures throughout the 20-year planning horizon, the analysis will fail to reflect benefits resulting from the last few years of those expenditures because the study period does not extend beyond the planning horizon. While shorter-term impacts are also important and are of course considered, it is important to include all costs and benefits. Extending the evaluation through 2044, beyond the 20-year planning horizon, paints a much more complete and accurate picture of the costs of resource decisions for our decision makers. In fact, Synapse Energy Economics' report – Best Practices in Electric Utility Integrated Resource Planning – was prepared for the Regulatory Assistance Project and recommends the use of end-effects to avoid bias:

> The study period for IRP analysis should be sufficiently long to incorporate much of the operating lives of any new resource options that may be added to a utility's portfolio— typically at least 20 years—*and should consider an "end effects" period* to avoid a bias against adding generating units late in the planning period.[2] [*Emphasis added*].

Q. Have any parties raised any concerns with Ameren Missouri's use of 2015-2044 as the full analysis time frame?

A. No. In fact, Ameren Missouri has been using the same rationale since at least the 2008 IRP and, to my knowledge, no stakeholder has ever raised an issue with this approach.

[2] Wilson, R. and Biewald, B, June 2013, Best Practices in Electric Utility Integrated Resource Planning, p. 31.

Q. Is an additional ten years beyond the planning horizon long enough to capture the benefits of all the DSM program expenditures?

A. It is for two reasons. First, the average life of the measures is approximately ten years; therefore, most, if not all, of the benefits are captured. Second, present value impacts of any costs and benefits would likely be negligible if you extend the analysis beyond thirty years.

Q. Moving on to your second observation; why should the levelized rates be used instead of an average increase in average rates to evaluate customer rate impacts?

A. Simply because the time value of money has to be accounted for when evaluating the rates, as we do when we use present value of revenue requirements ("PVRR") in evaluating long-term customer costs reflected in an IRP. We don't use <u>average</u> revenue requirements for that purpose, and we should not take the same kind of approach in evaluating rate impacts here. This same reasoning might be why the Commission's resource planning rule specifies levelized average rates as one of the specified performance measures to be used in the evaluation of alternative resource plans. 4 CSR 240-22.060(2)(A)4 states in part:

> (2) Specification of Performance Measures. The utility shall specify, describe, and document a set of quantitative measures for assessing the performance of alternative resource plans with respect to resource planning objectives.
> (A) These performance measures shall include at least the following:
> 4. Levelized annual average rates;

Average increase in average rates is not included in the measures the resource planning rule requires the utilities to include as one of the performance measures.

Q. Has Ameren Missouri used levelized rates as a performance measure in its 2014 IRP?

A. Yes. On page 29 of Chapter 9 in the Company's 2014 IRP, a chart that shows the levelized rates results without utility performance incentives is provided; this chart shows RAP-Plan I has the lowest levelized average rates, and No DSM Plan K has the highest levelized average rates. On page 40 of Chapter 9-Appendix A, a chart that shows the levelized rates results with utility performance incentives is provided.[3] It is important to note that we included a higher performance incentive assumption in the IRP solely based on the earnings opportunities from the two avoided natural gas combined cycle plants. With the higher performance incentives, the levelized average rates from the RAP-Plan I are only one-thousandth of a cent (0.001) higher than the No DSM Plan K. When I recalculate the levelized rates with the incentive levels requested in this case, then the levelized average rates for the RAP plan are lower than those for the No DSM plan. The levelized rates are shown in Table 1 below:

Table 1: Levelized Rates with and without Performance Incentives[4]

Levelized Rates (Cents/kWh)	No Utility Performance Incentives 2015-2044	With Utility Performance Incentives IRP Assumption 2015-2044	With Utility Performance Incentives Requested in This Case 2015-2044
No DSM-Plan K	12.062	12.062	12.062
RAP-Plan I	12.008	12.064	12.027
MAP-Plan R	12.054	12.121	12.073
Difference from No DSM Plan			
RAP-Plan I	(0.054)	0.001	(0.035)
MAP-Plan R	(0.008)	0.059	0.011

As the table shows, the MAP plan results in higher levelized average rates for customers, but the RAP plan reduces the levelized average rates by 0.035cents/kWh; therefore, from a long-

[3] PVRR and rate impact results in risk analysis have been provided in the IRP filing work papers: 22.060 Integrated Resource Plan-Risk\3-Risk\Results\ PVRR 08-25-14_HC.xlsx.

[4] MAP-Plan R includes the same incentive level as RAP-Plan I for the comparison reflecting the incentive level requested by the Company in this case.

term levelized rate perspective, the Company's RAP DSM programs do benefit all customers whether or not they participate in the programs.

Q. Disregarding for a moment that using average rates to measure customer benefit is inappropriate, has Mr. Rogers made any errors in his analysis of average rates?

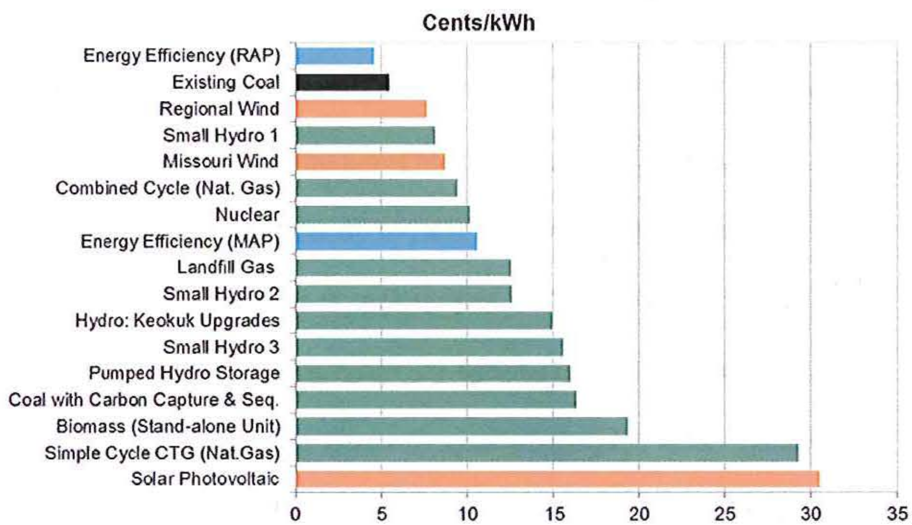
A. Yes. As stated in Mr. Rogers' testimony on page 27 in footnote 26, Staff assumed a performance incentive award annual rate impact of 0.45% in several years, seven of which were in the 2035-2044 timeframe. This period represents the end-effects years during which we do not assume implementation of additional DSM programs. Since there are no additional programs implemented, performance incentive rate impacts should not be included in those years after accounting for the performance incentive for the last year of additional energy efficiency programs in 2034. When that is corrected, the average annual average rate impacts over the 2016-2044 analysis period for RAP-Plan I and MAP-Plan R are -.03% and .29%, respectively. By Mr. Rogers' definition of customer benefits, the negative rate impact for RAP-Plan I would mean there are overall long-term benefits for all Ameren Missouri customers.

Q. Are there other considerations in deciding whether or not energy efficiency benefits all customers?

A. Yes. Levelized cost of energy ("LCOE") is a very useful tool in assessing how a resource may stack up against other options even though it does not tell the whole story for a resource's performance as part of an integrated plan. RAP level energy efficiency is the lowest cost resource available to Ameren Missouri to serve its customers as evident from Figure 1 below, which is similar to the figures included in Chapters 1 and 9 of Ameren

Missouri's 2014 IRP[5], except performance incentives requested by the Company in this case have been added to both RAP and MAP level energy efficiency costs in Figure 1:

Figure 1: Levelized Cost of Energy



Note: Does not reflect inclusion of tax incentives. Orange denotes intermittent resources.
MAP energy efficiency reflects costs and energy savings incremental to RAP
Performance incentives at the level requested in this case are included in RAP and MAP costs

Absent RAP level energy efficiency programs, the Company would have to invest in two 600 MW natural gas fired combined cycle ("CC") generation plants to serve its customers much earlier than it otherwise would with RAP level DSM programs. These two additional CC plants are included in the No DSM Plan -- the first CC would be needed in 2023 after Meramec Energy Center is retired, and the second CC would be needed in 2031 to meet reserve margin requirements.

Q. But the impacts of these additional CCs are included in the analysis results, aren't they?

A. Yes, they are included, hence the higher present value of revenue requirements and levelized average rates for the No DSM Plan as compared to the RAP DSM

[5] Ameren Missouri 2014 IRP Ch. 1, p. 7 and Ch. 9, p. 9.

Plan. Again, it is necessary to include the end-effects to more accurately capture the costs of these assets, one of which is assumed to go in-service in 2031, only three years before the end of the 20-year planning horizon. What is not included in the numbers is the benefit RAP energy efficiency adds by the flexibility it provides for planning for the future and the risks it helps the Company and all of its customers to continue to avoid. This brings me to my third observation regarding the benefits of our DSM programs for all customers.

Q. Please explain what you mean by flexibility in planning.

A. If there is one thing we know today, it is that the future is uncertain. We do not know how conditions that characterize the planning environment will evolve. Investing in energy efficiency helps delay investment in costly generation assets and lets us see how environmental regulations will evolve, what happens with fuel prices, or what technological advancements are taking place for a longer period of time. On the other hand, once you make the decision to build a CC, or any other generating resource, you have eliminated the ability to defer it and have given up some of that flexibility you had going forward. You are committed. Ameren Missouri does not have an unlimited amount of capital to invest. If that capital is used to build two CCs in eight years, there will be less low-cost capital available for other projects. This is another form of lost flexibility.

Thanks to the energy efficiency savings due to the already implemented programs and the assumed future programs, Ameren Missouri is able to retire its oldest and least efficient energy center, Meramec, in 2022 without the need to add costly new generating resources to serve its customers. Continuing to offer energy efficiency programs will help us identify more cost effective energy efficiency savings, and preserve flexibility for future resource decisions, including the potential for additional retirements if conditions warrant consideration of such actions.

Q. Are there any benefits related to the proposed GHG emissions regulations?

A. Yes, energy efficiency is very likely to be part of our plan for compliance with the final version of the CPP, currently in proposed form and under consideration by the EPA. This regulation is expected to require utility generator CO_2 emission rates to be reduced, in part through the implementation of energy efficiency programs. The EPA released its proposed CPP to reduce GHG emissions on June 2, 2014. At this point, we do not know what the final rule will look like, but what we can be sure of is that energy efficiency will almost certainly be part of that compliance plan. Whatever shape or form the final rule takes, if we do not include cost effective energy efficiency programs as part of our plan, it is quite probable that the cost of compliance to our customers will be higher.

Q. Please summarize your conclusion with respect to Mr. Rogers' contentions that RAP portfolio does not benefit all customers.

A. RAP portfolio benefits all customers because it 1) reduces levelized average rates relative to the levelized rates that would otherwise be realized in the absence of further DSM programs at RAP level, and 2) provides flexibility in long-term planning and helps mitigate risks.

IV. AMEREN MISSOURI'S DECISION TO INCLUDE THE RAP PORTFOLIO IN ITS PREFERRED PLAN IS APPROPRIATE

Q. What are the issues you will address in Mr. Woolf's rebuttal testimony related to Ameren Missouri's decision to choose RAP instead of MAP level energy efficiency in its 2014 IRP?

A. I will address Mr. Woolf's allegations that 1) 'IRPs should not define energy efficiency so narrowly, with only two possible future efficiency portfolios'[6], and 2) Ameren Missouri chose RAP even though MAP would reduce costs and average bills significantly.

Q. Please describe Mr. Woolf's criticism regarding Ameren Missouri's focus on the RAP and MAP energy efficiency portfolios.

A. Mr. Woolf claims that the IRP defined energy efficiency so narrowly, with only two possible future efficiency portfolios (RAP and MAP) that the Company did not fully investigate the amount of cost effective energy efficiency savings available.

Q. Would analyzing more than RAP and MAP portfolios be beneficial?

A. Perhaps in an academic sense, but not as a practical matter. Making the decision today on what is the best energy efficiency plan for the next twenty years is not practical. Avoided costs, technology and customer behavior are subject to periodic changes, all of which can result in changes to the potential for energy efficiency. RAP and MAP establish the range of reasonable possibilities over time. However, because of and in light of changing conditions, we will be re-evaluating the potential frequently. That is why the Commission's MEEIA rules require utilities to perform a potential study at least every four years, and the Commission's resource planning rules require utilities to file an IRP every three years. Ameren Missouri prefers to also perform the potential study every three years in order to match the MEEIA and IRP filings. We will continue to implement, assess and evaluate energy efficiency programs and to identify the most cost effective savings as we gain more experience. In turn, that will inform our planning and manifest itself in the specifics of future portfolios.

[6] Tim Woolf Rebuttal, p. 33, l. 13-14.

Q. Mr. Woolf states that the Company should at least investigate a portfolio of efficiency programs consistent with the assumptions used by the EPA in the proposed CPP;[7] how do you respond to that?

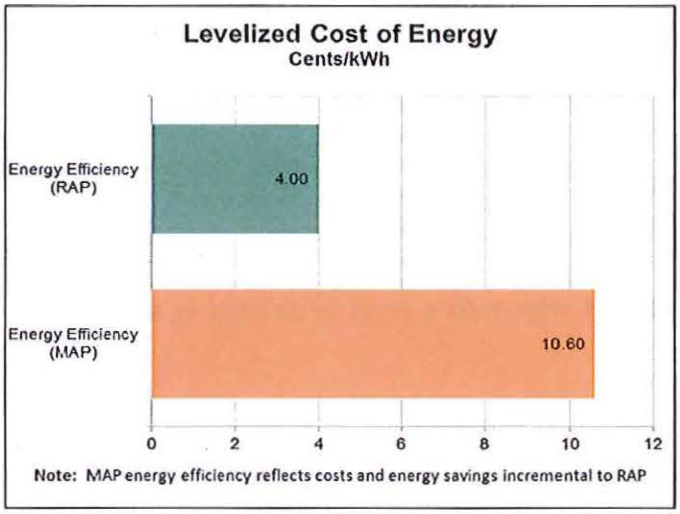
A. In his surrebuttal testimony, Ameren Missouri's witness Richard Voytas explains all the issues related to the EPA's energy efficiency savings potential in the proposed CPP and why such a level of savings is not appropriate to assume for Ameren Missouri.

Q. You mentioned levelized costs in your earlier response to Mr. Rogers' contentions. How do the levelized costs for MAP DSM compare to the levelized costs for RAP DSM?

A. Figure 2 below, which presents only the RAP and MAP energy efficiency levelized costs from the figure provided in the IRP filing Chapter 1, page 7, shows that levelized cost of energy efficiency savings for RAP is 4cents/kWh, whereas the levelized cost of achieving incremental savings up to the MAP level is 10.6cents/kWh.

[7] *Id.*, l. 20-21 and p. 34, l. 1.

Figure 2: LCOE for RAP vs MAP



LCOE is not a metric that can definitively assess the performance of a resource relative to others as part of an integrated resource plan, but it is a very good indicator of costs over the lifetime of a specific resource in isolation. Incremental costs that would be incurred to achieve additional savings to reach MAP level savings are more than double the cost of RAP level savings. RAP and MAP levels of energy efficiency savings and the costs of achieving them are explained in detail by Mr. Voytas in his surrebuttal testimony.

Q. How do you respond to Mr. Woolf's claim that the MAP portfolio would reduce costs and average bills by significantly more than the RAP portfolio?

A. This claim is only half correct. As shown in Table 2 below, while the total cost (PVRR) is lower for the MAP-Plan R, this plan results in higher levelized average rates than the RAP-Plan I, even without the inclusion of utility incentives. The levelized average rates for MAP-Plan R are 0.046cents/kWh higher than the levelized average rates for RAP-Plan I, without the inclusion of performance incentives or with the performance incentives requested in this case. When performance incentives using the IRP assumptions are added, which are higher for MAP than RAP and makes the rate impact for MAP-Plan R even greater, it is 0.057cents/kWh higher than the RAP Plan.

Table 2: RAP vs MAP Plan PVRR and Levelized Rates

	PVRR without Utility Performance Incentives 2015-2044 $Million	No Utility Performance Incentives 2015-2044 Cents/kWh	With Utility Performance Incentives IRP Assumption 2015-2044 Cents/kWh	With Utility Performance Incentives Requested in This Case 2015-2044 Cents/kWh
RAP-Plan I	61,352	12.008	12.064	12.027
MAP-Plan R	61,081	12.054	12.121	12.073
Difference MAP - RAP	(271)	0.046	0.057	0.046

Q. What is the significance of higher levelized average rates for the MAP Plan rather than the RAP Plan?

A. It means that, compared to the RAP Plan, implementing the MAP Plan would not reduce average bills for non-participants, but would cause an increase in the non-participants' average bills, contrary to what Mr. Woolf is claiming. Also shown in Table 1, the MAP Plan results in an increase in levelized rates compared to the No DSM Plan, while the RAP Plan results in a reduction in levelized rates. This is the same issue Mr. Rogers has raised -- 'do the programs benefit all customers whether or not they participate in the programs?' The answer for the MAP Plan is that it definitely does not reduce average rate impacts for non-participating customers like the RAP Plan does.

Q. Did consideration of these expected rate impacts cause Ameren Missouri to choose the RAP Plan in the IRP?

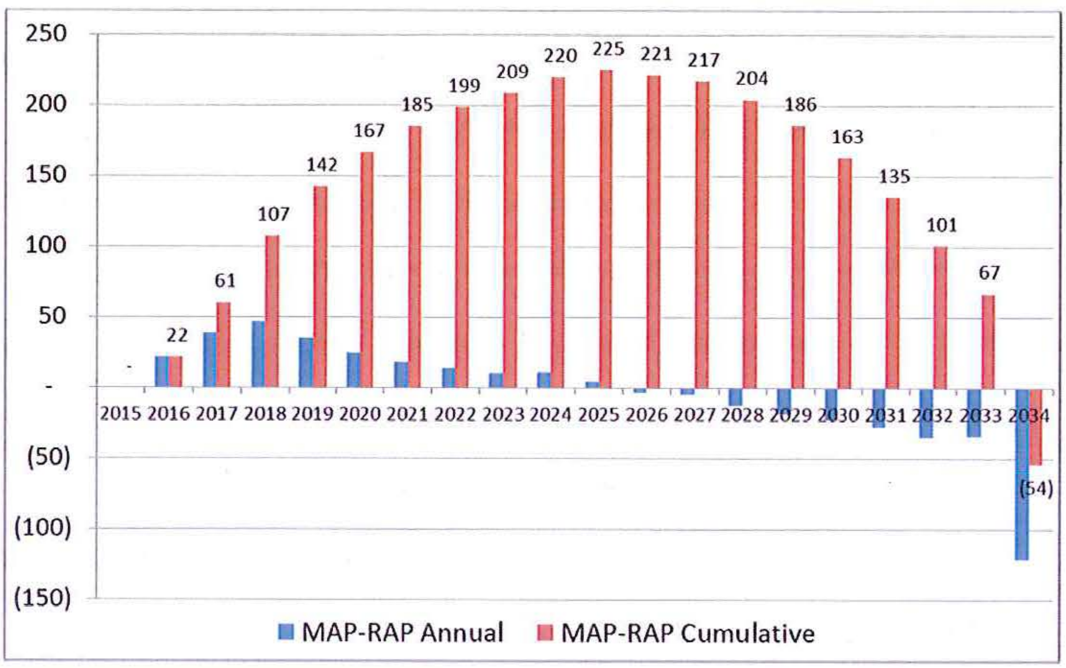
A. It certainly was an important consideration, because the rate impacts for non-participants are clearly unfavorable in the MAP Plan. In addition to that, we looked at total costs with utility performance incentives and/or participant out-of-pocket costs, which showed a de minimis cost advantage for MAP over the 30-year study period.

Table 3: Comparison of Total Cost to Customers for RAP and MAP[8]

$ Million	PVRR	PVRR w/ Incentives	PVRR w/ DSM Participant Costs	PVRR w/ Incentives & DSM Participant Costs
R - CC-MAP-Balanced	61,081	61,420	61,834	62,172
I - CC-RAP-Balanced	61,352	61,635	61,928	62,211
MAP Cost Advantage	271	215	94	38

We also looked at the year-by-year PVRR differences between RAP and MAP energy efficiency, which is shown in Figure 3 below and can also be found on page 9 in Chapter 10 of Ameren Missouri's 2014 IRP filing.

Figure 3: Year-by-year Cost Comparison for RAP and MAP[9]



[8] This table was provided in the IRP filing (EO-2015-0084) Ch. 10, p. 8.
[9] *Id.*, p. 9.

Q. What is the significance of this chart?

A. In short, it shows that any net benefit for the MAP portfolio is not realized until 2034 – the last year of the 20-year planning horizon. The chart shows the annual and cumulative PVRR differences between the RAP and MAP portfolios. It is noteworthy that the RAP energy efficiency Plan costs customers less than the MAP Plan through 2025 annually, and the cumulative cost advantage of RAP energy efficiency continues until 2034. All of the analysis results suggested that it would be a much better approach to start with RAP level energy efficiency programs instead of starting out with MAP energy efficiency and subjecting customers to higher rate and cost impacts with a great deal of uncertainty as to the benefit. As I stated earlier, it is not possible to decide what the best portfolio for the next twenty years would be right now, which is why the potential studies and IRPs are conducted periodically. The Commission's IRP and MEEIA rules recognize the ever-changing nature of the resource planning environment by requiring frequent updates to potential studies and resource planning analyses and by allowing for changes to our plans when circumstances warrant changes. Our approach provides us with the flexibility to identify and offer the most cost effective savings to our customers as we gain more experience through continued market research, program implementation and EM&V, and shields our customers from unnecessary cost and rate increase risks.

Q. Please summarize your conclusions with respect to Mr. Woolf's contentions regarding the Company's selection of the RAP portfolio over the MAP portfolio.

A. Based on our extensive analysis, Ameren Missouri has concluded that the RAP portfolio most appropriately balances the achievement of cost effective energy efficiency savings with the risks and rate impacts to all customers. The MAP portfolio does not because it 1) results in higher levelized rates over the IRP study period, 2) requires much higher incremental spending for each kWh saved, and 3) does not result in net savings to customers until 2034.

V. AMEREN MISSOURI'S TREATMENT OF CO_2 PRICES AND EVALUATION OF EPA'S PROPOSED GHG EMISSIONS REGULATIONS ARE APPROPRIATE

Q. Please explain Mr. Woolf's criticisms of Ameren Missouri's CO_2 emissions regulation assumptions and CPP compliance analysis.

A. Mr. Woolf claims, "by assuming very low probabilities that there will be *any* [*emphasis added*] federal greenhouse gas emission requirements, and by assuming relatively low estimates for CO_2 allowance prices, the Company significantly understates the additional costs that could be avoided by efficiency programs."[10] Mr. Woolf also claims that the Company does not intend to use energy efficiency resources to comply with the eventual final form of the EPA's proposed CPP.[11]

Q. How would you briefly respond to these criticisms?

A. Ameren Missouri's estimate of costs that could be avoided by energy efficiency programs is appropriate because the Company has properly considered and included costs of complying with environmental regulations, including federal GHG regulations. In its IRP, the Company assumed some type of GHG regulations through indirect mechanisms that do not include an explicit price on CO_2 emissions with an 85% probability, and through mechanisms that include an explicit CO_2 price with a 15% probability. Mr. Woolf's assertion that the Company does not intend to use energy efficiency

[10] Tim Woolf Rebuttal, p. 38, l. 20-22.
[11] Id., p. 39, l. 7-8.

to comply with the CPP is not correct at all, as it is fully expected to be part of our plan for compliance with the final form of the EPA's currently proposed CPP and was reflected in our IRP analysis of compliance with these regulations.

Q. Please describe how Ameren Missouri considered and included costs of complying with GHG regulations.

A. Ameren Missouri identified three key drivers for wholesale market prices of electricity: load growth, natural gas prices and environmental regulations. Various combinations of these key driver variables provided us with the fifteen distinct power price scenarios under which we evaluated the performance of the alternative resource plans and the illustrative plan we evaluated for compliance with the proposed CPP. For the environmental regulations scenarios, our internal experts considered existing, proposed and future regulations, including but not limited to National Ambient Air Quality Standards ("NAAQS"), Mercury and Air Toxics Standards ("MATS"), Coal Combustion Residuals ("CCR"), Clean Water Act regulations, and federal GHG emissions regulations. Compliance with these current/proposed/future regulations would manifest themselves through existing coal generation retirements and replacement generation additions. Our experts then developed the assumptions for the amount of retirements and the timing, and the likelihood of these retirements. The highest level of retirement scenarios also included explicit CO_2 prices.

Q. Can you please describe in more detail how the GHG regulations were considered in the scenarios?

A. Our assumptions in the scenario development concerning the GHG regulations were framed in our 2014 IRP filing as follows:

> In addition to the existing and future regulations outlined above, we must also consider potential actions with respect to climate policy and regulation of GHG emissions beyond what was recently proposed by EPA in the form of its Clean Power Plan. To help frame the ongoing possibilities for carbon policy and regulation of GHG emissions, we examined reports from several research and consulting companies, such as Wood Mackenzie, IHS Cera, and Synapse Energy Economics, Inc. We also reviewed US government reports on the so-called "social cost of carbon." Through this process we considered the structures [by which] a future GHG policy could be implemented which included the following;
>
> - Legislative
> - Regulatory
> - International Treaty
>
> We identified three general mechanisms by which GHG policy could be implemented through any of the above structures. Each implementation path could seek to achieve GHG reductions through any, or a combination of, three mechanisms:
>
> - Policies to mandate and/or promote low/no carbon resources
> - Specified limits on GHG emissions (emission rates or mass emission)
> - Implementation of an explicit price on GHG emissions
>
> This framework provided a vehicle for discussion with our internal experts to identify the probable ranges of coal retirements and carbon prices that define our scenarios. Through this process an updated set of assumptions was developed to reflect environmental policy effects on coal retirement expectations, as well as the timing, magnitude and probability of an explicit price on carbon dioxide emissions.[12]

It is important to note that two of these mechanisms – policies to mandate and/or promote low/no carbon resources and specified limits on GHG emissions – are the 'indirect' mechanisms that I mentioned earlier, represented by scenarios that carry a combined 85% probability. These "indirect" mechanisms are the same mechanisms that were mentioned in the study by Synapse Energy Economics – 2013 Carbon Dioxide Price Forecast – that the

[12] Ameren Missouri 2014 IRP (File No. EO-2015-0084) Ch. 2, p. 19.

Company relied on for CO_2 price assumptions, and was also referenced by Mr. Woolf in his rebuttal testimony.[13] This study is attached to my surrebuttal testimony as Schedule SHB-1.

Q. What does the 2013 Synapse study say regarding what you refer to as methods of imposing "indirect" costs on CO_2 emissions?

A. On page 6 of this study, it reads:

> However, many other types of climate policies work not by making polluting more expensive per se, but instead by requiring firms to use one technology instead of another, or to maintain particular emission limitations in order to avoid legal repercussions.

Moreover, Dr. Ezra Hausman, who is one of the co-authors of the study mentioned above, referred to the same kinds of indirect regulations used in Ameren Missouri's assumptions as part of his testimony in Ameren Missouri's most recent rate case:

> A more likely impact of CO_2 regulation would be to directly or indirectly increase the cost of generation from carbon-intensive resources such as coal plants. "Directly" would mean by imposing a carbon tax or a tradable allowance system, neither of which is currently part of EPA's proposal; "indirectly" would be any other mechanism that effectively imposes a preference for low-carbon resources, leading to curtailed operations or shutdown of existing coal plants.[14]

These indirect mechanisms are exactly the kind that were assumed when the timing and amount of coal retirements were determined for the environmental regulation scenarios that did not include explicit CO_2 prices, as determined by our subject matter experts. Therefore, all scenarios included some type of GHG emission regulation assumption, contrary to Mr. Woolf's allegation that the Company assumed very low probabilities that there will be *any* federal GHG emission requirements.

[13] Tim Woolf Rebuttal, p. 36, footnote 10.
[14] Ezra D. Hausman Direct in File No. ER-2014-0258, p.7, l. 6-9.

Q. What you have referenced in Dr. Hausman's testimony above states that a carbon tax or tradable allowance system are not part of EPA's proposal. Is this the same proposed CPP you have discussed previously in your testimony?

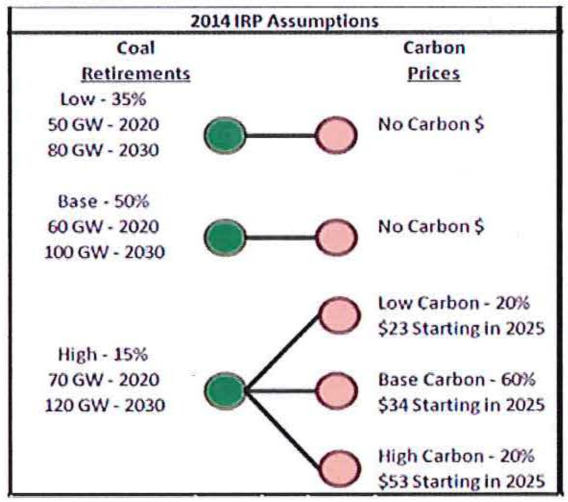
A. Yes, exactly. EPA's proposed CPP to reduce GHG emissions does not impose an explicit price on CO_2 emissions but instead makes use of the indirect mechanisms described by Dr. Hausman, and further affirms the appropriateness of Ameren Missouri's scenario assumptions.

Q. What are the resulting coal plant retirement assumptions in these scenarios?

A. Figure 4 below, which is reproduced from Ameren Missouri's IRP filing,[15] illustrates the timing and magnitude of the retirement assumptions. The least stringent environmental scenario assumptions result in 80 gigawatts ("GW") of coal retirements by 2030, the base level environmental regulations include 100 GW of retirements by 2030 and the high level retirement scenario with varying explicit carbon prices assume 120 GW of retirements by 2030.

[15] Ameren Missouri 2014 IRP (File No. EO-2015-0084), Ch. 2, p. 20.

Figure 4: Coal Retirement Assumptions



Q. Do you know how IRP retirement assumptions in the scenarios compare to other estimates?

A. Yes. They are consistent with what we are seeing from other sources. For example, the EPA's own analysis estimates that the CPP will result in approximately 100 GW of coal plant retirements.[16] Another study by the Bipartisan Policy Center assumes 50 GW of coal retirements by 2030 in its reference case, which does not include any GHG emission regulations, and an additional ~40 GW of retirements as a result of the proposed CPP that bring the total retirement estimate to just above 90 GW.[17] Another study by NERA Economic Consulting also shows 51 GW of retirements due to environmental regulations other than GHG emission regulations, and estimates a total of 97 GW of coal retirements by 2031 with the inclusion of the proposed CPP.[18] Again, our retirement assumptions that range from 80 to 120 GW with the highest probability given to 100 GW of retirements are entirely consistent with estimates from other sources, including the EPA.

[16] http://www.epa.gov/airmarkets/powersectormodeling/docs/Option%201%20State.zip.
[17] Modeling Proposed Clean Power Plan: Preliminary Results, September 22, 2014.
[18] Potential Energy Impacts of the EPA Proposed Clean Power Plan, October 2014.

Q. Are the retirements of Ameren Missouri coal units in the Company's IRP preferred resource plan also in line with these retirement estimates?

A. All of the estimates from the external sources I cited point to about 100 GW of coal retirements out of approximately 316 GW of available coal capacity, which is slightly less than one-third of all coal generation capacity in the U.S. In the IRP, with the retirement of Meramec and Sioux Energy Centers within the next twenty years, we are reflecting retirement of about one-third of our existing coal generation. I do not know how anyone can claim this is not consistent.

Q. How do you respond to Mr. Woolf's allegation that "Ameren's assumptions about the probability of CPP are clearly too low"?[19]

A. Mr. Woolf is confusing Ameren Missouri's scenario assumptions for GHG regulation with our analysis of a specific regulation that is currently only in proposed form. After the EPA released the details of its proposed CPP, we performed an analysis of a potential compliance plan based on the proposed regulations. Separately, and as explained earlier, we did include GHG emission regulation assumptions in all scenarios through either direct or indirect means, the latter of which are consistent with the kinds of mechanisms reflected in the proposed CPP and for which a probability of 85% was assigned by our subject matter experts. Ameren Missouri did not explicitly assign a probability to the proposed CPP.

Q. Given what you just stated, is Mr. Woolf's assertion that "Ameren applied a forecast of CO_2 allowance costs to represent the costs of complying with the

[19] Tim Woolf Rebuttal, p. 37, l. 6-7.

CPP"[20] correct?

A. No, it is not. The explicit CO_2 prices that Ameren Missouri assumed in its scenarios do not represent the costs of complying with the CPP but only the costs imposed on CO_2 emitting resources per ton of CO_2 emitted under those scenarios in which an explicit CO_2 price is included.

Q. Does Mr. Woolf agree with the timing and the probabilities the Company assigned to the CO_2 price scenarios?

A. No. We assumed there would not be any explicit CO_2 price through 2024, but assumed explicit prices equal to those presented in the Synapse 2013 Carbon Dioxide Price Forecast starting in 2025. Since the Synapse report has CO_2 price estimates in 2020-2024, Mr. Woolf does not agree with our timing assumption. A total of 15% probability was assigned to these scenarios, which, as I understand, Mr. Woolf claims to be low. But as I have demonstrated, this does not represent the entire range of GHG regulation based on imposing indirect costs, which carry a combined 85% probability.

Q. Mr. Woolf takes issue with the absence of a CO_2 price prior to 2025 in the scenarios in which a CO_2 price is assumed. Why did Ameren Missouri assume a 2025 starting point for CO_2 prices?

A. This assumption was based on our internal subject matter experts' assessments as part of the process described earlier in my testimony. On the environmental regulation scenario development, we worked with members of executive management who have direct relationships with policymakers, lobbyists, legislators, and regulators including EPA staff. The first issue regarding CO_2 prices that our experts deliberated on was whether the

[20] *Id.*, p. 36, l. 7-8.

imposition of a CO_2 price was likely under the existing regulations; the consensus was that it was not. This meant that new legislation would have to be passed by Congress and signed into law by the President to make imposition of CO_2 prices possible by regulations. Our internal experts did not see a favorable political climate for such a scenario in the near future and therefore determined that 2025 would likely be the first year in which an explicit CO_2 price would take effect. These same considerations were also the reason for the 15% probability assigned to the explicit CO_2 price scenarios.

Q. Does Mr. Woolf agree with the magnitude of CO_2 prices Ameren Missouri used in the scenarios?

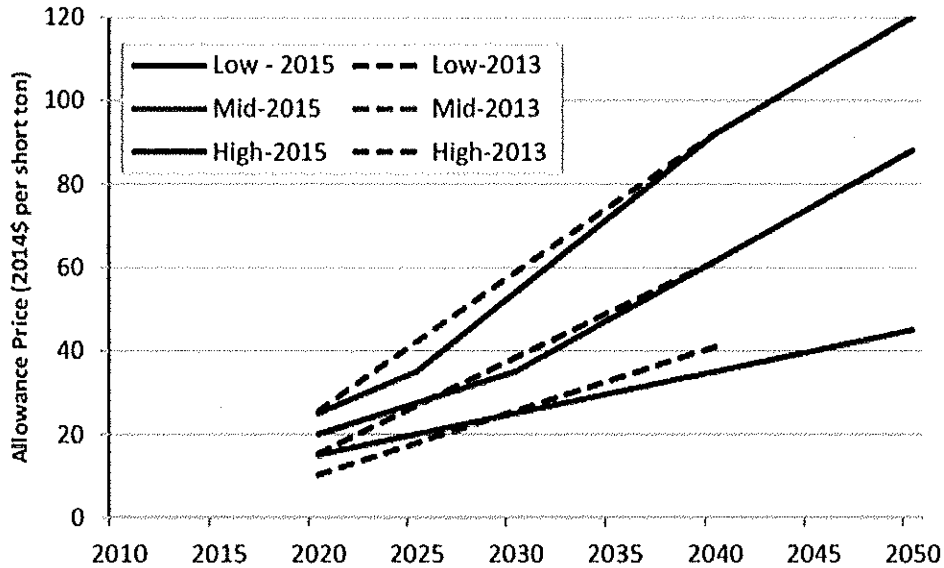
A. No, surprisingly, he does not seem to agree with the magnitude of CO_2 prices used by Ameren Missouri,[21] even though the prices we used were taken from the 2013 Carbon Price Forecast by Synapse Energy Economics, by whom Mr. Woolf is employed. He does state that a recent update to the Synapse CO_2 price forecast provides a much more reasonable range of future CO_2 prices.[22]

Q. What does the more recent Synapse study show?

A. The following figure is taken from Page 37 of this updated report, which I have attached to my surrebuttal testimony as Schedule SHB-2.[23]

[21] *Id.*, p. 38, l. 21.
[22] *Id.*, p. 37, l. 8-10.
[23] Carbon Dioxide Price Forecast, Synapse Energy Economics, March 3, 2015.

Figure 5: Comparison of 2013 and 2015 Synapse CO_2 Price Forecasts



As can be seen from the figure, between 2025 and 2040, most of the data points for the 2013 forecasts, used as the basis for Ameren Missouri's IRP assumptions, are higher than those in the 2015 Synapse update. Mr. Woolf's characterization that the CO_2 price assumptions used by Ameren Missouri are too low clearly cannot be based on a comparison to the more recent Synapse study.

Q. What is Mr. Woolf's basis then for claiming the CO_2 prices used in the IRP scenarios are too low?

A. I am really having a hard time understanding his basis. Maybe it is a misunderstanding on Mr. Woolf's part about the $53/ton cost we estimated for complying with the CPP that Mr. Woolf references in this testimony[24] followed by his assertion that "the Company does not explain why its modeling assumptions differ so dramatically from its

[24] Tim Woolf Rebuttal, p. 37, l. 14-18.

position that compliance costs are likely to be higher than the costs assumed in the High CO_2 Case."[25]

Q. Did the Company's modeling assumptions differ dramatically from its position that compliance costs are likely to be higher than the costs assumed in the High CO_2 case?

A. No. We explained all the assumptions and the results of our analyses, including a plan for compliance with the proposed CPP, and there is no inconsistency between the assumptions and the results and our position.

Q. What causes Mr. Woolf to make such a claim?

A. There seems to be some confusion and a case of comparing apples to oranges on Mr. Woolf's part. Within weeks after the proposed CPP was released, we did formulate an illustrative compliance plan that would require several changes to our IRP preferred plan – advancing retirement of Meramec to the end of 2019, advancing CC to 2020 and doubling the size, adding more wind energy, and uneconomically dispatching coal and natural gas plants. We estimated these changes could cost an additional $4 billion between 2020 and 2035. We presented this same information in a different way by calculating cost per ton of CO_2 reduction over that same time period, which is the $53/ton Mr. Woolf cites from the IRP.[26] The additional $4 billion in costs divided by the total CO_2 emission reductions estimated in that 15-year period resulted in that number. So, the $53/ton figure is the result of the analysis and is not an input to the analysis. It is also not analogous to an effective price, explicit or otherwise, on CO_2 emissions.

[25] *Id.*, p. 38, l. 1-3.
[26] *Id.*, p. 37, l. 16-18.

Q. Mr. Woolf also argues that Ameren Missouri did not explain why the High CO_2 case has a probability of only three percent; what is your response to that?

A. The scenario development process described previously, including the assumptions and the resulting probabilities assigned to each price scenario, have been explained in the IRP filing in Chapter 2. The final probability tree for the market price scenarios is provided as an attachment to my surrebuttal testimony as Schedule SHB-3.

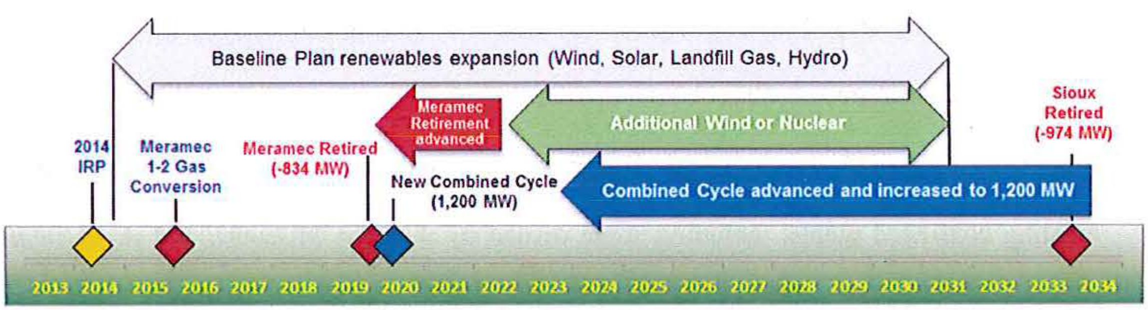
Q. Does Ameren Missouri consider energy efficiency an option for complying with the CPP plan?

A. Yes, it does.

Q. Then why does Mr. Woolf claim Ameren Missouri does not intend to use energy efficiency resources to mitigate the cost of complying with the CPP?[27]

A. I believe it is another misunderstanding on Mr. Woolf's part. He makes the claim, referencing a figure we provided in the IRP filing in Chapter 1, page 17, that "there is no mention of using efficiency to respond to the CPP regulations."[28] The figure referenced by Mr. Woolf is reproduced below as Figure 6.

Figure 6: Impacts of GHG Regulations on Preferred Resource Plan



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[27] *Id.*, p. 39, l. 5-8.
[28] *Id.*, l. 15.

This figure shows only the changes that would have to be made to the Company's IRP preferred plan to be compliant with the proposed CPP. The preferred resource plan already includes RAP level energy efficiency. Therefore, energy efficiency is also part of the illustrative CPP compliance plan. Had energy efficiency not been included in the compliance plan, the costs would have been even higher than we estimated. It is important to keep in mind that this is just one approach to compliance with a proposed rule. The CPP rule is expected to be finalized in summer 2015, there is high probability of legal challenges, and state implementation plans are supposed to be finalized in 2016. Given that MEEIA insures the utility incentives will be aligned with helping customers use energy more efficiently, Ameren Missouri expects to utilize opportunities to increase energy efficiency savings as we identify and offer the most cost effective savings to our customers including any such savings that will help Ameren Missouri comply with GHG regulations.

Q. Please summarize your conclusions with respect to Mr. Woolf's criticism of the Company's consideration of GHG regulations.

A. Ameren Missouri has appropriately considered GHG regulations as part of its IRP analysis and has properly evaluated the potential impacts of the EPA's proposed CPP. The high probability (85%) assigned by Ameren Missouri's subject matter experts to regulations that impose indirect costs on CO_2 emissions is appropriate in light of the EPA's proposed CPP, which does not impose an explicit price on CO_2 emissions. The retirement of existing coal-fired plants, including some owned by Ameren Missouri, and replacement of these plants with resources that produce lower (or no) CO_2 emissions fully account for the indirect costs of such regulations. As a result there is no need to also impose an explicit price for CO_2 emissions. The CO_2 prices assumed by the Company, with an estimated 15%

probability of occurrence, are exactly equal to those produced by Synapse in its last study prior to the filing of the Company's IRP and are similar to those produced by Synapse in its updated study released last month. Only the starting year for these prices, 2025 versus 2020, is different based on Ameren Missouri's own expert assessment of the policy landscape. Mr. Woolf's criticisms therefore have no basis in fact.

Q. Please summarize your conclusions.

A. The RAP portfolio benefits all customers whether or not they participate in the programs. In addition to reduced levelized rates relative to the No DSM plan (i.e., reduced average bills), the RAP portfolio also provides flexibility in long-term planning and helps mitigate risks, and therefore provides other benefits to all customers.

The Company's decision to include RAP DSM in its preferred plan instead of MAP DSM is appropriate as the Company considered and analyzed costs and benefits extensively, including any federal CO_2 emission regulations. Ameren Missouri has concluded that the RAP portfolio most appropriately balances the achievement of cost effective energy efficiency savings with the risks and rate impacts to all customers. The MAP portfolio does not because it 1) results in higher levelized rates over the IRP study period, 2) requires much higher incremental spending for each kWh saved, and 3) does not result in net savings to all customers until 2034.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company d/b/a Ameren Missouri's 2nd Filing to Implement Regulatory Changes in Furtherance of Energy Efficiency as Allowed by MEEIA.	))))	File No. EO-2015-0055

AFFIDAVIT OF S. HANDE BERK

STATE OF MISSOURI)
) ss
CITY OF ST. LOUIS)

S. Hande Berk, being first duly sworn on her oath, states:

1. My name is S. Hande Berk. I work in the City of St. Louis, Missouri, and I am employed by Ameren Services Company as Senior Corporate Planning Analyst.

2. Attached hereto and made a part hereof for all purposes is my Surrebuttal Testimony on behalf of Union Electric Company d/b/a Ameren Missouri consisting of 33 pages and Schedule(s) SHB-1 thru SHB-3, all of which have been prepared in written form for introduction into evidence in the above-referenced docket.

3. I hereby swear and affirm that my answers contained in the attached testimony to the questions therein propounded are true and correct.

Sebiha Hande Berk
S. Hande Berk

Subscribed and sworn to before me this 27th day of April, 2015.

Julie Irby
Notary Public

My commission expires:

Julie Irby - Notary Public
Notary Seal, State of
Missouri - St. Louis County
Commission #13753418
My Commission Expires 1/15/2017

2013 Carbon Dioxide Price Forecast

November 1, 2013

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CONTENTS

1. EXECUTIVE SUMMARY

Prudent planning requires electric utilities and other stakeholders in carbon-intensive industries to use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. However, forecasting a CO_2 price can be difficult. While several bills have been introduced in Congress, the federal government has yet to legislate a policy to reduce greenhouse gas emissions in the United States.

Although this lack of a defined policy that sets a price on carbon poses a challenge in CO_2 price forecasting, an assumption that there will be no CO_2 price in the long run is not, in our view, reasonable. The scientific basis for attributing climatic changes to human-driven greenhouse gas emissions is irrefutable, as are the type and scale of damages expected to both infrastructure and ecosystems. The need for a comprehensive U.S. effort to reduce greenhouse gas emissions is clear. Any policy requiring or leading to greenhouse gas emission reductions will result in higher costs to the electricity resources that emit CO_2.

The Synapse 2013 CO_2 price forecast is designed to provide a reasonable range of price estimates for use in utility Integrated Resource Planning (IRP) and other electricity resource planning analyses. The current forecast updates Synapse's 2012 CO_2 price forecast, published in October 2012.[1] Our 2013 forecast incorporates new data that have become available since 2012, in order to provide useful CO_2 price estimates for utility resource planning purposes.

1.1. Key Assumptions

Synapse's 2013 CO_2 price forecast reflects our expert judgment that near-term regulatory measures to reduce greenhouse gas emissions, coupled with longer-term cap-and-trade or carbon tax legislation passed by Congress, will result in significant pressure to decarbonize the electric power sector. The key assumptions of our forecast include:

- A federal program establishing a price for greenhouse gases is the probable eventual outcome, as it allows for a least-cost path to emissions reduction.
- Initial climate-focused policy actions are more likely to take a regulatory approach, e.g. Section 111(d) of the Clean Air Act. In the longer-term, federal legislation setting a price on emissions through a cap-and-trade policy or a carbon tax will likely be prompted by one or more of the following factors:
    - New technological opportunities that lower the cost of carbon mitigation;

[1] Wilson et al., "2012 Carbon Dioxide Price Forecast," October 2012. http://www.synapse-energy.com/Downloads/SynapseReport.2012-10.0.2012-CO2-Forecast.A0035.pdf.

- A patchwork of state policies that achieve state emission targets for 2020, spurring industry demands for federal action;
- A series of executive actions taken by the President that spur demand for Congressional action;
- A Supreme Court decision that permits nuisance lawsuits, making it possible for states to sue companies within their boundaries that own high-carbon-emitting resources, and creating a financial incentive for energy companies to act; and
- Mounting public outcry in response to increasingly compelling evidence of human-driven climate change.

Given the growing interest in reducing greenhouse gas emissions by states and municipalities throughout the nation, a lack of timely, substantive federal action will result in the enactment of diverse state and local policies. Heterogeneous—and potentially incompatible—sub-national climate policies would present a challenge to any company seeking to invest in CO_2 emitting power plants, both existing and new. Historically, there has been a pattern of states and regions leading with energy and environmental initiatives that have in time been superseded at the national level. It seems likely that this will be the dynamic going forward: a combination of state and regional actions, together with federal regulations, that are eventually eclipsed by a comprehensive federal carbon price.

We expect that federal regulatory measures together with regional and state policies will lead to the existence of a cost associated with greenhouse gas reductions in the near term. Prudent utility planning requires that utilities take this cost into account when engaging in resource planning, even before a federal carbon price is enacted.

1.2. Study Approach

To develop the 2013 CO_2 price forecast, Synapse reviewed several key developments that have occurred over the past year. These include:

- Proposed federal regulatory measures to limit CO_2 emissions from new power plants and administrative initiatives to advance regulation for existing units;
- Updates to the U.S. carbon price used to assess the climate benefit of federal rulemakings;
- Revisions to the Northeast's Regional Greenhouse Gas Initiative (RGGI) CO_2 policy and the first allowance auctions under California's AB 32 Cap-and-Trade program;
- The results of a multi-year Energy Modeling Forum (EMF) research effort on the costs of U.S. emissions abatement from nine integrated assessment modeling teams; and
- Carbon price forecasts from the most recent IRP efforts of 28 utilities.

1.3. Synapse's 2013 CO_2 Price Forecast

Based on analyses of the sources described in sections 3 through 9, and relying on our own expert judgment, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. Figure ES-1 (below) shows the range covered by the Synapse forecasts. These projections assume that state and regional policies will combine with federal regulatory measures to put economic pressure on carbon-emitting resources in the next several years such that the costs of operating a high-carbon-emitting plant increase—followed later by a broader federal, market-based policy. In states other than the RGGI region[2] and California, we assume a zero carbon price for the next several years; by 2020, we expect that federal regulatory measures will begin to put economic pressure on carbon-emitting power plants throughout the United States. All annual carbon prices are reported in 2012 dollars per short ton of CO_2.[3]

Each of the forecasts shown in Figure ES-1 represents a different level of political will for reducing carbon emissions, as described below.

- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $35 per ton in 2040, representing a $23 per ton levelized price over the period 2020-2040.[4] This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $65 per ton in 2040, representing a $39 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $59 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technological alternatives such as nuclear, biomass, and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

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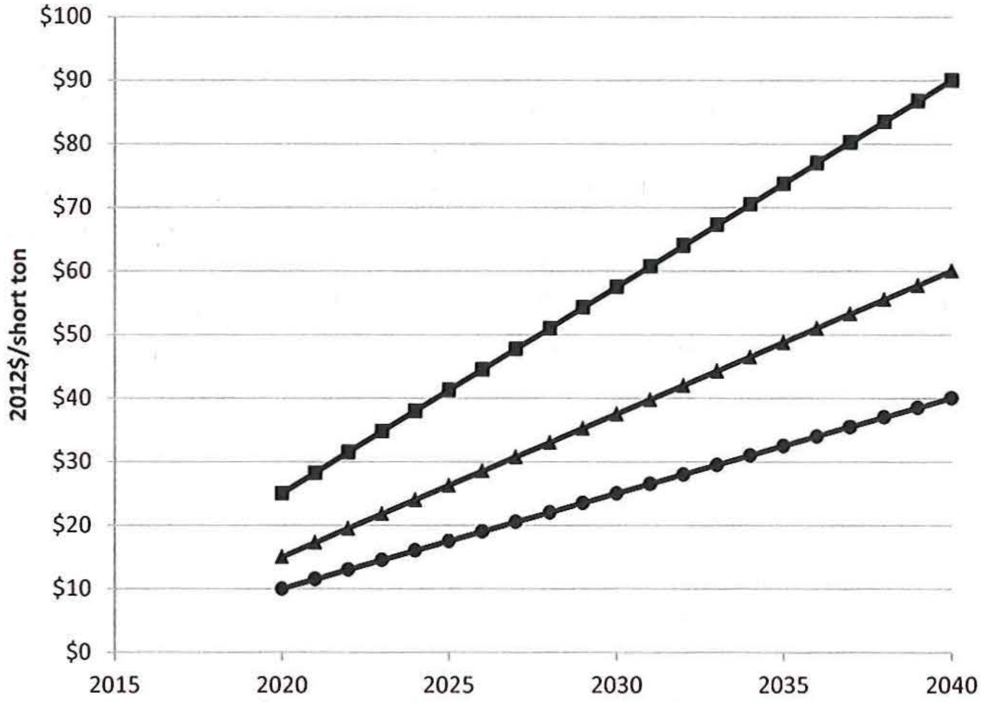
[2] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont.

[3] Results from public modeling analyses were converted to 2012 dollars using price deflators taken from the U.S. Bureau of Economic Analysis, and are available at: http://www.bea.gov/national/nipaweb/SelectTable.asp. Consistent with U.S. Energy Information Administration and U.S. Environmental Protection Agency modeling analyses, a 5 percent real discount rate was used in all levelization calculations.

ES- 1: Synapse 2013 CO_2 Price Trajectories



2. STRUCTURE OF THIS REPORT

This report presents Synapse's 2013 Low, Mid and High CO_2 price forecasts, along with the evidence assembled to inform these forecasts:

- Section 3 discusses broader concepts of CO_2 pricing.
- Sections 4 through 8 discuss existing state and federal legislation, potential future legislation, recent cap-and-trade results from the research community, and a range of current CO_2 price forecasts from utilities.
- Section 9 presents Synapse's 2013 Low, Mid, and High CO_2 price forecast, along with a comparison to recent utility forecasts.

Unless otherwise indicated, all prices are in 2012 dollars and CO_2 emissions are given in short tons.

3. WHAT IS A CARBON PRICE?

There are several co-existing meanings for the term "carbon price" or "CO_2 price": each of these meanings is appropriate in its own context. Here we give a brief introduction to five common types of carbon prices, along with a quick guide to which of the carbon price estimates reviewed in this report are based on which of these meanings. (Note that the definition of an additional term—the "price of carbon"—is ambiguous because it can at times mean several of the following.)

Carbon allowances (sometimes called credits or certificates, and best known for their use in policies called "cap and trade"): Allowances are certificates that give their holder the right to emit a unit of a particular pollutant. A fixed number of carbon allowances are issued by a government, some sold and, perhaps, some given away.[5] Subsequent trade of allowances in a secondary market is common to this policy design. The price that firms must pay to obtain allowances increases their cost of doing business, thereby giving an advantage to firms with cleaner, greener operations, and creating an incentive to lower emissions whenever it can be done for less than the price of allowances. The number of allowances—the "cap" in the cap-and-trade system—reflects the required society-wide emission reduction target. A greater reduction target results in a lower cap and a higher price for allowances. In the field of economics, pricing emissions is called "internalizing an externality": The external (not borne by the polluting enterprise) cost of pollution damages is assigned a market price (thus making it internal to the enterprise).

In this report: The Northeast's RGGI and California's Cap-and-Trade Program are both carbon allowance trading systems. In addition, the Kerry-Lieberman, Waxman-Markey, and Cantwell-Collins bills all proposed policy measures that included carbon allowance trading.

Carbon tax: A carbon tax also internalizes the externality of carbon pollution, but instead of selling or giving away rights to pollute (the allowance approach), a carbon tax creates an obligation for firms to pay a fee for each unit of carbon that they emit. In theory, if the value of damages were known with certainty, a tax could internalize the damages more accurately, by setting the tax rate equal to the damages; in practice, the valuation of damages is typically uncertain. In contrast to the government issuance of allowances, with a carbon tax there is no fixed amount of possible emissions (no "cap"). A cap-and-trade system specifies the amount of emission reduction, allowing variation in the price; a tax specifies the price on emissions, allowing variation in the resulting reductions. In both cases there is an incentive to reduce emissions whenever it can be done for less than the prevailing price. In both cases there is the option to continue emitting pollution, at the cost of either buying allowances or paying the tax. While some advocates have claimed that a tax is administratively simpler and reduces bureaucratic, regulatory, and compliance costs, a general aversion to new taxes has meant that no carbon tax proposals have received substantial support in recent policy debate.

[5] Whether or not allowances are initially given away for free or sold, they represent an opportunity cost of emissions to the holder.

Effective price of carbon (sometimes called the notional, hypothetical, or voluntary price): Carbon allowances and carbon taxes internalize the climate change externality by making polluters pay. However, many other types of climate policies work not by making polluting more expensive per se, but instead by requiring firms to use one technology instead of another, or to maintain particular emission limitations in order to avoid legal repercussions. Non-market-based emission control regulatory policies are called "command and control." For any such non-market policy there is an "effective" price: a market price that—if instituted as an allowance or tax—would result in the identical emission reduction as the non-market policy. An effective price may be used internally within a firm, government agency, or other entity to represent the effects of command and control policies for the purpose of improved decision making. Renewable Portfolio Standards, energy efficiency measures, and other policies designed to mitigate CO_2 emissions impose an effective price on carbon.

In this report: Utility carbon price forecasts are effective prices used for state-required IRPs and internal planning purposes. The U.S. Environmental Protection Agency's (EPA's) proposed carbon pollution standard for new sources of electric generation is a non-market-based policy that would represent an effective price.

Marginal abatement cost of carbon: An abatement cost refers to an estimate of the expected cost of reducing emissions of a particular pollutant. Estimation of a marginal abatement cost requires the construction of a "supply curve": all of the possible solutions to controlling emissions (these may be technologies or policies) are lined up in order of their cost per unit of pollution reduction. Then, starting from the least expensive option, one tallies up the pollution reduction from various solutions until the desired total reduction is almost achieved, and then asks: what would it cost to reduce emissions by one more unit to achieve the target? The answer is the "marginal" cost of that level of pollution reduction; a greater reduction target would have a higher marginal cost. The marginal abatement cost of carbon is not a market price used to internalize an externality. Rather, it is a method for estimating the price that, if it were applied as a market price, would have the effect of achieving a given emission reduction target. In a well-functioning cap-and-trade system, the allowance price would tend towards the marginal abatement cost of carbon.

In this report: We do not analyze any marginal abatement costs in this report—see the *2012 Synapse Carbon Dioxide Price Forecast* for further information. McKinsey & Company has been a consistent producer of this type of analysis, an example being their 2010 report *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve.*

Social cost of carbon: Whereas the marginal abatement cost estimates the price of stopping pollution, the social cost of carbon estimates the cost, per unit of emissions, of allowing pollution to continue. The social cost of carbon is the societal cost of current and future damages related to climate change from the emission of one additional unit of pollutant. Estimating the uncertain costs of uncertain future damages from uncertain future climatic events is, of course, a tricky business. If enough information were available, a marginal abatement cost for each level of future emissions (the supply of emission reductions) could be compared to a social cost of carbon for each level of future emissions (the demand for emission reductions) to determine an "optimal" level of pollution (such that the next higher unit of emission reduction would cost more to achieve than its value in reduced damages). More commonly, the social cost of carbon is used as part of the calculation of benefits of emission-reducing measures.

In this report: The U.S. federal government's internal carbon price for use in policy making is estimated as the social cost of carbon.

4. FEDERAL CLIMATE ACTION IS INCREASINGLY LIKELY

In the near term, comprehensive federal climate legislation appears unlikely to come out of a divided Congress. The Executive Branch, however, is moving forward with regulatory actions to limit greenhouse gas emissions. Following a directive issued by President Obama, EPA released revised CO_2 performance standards for new power plants on September 20, 2013.[6] In June 2013, President Obama also instructed EPA to use its Clean Air Act authority to propose CO_2 standards for existing power plants by June 2014 and to finalize these standards by June 2015.[7] While this report is focused on electric sector CO_2 policies, similar regulatory measures have been proposed for the transportation, buildings, and industrial sectors; policies enacted in other sectors include vehicle efficiency standards set to rise to 54.5 miles per gallon by 2025 for new cars and light-duty trucks, and new energy efficiency standards for federal buildings set to reduce energy consumption by nearly 20 percent.[8,9]

We continue to expect that a federal cap-and-trade program for greenhouse gases is the most likely policy outcome in the long term, because it permits reductions to come from sources that can mitigate emissions at the lower cost. While state and regional policies combined with federal regulatory actions appear to be more likely than a federal cap-and-trade policy in the near term, according to a WRI analysis these local measures are unlikely to be able to meet long-term goals of reducing total greenhouse gas emissions to 83 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[10]

[6] EPA. "2013 Proposed Carbon Pollution Standard for New Power Plants." Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

[7] Memorandum from President Obama to Administrator of the Environmental Protection Agency, Power Sector Carbon Pollution Standards (June 25, 2013). Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[8] Vlasic, Bill. "US Sets Higher Fuel Efficiency Standards." *The New York Times*. August 28th, 2012. Available at: http://www.nytimes.com/2012/08/29/business/energy-environment/obama-unveils-tighter-fuel-efficiency-standards.html.

[9] "Energy Efficiency Design Standards for New Federal Commercial and Multi-Family High-Rise Residential Buildings." A Rule by the Department of Energy. July 9th, 2013. Available at: https://www.federalregister.gov/articles/2013/07/09/2013-16297/energy-efficiency-design-standards-for-new-federal-commercial-and-multi-family-high-rise-residential#h-9.

[10] See WRI's analysis of these scenarios in the 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

4.1. Regulatory Measures for Reducing Greenhouse Gas Emissions

Clean Air Act

As a result of the 2007 Supreme Court finding in *Massachusetts v. EPA*, greenhouse gas emissions were determined to be subject to the Clean Air Act and (in a later ruling) to contribute to air pollution anticipated to endanger public health and welfare. In 2009, EPA issued an "endangerment finding," obligating the agency to regulate emissions of greenhouse gases from stationary sources such as power plants.[11] EPA released draft New Source Performance Standards (NSPS) in April 2012 and revised NSPS standards on September 20, 2013. The revised standards limit CO_2 emissions from new fossil-fuel power plants to 1,000-1,100 pounds of CO_2 per MWh (lbs/MWh)—a level achievable by a new natural gas combined-cycle plant. The exact limit of CO_2 emissions within that range depend on the type of plant and period over which the emission rate would be averaged.[12]

Under Section 111(d) of the Clean Air Act, the EPA is required to propose standards for existing power plants by June 2014, but there remains substantial uncertainty over what form these regulations will take. Unit-specific emission rates standards, such as the NSPS for greenhouse gases, are only one of several plausible options. Unit-specific standards could apply to power plants based on categories by fuel type and technology type, each with its own maximum emission rate. Units that are not in compliance could undertake upgrades to improve efficiency; however, these kinds of upgrades can be expensive, can only achieve small, one-time changes to emission rates, and could trigger New Source Review/Prevention of Significant Deterioration (NSR/PSD) provisions, increasing the cost further.[13,14]

Other regulatory design options for existing plants under 111(d) include maintaining a state-wide average maximum emission rate, and market-based (e.g. cap-and-trade) approaches. More flexible mechanisms like these could lower the cost of compliance, but could also result in additional legal challenges as compared to a simpler but more rigid system of unit-specific regulation.[15] An Edison Electric Institute white paper on potential regulation of existing sources notes that "because of concerns about legal challenges to the guidelines, EPA may be reluctant to incorporate a wide range of

[11] EPA. "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act." Available at: http://www.epa.gov/climatechange/endangerment/.

[12] EPA. "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units." Available at: http://www2.epa.gov/sites/production/files/2013-09/documents/20130920proposal.pdf.

[13] EEI. "Existing Source GHGH NSPS White Paper," Page 5. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[14] Tarr J., Monast J., Profeta T. "Regulating Carbon Dioxide under Section 111(d) of the Clean Air Act." The Nicholas Institute. January 2013. Available at: http://nicholasinstitute.duke.edu/sites/default/files/publications/ni_r_13-01.pdf.

[15] Fine, Steven and MacCracken, Chris. "President Obama's Climate Action Plan: What It Could Mean to the Power Sector." ICF International. August 2013. Available at: http://www.icfi.com/insights/white-papers/2013/president-obama-climate-action-plan.

compliance flexibility mechanisms in the guidelines, but may be more receptive to such mechanisms if proposed by the states in compliance plans."[16]

End-use energy efficiency may be an important part of a comprehensive compliance strategy in a regulation that averages emission rates across states. States may be able to achieve emissions reductions at a lower cost through the structures of their existing energy efficiency resource standards.

Methods for demonstrating compliance with 111(d) may be similar to existing regulations: in a process similar to Section 110 of the Clean Air Act, under which EPA sets National Ambient Air Quality Standards (NAAQS), states will be required to submit State Implementation Plans (SIPs) that specify how they intend to comply with 111(d). EPA can then decide whether a proposed SIP meets the terms of the regulation; in the absence of an acceptable SIP, EPA can impose a Federal Implementation Plan (FIP). Under the schedule outlined by President Obama in his Climate Action Plan, regulations for existing sources under 111(d) will be finalized by June 2015, and states would be required to submit SIPs to the EPA by June 2016.

Performance standards for new and existing sources will affect decisions made by utilities regarding operation, expansion, and retirements. Enforcement of the Clean Air Act creates an opportunity cost of greenhouse gas abatement: prudent utilities will take Clean Air Act compliance into consideration in their planning, either explicitly as a maximum allowable emissions rate, or implicitly as an effective carbon price. An NRDC analysis of the impacts of 111(d) implementation estimated compliance costs under this policy at $7.53 per ton of CO_2 avoided.[17]

Other regulatory measures put economic pressure on carbon-intensive power plants

A suite of current and proposed EPA regulations require pollution-intensive power plants to install environmental controls for compliance. The cost of complying with environmental regulations reduces the profitability of the worst polluters, sometime rendering them uneconomic. These policies demonstrate momentum towards appropriately regulating or pricing environmentally harmful activities in the electric sector. To the extent that plants with high emissions of other pollutants also have high carbon emissions, these policies would tend to *lower* the future CO_2 price necessary to achieve a given reduction; as more pollution-intensive plants retire in response to other EPA regulations, the necessary carbon price is reduced. Specific regulatory measures include:

- *National Ambient Air Quality Standards (NAAQS)* set maximum air quality limitations that must be met at all locations across the nation. EPA has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter—measured as particulate matter less than or equal to 10

[16] Edison Electric Institute. "Existing Source GHG NSPS White Paper," Page 2. Available at: http://online.wsj.com/public/resources/documents/carbon04232013.pdf.

[17] Natural Resources Defense Council. "Closing the Power Plant Carbon Pollution Loophole: Smart Ways the Clean Air Act Can Clean Up America's Biggest Climate Polluters," March 2013. Available at: http://www.nrdc.org/air/pollution-standards/files/pollution-standards-report.pdf.

micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)—and lead.

- *The Cross State Air Pollution Rule (CSAPR)*, finalized in 2011, establishes the obligations of each affected state to reduce emissions of NO_x and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. CSAPR was vacated by the U.S. Court of Appeals for the District of Columbia on August 21, 2012. In June 2013, the U.S. Supreme Court announced that it would review CSAPR. Even if EPA fails to salvage CSAPR through the courts, the Agency must still promulgate a replacement rule to implement Clean Air Act requirements to address the transport of air pollution across state boundaries. In the meantime, the court left the requirements of the 2005 Clean Air Interstate Rule in place.
- *Mercury and Air Toxics Standards (MATS)*: The final MATS rule, approved in December 2011, sets stack emissions limits for mercury, other metal toxins, organic and inorganic hazardous air pollutants, and acid gasses. Compliance with MATS is required by 2015, with a potential extension to 2016. Many utilities have already committed to capital improvements at their coal plants to comply with the standard.
- *Coal Combustion Residuals (CCR) Disposal Rule:* On June 21, 2010, EPA proposed to regulate CCR for the first time either as a Subtitle C hazardous waste or Subtitle D solid waste under the Resource Conservation and Recovery Act. Under a Subtitle C designation, the EPA would regulate siting, liners, run-on and run-off controls, groundwater monitoring, fugitive dust controls, and any corrective actions required. In addition, the EPA would implement minimum requirements for dam safety at impoundments. Under a solid waste Subtitle D designation, the EPA would require minimum siting and construction standards for new coal ash ponds, compel existing unlined impoundments to install liners, and require standards for long-term stability and closure care.
- *Steam Electric Effluent Limitation Guidelines (ELGs):* On June 7, 2013, EPA released eight regulatory options for new, proposed steam-electric ELGs to reduce or eliminate the release of toxins into U.S. waterways. A final rule is required by May 22, 2014.[18] New requirements will be implemented in 2014 to 2019 through the five-year National Pollutant Discharge Elimination System permit cycle.[19]

Other regulations which may raise costs for carbon-intensive resources include Regional Haze rules and cooling water rules under the Clean Water Act.

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[18] See U.S. Environmental Protection Agency website. Accessed February 21, 2013. Available at: http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm.

[19] See U.S. Environmental Protection Agency. Steam Electric ELG Rulemaking. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf.

4.2. Proposed Cap-and-Trade Legislation

Over the past decade, there have been several Congressional proposals to legislate cap-and-trade programs, with the goal of reducing greenhouse gas emissions by up to 83 percent below recent levels by 2050 through a federal cap. Such programs would allow trading of allowances to promote least-cost reductions in greenhouse gas emissions.

Comprehensive climate legislation was passed by the House in the 111th Congress: the American Clean Energy and Security Act of 2009, also known as Waxman-Markey or H.R. 2454. However, the Senate did not vote on either of the two climate bills before it in that session (Kerry-Lieberman APA 2010 and Cantwell-Collins S. 2877). Waxman-Markey was a cap-and-trade program that would have required a 17 percent reduction in emissions from 2005 levels by 2020, and an 83 percent reduction by 2050.[20] Further analysis of these proposals is provided in Synapse's 2012 Carbon Dioxide Price Forecast.

Congressional interest in climate policy has been ongoing. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S. 2146), which would have required larger utilities to meet a percentage of their sales with electric generation from sources that produce less greenhouse gas emissions than a conventional coal-fired power plant. Credits generated by these clean technologies would have been tradable with a market price. In February 2013, Senators Sanders and Boxer introduced new comprehensive climate change legislation, the Climate Protection Act of 2013. This bill proposed a carbon fee of \$20 per ton of CO_2 or CO_2 equivalent content of methane, rising at 5.6 percent per year over a ten-year period. The bill has not yet been brought to a vote.

We expect that federal cap-and-trade legislation will eventually be enacted but that it is unlikely to happen in the near term. In contrast, federal carbon regulations are in effect or under development today, and the economic pressure—or opportunity cost—that they create may be represented as an effective price of greenhouse gas emissions. Regulatory measures may be successful in achieving near-term targets of 17 percent below 2005 levels by 2020, but according to a WRI analysis are unlikely to meet long-term goals of reducing total greenhouse gas emissions to approximately 80 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[21] A broader approach will be increasingly attractive in order to meet these goals at lower costs, and our judgment indicates this is most likely to take the form of a federal cap-and-trade system.

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[20] U.S. Energy Information Administration (EIA); Energy Market and Economic Impacts of the American Power Act of 2010 (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html. EIA; Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

[21] See WRI's analysis of these scenarios in their 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-from-here.

5. State and Regional Climate Policies

Since the October 2012 release of our 2012 CO_2 price forecasts, there have been significant updates to the two existing regional and state cap-and-trade programs, the Northeast's RGGI and California's Cap-and-Trade Program under AB32. In addition, a total of 20 states plus the District of Columbia have set greenhouse gas emissions targets as low as 80 percent below 1990 levels by 2050.[22]

Recent Revisions to RGGI

RGGI is a cap-and-trade greenhouse gas program for power plants in the northeastern United States. Current participant states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. Pennsylvania, Québec, New Brunswick, and Ontario are official "observers" in the RGGI process. RGGI recently marked five years of successful CO_2 allowance auctions, with Auction 21 resulting in a clearing price of $2.67 per ton.[23] RGGI is designed to reduce electricity sector CO_2 emissions to at least 45 percent below 2005 levels by 2020.[24]

When RGGI was established in 2007, the expectation was that the CO_2 emissions allowance auction would generate revenues for consumer benefit programs such as energy efficiency, renewable energy, and clean energy technologies. While RGGI has provided significant revenues for consumer benefit, its allowance prices have generally remained near the statutory minimum price. External influences, including changes to fuel prices, caused a shift from coal and oil to lower-carbon natural gas generation. Compared to those external factors, the effect of the original RGGI cap requirements were relatively minor in meeting the goals of reducing CO_2 emissions in the power sector.[25]

In 2012 and 2013, the RGGI states evaluated a number of plans for tighter emissions caps with the goal of raising allowance prices. In February of 2013, participating states agreed to lower the CO_2 cap from 165 million to 91 million short tons in 2014, to be reduced by 2.5 percent each year from 2015 to 2020. RGGI analysis indicates that with these lower caps, allowance prices will rise to $4.16 per short ton in 2014, increasing to $10.40 per ton in 2020.[24]

California's Cap-and Trade-Program under AB32

With the goal of reducing the state's emissions to 1990 levels by 2020, California's Global Warming Solutions Act (AB32) has created the world's second largest carbon market, after the European Union's

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[22] "Greenhouse Gas Emissions Targets." Center for Climate and Energy Solutions. Accessed September 13, 2013. Available at: http://www.c2es.org/us-states-regions/policy-maps/emissions-targets.

[23] RGGI Auction 21 results available at: http://www.rggi.org/market/co2_auctions/results/Auction-21

[24] RGGI. "RGGI States Propose Lowering Regional CO_2 Emission Cap 45%, Implementing a More Flexible Cost-Control Mechanism." February 2013. Available at: http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf.

[25] Environment Northeast. "RGGI at One Year: An Evaluation of the Design and Implementation of the Regional Greenhouse Gas Initiative." February 2010. Available at: http://www.env-ne.org/public/resources/pdf/ENE_2009_RGGI_Evaluation_20100223_FINAL.pdf.

Emissions Trading System. The first compliance period for California's Cap-and-Trade Program began on January 1, 2013 and covers electricity generators, CO_2 suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 27,600 tons of CO_2e per year.[26,27] On August 16, 2013, the California Air Resources Board held its fourth quarterly allowance auction, resulting in a clearing price of $11.11 per ton.[28] This first phase of the program includes electricity generators and large industrials. Phase II, beginning in 2015, will also include transportation fuels and smaller industrial sources.

6. Assessment of Carbon Price for Federal Rulemaking

In 2010, the U.S. federal government began including a carbon cost in regulatory rulemakings to account for the climate damages resulting from each additional ton of greenhouse gas emissions;[29] updated values were released in 2013.[30] The 2013 Economic Report of the President acknowledges that these values will continue to be updated as scientific understanding improves.[31]

An Interagency Working Group on the Social Cost of Carbon—composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, and Department of Transportation, among others—was tasked with the development of a consistent value for the social benefits of climate change abatement. Four values were developed (see Section 3 for more explanation of the "social cost of carbon" methodology). These values--$11, $36, $55, and $101 per ton of CO_2 in 2013, rising over time— represent average (most likely) damages at three discount rates, along with one estimate at the 95th percentile of the assumed distribution of climate impacts.[32,33,34,35] While

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[26] "CO_2e" refers to CO_2-equivalent, the combination of CO_2 and an equivalent value for other greenhouse gases.

[27] CARB 2013a. "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments by Linked Jurisdictions." July 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/ctlinkqc.pdf. Legislated value is 25,000 metric tons, converted here to short tons.

[28] CARB 2013b. "CARB Quarterly Auction 4, August 2013: Summary Results Report." August 21, 2013. Available at: http://www.arb.ca.gov/cc/capandtrade/auction/august-2013/results.pdf.

[29] Interagency Working Group on the Social Cost of Carbon, U. S. G. (2010). Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866. In Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors. U.S. Department of Energy. URL http://go.usa.gov/3fH.

[30] Interagency Working Group on the Social Cost of Carbon (2013) Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866. Available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf.

[31] 2013 Economic Report of the President (2013). Chapter 6. March 2013. Available at: http://www.whitehouse.gov/sites/default/files/docs/erp2013/ERP2013_Chapter_6.pdf.

[32] These values represent recently revised costs for the SCC. Originally, these values were $5, $21, $35, and $65 per metric tonne for the year 2010 in 2007 dollars.

[33] In a 2012 paper, Ackerman and Stanton modified the Interagency Working Group's assumptions regarding uncertainty in the sensitivity of temperature change to emissions, the expected level of damages at low and high greenhouse gas concentrations, and the assumed discount rate, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater. Similarly, Laurie Johnson and Chris Hope modified discount rates and methodologies and found results up to twelve times larger than the Working Group's central estimate.

subject to significant uncertainty, this multi-agency effort represents an initial attempt at incorporating the benefits associated with CO_2 abatement into federal policy.

As of May 2012, these estimates had been used in at least 20 federal government rulemakings, for policies including fuel economy standards, industrial equipment efficiency, lighting standards, and air quality rules.[36, 37] In the first rule in which the revised 2013 values were used—improving energy efficiency in microwave ovens—the net present value of benefits over a 30-year timeframe increased by $400 million as a result of the increase in effective carbon price.[38] While a carbon price for federal rulemaking assessments is a fundamentally different kind of cost metric than the others discussed in this report, it nonetheless represents a dollar value for greenhouse gas emissions currently in use by the U.S. federal government.

7. Recent CO_2 Price Forecasts from the Research Community

The Energy Modeling Forum (EMF), a working group of government and private modeling teams, has been convening to explore energy system issues since the late 1970s. The group recently completed its EMF 24 analysis with the objective of evaluating what CO_2 price trajectories are consistent with proposed emission reduction targets under different technology scenarios. This analysis also incorporated several complementary policies in a cap-and-trade proposal, including: transportation emissions reduction through vehicle gas mileage standards; renewable portfolio standards in the electric sector; and mandates that all new coal facilities employ carbon capture and storage (CCS) technology—a

[34] Frank Ackerman and Elizabeth A. Stanton (2012). "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." *Economics: The Open-Access, Open-Assessment E-Journal*, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10.

[35] Laurie T. Johnson, Chris Hope. "The social cost of carbon in U.S. regulatory impact analyses: an introduction and critique." *Journal of Environmental Studies and Sciences*, 2012; DOI: 10.1007/s13412-012-0087-7.

[36] Robert E. Kopp and Bryan K. Mignone (2012). "The U.S. Government's Social Cost of Carbon Estimates after Their First Two Years: Pathways for Improvement." Economics: The Open-Access, Open-Assessment E-Journal, Vol. 6, 2012-15. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-15.

[37] See, for example, "Rulemaking for Microwave Ovens Energy Conservation Standard: Technical Support Document." May 2013. Available at: http://www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx/ruleid/37

[38] Brad Blumer (2013). "The social cost of carbon is on the rise." The Washington Post, June 6th, 2013. Available at: http://articles.washingtonpost.com/2013-06-06/business/39789409_1_carbon-dioxide-emissions-obama-administration.

policy similar to EPA's proposed NSPS for coal plants. Nine modeling teams participated in this study.[39,40]

Results from the EMF 24 exercise show a range of CO_2 price trajectories depending on availability of new technologies, policy type, model baseline trajectories, and other more structural characteristics of the models. One question asked by this study that is of particular relevance to users of the Synapse CO_2 price forecast is: which economic sectors would emissions reductions come from in an economically efficient approach to emissions mitigation? Consistent with earlier EMF analyses, the electric sector was found to be the largest contributor to CO_2 emissions reductions across all models.

Under a cap-and-trade scenario designed to reduce energy system emissions 50 percent below 2005 levels by 2050, most of the EMF 24 models reduced electric sector emissions by 75 percent by 2050. Under an 80 percent emissions reduction scenario, most of the additional emissions reductions came from other sectors. Although CO_2 prices are higher under the 80 percent scenario, most electricity customers are not paying these prices, as the electricity sector is largely decarbonized before 2050.

CO_2 prices estimated by the EMF 24 models show substantial variation. While it is difficult to distinguish the roles of model structure and model assumptions in this variation, the results present a reasonable range across which prices may fall. Under the most optimistic technology assumptions, with low-cost renewables, high levels of energy efficiency, and availability of new nuclear and CCS, CO_2 prices in 2020 fell between \$10 per tCO_2 and \$40 per tCO_2. In contrast, prices fell between \$20 per tCO_2 to \$80 per tCO_2 under the most pessimistic assumptions. Complementary policies, such as renewable portfolio standards or fuel economy standards, reduce carbon prices, as indicated in Figure 1.

Universally, the models show that substantial emissions reductions are not achievable in the absence of a policy. Even in the most optimistic technology scenario, the most aggressive emissions reductions from any model in the absence of a policy was 0.19 percent per year, resulting in emissions 7 percent below 2005 levels in 2050.

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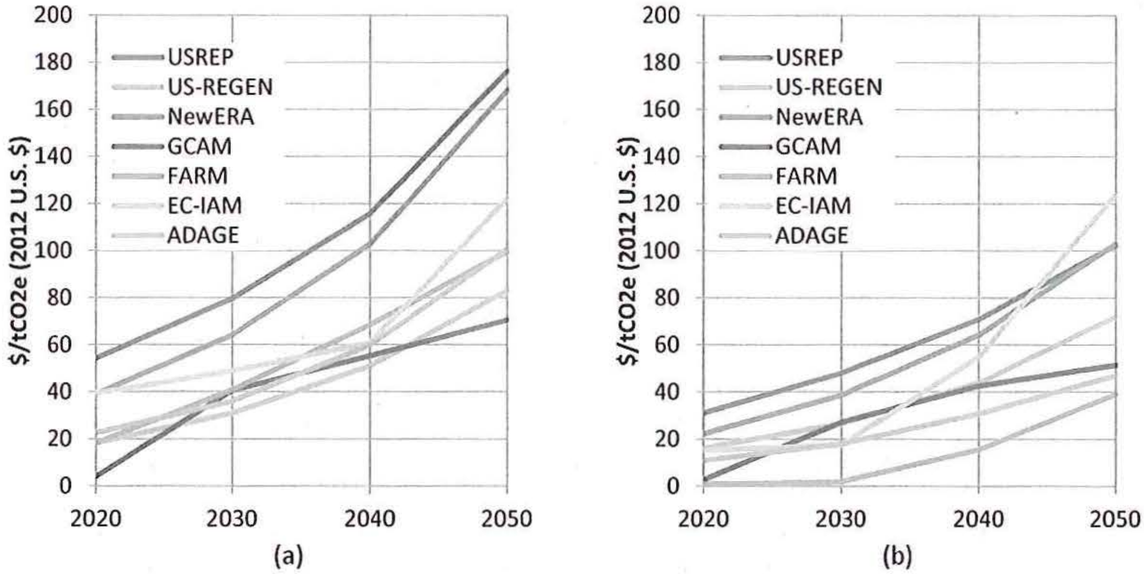
[39] Clarke, L.C., A.A. Fawcett, J.P. Weyant, V. Chaturvedi, J. MacFarland, Y. Zhou, "Technology and U.S. Emissions Reductions Goals: Results of the EMF 24 Modeling Exercise," (forthcoming). *The Energy Journal.*

[40] Fawcett, A.A., L.C. Clarke, S. Rausch, J.P. Weyant. "Overview of EMF 24 Policy Scenarios," (forthcoming). *The Energy Journal.*

Figure 1: Allowance prices from EMF study under (a) 50 percent cap-and-trade policy and with (b) the addition of several complementary policies (optimistic CCS/nuclear technology assumptions) [35,36]



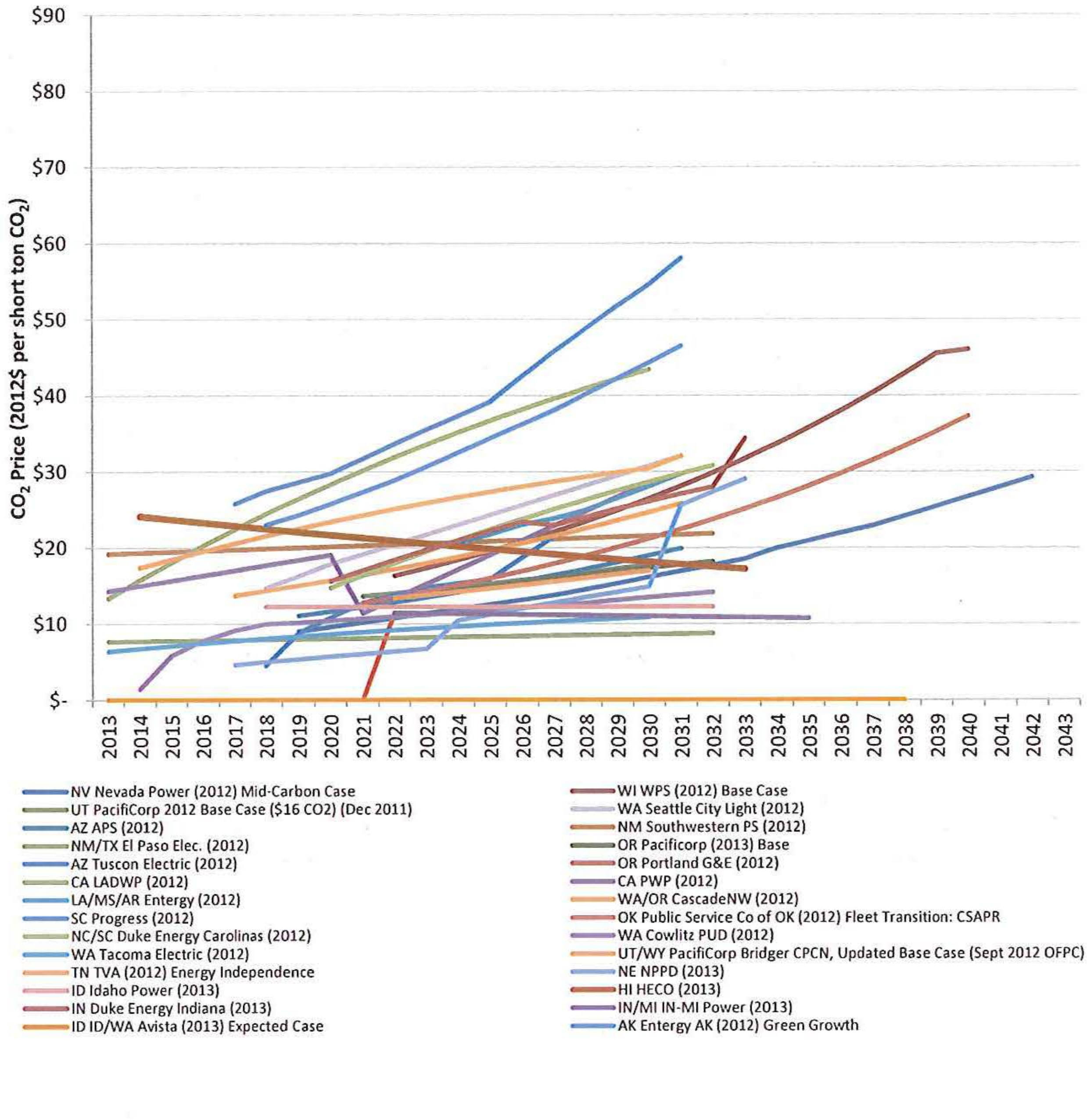
8. CO_2 PRICE FORECASTS IN UTILITY IRPS

A growing number of electric utilities include projections of the costs that will be associated with greenhouse gas emissions in their resource planning procedures. Figure 2 summarizes the reference case values (often described as their "mid" or "central" values) of publicly available forecasts used by utilities in resource planning over the past two years.[41]

Despite ongoing obstacles to a federally legislated CO_2 price and challenges in Congress to addressing climate or energy policy in a meaningful way, many utilities are including an effective price for carbon in their planning. The majority of utility reference case carbon price forecasts start in the 2015-2020 timeframe, and rise gradually (in real terms) throughout the study period.

[41] Where a utility has released multiple IRP or IRP updates in the past two years, we have included only the most recent value. The IRPs shown here represent those publicly available by internet as of the October 2013.

Figure 2: Utility Reference Case Forecasts from 2012 and 2013



9. OVERVIEW OF THE EVIDENCE FOR A FUTURE CO_2 PRICE

Our CO_2 price forecasts are developed based on the data sources and information presented above and reflect a reasonable range of expectations regarding future efforts to limit greenhouse gas emissions. The following items have guided the development of the Synapse forecasts:

- **Regulatory measures limiting CO_2 emissions from power plants will be implemented in the near term.** The EPA is required to propose emissions standards for existing power plants under Section 111(d) of the Clean Air Act by June 2014. Standards for new power plants were proposed on September 20, 2013. These actions represent an effective price that will affect utility planning and operational decisions.

- **State and regional action limiting CO_2 is ongoing and growing more stringent.** In the Northeast, the RGGI CO_2 cap has been tightened, resulting in higher CO_2 prices for electric generators in the region. California's Cap-and-Trade Program, which represents an even larger carbon market than RGGI, has held many successful allowance auctions, and has been successfully defended against numerous legal challenges.

- **A price for CO_2 is already being factored into federal rulemakings.** The federal government has demonstrated a commitment to considering the benefits of CO_2 abatement in rulemakings such as fuel economy and appliance standards.

- **Ongoing analysis of emissions caps suggests a wide range of possible prices.** Important factors include the stringency of any future climate policy, the existence of complementary policies, technology availability, and how quickly old capital stock can be phased out in favor of new technologies.

- **Electric suppliers continue to account for the opportunity cost of CO_2 abatement in their resource planning.** Prudent planning requires utilities to consider adequately the potential for future policies. The range of carbon prices reported in section 8 indicates that many utilities believe that by 2020 there will likely be significant economic pressure towards low-carbon electric generation.

10. SYNAPSE 2013 CO_2 PRICE FORECAST

Based on analyses of the sources described in sections 3 through 8 (above), and relying on our own expert judgment, Synapse has developed Low, Mid, and High case forecasts for CO_2 prices from 2013 to 2040. Figure 3 and Table 1 show the Synapse forecasts over this period.

Figure 3: Synapse 2013 CO_2 Price Trajectories

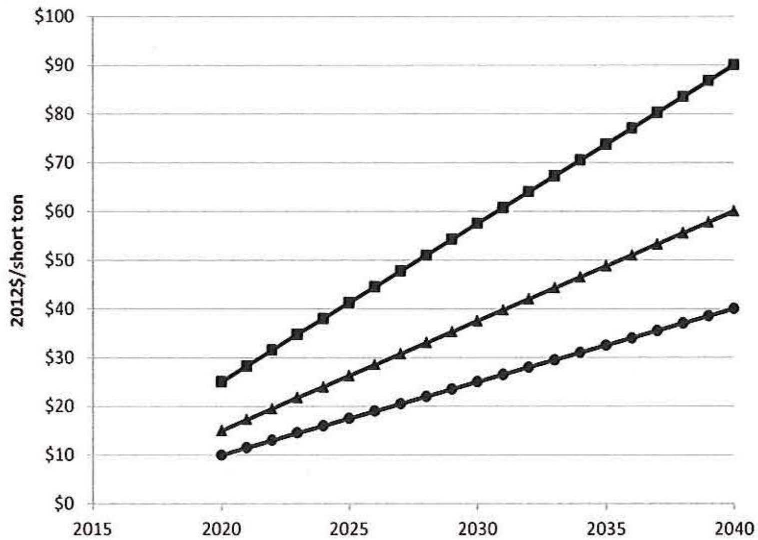


Table 1: Synapse 2013 CO_2 Allowance Price Projections (2012 dollars per ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$10.00	$15.00	$25.00
2021	$11.50	$17.25	$28.25
2022	$13.00	$19.50	$31.50
2023	$14.50	$21.75	$34.75
2024	$16.00	$24.00	$38.00
2025	$17.50	$26.25	$41.25
2026	$19.00	$28.50	$44.50
2027	$20.50	$30.75	$47.75
2028	$22.00	$33.00	$51.00
2029	$23.50	$35.25	$54.25
2030	$25.00	$37.50	$57.50
2031	$26.50	$39.75	$60.75
2032	$28.00	$42.00	$64.00
2033	$29.50	$44.25	$67.25
2034	$31.00	$46.50	$70.50
2035	$32.50	$48.75	$73.75
2036	$34.00	$51.00	$77.00
2037	$35.50	$53.25	$80.25
2038	$37.00	$55.50	$83.50
2039	$38.50	$57.75	$86.75
2040	$40.00	$60.00	$90.00
Levelized 2020-2040	$22.36	$33.54	$51.79

In these forecasts, state and regional policies, together with federal regulatory measures, place economic pressure on CO_2 emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. These pressures are followed later by a broader federal policy, such as cap and trade. In any state other than the RGGI region and California, we assume a zero carbon price through 2019; beginning in 2020, we expect that federal regulatory measures will put economic pressure on carbon-emitting power plants throughout the United States. All annual allowance prices and levelized values are reported in 2012 dollars per short ton of carbon dioxide.

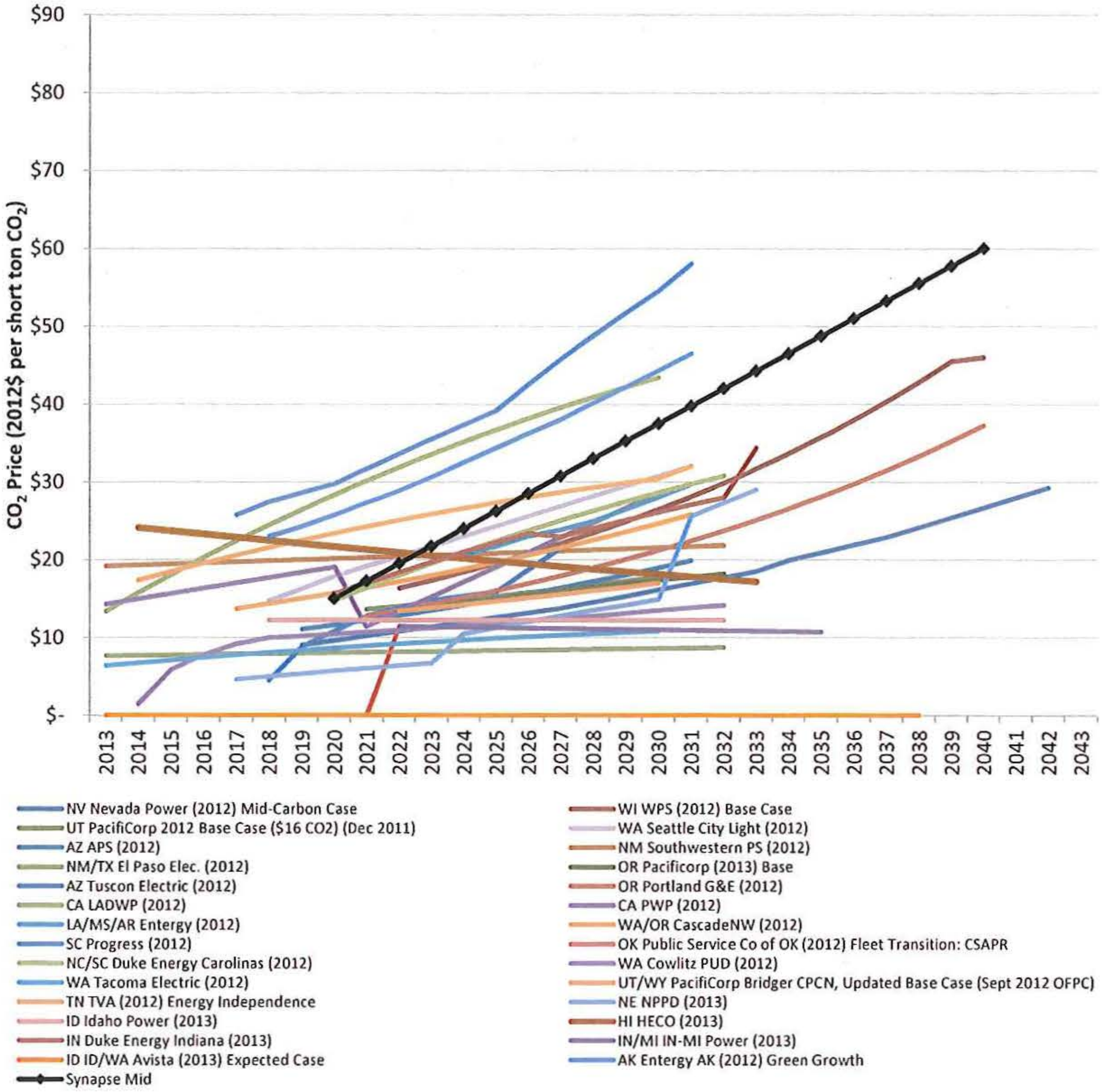
- The **Low case** forecasts a carbon price that begins in 2020 at $10 per ton, and increases to $35 per ton in 2040, representing a $23 per ton levelized price over the period 2020-2040.[42] This forecast represents a scenario in which federal policies—either regulatory or legislative—exist but are not very stringent.
- The **Mid case** forecasts a carbon price that begins in 2020 at $15 per ton, and increases to $65 per ton in 2040, representing a $39 per ton levelized price over the period 2020-2040. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals.
- The **High case** forecasts a carbon price that begins in 2020 at $25 per ton, and increases to approximately $90 per ton in 2040, representing a $59 per ton levelized price over the period 2020-2040. This forecast is consistent with the occurrence of one or more factors that have the

effect of raising carbon prices. These factors include somewhat more aggressive emissions reduction targets; greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass and carbon capture and sequestration; more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters); or higher baseline emissions.

These price trajectories are designed for planning purposes, so that a reasonable range of emissions costs can be used to investigate the likely costs of alternative resource plans. We expect an actual CO_2 price to fall somewhere between the low and high estimates throughout the forecast period.

In Figure 4, the Synapse Mid forecast is shown in comparison to the reference case utility forecasts presented earlier. See Appendix A for comparisons to utilities' Low and High case forecasts.

Figure 4: Synapse Mid Forecast Compared to Recent Utility Mid Case Forecasts



In Figure 5, the Synapse forecasts are compared to the carbon price used in federal rulemaking. While the federal price starts out higher in 2020, the Synapse Mid forecast approaches this value at the end of the projected period. In Figure 6, the Synapse forecasts for 2020 are compared to several of the sources identified in this report: the carbon price used in federal rulemakings, EMF 24 study results, and recent utility forecasts. The high and low ends of these sources span a wide range, but the central values show less variation.

Figure 5: Synapse Forecast Compared to Carbon Price Used in Federal Rulemakings

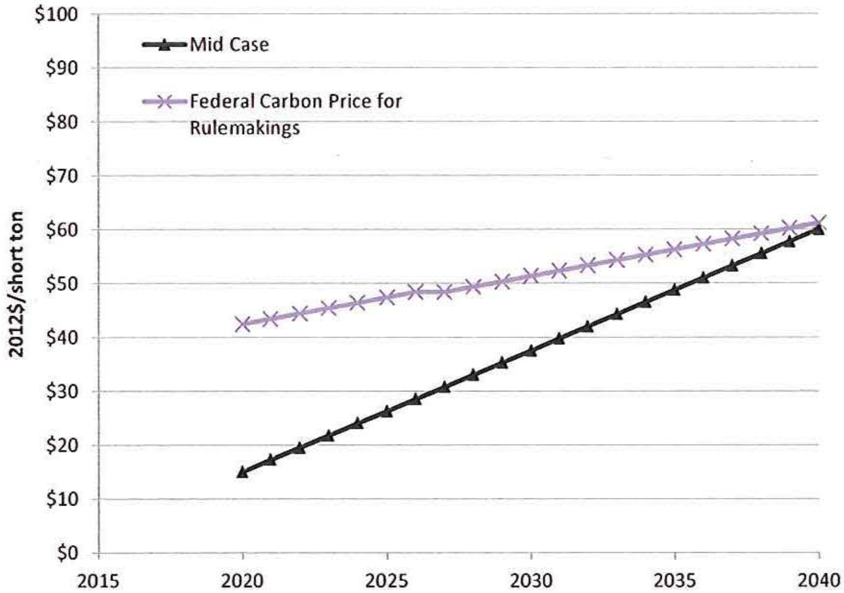
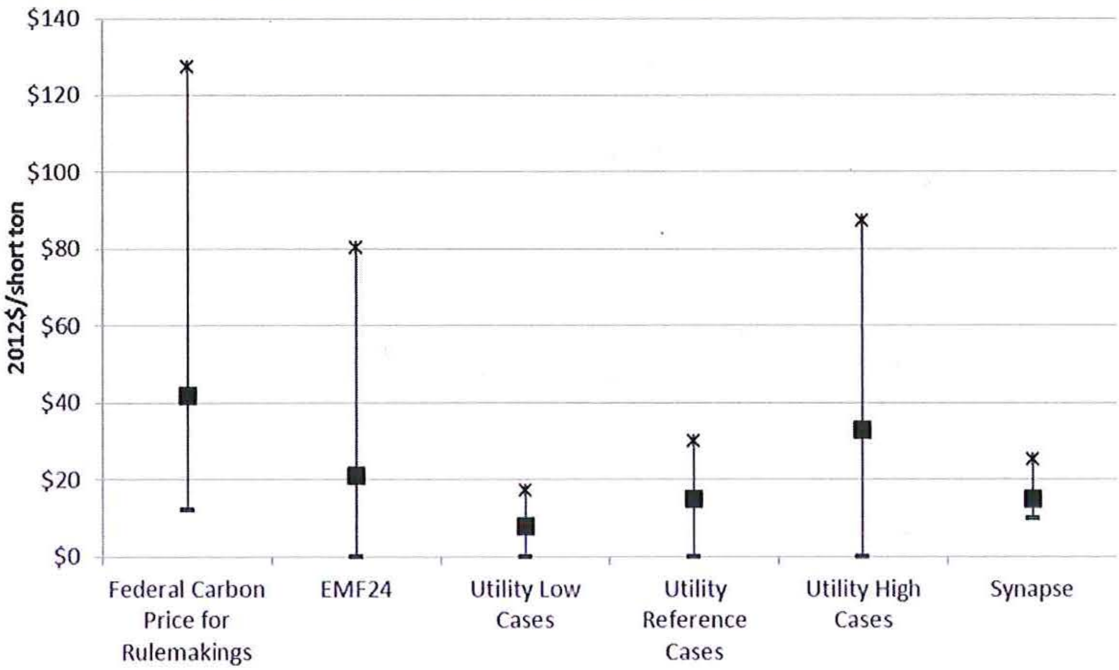


Figure 6: Synapse CO_2 Forecasts for 2020 Compared to Other Sources



APPENDIX A: SYNAPSE FORECAST COMPARED TO UTILITY FORECASTS

Figure 7: Synapse CO_2 Price Forecast Compared to Recent Utility Low-case Forecasts

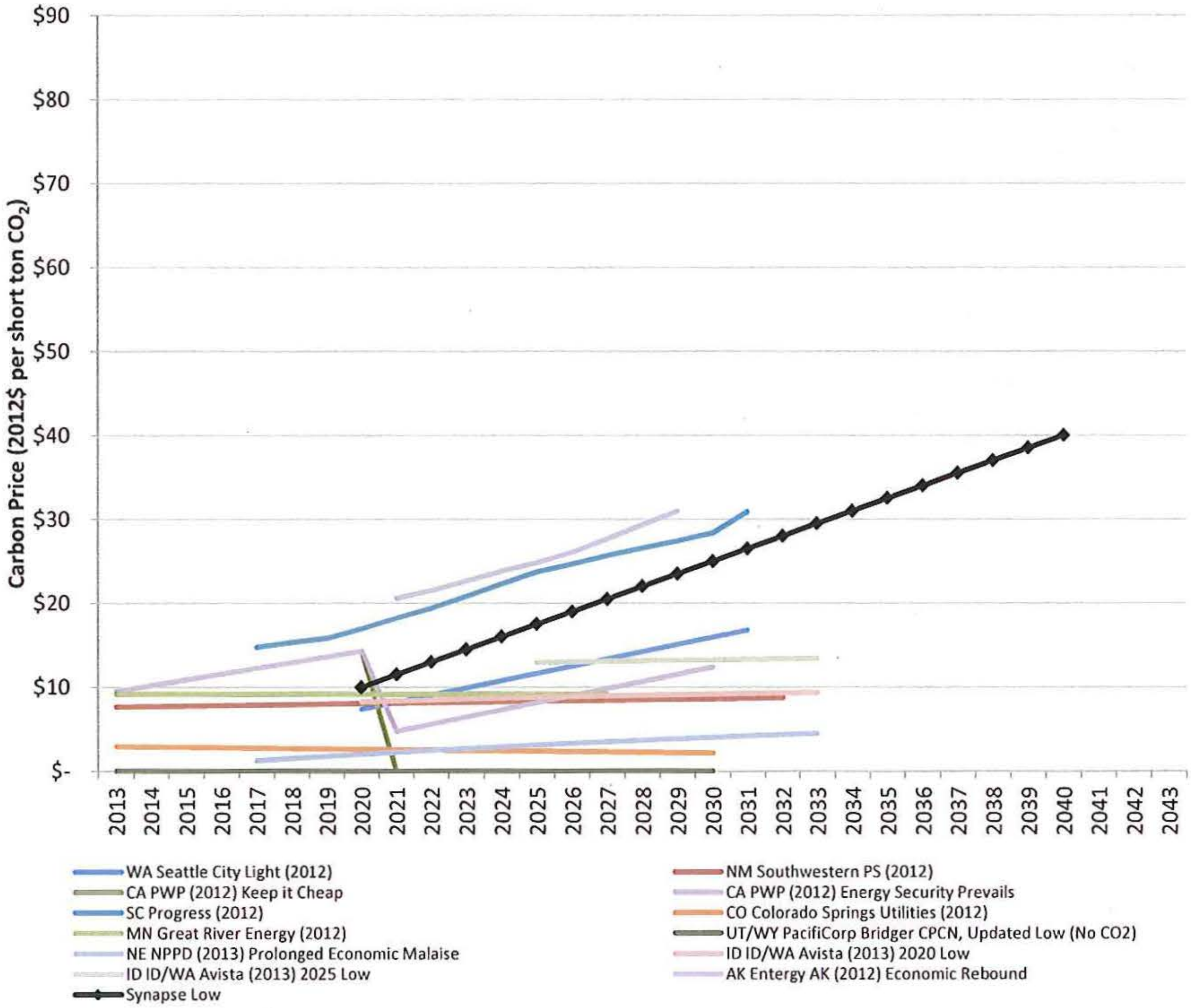
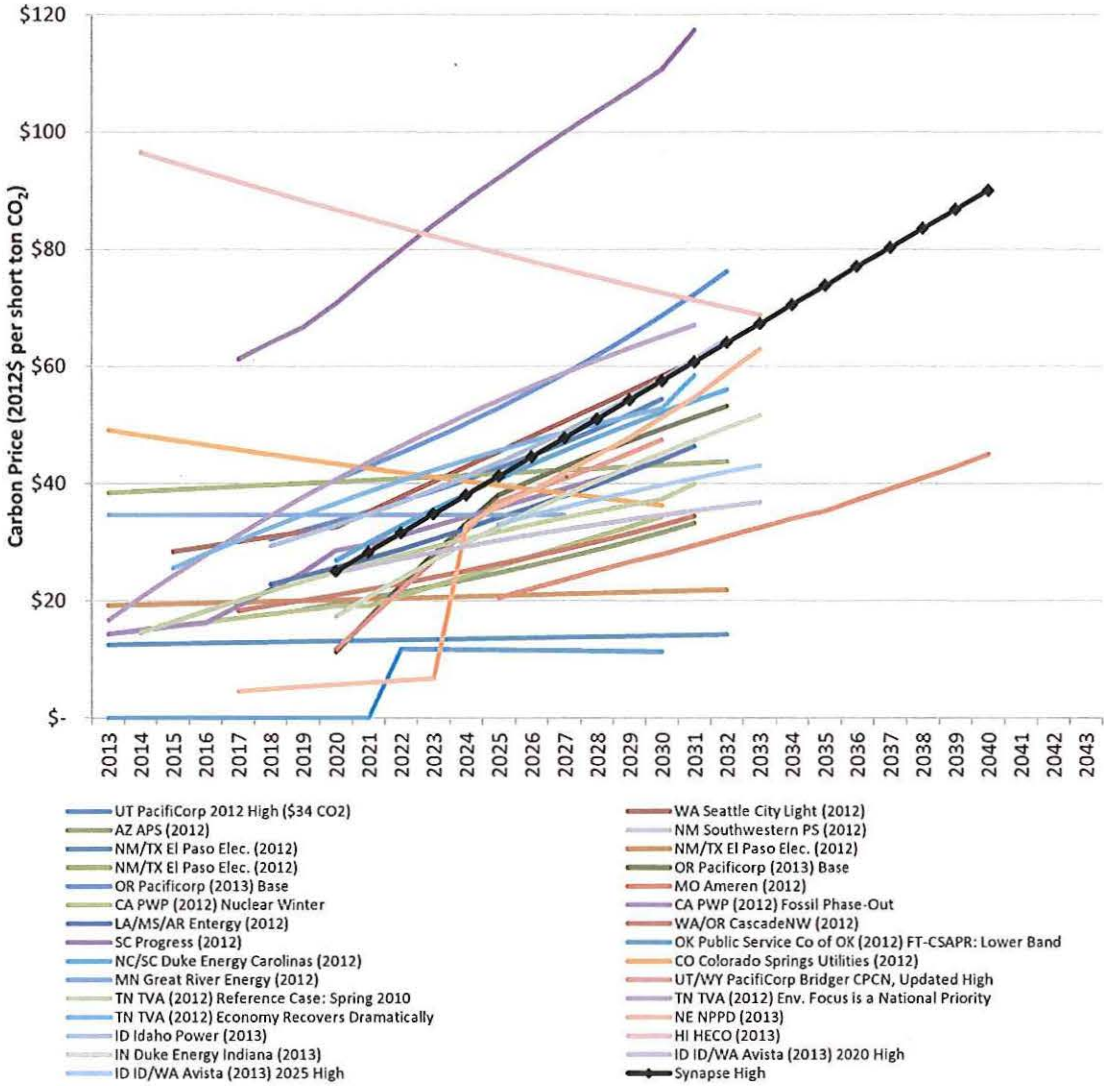


Figure 8: Synapse CO_2 Price Forecast Compared to Recent Utility High-case Forecasts



2015 Carbon Dioxide Price Forecast

March 3, 2015

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CONTENTS

1. Executive Summary

Prudent and reasonable planning requires electric utilities and other stakeholders in carbon-intensive industries to use a reasonable estimate of the future price of carbon dioxide (CO_2) emissions when evaluating resource investment decisions with multi-decade lifetimes. However, forecasting a CO_2 price can be difficult. The federal government is moving forward with regulations to limit CO_2 emissions from new and existing power plants, but a regulation is not yet finalized. To make sound investment decisions, utilities must consider existing, proposed, and expected future regulations.

Although the lack of a defined policy setting a price on carbon poses a challenge in CO_2 price forecasting, an assumption that there will be no CO_2 price in the long run is not, in our view, reasonable. The scientific basis for attributing climatic changes to human-driven greenhouse gas emissions is irrefutable, as are the type and scale of damages expected to both infrastructure and ecosystems. The need for a comprehensive U.S. effort to reduce greenhouse gas emissions is clear. While the Clean Power Plan proposed by the U.S. Environmental Protection Agency (EPA) in June 2014 does not specify a price on carbon, any policy requiring or leading to greenhouse gas emission reductions in the electric sector will result in higher costs to the generating resources that emit CO_2.

This 2015 report updates Synapse's Spring 2014 CO_2 Price Report with the most recent information on federal regulatory measures, state and regional climate policies, and utility CO_2 price forecasts, and provides an updated CO_2 price forecast.[1] The Synapse CO_2 price forecast is designed to provide a reasonable range of price estimates for use in utility integrated resource planning (IRP) and other electricity resource planning analyses. We have reviewed and updated our summary of the key regulatory developments and data from utility IRPs, which are frequently changing and crucial to understanding the impetus for a carbon price forecast and the number of utilities that have adopted one for planning purposes.

1.1. Key Assumptions

This report includes updated information on federal regulations, state and regional climate policies, and utility CO_2 price forecasts, as well as our own analysis of the proposed Clean Power Plan, EPA's proposed rule to regulate CO_2 emissions under Section 111(d) of the Clean Air Act. The Low, Mid, and High Synapse CO_2 price forecasts presented here are similar to those in our Spring 2014 report. This is the first Synapse CO_2 price forecast that we extend to 2050, to reflect long-term climate targets. Synapse's CO_2 price forecast reflects our expert judgment that near-term regulatory measures to reduce

[1] Luckow P., E. Stanton, B. Biewald, S. Fields, J. Fisher, F. Ackerman. 2014. *CO_2 Price Report, Spring 2014*. Synapse Energy Economics.

greenhouse gas emissions, coupled with longer-term cap-and-trade or carbon tax legislation passed by Congress, will result in significant pressure to decarbonize the electric power sector. Key assumptions of our forecast include:

- Near-term climate policy actions reflect a regulatory approach; for example, under Section 111(d) of the Clean Air Act.
- A federal program establishing a price for greenhouse gases is probable in the long run as it provides an efficient, least-cost path to emissions reduction.
- Future federal legislation setting a price on emissions through a cap-and-trade policy or a carbon tax will likely be prompted by one or more of the following factors:
    - New technological opportunities that lower the cost of carbon mitigation;
    - A series of executive actions taken by the President that spur demand for congressional action;
    - The inability of executive actions to meet long-term emissions goals;
    - A Supreme Court decision making it possible for states to sue companies within their boundaries that own high-carbon-emitting resources, and creating a financial incentive for energy companies to act; and
    - Mounting public outcry in response to increasingly compelling evidence of human-driven climate change.

Given the growing interest in reducing greenhouse gas emissions by states and municipalities throughout the nation, a lack of timely, substantive federal action will result in the enactment of diverse state and local policies. Heterogeneous—and potentially incompatible—sub-national climate policies would present a challenge to any company seeking to invest in CO_2-emitting power plants, both existing and new. Historically, there has been a pattern of states and regions leading with energy and environmental initiatives that have in time been superseded at the national level. It seems likely that this will be the dynamic going forward: a combination of state and regional actions, together with federal regulations, that are eventually eclipsed by a comprehensive federal carbon price.

We expect that federal regulatory measures together with regional and state policies will lead to the existence of a cost associated with greenhouse gas reductions in the near term. Prudent and reasonable utility planning requires that utilities take this cost into account when engaging in resource planning, even before a federal carbon price is enacted.

1.2. Study Approach

In this report, Synapse reviews several key developments that have occurred over the past 12 months. These include:

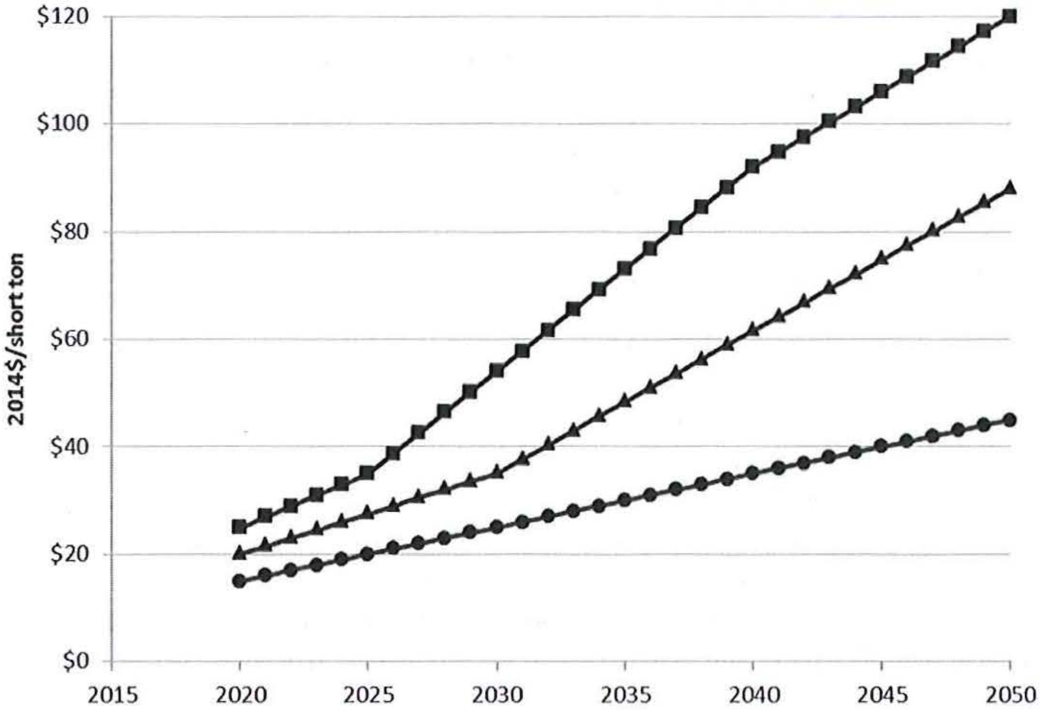
- Proposed federal regulatory measures to limit CO_2 emissions from existing power plants and an updated proposal for new power plants;
- Continuation of the Northeast's Regional Greenhouse Gas Initiative (RGGI) CO_2 policy and the most recent auctions under both RGGI and California's AB 32 Cap-and-Trade program; and
- Synapse's collection and analysis of carbon price forecasts from 115 recent utility filings.

1.3. Synapse's 2015 CO_2 Price Forecast

Based on analyses of the sources described in this report, and relying on our own judgment and experience, Synapse developed Low, Mid, and High case forecasts for CO_2 prices from 2015 to 2050. In these forecasts, the proposed Clean Power Plan together with other existing and proposed federal regulatory measures place economic pressure on CO_2-emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. These pressures are followed later by a broader federal policy, such as cap and trade. In any state other than the RGGI region and California, we assume a zero carbon price through 2019; beginning in 2020, we expect Clean Power Plan compliance will put economic pressure on carbon-emitting power plants throughout the United States. All annual allowance prices and levelized values are reported in 2014 dollars per short ton of CO_2.

- The **Low case** forecasts a CO_2 price that begins in 2020 at $15 per ton, and increases to $25 in 2030 and $45 in 2050, representing a $26 per ton levelized price over the period 2020-2050. This forecast represents a scenario in which the final version of the Clean Power Plan is relatively lenient and readily achieved, and a similar level of stringency is assumed after 2030.
- The **Mid case** forecasts a CO_2 price that begins in 2020 at $20 per ton, and increases to $35 in 2030 and $85 in 2050, representing a $41 per ton levelized price over the period 2020-2050. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals. The stated goals of the Clean Power Plan are achieved and science-based climate targets are enacted mandating at least an 80 percent reduction in electric section emissions from 2005 levels by 2050.
- The **High case** forecasts a CO_2 price that begins in 2020 at $25 per ton, and increases to approximately $53 in 2030 and $120 in 2050, representing a $52 per ton levelized price over the period 2020-2050. This forecast is consistent, in the short term, with a more stringent version of the Clean Power Plan, as well as a recognition that achieving science-based emissions goals by 2050 requires significant near-term reductions. In recognition of this difficulty, implementation of standards more aggressive than the Clean Power Plan may begin as early as 2025. New regulations may mandate that electric-sector emissions are reduced to 90 percent or more below 2005 levels by 2050, in recognition of lower-cost emission reduction measures expected to be available in this sector. Other factors that may increase the cost of achieving emissions goals include: greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass, and carbon capture and sequestration; and more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters).

Figure ES-1: Synapse 2015 CO_2 Price Trajectories



2. STRUCTURE OF THIS REPORT

This report presents Synapse's 2015 Low, Mid and High CO_2 price forecasts, along with the evidence assembled to inform these forecasts, including developments from the past 12 months:

- Section 3 discusses broader concepts of CO_2 pricing.
- Section 4 provides an overview of existing state and federal legislation, including EPA's proposed Clean Power Plan.
- Section 5 discusses our recommendations for planning for the Clean Power Plan, a review of existing studies of compliance cost, and Synapse's modeling of compliance with the Plan.
- Section 6 provides a range of current CO_2 price forecasts used by utilities.
- Section 7 gives a summary of the evidence that has guided the development of the Synapse forecasts.
- Section 8 presents Synapse's 2015 Low, Mid, and High CO_2 price forecast, along with a comparison to recent utility forecasts.

- Appendix A presents additional graphs comparing the 2015 forecast with past Synapse forecasts and utility forecasts.

Unless otherwise indicated, all prices are in 2014 dollars and CO_2 emissions are given in short tons.

3. What is a Carbon Price?

There are several co-existing meanings for the term "carbon price" or "CO_2 price": each of these meanings is appropriate in its own context. Here we give a brief introduction to five common types of carbon prices, along with a quick guide to which of the carbon price estimates reviewed in this report are based on which of these meanings. (Note that the definition of an additional term—the "price of carbon"—is ambiguous because it can at times mean several of the following.)

Carbon allowances (sometimes called credits or certificates, and best known for their use in policies called "cap and trade"): Allowances are certificates that give their holder the right to emit a unit of a particular pollutant. A fixed number of carbon allowances are issued by a government, some sold and, perhaps, some given away.[2] Subsequent trade of allowances in a secondary market is common to this policy design. The price that firms must pay to obtain allowances increases their cost of doing business, thereby giving an advantage to firms with cleaner, greener operations, and creating an incentive to lower emissions whenever it can be done for less than the price of allowances. The number of allowances—the "cap" in the cap-and-trade system—reflects the required society-wide emission reduction target. A greater reduction target results in a lower cap and a higher price for allowances. In the field of economics, pricing emissions is called "internalizing an externality": the external (not borne by the polluting enterprise) cost of pollution damages is assigned a market price (thus making it internal to the enterprise).

In this report: The Northeast's RGGI and California's Cap-and-Trade Program are both carbon allowance trading systems. In addition, the Kerry-Lieberman, Waxman-Markey, and Cantwell-Collins bills all proposed policy measures that included carbon allowance trading.

Carbon tax: A carbon tax also internalizes the externality of carbon pollution, but instead of selling or giving away rights to pollute (the allowance approach), a carbon tax creates an obligation for firms to pay a fee for each unit of carbon that they emit. In theory, if the value of damages were known with certainty, a tax could internalize the damages more accurately, by setting the tax rate equal to the damages; in practice, the valuation of damages is typically uncertain. In contrast to the government issuance of allowances, with a carbon tax there is no fixed amount of possible emissions (no "cap"). A

[2] Regardless of whether allowances are initially given away for free or sold, they represent an opportunity cost of emissions to the holder.

cap-and-trade system specifies the amount of emission reduction, allowing variation in the price; a tax specifies the price on emissions, allowing variation in the resulting reductions. In both cases there is an incentive to reduce emissions whenever it can be done for less than the prevailing price. In both cases there is the option to continue emitting pollution, at the cost of either buying allowances or paying the tax. While some advocates have claimed that a tax is administratively simpler and reduces bureaucratic, regulatory, and compliance costs, a general aversion to new taxes has meant that no carbon tax proposals have received substantial support in recent policy debate.

Effective price of carbon (sometimes called the notional, hypothetical, or voluntary price): Carbon allowances and carbon taxes internalize the climate change externality by making polluters pay. However, many other types of climate policies work not by making polluting more expensive *per se*, but instead by requiring firms to use one technology instead of another, or to maintain particular emission limitations in order to avoid legal repercussions. Non-market-based emission control regulatory policies are called "command and control." For any such non-market policy there is an "effective" price: a market price that—if instituted as an allowance or tax—would result in the identical emission reduction as the non-market policy. An effective price may be used internally within a firm, government agency, or other entity to represent the effects of command and control policies for the purpose of improved decision making. Renewable Portfolio Standards, energy efficiency measures, and other policies designed to mitigate CO_2 emissions impose an effective price on carbon.

In this report: Utility carbon price forecasts are effective prices used for state-required IRPs and internal planning purposes. EPA's proposed carbon pollution standard for new sources of electric generation is a non-market-based policy that would result in an effective price of carbon; similarly, building blocks 1, 3, and 4 of the Clean Power Plan (coal plant efficiency improvements, renewable energy, and demand-side management) are also fundamentally non-market policies that result in an imputed cost of mitigation.

Marginal abatement cost of carbon: An abatement cost refers to an estimate of the expected cost of reducing emissions of a particular pollutant. Estimation of a marginal abatement cost requires the construction of a "supply curve": all of the possible solutions to controlling emissions (these may be technologies or policies) are lined up in order of their cost per unit of pollution reduction. Then, starting from the least expensive option, one tallies up the pollution reduction from various solutions until the desired total reduction is achieved, and then asks: What would it cost to reduce emissions by the last unit needed to achieve the target? The answer is the "marginal" cost of that level of pollution reduction; a greater reduction target would have a higher marginal cost. The marginal abatement cost of carbon is not a market price used to internalize an externality. Rather, it is a method for estimating the price that, if it were applied as a market price, would have the effect of achieving a given emission reduction target. In a well-functioning cap-and-trade system, the allowance price would tend towards the marginal abatement cost of carbon.

In this report: We do not analyze any marginal abatement costs in this report—see the *2012 Synapse Carbon Dioxide Price Forecast* for further information.[3] McKinsey & Company has been a consistent producer of this type of analysis (see, for example, its 2010 report *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve)*.[4]

Average policy cost versus marginal abatement cost: Many policy analyses compare the total benefits of a policy to the total costs—this represents the net cost (or benefit) of the policy. The average cost of the policy is the net cost divided by the expected tons of emissions abated. This value is fundamentally different than the marginal cost of compliance, which is the cost to reduce the last ton of emissions (i.e., the most expensive ton actually abated). For example, a policy may result in total net benefits, but require reductions through a trading mechanism wherein the market price is set by the marginal cost of emissions. In this case, the net (and average) policy cost are negative, but the marginal cost of abatement is positive.

In this report: Most prices in this report, including are CO_2 price forecast, are expressed in terms of marginal abatement costs.

Social cost of carbon: Whereas the marginal abatement cost estimates the price of stopping pollution, the social cost of carbon estimates the cost, per unit of emissions, of allowing pollution to continue. The social cost of carbon is the societal cost of current and future damages related to climate change resulting from the emission of one additional unit of pollutant. Estimating the uncertain costs of uncertain future damages from uncertain future climatic events is, of course, a tricky business. If enough information were available, a marginal abatement cost for each level of future emissions (the supply of emission reductions) could be compared to a social cost of carbon for each level of future emissions (the demand for emission reductions) to determine an "optimal" level of pollution (such that the next higher unit of emission reduction would cost more to achieve than its value in reduced damages). More commonly, the social cost of carbon is used as part of the calculation of benefits of emission-reducing measures.

In this report: The U.S. federal government's internal carbon price for use in policy making is intended to be an estimate of the social cost of carbon.

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[3] Wilson et al. 2012. *2012 Carbon Dioxide Price Forecast*. Synapse Energy Economics. Available at: http://www.synapse-energy.com/project/synapse-carbon-dioxide-price-forecast.

[4] McKinsey & Company. 2010. *Impact of the Financial Crisis on Carbon Economics: Version 2.1 of the Global Greenhouse Gas Abatement Cost Curve*. Page 8.

4. FEDERAL CLIMATE ACTION IS EXTREMELY LIKELY

In the near term, comprehensive federal climate legislation appears unlikely to come out of a Republican-controlled Congress. The Executive Branch, however, is moving forward with regulatory actions to limit greenhouse gas emissions. Following a directive issued by President Obama,[5] EPA released revised CO_2 performance standards for new power plants on September 20, 2013,[6] and on June 2, 2014, used its Clean Air Act authority to propose CO_2 standards for existing power plants.[7] Beyond the realm of electric-sector CO_2 policies (which are the focus of this report), similar regulatory measures have been proposed for the transportation, buildings, and industrial sectors; policies enacted in other sectors include vehicle efficiency standards set to rise to 54.5 miles per gallon by 2025 for new cars and light-duty trucks, and new energy efficiency standards for federal buildings set to reduce energy consumption by nearly 20 percent below the previous standard.[8,9] Still other rules aimed at reducing methane emissions from oil and gas production and CO_2 from aircrafts are currently under development.[10,11]

We continue to expect that a federal cap-and-trade program for greenhouse gases is the most likely policy outcome in the long term, because it enables participants to find the most cost-effective method of emissions abatement among many alternatives, rather than regulating a limited subset of alternatives. While state and regional policies combined with federal regulatory actions appear to be more likely than a federal cap-and-trade policy in the near term, according to a World Resources Institute (WRI) analysis, these local measures are unlikely to be able to meet long-term goals of reducing

[5] Memorandum from President Obama to Administrator of the Environmental Protection Agency, Power Sector Carbon Pollution Standards (June 25, 2013). Available at: http://www.whitehouse.gov/the-press-office/2013/06/25/presidential-memorandum-power-sector-carbon-pollution-standards.

[6] EPA. 2013. "2013 Proposed Carbon Pollution Standard for New Power Plants." *Carbon Pollution Standards.* Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

[7] EPA. "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units." *Carbon Pollution Standards.* Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule.

[8] Vlasic, Bill. August 28th, 2012. "US Sets Higher Fuel Efficiency Standards." *The New York Times.* Available at: http://www.nytimes.com/2012/08/29/business/energy-environment/obama-unveils-tighter-fuel-efficiency-standards.html.

[9] U.S. Department of Energy. 2013. "Energy Efficiency Design Standards for New Federal Commercial and Multi-Family High-Rise Residential Buildings." A Rule by the Department of Energy. July 9th, 2013. Available at: https://www.federalregister.gov/articles/2013/07/09/2013-16297/energy-efficiency-design-standards-for-new-federal-commercial-and-multi-family-high-rise-residential#h-9.

[10] See "Fact Sheet: EPA's Strategy for Reducing Methane and Ozone-Forming Pollution from the Oil and Natural Gas Industry." Available at: http://www.epa.gov/airquality/oilandgas/pdfs/20150114fs.pdf.

[11] See "U.S. Aircraft Greenhouse Gas Rulemaking Process." Available at: http://www.epa.gov/otaq/documents/aviation/us-ghg-endangerment-ip-9-3-14.pdf.

total greenhouse gas emissions to 83 percent below 2005 levels by 2050, even in the most aggressive of scenarios.[12]

4.1. Regulatory Measures for Reducing Greenhouse Gas Emissions

There are a number of federal regulations that directly and indirectly mandate a reduction in greenhouse gas emissions in the power sector. These are summarized in Table 1 and described in detail below.

[12] See WRI's analysis of these scenarios in the 2013 report "Can the U.S. Get There From Here?: Using Existing Federal Laws and State Action to Reduce Greenhouse Gas Emissions." Available at: http://www.wri.org/publication/can-us-get-there-here.

Table 1: Summary of power sector regulatory measures that may result in reduced greenhouse gas emissions

Rule	Current Status as of Release	Next Deadline(s)	Pollutants Covered
Federal Regulations			
Clean Air Act, Section 111	EPA released a revised 111(b) rule, New Source Performance Standards for GHGs from new sources, in September 2013	Awaiting final rule; expected before or in conjunction with release of final 111(d) rule	CO_2 and other greenhouse gases
	EPA released a draft 111(d) rule controlling GHGs from existing sources on June 2, 2014	June 2015: EPA must finalize standards for existing power plants June 2016: States must submit state compliance plans to EPA	
National Ambient Air Quality Standards (NAAQS)	1-Hour SO_2 NAAQS was finalized in June 2010	Initial designations based on monitoring data were made in June 2013; additional designations expected by or before 2017	Sulfur dioxide; nitrogen dioxide; carbon monoxide; ozone; particulate matter; and lead
	PM2.5 annual NAAQS was finalized on December 2012	Final designations announced December 18, 2014; SIPs due in April 2018 with attainment required by 2020	
	EPA proposed to strengthen the 8-Hour Ozone NAAQS on November 24, 2014	SIPs for the existing (2008) standard are due in spring of 2015 Revisions to the 2008 standard must be finalized by October 1, 2015	
Cross State Air Pollution Rule (CSAPR)	The U.S. Supreme Court reinstated CSAPR in April 2014, finding that EPA had not exceeded its authority in crafting the rule	Court lifted stay of CSAPR on October 23, 2014; on November 21, 2014, EPA published rules tolling CSAPR deadlines three years – Phase I began January 1, 2015 and Phase II begins January 1, 2017	Nitrogen oxides and sulfur dioxide
Mercury and Air Toxics Standards (MATS)	Finalized in December 2011	April 16, 2015: Compliance deadline (rule allows for a one-year extension if certain conditions are met)	Mercury, metal toxins, organic and inorganic hazardous air pollutants, and acid gases
Coal Combustion Residuals (CCR) Disposal Rule	EPA issued final rule regulating CCR on December 19, 2014	Compliance timeline is structured to take into account overlap with yet-to-be-determined ELG compliance obligations	Coal combustion residuals (ash)
Steam Electric Effluent Guidelines (ELGs)	EPA released a proposed rule with eight regulatory options in June 2013	Final rule for release of toxins into waterways must be finalized by September 30, 2015	Toxins entering waterways
Cooling Water Intake Structure (316(b)) Rule	EPA released a final rule for implementation of Section 316(b) of the Clean Water Act on May 19, 2014	Final rule became effective October 14, 2014 and requirements will be implemented in NPDES permits as they are renewed	Cooling water
Regional Haze Rule	Regional Haze Rule issued in July 1999	States must file SIPs and install the Best Available Retrofit Technology (BART) controls within 5 years of SIP approval	Sulfur oxides, nitrogen oxides, and particulate matter

The Clean Air Act

As a result of the 2007 Supreme Court finding in *Massachusetts v. EPA*, greenhouse gas emissions were determined to be subject to the Clean Air Act and (in a later ruling) to contribute to air pollution anticipated to endanger public health and welfare. In 2009, EPA issued an "endangerment finding," obligating the agency to regulate emissions of greenhouse gases from stationary sources such as power plants.[13] In compliance with Section 111(b) of the Clean Air Act, EPA released draft New Source Performance Standards (NSPS) for the electric sector in April 2012 and revised NSPS standards in September 2013. The revised standards limit CO_2 emissions from new fossil-fuel power plants to 1,000-1,100 pounds of CO_2 per MWh (lbs/MWh)—a level achievable by a new natural gas combined-cycle plant. The exact limit of CO_2 emissions within that range depends on the type of plant and period over which the emission rate would be averaged.[14]

Under Section 111(d) of the Clean Air Act, once EPA has set standards under Section 111(b) for new sources of a pollutant that is not covered by another section of the Act (in this case, CO_2), EPA must propose standards for *existing* sources of that pollutant as well. On June 2, 2014, EPA proposed what it is calling the Clean Power Plan under Section 111(d) of the Clean Air Act. The Clean Power Plan aims to regulate emissions of CO_2 from existing fossil fuel-fired power plants by setting binding, state-specific carbon emission reduction goals for all affected electric generating units. These emissions reduction goals reflect the degree of emissions reductions achievable through the application of the "best system of emission reduction." States will be required to reduce their average CO_2 emission rate for affected generating units from a 2012 baseline rate to a lower target rate by 2030. Overall, EPA expects the Clean Power Plan will yield CO_2 reductions of approximately 30 percent below 2005 levels by 2030.

The Clean Power Plan's reach is broad and seeks to explicitly impact electric power planning, dispatch, and procurement, with provisions that encourage switching from high-emitting coal to lower-emitting gas, renewable energy procurement, and increased energy efficiency. The proposed rule provides for flexibility in state compliance, including options for states to meet fleet-wide emission rate limits (in tons of CO_2 per MWh) or mass-based emissions targets (in tons) through heat rate improvements at coal-fired generators, increased dispatch of more efficient combined cycle natural gas generating resources, renewable energy programs, energy efficiency, and/or cap-and-trade programs. States can act independently, or enter into regional agreements with other states to achieve compliance.

EPA is currently reviewing the nearly 4 million comments it received on the proposed Clean Power Plan, and the final rule is anticipated in mid-summer of this year. The exact requirements of the final rule are

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[13] EPA. 2013. "Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act." *Climate Change.* Available at: http://www.epa.gov/climatechange/endangerment/.

[14] EPA. "Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units." Available at: http://www2.epa.gov/carbon-pollution-standards/2013-proposed-carbon-pollution-standard-new-power-plants.

still uncertain at this time, but it is very likely that renewable energy and end-use energy efficiency will be an important part of a comprehensive compliance strategy. Many states will be able to achieve compliance at a lower cost through the structures of their existing renewable portfolio and energy efficiency resource standards.

The precise means of demonstrating compliance with the final rule is also still being determined, but EPA's proposal involves a process similar to Section 110 of the Clean Air Act, under which states will be required to submit plans that specify how they intend to comply with the Clean Power Plan. States can develop individual plans or create a multi-state compliance strategy. EPA will then decide whether a proposed plan meets the terms of the regulation. If a state fails to submit a plan, or the submitted plan does not meet the requirements of the rule, then EPA can impose a federal compliance plan.

Under the schedule proposed by EPA, both new source performance standards under Section 111(b) and existing source performance standards under Section 111(d) will be finalized by mid-summer 2015. Under Section 111(d), states would then be required to submit compliance plans to EPA within one year, with the possibility of an extension for an additional year. States that collaborate on a multi-state plan would get an additional two years to submit their plan.

These pending performance standards for new and existing sources will affect decisions made by utilities regarding operation, expansion, and retirements. Enforcement of the Clean Air Act creates an opportunity cost of greenhouse gas abatement: prudent utilities will take Clean Air Act compliance into consideration in their planning, either explicitly as a maximum allowable emissions rate, or implicitly as an effective CO_2 price. Section 5 of this report discusses several independent analyses of the compliance cost of the Clean Power Plan. While costs vary depending on the assumptions used by the modeling teams, 2030 compliances costs tend to hover around $30 per short ton.

Other regulatory measures put economic pressure on carbon-intensive power plants

A suite of current and proposed EPA regulations require pollution-intensive power plants to install environmental controls for compliance. The cost of complying with environmental regulations reduces the profitability of the worst polluters, sometimes rendering them uneconomic. These policies demonstrate momentum towards appropriately regulating or pricing environmentally harmful activities in the electric sector. To the extent that plants with high emissions of other pollutants also have high carbon emissions, these policies would tend to *lower* the future CO_2 price necessary to achieve a given reduction; as more pollution-intensive plants retire in response to other EPA regulations, the necessary carbon price is reduced. Specific regulatory measures include:

- *National Ambient Air Quality Standards (NAAQS)* set maximum health-based air quality limitations that must be met at all locations across the nation. EPA has established NAAQS for six pollutants: sulfur dioxide (SO_2), nitrogen dioxides (NO_2), carbon monoxide (CO), ozone, particulate matter—measured as particulate matter less than or equal to 10 micrometers in diameter (PM10) and particulate matter less than or equal to 2.5 micrometers in diameter (PM2.5)—and lead.

- *The Cross State Air Pollution Rule (CSAPR)* establishes the obligations of each affected state to reduce emissions of NO_X and SO_2 that significantly contribute to another state's PM2.5 and ozone non-attainment problems. Implementation of CSAPR was delayed when the rule was vacated by the U.S. Court of Appeals for the District of Columbia in August 2012; it was then reinstated by the Supreme Court on April 29, 2014. Significantly, the Supreme Court found that EPA had not exceeded its authority in crafting an emission control program that utilized cap and trade and considered cost as a factor where the language of the Clean Air Act was ambiguous in addressing the complex problem of interstate transport of pollution.
- *Mercury and Air Toxics Standards (MATS)*: The final MATS rule, approved in December 2011, sets stack emissions limits for mercury and other metal toxins, organic and inorganic hazardous air pollutants, and acid gases. Compliance with MATS is required by 2015, with a potential extension to 2016. Many utilities have already committed to capital improvements at their coal plants to comply with the standard. In fact, the U.S. Energy Information Administration (EIA) recently found that approximately 70 percent of U.S. coal-fired power plants already comply with MATS.[15]
- *Coal Combustion Residuals (CCR) Disposal Rule:* On December 19, 2014, EPA issued a final rule regulating CCR under Subtitle D of the Resource Conservation and Recovery Act. In the final rule, EPA designates coal ash as municipal solid waste, rather than hazardous waste, which allows its continued "beneficial reuse" in products such as cement, wallboard, and agricultural amendments. The rule applies to new and existing landfills and ash ponds and establishes minimum siting and construction standards for new CCR facilities, requires existing ash ponds at operating coal plants to either install liners and ground water monitoring or permanently retire, and sets standards for long-term stability and closure care. The rule also establishes a number of requirements for facilities to make monitoring data and compliance information available to the public online, which is significant as the Subtitle D designation makes the CCR regulations "self-implementing," meaning EPA has no formal role in implementing or enforcing the regulations. Instead, enforcement is expected to be achieved through citizen suits under the Solid Waste Disposal Act. States may—but are not required to—incorporate the federal CCR requirements into their own solid waste management plans.
- *Steam Electric Effluent Limitation Guidelines (ELGs):* On June 7, 2013, EPA released eight regulatory options for new, proposed steam-electric ELGs to reduce or eliminate the release of toxins into U.S. waterways. A final rule is required by September 30, 2015.[16]

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[15] See U.S. Energy Information Administration website. Accessed February 4, 2015. Available at: http://www.eia.gov/todayinenergy/detail.cfm?id=15611.

[16] See U.S. Environmental Protection Agency website. Accessed February 4, 2014. Available at: http://water.epa.gov/scitech/wastetech/guide/steam-electric/amendment.cfm.

New requirements will be implemented in 2015 to 2020 through the five-year National Pollutant Discharge Elimination System permit cycle.[17]

- *Cooling Water Intake Structure (§316(b)) Rule:* In March 2011, EPA proposed a long-expected rule implementing the requirements of Section 316(b) of the Clean Water Act at existing power plants that withdraw large volumes of water from nearby water bodies. Under this rule, EPA would set new standards to reduce the impingement and entrainment of fish and other aquatic organisms from cooling water intake structures at electric generating facilities. The final rule was released on May 19, 2014. The requirements of the rule will be implemented through renewal of a facility's NPDES permit, which must be renewed every five years, and will be determined on a case-by-case basis.[18]

- *Regional Haze Rule:* The Regional Haze Rule, released in July 1999, requires states to develop state implementation plans (SIPs) for reducing emissions that impair visibility at pristine areas such as national parks. The rule also requires periodic SIP updates to ensure progress is being made toward improving visibility. The initial development of SIPs, which is just now being completed, requires Best Available Retrofit Technology (BART) controls for SO_X, NO_X, and PM emissions on large emission sources built between 1962 and 1977 that are found to be contributing to visibility impairment. BART controls must be installed within five years of SIP approval.

4.2. Proposed Cap-and-Trade Legislation

Over the past decade, there have been several congressional proposals to legislate cap-and-trade programs, with the goal of reducing greenhouse gas emissions by more than 80 percent below recent levels by 2050 through a federal cap. Such programs would allow trading of allowances to promote least-cost reductions in greenhouse gas emissions.

Comprehensive climate legislation was passed by the House in 2009: the American Clean Energy and Security Act, also known as Waxman-Markey or H.R. 2454. However, the Senate did not vote on either of the two climate bills before it in the 2009-2010 session (Kerry-Lieberman APA 2010 and Cantwell-Collins S. 2877). Waxman-Markey was a cap-and-trade program that would have required a 17 percent

[17] See U.S. Environmental Protection Agency. Steam Electric ELG Rulemaking. UMRA and Federalism Implications: Consultation Meeting. October 11, 2011. Available at: http://water.epa.gov/scitech/wastetech/guide/upload/Steam-Electric-ELG-Rulemaking-UMRA-and-Federalism-Implications-Consultation-Meeting-Presentation.pdf.

[18] See U.S. Environmental Protection Agency website. Accessed May 21, 2014. Available at: http://water.epa.gov/lawsregs/lawsguidance/cwa/316b/index.cfm.

reduction in emissions from 2005 levels by 2020, and an 83 percent reduction by 2050.[19] Further analysis of these proposals is provided in Synapse's *2012 Carbon Dioxide Price Forecast*.[20]

Congressional interest in climate policy has been ongoing. In March 2012, Senator Bingaman introduced the Clean Energy Standard Act of 2012 (S. 2146), which would have required larger utilities to meet a percentage of their sales with electric generation from sources that produce fewer greenhouse gas emissions than a conventional coal-fired power plant. Credits generated by these clean technologies would have been tradable with a market price. In February 2013, Senators Sanders and Boxer introduced new comprehensive climate change legislation, the Climate Protection Act of 2013. This bill proposed a fee of $20 per ton of CO_2 or CO_2-equivalent content of methane, rising at 5.6 percent per year over a ten-year period. Finally, in November 2014, Senators Whitehouse and Schatz introduced the American Opportunity Carbon Fee Act, which would assess a fee for every ton of CO_2 pollution emitted by all coal, oil, and natural gas produced in or imported to the United States. The bill would also cover large emitters of non-carbon greenhouse gases (such as methane) and CO_2 from non-fossil-fuel sources. The fee would start at $38 per short ton in 2015 and increase annually by an inflation-adjusted 2 percent, following the Obama Administration's estimate of the social cost of carbon. All revenue generated by the bill would be returned to the American people through an as-yet undetermined mechanism. The bill has not yet been brought to a vote.[21]

As discussed earlier, we expect that federal cap-and-trade legislation will eventually be enacted but that it is unlikely to happen in the near term. Federal carbon regulations are in effect or under development today, and the economic pressure—or opportunity cost—that they create may be represented as an effective price of greenhouse gas emissions. Regulatory measures are unlikely to meet long-term goals of reducing total greenhouse gas emissions to approximately 80 percent below 2005 levels by 2050, and a broader approach will be increasingly attractive in order to meet these goals at lower costs. Our judgment indicates this is most likely to take the form of a federal cap-and-trade system.

4.3. State and Regional Policies

There are two regional and state cap-and-trade programs in the United States today: the Northeast's Regional Greenhouse Gas Initiative (RGGI) and California's Cap-and-Trade Program under the state's

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[19] U.S. Energy Information Administration (EIA); Energy Market and Economic Impacts of the American Power Act of 2010 (July 2010). Available at http://www.eia.gov/oiaf/servicerpt/kgl/index.html. EIA; Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009 (August 2009). Available at http://www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

[20] Wilson et al. 2012. *2012 Carbon Dioxide Price Forecast*. Synapse Energy Economics. Available at: http://www.synapse-energy.com/project/synapse-carbon-dioxide-price-forecast.

[21] "Introducing the American Opportunity Carbon Fee Act" (November 2014). Available at: http://www.whitehouse.senate.gov/news/release/introducing-the-american-opportunity-carbon-fee-act.

Global Warming Solutions Act (Assembly Bill 32). In addition, a total of 20 states plus the District of Columbia have set greenhouse gas emissions targets as low as 80 percent below 1990 levels by 2050.[22]

Regional Greenhouse Gas Initiative

RGGI is a cap-and-trade greenhouse gas program for power plants in the northeastern United States. Current participant states are Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New York, Rhode Island, and Vermont. RGGI has had more than six years of successful CO_2 allowance auctions, with Auction 26 in December 2014 resulting in a clearing price of $5.21 per ton.[23] RGGI is designed to reduce electricity sector CO_2 emissions to at least 45 percent below 2005 levels by 2020.[24] RGGI is also a potential avenue for Clean Power Plan compliance for these states.

When RGGI was established in 2007, the expectation was that the CO_2 emissions allowance auction would generate revenues for consumer benefit programs such as energy efficiency, renewable energy, and clean energy technologies. While RGGI has provided significant revenues for consumer benefit, its allowance prices have generally remained near the statutory minimum price until recently. External influences, including changes to fuel prices, caused a shift from coal and oil to lower-carbon natural gas generation. Compared to those external factors, the effect of the original RGGI cap requirements were relatively minor in meeting the goals of reducing CO_2 emissions in the power sector.[25]

In 2012 and 2013, the RGGI states evaluated a number of plans for tighter emissions caps with the goal of raising allowance prices. In February of 2013, participating states agreed to lower the CO_2 cap from 165 million to 91 million short tons in 2014, to be reduced by 2.5 percent each year from 2015 to 2020. RGGI analysis indicated that with these lower caps, allowance prices will rise to $10.60 per short ton by 2020.[26]

In March 2014, the first auction under the new cap cleared at $4 per short ton. This auction used all available "cost containment reserve" allowances for the year—a fixed additional supply of allowances (above the cap) at a fixed price ($4 in 2014, rising to $10 in 2017) used to prevent rapid increases in the allowance price when auction prices rise above a set trigger. No more cost containment reserve

[22] Center for Climate and Energy Solutions. "Greenhouse Gas Emissions Targets." *U.S. Climate Policy Maps*. Accessed September 13, 2013. Available at: http://www.c2es.org/us-states-regions/policy-maps/emissions-targets.

[23] RGGI Auction 23 results available at: http://rggi.org/market/co2_auctions/results/Auction-23.

[24] RGGI. 2013. "RGGI States Propose Lowering Regional CO_2 Emission Cap 45%, Implementing a More Flexible Cost-Control Mechanism." Press Release. Available at: http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf.

[25] Environment Northeast. 2010. "RGGI at One Year: An Evaluation of the Design and Implementation of the Regional Greenhouse Gas Initiative." Available at: http://www.usclimatenetwork.org/resource-database/rggi-at-one-year-an-evaluation-of-the-design-and-implementation-of-the-regional-greenhouse-gas-initiative/.http://www.env-ne.org/public/resources/pdf/ENE_2009_RGGI_Evaluation_20100223_FINAL.pdf.

[26] RGGI. 2013. "RGGI States Propose Lowering Regional CO2 Emission Cap 45%, Implementing a More Flexible Cost-Control Mechanism." Press Release. Available at: http://www.rggi.org/docs/PressReleases/PR130207_ModelRule.pdf. Allowances prices have been converted to 2014 dollars.

allowances were available for the remaining three auctions in 2014, and prices rose to $5.21 per short ton by the end of the year.

The December 2014 clearing price was the highest-ever clearing price at a RGGI auction. In 2015, the number of cost containment reserve allowances will rise from 5 million to 10 million, alongside an increase in the trigger price from $4 to $6 per short ton. We expect this to result in a continuation of the slow but steady rise in RGGI allowance prices.

California's Cap-and-Trade-Program under AB32

With the goal of reducing the state's emissions to 1990 levels by 2020, California's Global Warming Solutions Act (AB32) has created the world's second largest carbon market, after the European Union's Emissions Trading System. The first compliance period for California's Cap-and-Trade Program began on January 1, 2013 and covers electricity generators, CO_2 suppliers, large industrial sources, and petroleum and natural gas facilities emitting at least 27,600 short tons of CO_2 equivalents per year.[27] This first phase of the program included electricity generators and large industrials. Phase II began in 2015, and also includes transportation fuels, natural gas suppliers, and smaller industrial sources. In 2015 the annual allowance budget rises to 434 million short tons, from 176 million short tons, due to the increasing scope of the policy.[28]

On January 1, 2014, California and Québec formally linked their carbon markets. The first joint auction was held in November 2014 and cleared at $10.98 per short ton.[29] The second joint auction was held on February 18, 2015, and cleared at $11.08. This was the first auction to include transportation fuels, and sold 73.6 million allowances, as compared to only 23 million allowances in the prior November 2014 auction.[30]

While the current cap-and-trade program in California only runs through 2020, several bills were introduced in 2014 suggesting direction through 2030. While none were taken to a final vote, there is an

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[27] California Air Resources Board. 2013. "California Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms to Allow for the Use of Compliance Instruments by Linked Jurisdictions." Available at: http://www.arb.ca.gov/cc/capandtrade/ctlinkqc.pdf. Legislated value is 25,000 metric tons, converted here to short tons.

[28] CARB AB 32 Final Regulation Order. Available at: http://www.arb.ca.gov/cc/capandtrade/capandtrade/unofficial_c&t_012015.pdf.

[29] California Air Resources Board. 2015. California Cap and Trade Program Summary of Auction Results. Updated 1/12/2015. Available at: http://www.arb.ca.gov/cc/capandtrade/auction/results_summary.pdf.

[30] California Air Resources Board. 2015. *California Cap and Trade Program and Quebec Cap and Trade System February 2015 Joint Auction #2 Summary Results Report*. Available at: http://www.arb.ca.gov/cc/capandtrade/auction/feb-2015/summary_results_report.pdf.
Auctions clear in dollars per metric tons – values here have been converted to short tons.

expectation that they will be reconsidered in 2015.[31] ICIS industries forecasts California CO_2 allowance prices to hit $45 per short ton by 2030.[32]

4.4. Assessment of CO_2 Price for Federal Rulemaking

In 2010, the U.S. federal government began including a carbon cost in regulatory rulemakings to account for the climate damages resulting from each additional ton of greenhouse gas emissions;[33] updated values were released in 2013.[34] The 2013 Economic Report of the President acknowledges that these values will continue to be updated as scientific understanding improves.[35]

An Interagency Working Group on the Social Cost of Carbon—composed of members of the Department of Agriculture, Department of Commerce, Department of Energy, Environmental Protection Agency, Department of Transportation, and Office of Management and Budget, among others—was tasked with developing a consistent value for the social benefits of climate change abatement. Four values were developed (see Section 3 for more explanation of the "social cost of carbon" methodology). These values—$11, $36, $57, and $103 per short ton of CO_2 in 2013, and rising over time—represent average (most likely) damages at three discount rates, along with one estimate at the 95th percentile of the assumed distribution of climate impacts.[36] While subject to significant uncertainty, this multi-agency

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[31] Environmental Defense Fund. "Carbon Market California – Year Two: 2014." Available at: http://www.edf.org/sites/default/files/content/carbon-market-california-year_two.pdfhttp://www.edf.org/sites/default/files/content/carbon-market-california-year_two.pdf.

[32] ICIS. 2015. "ICIS launches 2030 Forecast for California Carbon Allowances." Press Release. January 2015. Available at: http://www.icis.com/press-releases/icis-launches-2030-forecast-for-california-carbon-allowances/. Forecast in metric tons, value here converted to short tons.

[33] Interagency Working Group on the Social Cost of Carbon, U. S. G. 2010. "Appendix 15a. Social cost of carbon for regulatory impact analysis under Executive Order 12866." In *Final Rule Technical Support Document (TSD): Energy Efficiency Program for Commercial and Industrial Equipment: Small Electric Motors*. U.S. Department of Energy. Available at: http://go.usa.gov/3fH.

[34] Interagency Working Group on the Social Cost of Carbon. 2013. *Technical Support Document – Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866*. Available at: http://www.whitehouse.gov/sites/default/files/omb/inforeg/social_cost_of_carbon_for_ria_2013_update.pdf. Reported values have been converted to 2014 dollars per short ton.

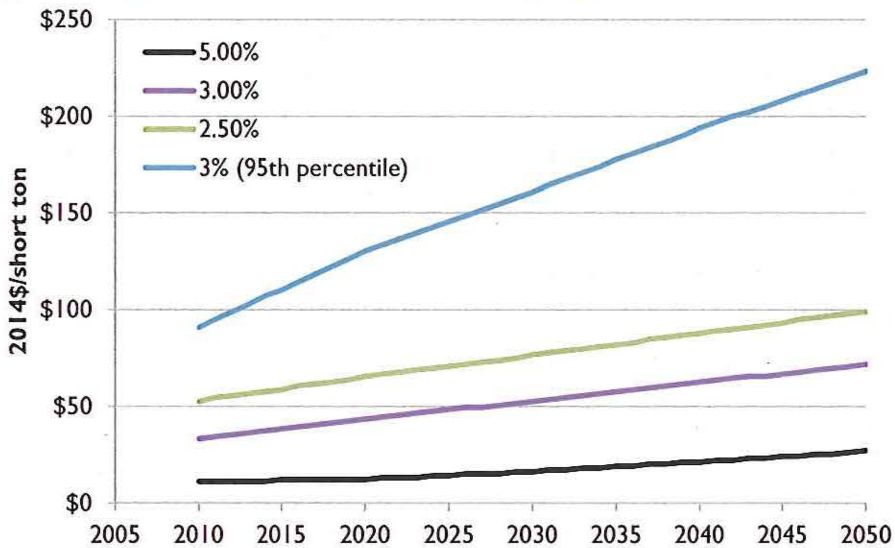
[35] The White House. 2013."Climate Change and the Path Toward Sustainable Energy Sources." *2013 Economic Report of the President*. Available at: http://www.whitehouse.gov/sites/default/files/docs/erp2013/ERP2013_Chapter_6.pdf.

[36] In a 2012 paper, Ackerman and Stanton modified the Interagency Working Group's assumptions regarding uncertainty in the sensitivity of temperature change to emissions, the expected level of damages at low and high greenhouse gas concentrations, and the assumed discount rate, and found values for the social cost of carbon ranging from the Working Group's level up to more than an order of magnitude greater [Frank Ackerman and Elizabeth A. Stanton. 2012. "Climate Risks and Carbon Prices: Revising the Social Cost of Carbon." *Economics: The Open-Access, Open-Assessment E-Journal*, Vol. 6, 2012-10. http://dx.doi.org/10.5018/economics-ejournal.ja.2012-10]. Similarly, Laurie Johnson and Chris Hope modified discount rates and methodologies and found results up to 12 times larger than the Working Group's central estimate [Laurie T. Johnson, Chris Hope. 2012. "The social cost of carbon in U.S. regulatory impact analyses: an introduction and critique." *Journal of Environmental Studies and Sciences*; DOI: 10.1007/s13412-012-0087-7].

effort represents an initial attempt at incorporating the benefits associated with CO_2 abatement into federal policy. These values are presented in Figure 1.

These estimates continue to be used in federal government rulemakings for the purpose of calculating costs and benefits of new and updated policies. While a CO_2 price for federal rulemaking assessments is a fundamentally different kind of cost metric than the others discussed in this report, it nonetheless represents a dollar value for greenhouse gas emissions currently in use by the U.S. federal government.

Figure 1: Range of Federal CO_2 Prices for Rulemakings, by discount rate



5. The Cost of Implementing EPA's Clean Power Plan

In Section 4, we discuss the EPA's Clean Power Plan in the context of federal climate legislation that may result in reduced greenhouse gas emissions. As the proposal aims to regulate CO_2 emissions directly and represents a significant change in near-term climate policy certainty as compared to our previous CO_2 price forecast, we examine it more fully in this section. We discuss factors that will affect states' implementation methods, as well as the expected costs of compliance as modeled by EPA, Synapse, and third-party analysts.

5.1. Issues in Implementing the Clean Power Plan for Utility Planning

The Clean Power Plan is EPA's proposal to meet CO_2 emissions limitations from existing sources using a Best System of Emissions Reductions ("BSER"). EPA has structured the Clean Power Plan around four fundamental "building blocks" that represent possible means for achieving the established emissions standard: (1) increasing existing coal plant efficiency, (2) displacing coal generation with existing natural gas, (3) increasing renewable energy acquisitions, and (4) implementing energy efficiency programs.

Taken together, EPA estimates that these programs will reduce emissions by a certain amount in each state. EPA's targets for each state are set as a rate, measured in pounds of CO_2 per megawatt-hour (lbs/MWh). The rate has been a source of confusion to many parties: it represents both projected emissions from existing sources, as well as generation from new renewable energy and energy efficiency programs.

EPA's proposal allows states to choose the metric by which they measure compliance: states can either meet the rate-based target using a combination of the building blocks or other programs, or meet an alternate mass-based target, measured in total tons of CO_2.

The mass-based compliance route is fundamentally a cap on sectoral emissions on a state-by-state basis. It is not unreasonable to assume that implementing states might choose to use a cap-and-trade scheme, such as is currently employed for national SO_2 emissions under the Acid Rain Program, regionally for NO_X budget trading program, and for CO_2 in California and RGGI states. Planning and modeling under a mass-based cap is fairly well understood; it involves a marginal abatement cost applied to electric sector emissions reduces emissions. The price is adjusted either by the market or an administrative body such that total emissions hit the required target. Modeling mass-based compliance effectively requires finding a price (either real or shadow) for CO_2 that maintains emissions under the cap. Utilities may elect to either review their pro-rata share of mass-based emissions reductions under the cap, or model the impact of mass compliance on the state fleet to determine an effective CO_2 price. For utilities that trade electricity bilaterally or on the open market, the market price of electricity should also account for the CO_2 price impacts.

The rate-based compliance mechanism sets a rate target for individual states based on an (outwardly) simple formula, in which emissions from existing generators are divided by generation from existing generators plus generation from renewable energy and energy efficiency (EERE). States or utilities seeking to model the impact of the Clean Power Plan under a rate-based compliance scheme need to find a least-cost solution that reduces the emissions rate of existing fossil generators while including the amount of EERE as an additional factor in that emissions rate. Effectively, modeling a rate-based compliance mechanism requires utilities (and states) to simultaneously optimize power plant operations and EERE, while also accounting for how compliance in neighboring utilities (and states) impacts generators and the price for market electricity. States with different rate targets (or different rate-based mechanisms) may impose different restrictions on fossil generators, and thus significantly impact market electricity prices.

5.2. Expected Pricing and Stringency of EPA's Clean Power Plan

As of the date of publication of this report, the Clean Power Plan is still a proposal and leaves numerous open questions and ambiguities. While it is expected that many of these ambiguities will be resolved by the time the final rule is published, the exact implications of the rule are still difficult to fully resolve. Depending on interpretations of various open questions, including the role of new gas and the treatment of EERE, the rule may prove to be fairly low-cost, or higher cost. It is possible to envision high-and low-cost scenarios for both high and low efficacy rule implementations. All estimates in this section have been converted to 2014 dollars per short ton.

EPA's Estimates

Several studies have attempted to quantify the costs and benefits of implementing the proposed Clean Power Plan.[37] In developing the proposed rule, EPA estimated the average compliance cost for each of the building blocks.[38] EPA found that:

- Heat rate improvements at existing coal-fire units (Building Block 1) would have net costs between $6 and $11 per short ton
- Substituting generation from existing natural gas plants for generation from existing coal plans (Building Block 2) would have net costs of about $283 per short ton
- Encouraging new renewable energy and discouraging the retirement of existing nuclear power plants (Building Block 3) would have costs between $9 and $38 per short ton
- Demand-side energy efficiency (Building Block 4) would range from $15 to $23 per short ton

EPA also used the IPM electricity capacity expansion model to analyze compliance in a more integrated framework, finding average compliance costs of $28 per short ton in 2030 (ranging from zero to $106 per ton depending on the state). They also modeled a regional compliance approach, where nearby states could work together to reduce costs. This approach resulted in average costs of $29 per short ton in 2030 (ranging from $26 to $34 per ton depending on the region).

Independent Analyses

The Rhodium Group and CSIS Energy used the EIA's NEMS model to project the effects of the proposed Clean Power Plan. NEMS is a model that considers not only the electricity sector, but other elements of the energy economy, including transportation, industrial, commercial, and residential uses. They found simple state-by-state compliance to be highly unlikely, and as a result compared a national compliance approach (with a single rate- or mass-based standard) to a more fragmented 22-region approach. With the inclusion of energy efficiency, they found expenditures on electricity decreased by 2.4 percent under a national compliance approach relative to a base case without the Clean Power Plan. Under regional

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[37] Results from public modeling analyses were converted to 2014 dollars using price deflators taken from the U.S. Bureau of Economic Analysis, and are available at: http://www.bea.gov/national/nipaweb/SelectTable.asp.

[38] EPA. 2014. *Clean Power Plan Proposed Rule (June 2014 release)*. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule.

compliance, electricity expenditures increased 0.6 percent.[39] This small change in expenditures indicates that Clean Power Plan compliance can be implemented at a relatively modest cost. The use of an economy-wide energy model also allowed this study to demonstrate the impacts on national gas demand; Rhodium Group and CSIS Energy projected total national gas demand to increase 10.9 billion cubic feet per day by 2030, as compared to a no policy case. This higher gas demand resulted in an increase in Henry Hub gas prices of $0.48 per MMBtu.

SNL Energy completed modeling of the proposed rule using AuroraXMP, a high-resolution electric sector model incorporating both capacity expansion and dispatch. They modeled the policy as a mass-based target, including emissions from new builds, with regional compliance across five regions in the Eastern Interconnect. SNL imposed a CO_2 constraint, and reported the resulting shadow prices. Their values ranged from $13 to $29 per short ton for the 2020-2029 average targets, rising to $21 to $33 per short ton in 2030. This analysis implied that the RGGI states could largely meet their target under the existing RGGI system, PJM could comply at a cost of $21 per ton (well below the prices implied in the EPA IPM analysis), and other regions could comply at costs quite similar to those assumed by EPA under regional cooperation.[40]

Energy Ventures Analysis conducted a similar study for the National Mining Association, using the same model as SNL but focusing on state, rather than regional, compliance. They found average CO_2 prices over the 2020-2030 period ranging from $10 to $31 per short ton for most states, although prices in Arizona, Nevada, Oregon, and Washington were much higher: $55 per ton, $83 per ton, $54 per ton, and $70 per ton, respectively.[41]

Several independent system operators (ISOs) are in the process of conducting their own analyses. MISO used the EGEAS electricity capacity expansion model to consider compliance approaches directly following EPA's building blocks, as well as a generic CO_2 constraint based on EPA's mass-based targets.[42] The building block approach resulted in an overall CO_2 cost of $60 per ton reduced, while the more flexible mass-based approach cost $38 per ton reduced. The MISO analysis only focused on existing-source CO_2 emissions—any emissions from new gas plants to be regulated under 111(b) are not counted. As a result, the mass-based approach above may create a loophole in the proposed policy design whereby new gas combined-cycle plants could replace generation from old gas combined-cycle

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39 Larsen et al. 2014. *Remaking American Power: Potential Energy Market Impacts of EPA's Proposed GHGH Emission Performance Standards for Existing Electric Power Plants*. CSIS and Rhodium Group. Available at: http://csis.org/publication/remaking-american-power.

40 Gelbaugh et al. 2014. *Critical Mass: An SNL Energy Evaluation of Mass-based compliance under the EPA Clean Power Plan*. Available at: http://center.snl.com/Resources/Whitepaper.aspx?id=4294973757.

41 Energy Ventures Analysis. 2014. *EPA Clean Power Plan: Costs and Impacts on US Energy Mark*ets. Energy Ventures Analysis for National Mining Association. Available at: http://www.countoncoal.org/assets/Executive-Summary-EPA-Clean-Power-Plan-Costs-Impacts.pdf.

42 MISO. 2014. "GHG Regulation Impact Analysis – Initial Study Results." September 17, 2014. Available at: http://www.eenews.net/assets/2014/09/18/document_ew_01.pdf.

plants to reduce emissions under the 111(d) umbrella without actually reducing overall system emissions. It is likely that EPA will address such potential limitations in the final rule.

PJM used the PROMOD hourly production cost model to review the cost of compliance under mass-based targets, assuming that new gas units are regulated under Clean Air Act section 111(b).[43] PJM analyzed a number of different scenarios of renewable energy and energy efficiency implementation and gas prices. Required CO_2 prices ranged from $5 to $30 per short ton in 2030, except for scenarios with high natural gas prices which ranged from $35 to $55 per short ton.

Other studies have focused on modeling the rate-based provisions of the Clean Power Plan and reported changes in total system costs and electricity prices, but not CO_2 prices. The Missouri utility Ameren found an incremental cost of $4 billion to achieve the Clean Power Plan goals, as compared to its latest IRP that would achieve the same goals by 2035.[44] A NERA Economic Consulting report found incremental costs of $366 billion (in $2013 present value) nationwide, or $479 billion without the availability of energy efficiency and renewable energy.[45] The PJM study cited above found incremental costs in 2029 of $0.1 billion to $3.5 billion in the high natural gas price case for the PJM system as a whole.

Synapse Analysis: What Would the Cost Be with Nationwide Cooperation?

Synapse used the ReEDS (Regional Energy Deployment System) model, built by the National Renewable Energy Lab, to estimate expected allowance prices under two scenarios of full national cooperation in meeting the Clean Power Plan. ReEDS selects the types of power generation to build and operate in different parts of the country with the goal of achieving the least total cost; it draws many of its assumptions from the EIA's 2014 Annual Energy Outlook. Our Clean Power Plan scenarios included a cap on CO_2 emissions consistent with EPA's mass-based targets.[46] Modeling results were produced using both "annual" and "average" assumed targets. The annual approach matches the EPA mass-based targets in each year beginning in 2020, while the average approach matches the 2020-2029 average mass. Figure 2 reports yearly emissions for both types of targets. As shown in Figure 3, allowance prices typically range from $16 to $25 per short ton (in 2012 dollars) throughout the 2020-2030 timeframe.

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43 Sotkiewics, Paul and Abdur-Rahman, Muhsin. 2014. "EPA's Clean Power Plan Proposal Review of PJM Analyses Preliminary Results." PJM Members Committee Webinar November 17, 2014. Available at: http://www.pjm.com/~/media/documents/reports/20141117-epas-clean-power-plan-proposal-review-of-pjm-analyses-preliminary-results.ashx.

44 Ameren. 2015. *Ameren's Alternative to the EPA's proposed Greenhouse Gas Rules*. Available at: https://www.ameren.com/-/media/Corporate-Site/Files/aboutameren/amerens-alternative-ghg-white-paper.pdf?la=en.

45 NERA Economic Consulting. 2014. *Potential Energy Impacts of the EPA Proposed Clean Power Plan*. Available at: http://americaspower.org/sites/default/files/NERA_CPP%20Report_Final_Oct%202014.pdf.

46 EPA. 2014. "Clean Power Plan Proposed Rule: Translation of State-Specific Rate-Based CO2 Goals to Mass-Based Equivalents." November 6, 2014. Available at: http://www2.epa.gov/carbon-pollution-standards/clean-power-plan-proposed-rule-translation-state-specific-rate-based-co2.

Using the average targets, prices start lower in 2020 before gradually rising as the policy becomes more stringent. These two cases can be seen as a low-end estimate for the cost of compliance with the Clean Power Plan. Less cooperation between states would result in higher costs by reducing the number of low-cost compliance options available to each state.

Figure 2: U.S. CO_2 emissions under two ReEDS Clean Power Plan scenarios (million short tons)

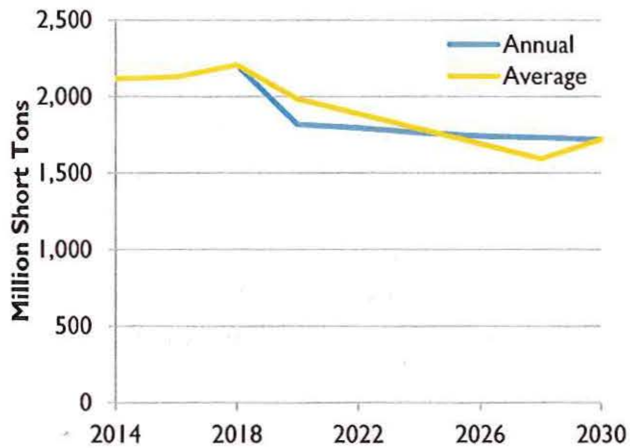
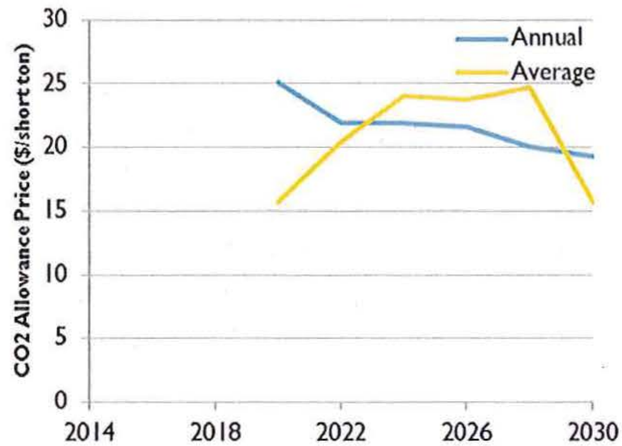


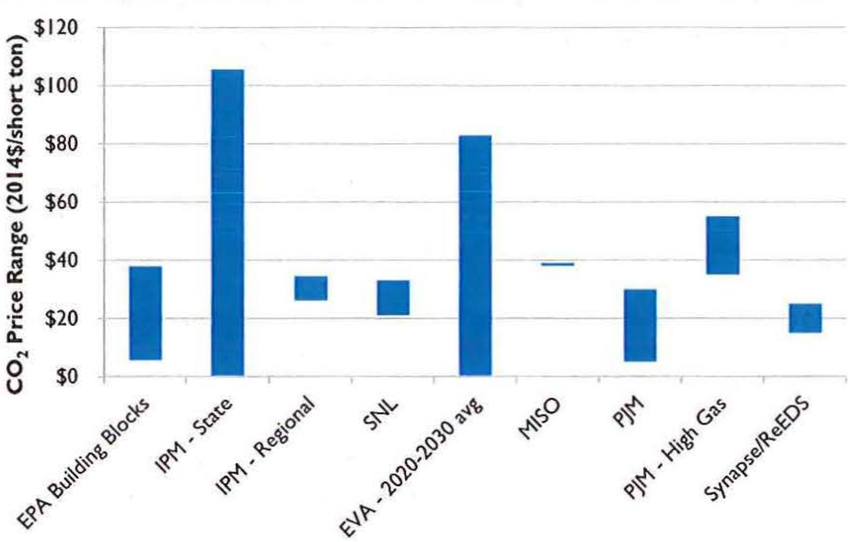
Figure 3: U.S. CO_2 allowance prices under two ReEDS Clean Power Plan scenarios ($/short ton)



Comparison of Price Estimates

Figure 4 below compares Synapse's nationwide analysis (referred to as Synapse/ReEDS) to the range of other analyses discussed in this section. The Synapse analysis falls well within this range. Modeled compliance costs depend on a number of factors, including assumptions about cooperation, fuel prices, renewable and energy efficiency costs, and retirements.

Figure 4: Summary of Clean Power Plan study CO_2 price estimates (2014 dollars per short ton)



6. CO_2 Price Forecasts in Utility IRPs

A growing number of electric utilities include projections of the expected costs associated with greenhouse gas emissions in their resource planning. In addition to the pool of recent IRPs reviewed for this forecast, which are characterized below, Synapse has previously conducted an extensive study of resource plans dating back to 2003:

- None of the 15 IRPs published from 2003-2007 that we reviewed included a CO_2 price forecast.
- Of the 56 IRPs from 2008-2011 that we reviewed, 23 included a CO_2 price forecast. This jump in the inclusion of carbon price projections in IRPs from 2008 onwards coincided with the introduction of the Waxman-Markey bill in Congress, which sought to legislate a cap-and-trade system. As a result of this bill, the inclusion of carbon pricing sensitivities in IRPs became paramount to prudent planning beginning in 2008; a majority of the IRPs in our 2015 review reflect an understanding that inclusion of a methodology to reflect future environmental regulations is prudent planning.
- Of the 115 IRPs released in 2012-2015 reviewed by Synapse (referred to below as our "current sample"), 66 include a CO_2 price in at least one scenario, including 61 with a CO_2 price in their reference case scenario (53 percent).
- Moreover, of the 24 IRPs released in 2014-2015 reviewed by Synapse, 20 include a CO_2 price in at least one scenario, of which 19 include a CO_2 price in their reference case scenario (79 percent).

These data show that the resource plans in the current sample includes a similar fraction of IRPs with a CO_2 price forecast as the 2008-2011 sample, when major climate bills were actively under consideration (57 percent in 2012-2015 as compared to 50 percent in 2008-2011).

Table 2: IRP database summary statistics

	Number of IRP Reviewed	Number of IRPs with CO_2 considered
2003-2007	15	0
2008-2011	56	23
2012-2015	115	66
2012-2013	91	46
2014-2015	24	20

How well does our current sample represent utility planning across the United States? A total of 3,412 utilities operated in the United States in 2012.[47] In terms of generation, the top 5 percent—170

[47] EIA Form 860, 2012 (Released Oct. 10, 2013).

utilities—accounted for 77 percent of total U.S. generation in 2012. Our sample includes IRPs from 33 utilities within this largest 5 percent. Of those 33, 29 utilities have IRPs with non-zero CO_2 prices. This means that almost all of the IRPs we reviewed from the largest utilities in the country include a non-zero CO_2 price in their planning process.

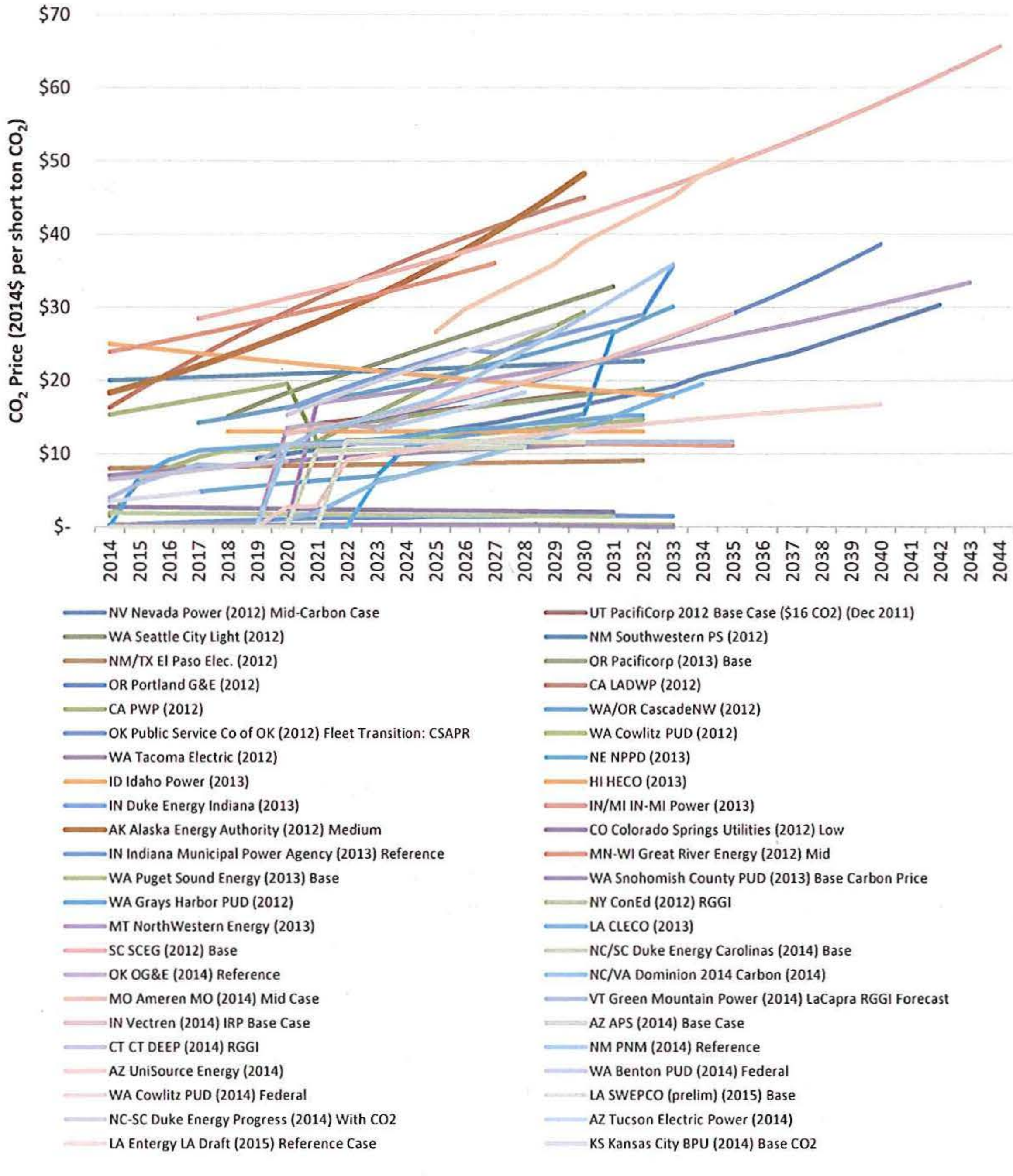
Not all utilities produce IRPs. In fact, 11 states have no filing requirements for long-term planning, while 10 other states require long-term plans, but not IRPs.[48] While long-term planning is an important part of the procurement process in regions with wholesale energy markets, traditional utility-centric IRPs are less common. As a result, regions with wholesale markets are not well represented in our sample.

Figure 5 below displays non-zero reference case CO_2 price forecasts from 46 utility IRPs over the period of 2014-2044.[49] Although we refer above to 61 non-zero CO_2 price reference case forecasts in the current sample, fifteen of these forecasts are excluded from this chart for various reasons. In some cases, our sample includes IRPs from companies in 2012 *and* 2014, in which case we only include the most recent forecast. The remaining non-zero forecasts that are not included in the figure below are from companies that operate in multiple states but produce the same CO_2 forecast, are confidential, or forecast a price that begins following the end of the IRP planning period.

[48] See: Wilson, R. and B. Biewald. *Best Practices in Electric Utility Integrated Resource Planning*. June 1, 2013. Synapse Energy Economics. Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2013-06.RAP.Best-Practices-in-IRP.13-038.pdf.

[49] We also provide a figure showing only forecasts produced in 2014 and 2015 in Appendix A. These forecasts do not appear materially different than the range of 2012 to 2015 forecasts shown below.

Figure 5: Utility non-zero and non-confidential reference case forecasts from 2012-2015[50]



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50 A number of non-zero, non-confidential reference case forecasts are excluded, discussed further on page 24.

Four of the utility forecasts displayed in Figure 5 are particularly low in the context of the other forecasts. Two IRPs from the Northeast—Commonwealth Edison of New York and the Connecticut Department of Energy and Environmental Protection—base their reference case forecasts on RGGI prices before the recent RGGI revisions discussed in Section 4, resulting in prices just under $2 per short ton. Two other IRPs—Puget Sound Energy and Snohomish County PUD—use a Washington State mandated CO_2 price of $0.32 per short ton for their base case analyses.

The five utilities that assume a $0 CO_2 price in their reference cases also consider several additional non-zero scenarios. These are provided in Appendix A.[51]

Table 3 summarizes the range of CO_2 prices forecasted for 2020 and 2030. Not all forecasts start by 2020, and those that do are generally below $20 per ton. Of the utilities with a non-zero CO_2 price, all but four assume a price in 2025.

Table 3: Number of utility CO_2 Forecasts from 2012-2015 in several price ranges in 2020 and 2030

	Compliance Year	
	2020	2030
>$0 - <$10	14	5
$10 - $20	17	18
$20 - $30	6	11
$30 - $40	2	2
>$40	0	4

7. OVERVIEW OF THE EVIDENCE FOR A FUTURE CO_2 PRICE

Our CO_2 price forecasts are developed based on the data sources and information presented above and reflect a reasonable range of expectations regarding future efforts to limit greenhouse gas emissions. The following evidence has guided the development of the Synapse forecasts:

- **Regulatory measures limiting CO_2 emissions from power plants will be finalized in the near term.** The EPA has proposed emissions standards for new and existing power plants under Section 111(d) of the Clean Air Act, to be finalized by mid-summer 2015. These actions represent an effective price that will affect utility planning and operational decisions.

- **Environmental regulation can, and often does, evolve incrementally over time.** Initial awareness of environmental damages, followed successively by measurement and study

[51] Indianapolis Power & Light's "Environmental Case" CO_2 forecast is provided only as a trajectory with no values on its axes, and is excluded from Appendix A.

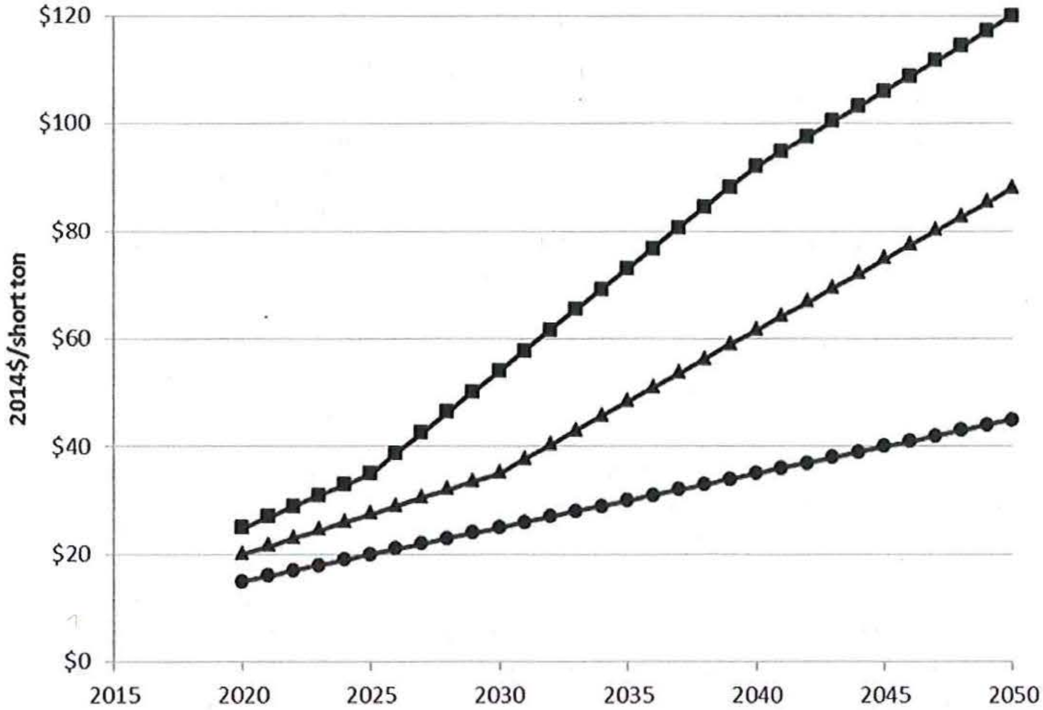
of the damages and initial attempts to regulate the responsible sources (and associated debate and legal challenges), are eventually followed by more detailed or nuanced regulations. For climate change and greenhouse gas emissions from the electric power sector in the United States, this process has been in progress for several decades, and in our view the trends are likely to continue, as risks are increasingly apparent and regulatory and policy response to address the risks is demanded.

- **State and regional action limiting CO_2 emissions is ongoing and growing more stringent.** In the Northeast, the RGGI CO_2 cap has been tightened, and recent auctions have used all available cost-containment reserves, resulting in higher CO_2 prices for electric generators in the region. California's Cap-and-Trade Program, which represents an even larger carbon market than RGGI, has held many successful allowance auctions, has been successfully defended against numerous legal challenges, and was expanded to include natural gas and transportation fuels in 2015.
- **A price for CO_2 is already being factored into federal rulemakings.** The federal government has demonstrated a commitment to considering the benefits of CO_2 abatement in rulemakings such as fuel economy and appliance standards.
- **Ongoing analysis of the Clean Power Plan proposal suggests a wide range of possible prices.** Important factors include the level of regional cooperation, the availability of renewable energy and energy efficiency, and natural gas prices.
- **Electric suppliers continue to account for the opportunity cost of CO_2 abatement in their resource planning.** Prudent planning requires utilities to consider adequately the potential for future policies. The range of CO_2 prices reported in Section 6 indicates that many utilities believe that by 2020 there will likely be significant economic pressure towards low-carbon electric generation.

8. SYNAPSE 2015 CO_2 PRICE FORECAST

Based on the evidence discussed in this report, Synapse has developed Low, Mid, and High case forecasts for CO_2 prices from 2015 to 2050. These forecasts reflect our best understanding of Clean Power Plan compliance costs, as well as future expected costs after 2030 to meet science-based emissions targets. We believe it is highly likely that neighboring states with large disparities in mitigation costs will work together to their mutual benefit to reduce overall compliance costs. EPA has indicated it is open to such cooperation. As a result, we provide a single national-level CO_2 price and do not attempt to provide state-level forecasts. Figure 6 and Table 4 show the Synapse forecasts over the 2015-2050 period.[52]

Figure 6: Synapse 2015 CO_2 Price Trajectories



[52] Figure 11 in Appendix A also provides a comparison of this updated Synapse CO_2 forecast to the 2013 Synapse forecast. These forecasts do not differ substantially. Two key differences are a tighter range of prices in 2020 resulting from greater policy certainty, as well as higher 2015 forecasts for the mid and high cases, resulting from the indicated stringency of the Clean Power Plan. The 2015 forecast is also the first Synapse forecast to extend to 2050.

Table 4: Synapse 2015 CO_2 price projections (2014 dollars per short ton CO_2)

Year	Low Case	Mid Case	High Case
2020	$15.00	$20.00	$25.00
2021	$16.00	$21.50	$27.00
2022	$17.00	$23.00	$29.00
2023	$18.00	$24.50	$31.00
2024	$19.00	$26.00	$33.00
2025	$20.00	$27.50	$35.00
2026	$21.00	$29.00	$38.80
2027	$22.00	$30.50	$42.60
2028	$23.00	$32.00	$46.40
2029	$24.00	$33.50	$50.20
2030	$25.00	$35.00	$54.00
2031	$26.00	$37.65	$57.80
2032	$27.00	$40.30	$61.60
2033	$28.00	$42.95	$65.40
2034	$29.00	$45.60	$69.20
2035	$30.00	$48.25	$73.00
2036	$31.00	$50.90	$76.80
2037	$32.00	$53.55	$80.60
2038	$33.00	$56.20	$84.40
2039	$34.00	$58.85	$88.20
2040	$35.00	$61.50	$92.00
2041	$36.00	$64.15	$94.80
2042	$37.00	$66.80	$97.60
2043	$38.00	$69.45	$100.40
2044	$39.00	$72.10	$103.20
2045	$40.00	$74.75	$106.00
2046	$41.00	$77.40	$108.80
2047	$42.00	$80.05	$111.60
2048	$43.00	$82.70	$114.40
2049	$44.00	$85.35	$117.20
2050	$45.00	$88.00	$120.00
Levelized 2020-2050	$26.24	$41.64	$59.35

In these forecasts, the Clean Power Plan, together with other federal regulatory measures, place economic pressure on CO_2-emitting resources in the next several years, such that it is relatively more expensive to operate a high-carbon-emitting power plant. These pressures are followed later by a broader federal policy, such as cap and trade. In any state other than the RGGI region and California, we assume a zero carbon price through 2019; beginning in 2020, we expect Clean Power Plan compliance will put economic pressure on carbon-emitting power plants throughout the United States. All annual allowance prices and levelized values are reported in 2014 dollars per short ton of CO_2.

- The **Low case** forecasts a CO_2 price that begins in 2020 at $15 per ton, and increases to $25 in 2030 and $45 in 2050, representing a $26 per ton levelized price over the period 2020-2050. This forecast represents a scenario in which Clean Power Plan compliance is relatively easy, and a similar level of stringency is assumed after 2030. Low case prices are also representative of the incremental cost to produce electricity with gas over coal, as indicated in the EIA's 2014 Annual Energy Outlook.
- The **Mid case** forecasts a CO_2 price that begins in 2020 at $20 per ton, and increases to $35 in 2030 and $88 in 2050, representing a $42 per ton levelized price over the period 2020-2050. This forecast represents a scenario in which federal policies are implemented with significant but reasonably achievable goals. Clean Power Plan compliance is achieved and science-based climate targets are enacted mandating at least an 80 percent reduction in electric section emissions from 2005 levels by 2050.
- The **High case** forecasts a CO_2 price that begins in 2020 at $25 per ton, and increases to approximately $54 in 2030 and $120 in 2050, representing a $59 per ton levelized price over the period 2020-2050. This forecast is consistent with a stringent level of Clean Power Plan targets that recognizes that achieving science-based emissions goals by 2050 will be difficult. In recognition of this difficulty, implementation of standards more aggressive than the Clean Power Plan may begin as early as 2025. New regulations may mandate that electric-sector emissions are reduced to 90 percent or more below 2005 levels by 2050, in recognition of lower-cost emission reduction measures expected to be available in this sector. Other factors that may increase the cost of achieving emissions goals include: greater restrictions on the use of offsets; restricted availability or high cost of technology alternatives such as nuclear, biomass, and carbon capture and sequestration; and more aggressive international actions (thereby resulting in fewer inexpensive international offsets available for purchase by U.S. emitters).

These price trajectories are designed for planning purposes, so that a reasonable range of emissions costs can be used to investigate the likely costs of alternative resource plans. We expect an actual CO_2 price incurred by utilities in all states to fall somewhere between the low and high estimates throughout the forecast period.

In Figure 7, the Synapse forecasts are shown in comparison to the reference case utility forecasts presented earlier. In Figure 8, the Synapse forecasts are compared to a summary of the other evidence presented in this report, including the federal CO_2 price for rulemakings; existing Clean Power Plan studies; and utility reference, low , and high scenarios. The forecasts are also compared to the Synapse 2013 forecasts and the federal CO_2 price for rulemakings in Appendix A.

Figure 7: Synapse forecast compared to recent utility reference case forecasts

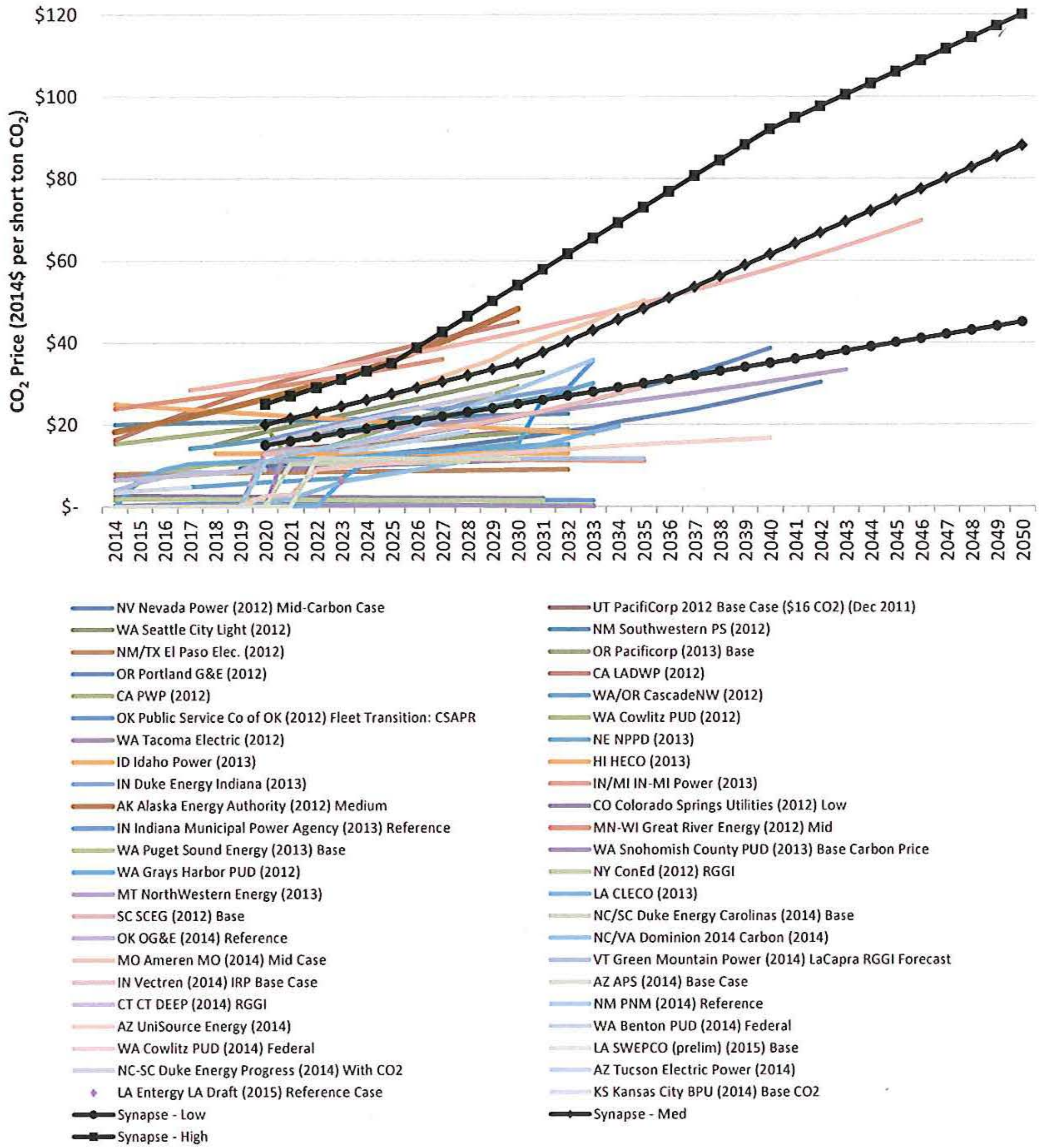
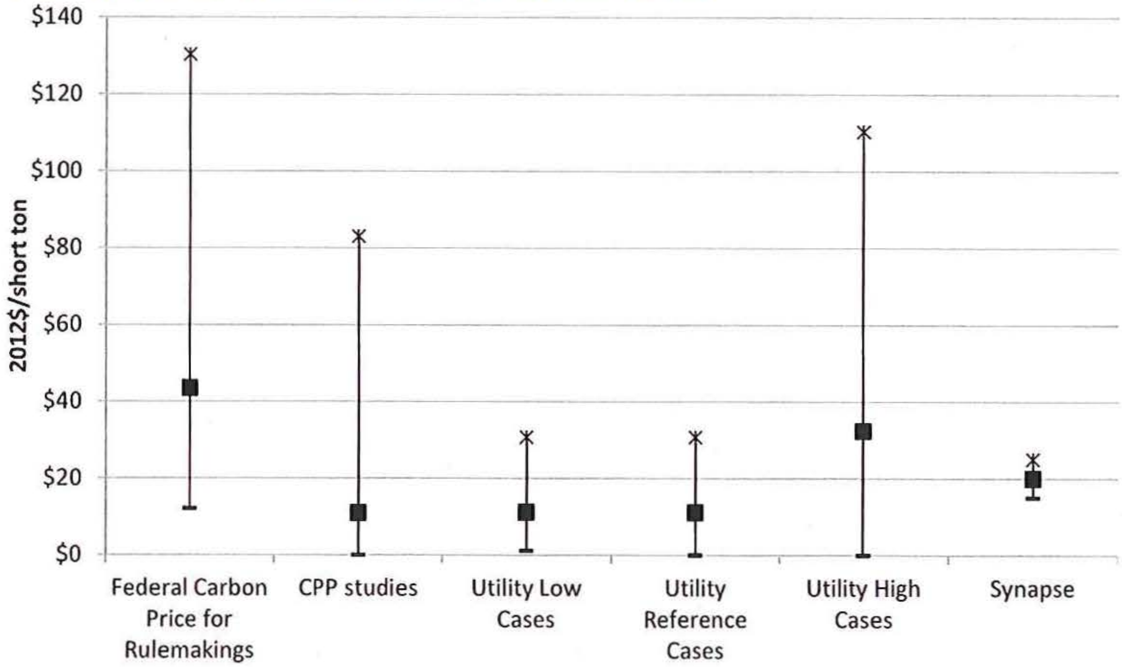
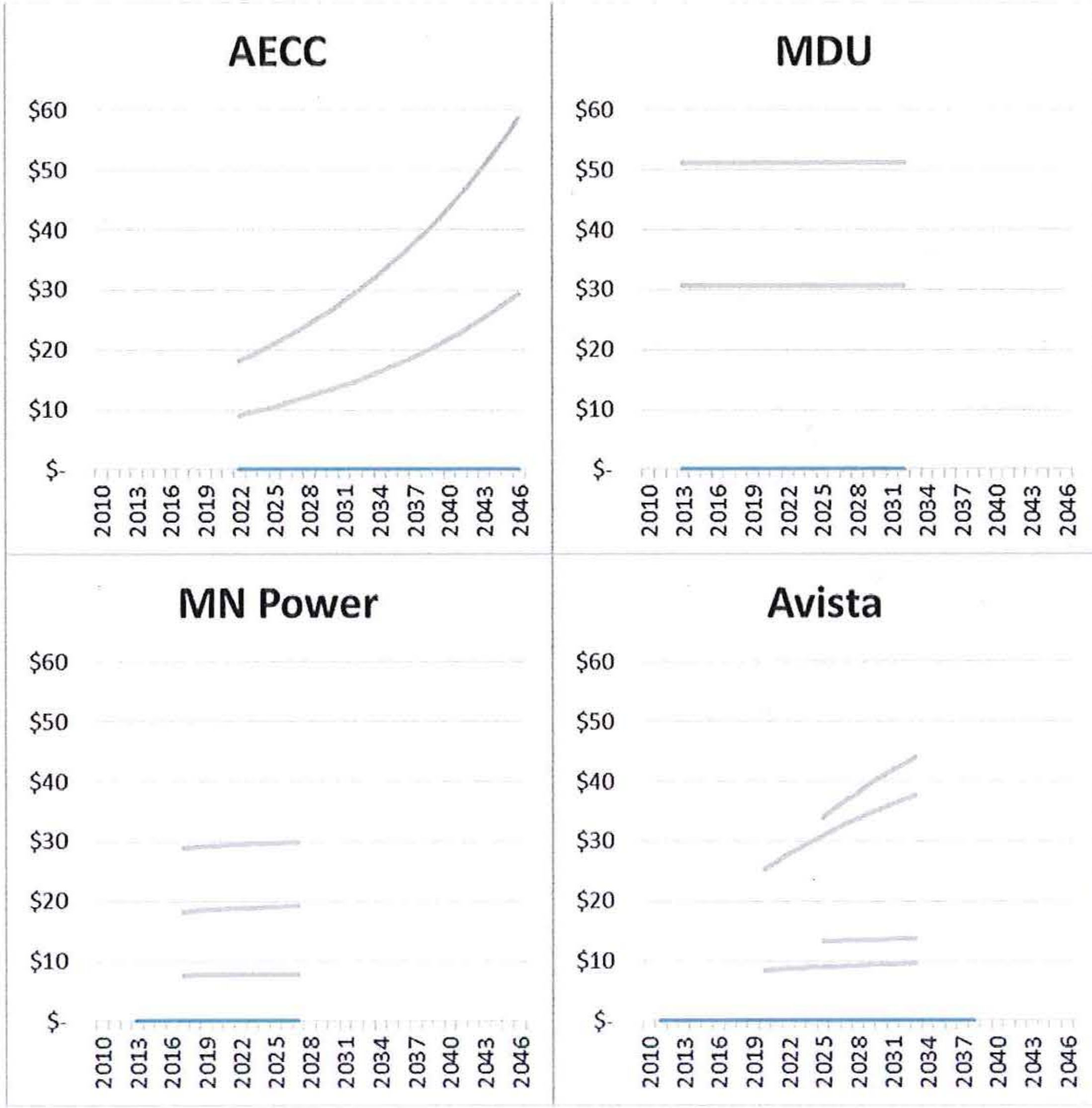


Figure 8: Synapse CO_2 forecasts for 2020 compared to other sources



9. Appendix A: Synapse Forecasts Compared to Utility Forecasts and Past Synapse Forecasts

Figure 9: Range of CO_2 price scenarios for utilities with \$0 reference cases (2014\$/short ton)



Note: Reference forecasts are presented in blue. All other sensitivities are in grey.

Figure 10: 2014 and 2015 utility reference case forecasts

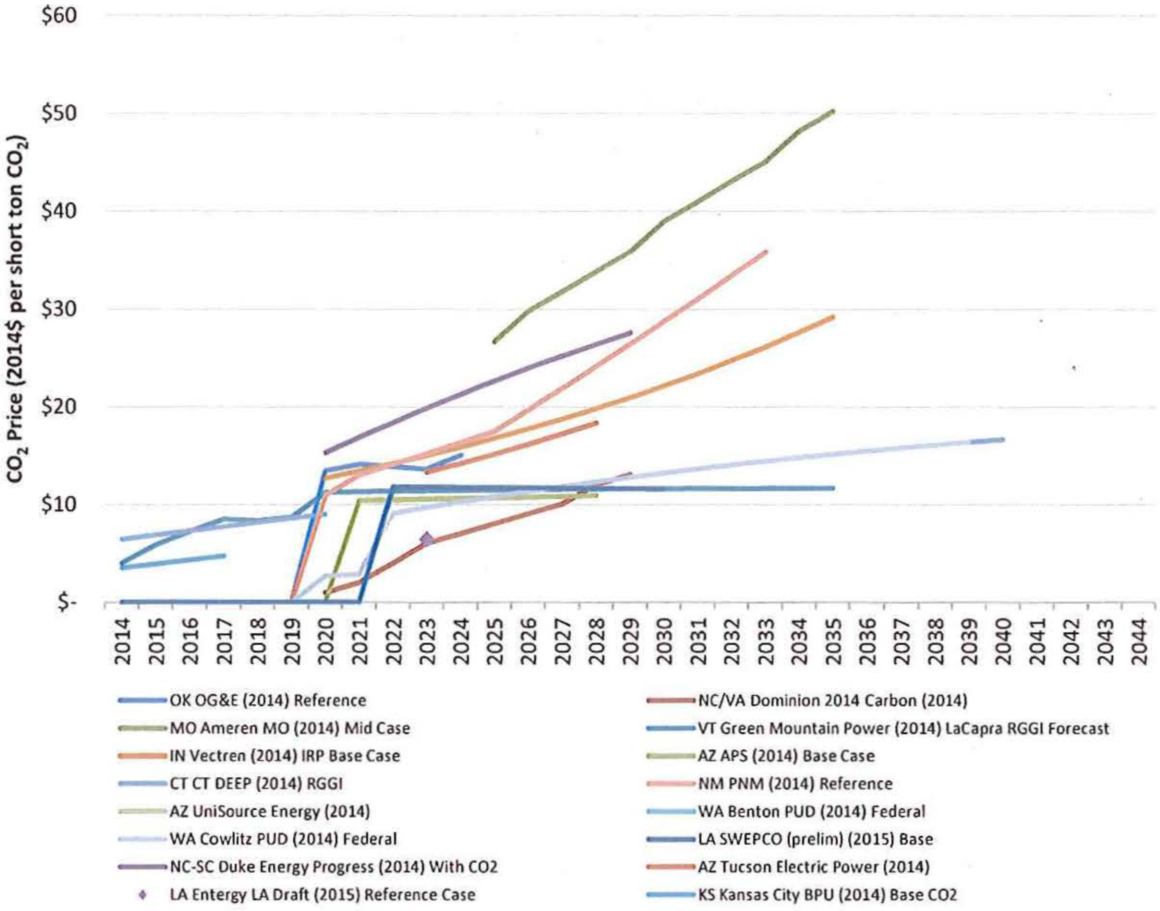


Figure 11: Comparison of 2013 and 2015 Synapse CO_2 price forecasts

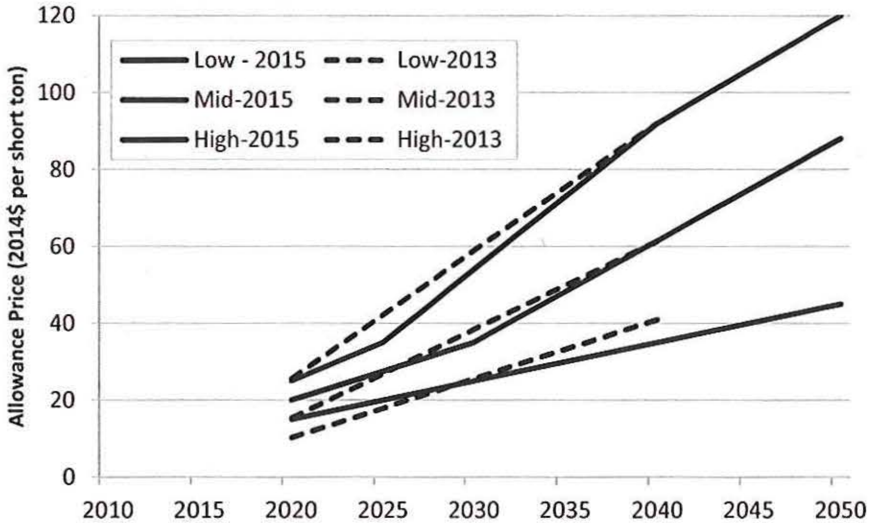


Figure 12: Synapse Mid case compared to federal CO_2 price for rulemakings (3% discount rate)

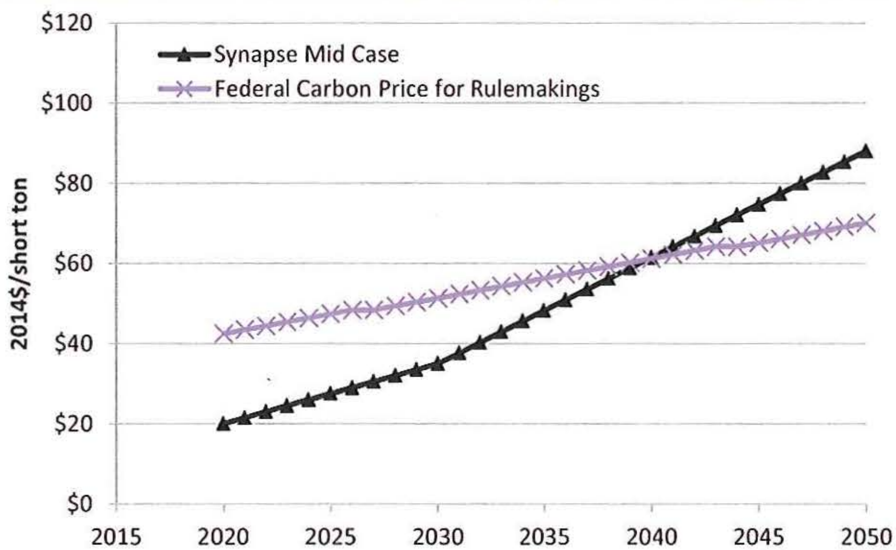
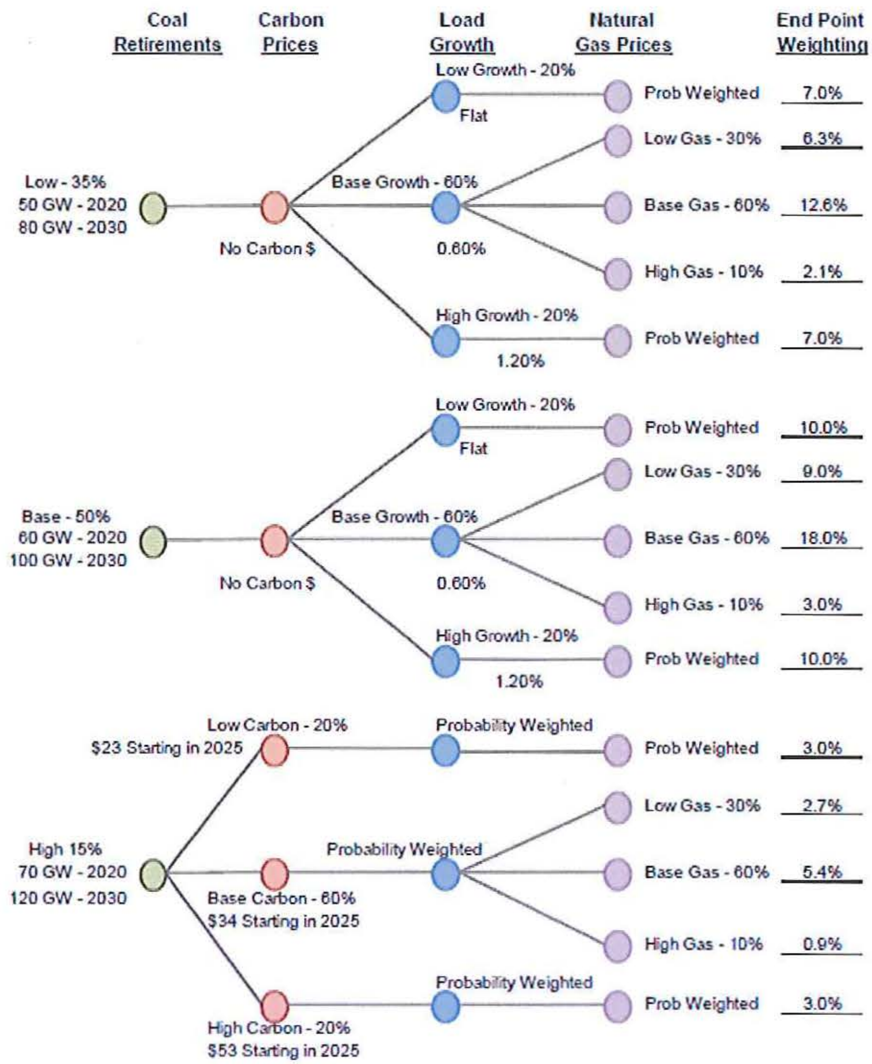


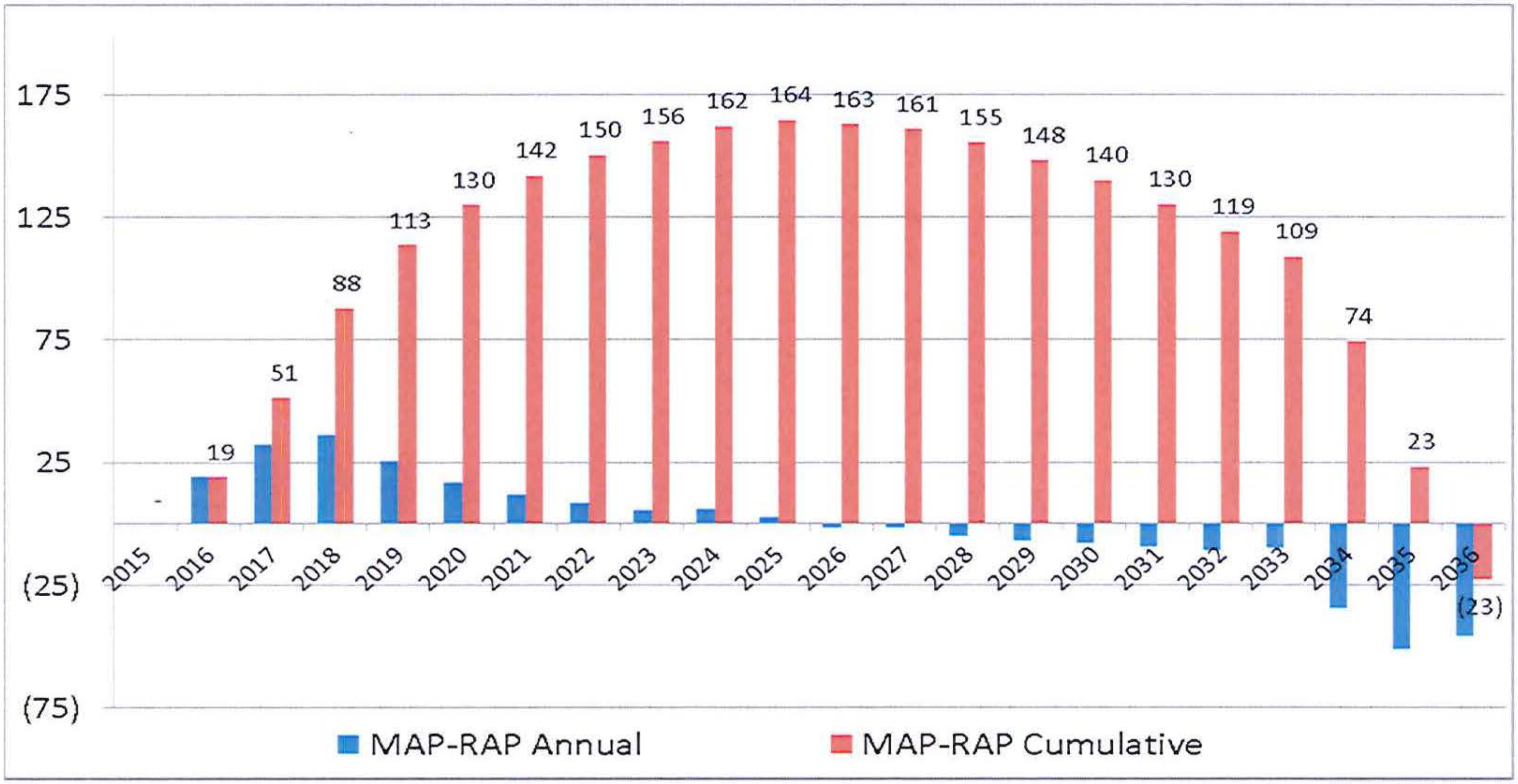
Figure 2.7 Final Scenario Tree



Electric Power Prices[10]

To support our analysis of alternative resource plans, as described in Chapter 9, we developed forward price forecasts at the Indy Hub using modeling software provided by Ventyx and commonly referred to as "Strategic Planning" or "MIDAS". This detailed simulation modeling software provides an economic dispatch production cost projection that utilizes load, fuel price, power production capabilities and many other assumptions

[10] 4 CSR 240-22.060(5)(G); 4 CSR 240-22.060(7)(C)1A; 4 CSR 240-22.060(7)(C)1B



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