SCHOOL OF PUBLIC AND ENVIRONMENTAL AFFAIRS

INDIANA UNIVERSITY

HOOSIER ENERGY

A Touchstone Energy® Cooperative

Assessment of Clean Power Plan Compliance Options for Hoosier Energy

SPEA V600 Capstone

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I. Executive Summary

In August of 2015, the EPA finalized the Clean Power Plan (CPP), which sets emission standards for existing power plants and customized goals for states to reduce carbon dioxide (CO_2) emissions. To comply with the CPP, Indiana must prepare a state plan that allows them to meet these emission requirements. A capstone team of 22 Masters students from the Indiana University School of Public and Environmental Affairs (SPEA), guided by SPEA professors Sanya Carley and John Rupp, created the following report for Hoosier Energy on options for complying with the CPP.

This report takes two interrelated approaches to advise Hoosier Energy on compliance with the CPP. The first approach involves a qualitative analysis, providing a clear conceptualization of policy, technical, and consumer considerations with regard to complying with the CPP. The second approach involves a quantitative analysis, in which we design a financial model to receive inputs from our policy and technical research. The outputs of this model inform two key recommendations for Hoosier Energy: the most cost-effective way to comply with the state plan Indiana is likely to adopt to meet the CPP, and which state plan is in the best interest of Hoosier Energy.

The qualitative approach looks at the problem from three perspectives and provides several key outcomes for Hoosier Energy. From a policy perspective, we identify eight important decisions Indiana will have to make that collectively form a **policy framework** and discuss the implications of each decision for Hoosier Energy. Based on this research, we describe the framework Indiana regulators are most likely to adopt as well as our hypothesis for the most preferable framework for Hoosier Energy. From a technical perspective, we identify and rank compliance options to reduce CO_2 emissions to a compliant level while minimizing costs. For each framework, these options are considered to form three **compliance plans**. Finally, from a public and consumer interest perspective, we examine primary considerations for Hoosier Energy with regard to importance to the general public and desirability to Hoosier Energy's consumers.

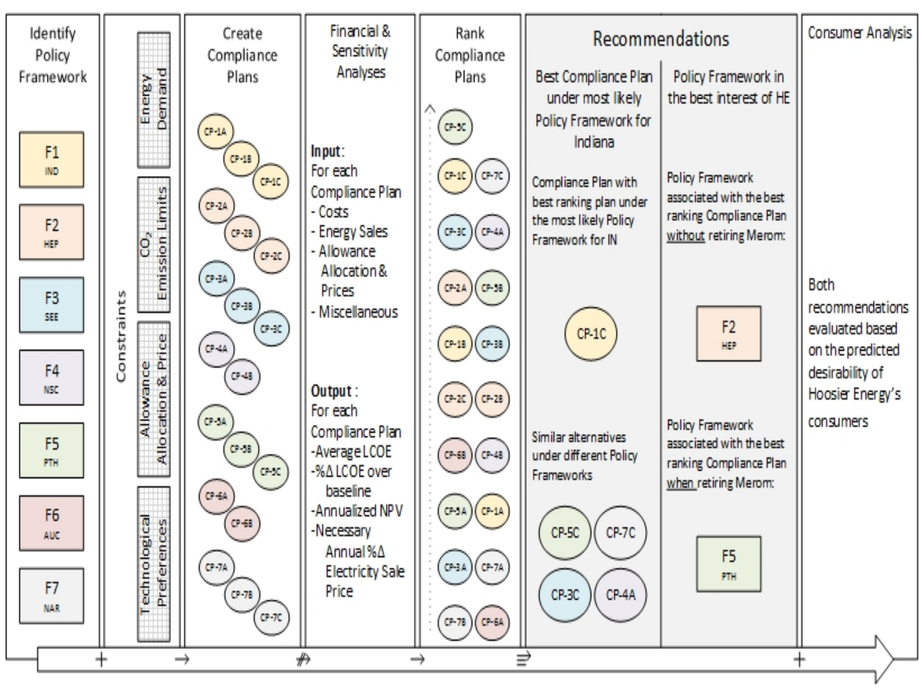


Figure 1-1. Summary of quantitative approach

The quantitative approach is summarized in Figure 1-1. The approach operationalizes information from the qualitative approach for use in a financial model. Financial viability of compliance options that meet the requirements of a state or federal plan is critical to Hoosier Energy's continued operation. We design a model to receive inputs including, but not limited to, allowance prices, energy demand, and changes to the generation portfolio. The model produces estimates of the net present value (NPV), levelized cost of electricity (LCOE), and other financial indicators for each compliance plan averaged over 30 years. Our financial analysis provides evidence to support our two fundamental recommendations for Hoosier Energy, although with greater levels of uncertainty than the risks associated with the qualitative approach.

Initially we identified a series of policy frameworks that are combinations of eight key decisions that Indiana must make in designing a state plan--including the option to default to a federal plan. Two key frameworks are identified in the qualitative approach--the most likely framework for Indiana and the framework that could be in Hoosier Energy's best interest--with five variations also considered. These frameworks are constrained by several factors including: energy demand, CO_2 emission limits, allowance allocation and prices, and Hoosier Energy's technology preferences. Taking these constraints into account, we created three compliance plans for each framework, with each plan representing a series of actions Hoosier Energy can take to reach compliance. Each compliance plan is processed through the financial model and the results are compared to a baseline scenario. Compliance plans are sorted and ranked according to their deviation from the baseline with the smallest change ranking the highest.

Based on the results of the quantitative analysis, we identified the best compliance plan for Hoosier Energy to adopt under the most likely policy framework for Indiana. This compliance plan performed well under almost all policy frameworks. Second, we recommend a set of policy frameworks that the financial model predicts to be in the best interest of Hoosier Energy. The highest-ranking policy framework involves keeping the Merom coal plant online; the second highest ranked state decision involves retiring it early and replacing it with a natural gas combined cycle (NGCC) plant. Finally, we analyze these recommendations through the lens of public interest and consumer desirability. The conclusions integrate the results of the qualitative and quantitative approaches.

Policy Analysis Outcomes

The initial step in outlining the policy frameworks involved identifying the critical decisions that state policymakers will need to make as they formulate a regulatory system. We assess each of these decisions relative to which outcome is most likely for Indiana, which appears to be most favorable for Hoosier Energy, and the significance of each decision for Hoosier Energy. We then use this analysis to construct two policy frameworks--the most likely framework to occur in Indiana (denoted IND) and the framework that is considered to be in the best interest of Hoosier Energy (denoted HEP).

Figure 1-2. Summary of Policy Decisions

Figure 1-2 provides an illustrative summary of the eight decisions discussed in this section. Each bubble represents a decision, with the size of the bubble representing the magnitude of the importance of the decision for Hoosier Energy. The arrow points toward which decision is more likely for Indiana; the angle of the arrow gives some degree of our confidence in each case. The color of the bubble indicates whether the decision that is more likely for Indiana is also favorable for Hoosier Energy. Red bubbles represent likely decisions to occur in Indiana that do not appear to be favorable for Hoosier Energy. Therefore, it is in Hoosier Energy's interest to consider more closely those policy decisions that are the most significant of these decisions (the largest bubbles). The financial analysis provides more insight into whether this qualitative policy analysis is properly represented, given a select set of assumptions.

Table 1-1 summarizes the two most important policy frameworks under consideration. Based on the results of the analysis, Indiana will likely adopt a trading-ready mass-based state plan, distributing allowances directly based on historical generation, and employing set-asides to address leakage. Indiana will most likely not adopt the New Source Complement (NSC), state measures, or a more rigorous statewide energy efficiency program. The analysis indicates that

Hoosier Energy stands to benefit from a preferential allocation of allowances, the use of the NSC rather than set-asides, and a statewide energy efficiency program. Hoosier Energy could benefit from a more preferential allocation of allowances if the state allocates a greater proportion of allowances to rural electric membership cooperatives, based on the additional costs associated with serving a highly distributed network of rural consumers.

Table 1-1. Comparison of IND and HEP

Decision	IND	HEP
State or federal	State	State
Mass or rate	Mass	Mass
Trading ready	Yes	Yes
Allocation method	Direct (historical)	Direct (preferential)
New Source Complement	No	Yes
Set asides	All three	None
State measures plan	No	No
Statewide energy efficiency program	No	Yes

Technical Analysis Outcomes

The comprehensive suite of technologies and processes that Hoosier Energy could feasibly employ under different policy frameworks is presented as compliance options. Certain options, such as constructing a nuclear or hydropower plant, are excluded due to their clear technical and economic infeasibility. The final menu includes ten compliance options: cofire the Merom plant with natural gas, repower Merom with natural gas, cofire Merom with biomass, improve the quality of coal used at Merom, improve thermal efficiency at Merom, convert the Worthington and Lawrence plants from simple cycle gas turbines to a combined cycle plant, improve transmission and distribution efficiencies, increase battery storage, increase solar energy generation, and increase wind energy generation.

Table 1-2. Compliance option categorization

Viability of Compliance Options for Hoosier Energy		
High	**Moderate**	**Low**
Thermal Efficiency Improvements at Merom	Repowering Merom With NG	Cofiring Merom with Biomass
Cofiring Merom with Natural Gas	Improving Coal Quality Through Washing	Increased Wind Energy Generation
	Converting Natural Gas Peaking Plants to Combined Cycle	Increased Solar Energy Generation
	Battery Storage	Distribution and Transmission Efficiency Improvements

Compliance options are analyzed relative to the specific needs, resources, and constraints of Hoosier Energy. The results of this analysis are used to score each option in six categories: technical maturity, capital cost, emission reduction potential, cost effectiveness of emission reductions, implementation constraints, and lead time to implementation. Compliance options are categorized by their viability for Hoosier Energy, as determined by the summation of their categorical scores (Table 1-2). High viability options are components in the compliance plans under all policy frameworks. Certain moderately viability options are included in some compliance plans under specific policy frameworks. Low viability options are not included in any compliance plans.

Optimizing power plant operations through **thermal efficiency improvements** is a cost effective way to reduce power plant emissions. A power plant that improves its thermal efficiency by 1-2% can expect to see a nearly equivalent 1-2% reduction in CO_2 as well (NACAA, 2015). Plant optimization projects can range from small increases in preventative maintenance to large system overhauls and equipment/control system upgrades. Power plants can achieve different potential efficiency gains depending on three factors: project feasibility, past optimization projects, and the capital cost of projects. Hoosier Energy has already invested a considerable amount of capital in optimizing operations at Merom. As such, the cooperative should not expect operators to reduce the heat rate at Merom by more than 2%. Based on data provided by Hoosier Energy, operators should be able to achieve a 2% heat increase in thermal efficiency at the Merom plant for an annual cost of $1,000,000.

One option to reduce the rate of CO_2 emissions from power generation is to **cofire coal with natural gas** simultaneously within Merom's existing boiler units, using any proportion of natural gas up to 100%. Cofiring preserves the option to change the proportion of the two fuels as needed due to interruptions in supply, fuel price changes, or other contingencies. Additionally, cofiring adds flexibility to unit operation, allowing it to operate more like a peaking power unit. Modifications can range from installing gas nozzles on the existing boiler to installing new natural gas burners. We include co-firing with natural gas in several modeled compliance plan analyses due to relatively low infrastructure modification requirements and capital costs, low projected future natural gas costs, and the potential for significant CO_2 emissions reductions.

Hoosier Energy can replace Merom's boilers with a higher efficiency NGCC system through several means. Option 1 is **building a new NGCC unit** on the Merom property or another property. Option 2 is replacing existing boiler units with new combustion turbines, heat recovery steam generators, and steam turbines to **repower the site as an NGCC plant** while reusing the plant's supporting infrastructure, including the cooling water and wastewater treatment systems, water supply, and switchyard. Option 3 is replacing the boiler units with combustion turbines and heat recovery steam generators to **make an NGCC unit while reusing the existing steam turbine and cooling system**. Some analysts do not recommend reconfiguring coal steam plants to create NGCC units with existing equipment, as the system might not run as efficiently as a new NGCC unit and savings may not outweigh project risks.

Capital costs for options 2 and 3 will vary greatly depending on many factors, such as whether reused components need to be refurbished. In some cases, they may even be as great as option 1 (building a new NGCC plant). Due to the uncertainty in how the costs would differ between options, we did not differentiate between them in this analysis; whenever we mention building a new NGCC plant, we assume that repowering Merom as an NGCC plant can be substituted instead. Regardless of the option Hoosier Energy chooses, using the Merom site for an NGCC unit avoids the need for acquiring and permitting a new plant site and acquiring right-of-way for and constructing new transmission infrastructure. Additionally, using the same site reduces the risk of negative transmission system balance impacts due to bringing a large generator offline.

NGCC implementation is included in several modeled compliance plan analyses, as the fuel and operations and maintenance (O&M) savings (compared to gas cofiring) and potential allowance sale revenues may outweigh the high upfront capital investment over the long run.

Demand side management is a cost-effective way to decrease generation needs and shift load through actions taken by end-users. Since Hoosier Energy recently hired an outside consultant to determine the feasible magnitude and price of energy savings, we do not further analyze these issues. It is assumed that Hoosier Energy will continue to pursue the energy savings programs at the costs specified in their Integrated Resource Plan.

The cofiring of Merom with biomass, improving the quality of coal used at Merom, converting the NGSC Worthington and Lawrence plants to NGCC, or acquiring more solar and wind generation are not included in any modeled compliance plans. While these options are both technically and economically feasible--and some may significantly curtail O&M costs or reduce emissions not covered by the CPP--they do not represent least-cost CPP compliance pathways. Options for compliance plans are selected with the single goal of providing Hoosier Energy the most cost-effective way to meet the CO_2 emission schedules stipulated under the various policy frameworks. Due to regulatory and resource supply uncertainties, logistical challenges, and the relatively small proportion of CO_2 emissions that would be offset, the aforementioned options do not achieve this goal. Additionally, upgrading transmission and distribution lines or investing in grid scale battery storage are not included due to the capital costs of implementation and long payback periods. A more detailed analysis of the potential benefits and challenges of these options is included in the full report.

Compliance plans were built based on the viability of the various compliance option. Inclusion in a given compliance plan is based on viability ranking (Table 1-2). The compliance plans can be broadly categorized as cofiring Merom with natural gas, replacing Merom with an NGCC plant, and continuing business as usual with no significant operational changes. The efficacy of these plans was tested alone and in conjunction with thermal efficiency improvements at Merom. The schedule for implementing cofiring and the proportion of gas that Hoosier Energy utilizes over time depends on a policy framework's applicable allowance limits. Implementation dates and gas proportion increases are delayed when possible in order to put off making major changes to Merom until the state decides legal and political issues, to transition away from coal gradually, and to allow time to resolve any operational or equipment changes needed to fire 100% gas. Electricity generation levels at Merom, Worthington and Lawrence, Holland, and Hoosier Energy's renewable assets are assumed to stay stable at IRP projected 2018 levels for 2019 – 2046 unless otherwise altered by an applied compliance option (such as taking Merom offline for a year for modifications). Detailed descriptions of the complete set of compliance plans are available in Appendix D of the full report

Financial Analysis

Based on the designated policy frameworks and corresponding compliance plans, a model was constructed to assess the financial impacts of compliance with the CPP. The model is used to analyze impacts for the baseline scenario and under each compliance plan. Specifically, the model assesses financial impact through 4 different outputs: the average LCOE ($/kWh), the percent increase in the average LCOE compared to the baseline, the net present value (NPV), and the average annual percentage increase in electricity sale price over a 30-year time horizon for each compliance plan. The LCOE estimates the sale price of electricity needed to recover costs of compliance, and the NPV represents the difference in revenue and costs for each compliance plan in 2014 dollars. Additionally, a Monte Carlo simulation tool was integrated into each compliance plan in order to account for uncertainty of key variables.

Considering the high stakes of compliance actions that Hoosier Energy ultimately chooses, it is important to have a clear understanding of the context of our recommendations. To compare this report's final recommendations to a "business as usual" approach ignores the gravity of the regulatory burden imposed by the CPP. To account for this, the model makes a number of assumptions and leans towards the most conservative estimates possible. A detailed list of all assumptions is available in Appendix B of the full report. The calculation of a negative NPV under the baseline forecast is an expression of that sense of caution. Overall, there are a few important takeaways independent of the final recommendations presented in this report:

- The policy framework we believe to be most likely for Indiana is a relatively good option for Hoosier Energy.
- We anticipate an increase in Hoosier Energy's LCOE of 22-46% depending on the policy framework adopted by Indiana and the compliance plan adopted by Hoosier Energy.
- Depending on the compliance plan, we anticipate that Hoosier Energy will need to increase the sale price of electricity by an average of 3.9-5.6% annually compared to the 1.4% under the baseline forecast.

Table 1-3 summarizes the financial outputs for compliance plans corresponding to the most likely policy framework for Indiana, with full details given in Table 9-2. Hoosier Energy can achieve compliance at least-cost by purchasing allowances. Given that this plan rests on highly uncertain assumptions, Hoosier Energy can reduce its risk by choosing compliance plan 1C, in which the cooperative retires Merom early in favor of building a new NGCC plant.

Table 1-3. Outputs of compliance plans for most likely framework for Indiana

Compliance Plan	Description	LCOE	LCOE %Δ over baseline
	baseline	0.087	
1A	cofire Merom with NG (to 100%)	0.119	37.8%
1B	purchase allowances	0.111	28.6%
1C*	NGCC	0.114	31.1%

*Value is an estimate corresponding to a late change in assumptions; see Section IX for more details

Table 1-4 summarizes lowest LCOE compliance plans across all frameworks--leaving out several more expensive plans--with full details in Table 9-4. The top compliance plans involve thermal efficiency improvements--which also entail large purchases of allowances--and taking no action other than to purchase allowances. The next best compliance plan (5C) involves building an NGCC plant, suggesting that Hoosier Energy should advocate for framework 5; this framework only differs from the most likely framework for Indiana by having Hoosier Energy receive a greater proportion of allowances through direct allocation.

If Hoosier Energy does not want to retire Merom, the next best option is compliance plan 2C. This plan entails thermal efficiency improvements and cofiring Merom with natural gas. This suggests that Hoosier Energy should advocate for framework 2: our original hypothesis for the framework in Hoosier Energy's best interest.

Table 1-4. Compliance plans ordered by LCOE

Compliance Plan	Description	LCOE	LCOE %Δ over baseline
	baseline	0.087	
4A	thermal efficiency + purchase allowances	0.111	27.5%
2A	thermal efficiency + purchase allowances	0.111	27.7%
5B	purchase allowances	0.111	27.7%
1B	purchase allowances	0.111	28.6%
3B	purchase allowances	0.112	29.3%
5C	NGCC	0.113*	30.5%
1C	NGCC	0.114*	31.3%
7C	NGCC	0.115*	32.3%
2C	thermal efficiency + cofire Merom with NG	0.115	32.9%
2B	cofire Merom with NG	0.117	34.5%
3C	NGCC	0.118*	36.3%

*Values are estimates corresponding to a late change in assumptions; see Section IX for more details

Recommendations

Based on the analysis of potential state plans, an assessment of the viability of various technical compliance options, and a financial evaluation of these technical options, we offer the following three recommendations:

1. Indiana is most likely to develop a mass-based, trading-ready state plan that allocates allowances directly based on historical generation, uses set-asides rather than the NSC, and does not use state measures or a statewide energy efficiency program. In this case, Hoosier Energy should follow **Compliance Plan 1C** (with an LCOE of $0.114/kWh) by building an NGCC plant, with construction beginning in 2021 and the plant coming online in 2024.

2. At an LCOE of $0.113/kWh, the most financially favorable plan for Hoosier Energy that avoids the risk of relying heavily on purchasing allowances is **Compliance Plan 5C**, which also involves constructing an NGCC plant. Hoosier Energy should advocate for **Framework 5**, which only differs from the most likely framework for Indiana by having the cooperative receive extra allowances beyond historical generation.

3. If Hoosier Energy chooses not to retire Merom, the cooperative can comply at least cost under **Framework 2**. In this case, Hoosier Energy should advocate for the plan most likely for Indiana, but with an allocation scheme that favors them as a rural electric membership cooperative, the NSC instead of set-asides, and a statewide energy efficiency program.]

In 2014, Hoosier Energy produced 6.4 million MWh of energy from coal at Merom, or about 88% of their net generation. Now Hoosier Energy faces a pivotal question about the operations of the company. The cooperative can continue to generate with coal and open itself up to uncertainty in the CPP's allowance market, or it can build an NGCC plant and face the uncertainty of fundamentally changing its generation strategy. Regardless of the results of the financial modeling, Hoosier Energy's decision ultimately comes down to a question of the strategic direction that the cooperative wishes to pursue and the associated risks that accompany such a direction.

It is important to note that the numbers used to determine the price of allowances in the market are inherently uncertain. The market does not yet exist so it is very possible that allowances will be much higher or lower in value than is shown in our model. By continuing to operate the Merom facility, Hoosier Energy opens itself up to this uncertainty, especially as the number of allowances in circulation shrinks over time. If Hoosier Energy builds a new NGCC plant, it can avoid the risk of allowance markets, but it will then be dependent on fluctuations in the natural gas market.

If Hoosier Energy wants to keep Merom operational and continue generating with coal, the best option under the most likely framework for Indiana is to take no action and purchase allowances. If the cooperative is comfortable moving away from coal but still wants to keep Merom operating, it may face lower risks by moving away from the allowance market and cofiring the facility with 100% natural gas. Hoosier Energy can reduce its costs by advocating for a framework with the NSC (framework 4) or for the framework we determined to be in the best interest of Hoosier Energy (framework 2). Under either of these plans, the cooperative can achieve least cost with thermal efficiency improvements and the purchase of allowances. Again, moving away from the purchase of allowances, framework 2 is best if Hoosier Energy chooses to cofire Merom with natural gas.

If Hoosier Energy is comfortable retiring Merom, the cooperative will face significantly reduced uncertainty by avoiding the allowance market, albeit possibly at a higher cost. Given the most likely framework for Indiana, Hoosier Energy should retire Merom and build an NGCC plant. Hoosier Energy can achieve this at a lower cost by advocating for framework 5, in which the cooperative receives a greater share of allowances through direct allocation.

Consumer Desirability Considerations

In an effort to assess the impacts that adoption of policy frameworks by the state and compliance plans by Hoosier Energy could potentially have on consumers and the general public, we evaluate their interests and priorities. This includes how consumers observe the impacts of CPP compliance and connects the potential concerns of consumers into key topic areas. Research indicates that consumers are most concerned with their electricity bills, the local economy, and the environment. Table 1-5 shows the complete ratings for the top three compliance plans based on the four primary categories of concern: cost of electricity, economic development, local environmental issues, and renewables & global climate change. The general importance ratings are a reflection of how the general public views these concerns. The consumer desirability ratings are a reflection of how Hoosier Energy's consumers will respond to intended changes. The total desirability scores are the sum of these individual ratings for each category. A comprehensive discussion of our ratings is found in Appendix G. We also discuss possible strategies for outreach with consumers to mitigate their concerns associated with CPP compliance.

Table 1-5 Consumer Desirability Conclusions

	Cost of Electricity	Economic Development	Local Environmental Issues	Renewables & Global Climate Change	Total Desirability
General Importance	3	3	2	1	
Recommendation 1 (1C)	2	1	1	2	6
Recommendation 2 without retiring Merom (2A)	1	3	3	1	8
Recommendation 2 with retiring Merom (5C)	3	1	1	2	7

The change in the cost of electricity, the amount of staff required to operate an NGCC plant, the effects on retiring Merom in regards to job loss, the environmental impact of constructing new gas pipelines, and the impact that the plan will have on greenhouse gas emissions was considered for compliance plan 1C. The results of the analysis for each category of compliance plan 1C was then compared to give a final rating for each of the four areas of concern. Based on that analysis, Compliance Plan 1C was given a total rating of 6.

For compliance plan 2A, two major factors that might affect Hoosier Energy's consumers upon implementation were considered: changes in the cost of electricity and the impact this compliance plan will have on greenhouse gas emissions. Based on that analysis, Compliance Plan 2A was given a total rating of 8.

For compliance plan 5C we consider a number of aspects that might affect Hoosier Energy's consumers upon implementation, including the change in the cost of electricity, the amount of staff required to operate an NGCC plant, the effects on retiring Merom in regards to job loss, the environmental impact of constructing new gas pipelines, and the impact the compliance plan will have on greenhouse gas emissions. Based on that analysis, Compliance Plan 5C was given a total rating of 7.

Based on this analysis, the most desirable compliance plan from a consumer's perspective is 2A. This is primarily a result of the economic and environmental benefits of keeping Merom operational. This prevents additional environmental damage from new plant construction, and minimizes the economic impact of job loss. The compliance plan with the lowest consumer desirability is 1C, and compliance plan 5C falls in between these two compliance plans. Compliance plan 1C results in a higher cost of electricity, which is less desirable for consumers. Only two points separates the most and least desirable compliance plan. This signals that these compliance plans, despite different areas of concerns, are not likely to raise significant concerns for consumers.

The most desirable compliance plan has the lowest desirability in terms of electricity cost, despite this being one of the most important concerns to the general public. In terms of economic development, another critical component, Hoosier Energy consumers will find this plan to be the most desirable. Because this compliance plan does not shut down Merom, there is likely to be fewer disruptions in employment, the operation portfolio, and business structure of Hoosier Energy. There appears to be trade off between economic development and the cost of electricity, the two most important public concerns.

The general public views local environmental issues as somewhat important, and the most desirable overall plan for consumers is also the most environmentally desirable. Overall, this plan will provide desirable economic and environmental impacts in line with what the public values. The category of least concern to the public is climate change and renewable energy. The most desirable compliance plan for Hoosier Energy's consumers is least desirable in this category, as it does not advance renewable energy production or significantly mitigate carbon production.

Conclusions

Taking the analysis of potential state plans, an assessment of the viability of various technical compliance options, a financial evaluation of these technical options, and assessment of consumer and public concerns into consideration, we offer the following conclusions:

1. If Indiana adopts the most likely state plan, **Framework 1**, Hoosier Energy should follow **Compliance Plan 1C** by building an NGCC plant, with construction beginning in 2021 and the plant coming online in 2024.
2. If Hoosier Energy wants to advocate for its most financially favorable state plan, **Framework 5**, then Hoosier Energy should follow **Compliance Plan 5C**, which also involves constructing an NGCC plant.
3. If Hoosier Energy chooses not to retire Merom, the cooperative can comply at least cost under and should advocate for **Framework 2**. In this case, Framework 2 is the plan most likely for Indiana, but with an allocation scheme that favors Hoosier Energy as a rural electric membership cooperative, the NSC instead of set-asides, and a statewide energy efficiency program. Notably, **Compliance Plan 2A** is the most desirable compliance plan from the consumer perspective as a result of the local economic benefits of keeping Merom operational and the local environmental benefits from not building additional infrastructure.

II. Introduction

The Clean Power Plan (CPP), finalized in 2015, is the Environmental Protection Agency's (EPA) carbon dioxide (CO_2) emissions reduction policy that sets emission standards for existing fossil fuel-based power plants. It contains specific goals for each state to cut their CO_2 emissions. States must now choose policy measures to create a plan to reduce CO_2 emissions in compliance with the specified emission requirements.

In an effort to assess both the state regulatory options as well as efforts that the state's power generators could potentially adopt to comply with the CPP, an evaluation was conducted by graduate students in Indiana University's School of Public and Environmental Affairs (SPEA). The evaluation was completed as a culmination (capstone course) to their Master of Public Affairs and Master of Science in Environmental Science degrees and was guided by SPEA Professors Sanya Carley and John Rupp. The client for the assessment is Hoosier Energy, an Indiana rural electric membership cooperative. The evaluation was designed to advise Hoosier Energy on the state plan most likely to be adopted by Indiana and to assess the actions Hoosier Energy can take to reach compliance. The results of this analysis can assist Hoosier Energy in their advocacy for appealing aspects of Indiana's state plan and to guide the cooperative towards their most effective compliance strategy under several potential state plans.

III. Background

A. Clean Power Plan Overview

The Supreme Court decision in *Massachusetts v. Environmental Protection Agency* (2007) established the legal framework for the EPA to regulate CO_2 emissions. In that decision, the Supreme Court sided with Massachusetts and 11 other states that sued the EPA for not regulating CO_2 under section 111 of the Clean Air Act (CAA). After a failed attempt at passing cap-and-trade legislation in 2009 and due to the results of the 2010 midterm elections, momentum for carbon regulation slowed. In a June 2013 speech given at Georgetown University, President Obama announced the Climate Action Plan that favored top-down emissions regulations. Regulators turned to a 9th U.S. Circuit Court of Appeals decision that concluded "the value of carbon emissions reduction is certainly not zero" (Martinez 2015). They then argued for organizing CO_2 regulations under section 111(d) of the CAA. Section 111(d) allows for the establishment of nationwide emission standards for major existing stationary sources of hazardous air pollutants.The result was the CPP, which was finalized on August 3, 2015.

In preparation for the 2015 U.N. Framework Convention on Climate Change (UNFCCC) meeting in Paris, the U.S. presented their Intended Nationally Determined Contribution (INDC) to emissions reduction. The U.S. INDC was to use the CPP to partially reduce overall carbon emissions by 28% from 2005 levels by 2025. The CPP, however, does not allow the U.S. to fully meet its commitment under the Paris agreement. In fact, there is still a gap of about one billion tons of emissions between the CPP reduction goals and U.S. commitment in Paris (Lehmann and Marshall 2015).

Based on an appeal by seven coal generation-dominated states, on February 9, 2016, the Supreme Court issued a stay on implementation until the D.C. Circuit Court rules on legal challenges to the CPP (EPA, 2015). The Circuit Court is scheduled to hear arguments on the case beginning on June 2, 2016, and will likely make a ruling in late summer or fall of 2016. Once the Circuit Court rules, legal challenges will then likely go to the Supreme Court. The death of Supreme Court Justice Antonin Scalia and political battle surrounding the nomination of his successor bring additional uncertainty to the legal future of the CPP. Despite the uncertainty, this analysis presents options for Hoosier Energy to consider for compliance with CPP regulations. We will conduct this analysis under the assumption that the CPP will not change in any significant way due to the stay, since we cannot say how the plan will be affected if it survives the challenge.

B. Terminology

The following definitions are not technical or legal terms. Instead, these definitions are unique terms that are used throughout this report. The appendix includes an exhaustive glossary of technical and legal terms and acronyms.

1. **Policy decision** - a choice a state must make in developing a state plan for the Clean Power Plan (e.g. choosing to design a state plan or defaulting to the federal plan; choosing a mass- or rate-based plan).
2. **Policy framework** - a possible state (or federal) plan for the Clean Power Plan; operationally, a potential combination of the eight identified policy decisions.
3. **Compliance option** - an action Hoosier Energy can take to move towards CPP compliance.
4. **Compliance plan** - a combination of compliance options to fit under a particular policy framework.
5. **Public Importance -** a rating of how important a particular concern is to the general public.
6. **Desirability -** a rating of how desirable a compliance plan is to Hoosier Energy's consumers based on their specific concerns.

IV. Objectives and Approach

A. Objectives

The goal of this report is to find the least costly way for Hoosier Energy to comply with the state plan deemed to be most likely for the Indiana, and to provide advice on the policy framework most advantageous to Hoosier Energy. To do this, the report will provide a clear conceptualization of the CPP and how different state plans will affect the costs and methods for compliance. This report will also rank technical options available for compliance and provide a list of considerations with regard to public, consumer, and member interests. This qualitative analysis will provide the basis for a quantitative evaluation of compliance options. We develop a financial model to be used for this quantitative analysis and in the ranking of potential compliance plans within each framework by cost-effectiveness. The final recommendations can be used by Hoosier Energy to design a least-cost compliance plan under the framework which we have determined to be the most likely for Indiana. Additionally, these recommendations may be used to potentially influence the state's decisions as it formulates its actual policy framework for CPP compliance. Finally, the appendix provides all assumptions, tables, and other considerations used to determine the characteristics of the compliance plans.

B. Approach

The complexity and magnitude of the problem justifies using two interrelated approaches to ensure that we deliver the maximum benefit and insight to Hoosier Energy. Our first approach is qualitative, aiming to give Hoosier Energy a better conceptualization of the implications of different policy frameworks, available technical options that could be used to reach compliance, and consumer and public interests which should be considered and addressed before moving forward with a compliance plan. Our second approach is more quantitative, operationalizing the results in the first approach to enter into a financial model we developed for this purpose; these outputs have greater uncertainty associated with them, but they help inform the relative costs of different compliance plans under different policy frameworks. The results of both approaches are then used to justify a list of recommendations regarding least-cost compliance plans under different policy frameworks and important issues on which to focus advocacy efforts.

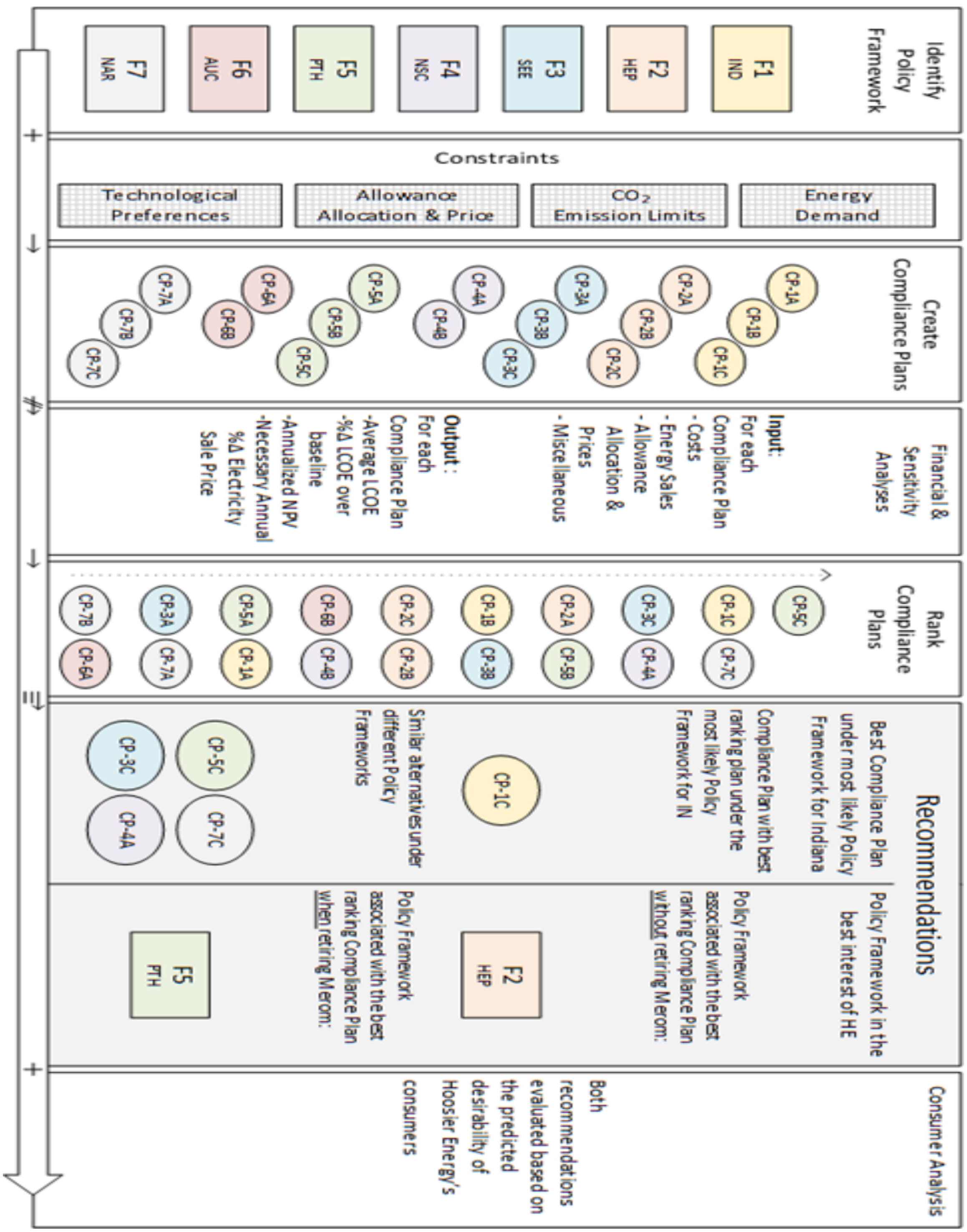
Section V begins our qualitative approach with a policy analysis. In this section, we focus on the different policy decisions that go into designing a policy framework--defined here as a possible state or federal plan to comply with the CPP. We specifically identify eight important decisions states will have to make to design a framework, and present research on the implications of these decisions on utilities' costs of compliance. For each decision, we then estimate which is more likely to be chosen in Indiana's policy framework, which appears to be preferable for Hoosier Energy, and how significant this decision is with regard to Hoosier Energy's compliance costs. We continue this analysis by creating frameworks for what we think is most likely for Indiana and what we think would be in the best interest of Hoosier Energy. We conclude with a list of important insights and a summary of our findings. We use this analysis later to inform the policy frameworks under which we test compliance plans in our financial model, as well as to determine how differences in these frameworks translate to changes in constraints and other important variables.

Section VI continues our qualitative approach, focusing on an analysis of the different options available to Hoosier Energy in working toward compliance with the CPP. We begin by conducting research using National Association of Clean Air Agencies (NACAA) and EPA technical documents, devising a list of potential compliance options. We refine our list through discussions with Hoosier Energy, trimming options that the cooperative does not think are appropriate for its situation. We use data about Hoosier Energy's generation portfolio to frame the list of compliance options in the context of the cooperative. We then examine consultant reports and case studies of compliance option implementation at similar facilities to better understand important challenges and ways in which they can be addressed. Using the above research, additional information from Hoosier Energy, and EPA's Integrated Planning Model documentation, we develop a final list and ranking of compliance options with a goal of reducing CO_2 emissions to a compliant level while minimizing costs. We note that our analysis is not limited to technical changes but also includes other options, such as purchasing allowances or power purchase agreements. We also investigate options that may not be advantageous to select with today's economy, technology, and policies but may become more attractive in the future. We later use our ranking system to choose options and develop compliance plans for use in the financial model.

Section VII concludes our qualitative approach, focusing on developing a list of important considerations for Hoosier Energy with regard to public and consumer interests. In our approach, we review concerns regarding four general topic areas (community and education, environment, economic development, and service delivery) from the perspective of the general public as well as Hoosier Energy's consumers. We then use this analysis to determine the four primary concerns of both the general public and Hoosier Energy's consumers. Finally, using information gathered via case studies, research, and consumer surveys, we rate the four concerns in regard to importance to the general public and desirability to Hoosier Energy's consumers. We later use these considerations to offer insights regarding the consumer desirability of the compliance plans we recommend in our financial analysis.

Section VIII begins our quantitative approach, focusing on the design of our financial model and how we incorporated information from our qualitative sections. Figure 1 below summarizes each stage of this approach, as well as Section IX (the financial model) and Section X (our recommendations and conclusions).

Figure 4-1. Summary of quantitative approach



Section VIII first details how the first two panels of Figure 1 incorporate information from the policy analysis of Section V. We identify seven policy frameworks that allow us to explore the implications for compliance when toggling different key policy decisions, working from two important baselines--our estimates of the most likely framework for Indiana and the framework that is in the best interest of Hoosier Energy. Each of these frameworks ultimately act as imposing constraints on the actions--or the costs of such actions--that Hoosier Energy may take to comply with the CPP. These constraints are represented in the second panel of Figure 1. For example, the price of allowances that Hoosier Energy receives will change depending on whether Indiana's policy framework allows for trading with other states. The numbers of allowances and the overall energy demand - as well as other considerations such as uncertainty - also differ between frameworks.

Next, section VIII describes the third panel of Figure 1, where we combine the more viable compliance options from the technical analysis of Section VI to develop compliance plans that Hoosier Energy could implement under each of the policy frameworks and their corresponding constraints. We evaluate two to three compliance plans for each policy framework in order to add robustness to the analysis and account for uncertainty.

Section VIII then discusses the fourth pane of Figure 1, detailing how we develop our financial model and listing some important assumptions. We design our financial model to accept costs, energy sales, allowance allocations, allowance prices, and other key inputs corresponding to a given policy framework and compliance plan. The model then gives the resulting average LCOE, percent of the LCOE over the baseline, annualized NPV, and annual percent change in electricity sale price. In this section, we also lay out how panels 5, 6, and 7 will be used to rank compliance plans and offer recommendations to Hoosier Energy.

Finally, Section VIII includes a discussion of the eighth and final panel of Figure 1, which subjects the final recommendations to a consumer analysis using research from Section VII. In particular, we look at our recommended compliance plans through a consumer desirability lens--including impact on economic development and local environmental concerns--to offer additional insights.

Section IX looks at the output of our financial model. As shown in the fifth panel of Figure 1, we rank compliance plans in order of their cost effectiveness as expressed by their financial indicators. We then make determinations of the best compliance plan under the framework most likely for Indiana, as well as the best compliance plans under other frameworks.

Section X uses the information from Section IX to make two recommendations to Hoosier Energy, shown in the sixth and seventh panels of Figure 1. The first recommendation identifies what we believe is the most cost-effective compliance plan under the most likely policy framework for Indiana. The second recommendation identifies the policy frameworks that we think are in the best interest of Hoosier Energy. Hoosier Energy should take these frameworks into account when lobbying the design of Indiana's policy framework to move towards a more favorable regulatory environment. Recognizing the significance of potentially ceasing operation of the Merom plant, we identify ideal policy frameworks under two scenarios: one in which Merom remains operating throughout its useful life, and another in which Merom is retired early. In both scenarios, we recommend least-cost compliance plans to Hoosier Energy. We discuss these recommendations in greater detail in Section X, which includes subjecting the recommendations to a consumer desirability analysis as shown in the eighth panel of Figure 1. We also give conclusions that tie together the results from our qualitative and quantitative analyses.

V. Policy Analysis

A. Policy Options and Decisions

A.1 Introduction

To determine the frameworks under which Hoosier Energy may need to comply, we first identify a non-exhaustive list of important decisions that regulators will make when designing Indiana's state plan. We then research the advantages and disadvantages of each decision and the ways each decision could affect the methods utilities use to reach compliance. Finally, we construct a set of policy frameworks--each consisting of a set of choices for each of the decisions-- for Hoosier Energy to consider. The following sections of this report demonstrate how Hoosier Energy's compliance plans and compliance costs may change under different frameworks.

A.2. Decision Analysis

We identify eight decisions as especially important in the design of a state plan, which are listed below. Each subsection offers background information on the decision and discusses why one decision might be preferred to another, which decision is most likely for Indiana, which decision is favorable for Hoosier Energy, and the significance of the decision for Hoosier Energy. This analysis is based on information from the EPA, regulatory bodies in Indiana, Hoosier Energy, and previous studies from consulting firms and academic institutions. The hypothesis of which decision would be best for Hoosier Energy is based on our best judgment and is validated or refuted by the cost analysis of each compliance plan.

The eight decisions are as follows:

- Will Indiana design a state plan, or will it default to the federal plan?
- Will Indiana opt for a rate- or mass-based plan?
- Will Indiana submit their plan as trading-ready?
- Under a mass-based plan, will Indiana distribute allowances directly, as part of an auction, or through a hybrid of these methods?
- Will Indiana use the New Source Complement?
- Will Indiana use set-asides?
- Will Indiana use a state measures plan?
- Will Indiana adopt a statewide energy efficiency program?

It is important to note that these decisions are not independent of each other. For example, if Indiana chooses a federal plan over a state plan, then the remaining seven decisions default to what they would be under the federal plan. As another example, if Indiana opts for a rate-based plan instead of a mass-based plan, then questions regarding allocation methods and set-asides are no longer applicable.

The following subsections describe these decisions in great detail. The subsequent section uses this analysis to construct potential frameworks under which Hoosier Energy might have to comply.

Decision 1: State plan or federal plan

States are encouraged to develop their own state plans to demonstrate how they will comply with the CPP. In developing a state plan, states have control over many details (e.g. the other seven decisions considered in this report) and can design their plan to minimize costs given their unique situations. States must submit their plans by September 6, 2016 or apply for an extension. However, the stay on the CPP nullifies this original date--should the CPP hold up in court, the EPA will likely set a new regulatory timeline as it has with past regulations, and this date will be pushed back. If states miss the deadline and do not receive an extension, then the EPA will impose the federal plan on them to ensure compliance.

The EPA has developed proposed federal plans for rate-based and mass-based schemes, but will ultimately only select one scheme for its final federal plan. The proposed mass-based federal plan is trading-ready with direct allocation of allowances based on historical generation from 2010-2012. It uses set-asides to address leakage rather than the NSC, and it does not employ a state measures plan or statewide energy efficiency program (EPA, 2015b). If the EPA imposes the federal plan on a state, the state can regain control in several ways--it can submit a state plan that, if approved, would allow it to supercede the federal plan, it can take control of implementing certain aspects of the federal plan, or it can develop complementary policies to reduce compliance costs. Regardless, it will almost certainly be more efficient for a state to propose a state plan rather than default to the less flexible federal plan for any amount of time.

Along with proposed federal plans, the EPA also laid out model rules for the states--if a state adopts a plan based on the model rule, it will automatically be considered trading-ready and will not have to coordinate with every other trading-ready state in order to facilitate trade. However, states can still differ from the model rule and submit as trading-ready without limiting their access to the market. The model rule should be seen as the default scenario for all states planning on submitting a state plan--they should only stray from the model rule when it makes sense to do so under their unique situations. It is in the best interest of all states to develop their state plans to address their particular situations, including deciding how to allocate allowances, which rate-based scheme to adopt, and whether to opt into the set-aside program. Despite the rhetoric of many state governors, states will most likely develop their own plans if the CPP is upheld and they will be required to comply, as doing so will grant them more flexibility and control (Harbell, 2016).

Indiana's decision to either create a state plan or adopt the federal plan is important to Hoosier Energy because it influences the cooperative's ability to advocate for certain policies. Hoosier Energy could lobby IDEM and other stakeholders to make a state plan that is more favorable to its situation. Under a federal plan, Hoosier Energy would have limited influence over the plan's implementation. Because of the significant, likely negative, impact of a federal plan, Indiana will most likely opt to submit a more favorable state plan. Hoosier Energy should assume that Indiana will develop its own state plan when considering compliance options, understanding that costs could be higher under a federal plan.

Decision 2: Mass- or rate-based plan

The fundamental decision states will have to make in developing a state plan is whether to adopt a rate- or mass-based trading scheme. Rate-based trading schemes set emissions rate limits for each EGU and allow EGUs that outperform their limits to generate and sell emission rate credits (ERCs) to EGUs that fall short of their limits. Mass-based trading schemes set total emission limits for entire states and allow states to allocate allowances to EGUs, trading between themselves as necessary to stay within compliance. These schemes will be described in more detail below, followed by reasons a state may prefer one to the other, which Indiana is more likely to select, and which Hoosier Energy would prefer.

Rate-based trading schemes set a limit on CO_2 emissions in pounds of carbon dioxide emitted per megawatt-hour (MWh). Three types of rate-based plans are available to states. The first option (R1) is to follow the model rule, which sets a uniform emissions rate for all EGUs within every state--one rate for coal plants and one rate for natural gas plants. The second option (R2) is to create a state plan that sets a uniform, state-specific rate for all EGUs within the state. The final option (R3) is to create a state plan that sets different rates for all EGUs within the state (Knight, 2015). All state plans have the option of implementing "emissions standards," which are federally enforceable and only apply to EGUs, or to implement "state measures," which allow states to regulate EGUs, a mixture of EGUs and other entities, or just other entities in a way that leads to reductions in carbon emissions from EGUs (EPA, n.d.). Under the state measures plan, only regulations on EGUs are federally enforceable, and so any mixture of regulated entities requires a backstop of federally enforceable standards for EGUs should the mixture fail to meet the emissions reduction plan (EPA, n.d.).

Rate-based trading schemes introduce the concept of ERCs--which represent one MWh of emission-free generation--to offer more flexibility and reduced costs. ERCs are generated by zero-emissions facilities and EGUs that emit below the set rate; they are then traded to other EGUs emitting above their set rate and can be applied to lower their emission rate to move them toward compliance (Prescoe, 2015). ERC trading differs in flexibility between the three rate-based schemes, however, since ERCs are ultimately defined by each state's average emissions rate. R1 states can trade ERCs freely amongst each other, R2 states must set up agreements between each other to ensure their state average emissions rates are the same and then submit joint state plans, and R3 states are limited to selective intrastate trading.

This format of trading under a rate-based plan is less familiar to states, as this scheme is untested, and the capacity for intra- and interstate trading may be reduced by differences in types of rate-based plans and definitions of ERCs. These differences can contribute significant administrative costs and limit the appeal of a rate-based plan. On the other hand, a rate-based plan may benefit states anticipating high economic development, as these rate-based measures pay no attention to the magnitude of CO_2 emitted. In other words, an EGU emitting at a rate below its limit can increase its generation without penalty, assuming this increase in generation does not increase the rate at which it emits CO_2.

A mass-based plan sets a cap on total CO_2 emissions from a state, and this cap remains the same regardless of whether a federal or state plan is adopted. The state then receives allowances corresponding to this cap, where an allowance represents one short ton of CO_2. States can choose how they wish to allocate allowances to EGUs--for example, by allocating allowances to EGUs directly, having EGUs bid for them in an auction, or implementing both options to some degree in a hybrid method. Allowances for a mass-based plan are more fungible than ERCs in a rate-based plan; they represent the same thing in every situation and can be traded freely within and between states if the involved states submit their plans as trading-ready. Mass-based plans are also relatively similar to other carbon and air pollutant markets. Agencies and EGUs are therefore familiar with this style of regulation, removing some uncertainty, confusion, and administrative costs.

A mass-based plan must address concerns about leakage, which occurs when EGUs find ways to comply with the plan without necessarily curbing emissions (Weiskopf, 2014). For example, leakage occurs when existing power plants reduce generation while new fossil fuel plants, which are subject to 1.11(b) rather than the CPP, increase generation. To address leakage, EPA recommends that a state adopt one of the following: (1) use of the NSC (discussed as a separate decision), (2) an allocation plan that reduces the risk of leakage (e.g., allocating credits to coal plants that choose to retire or to new renewable energy projects), or 3) a demonstration that the state does not face leakage threats due to its unique conditions. The mass-based rule also includes three allowance set-aside programs (also discussed as a separate decision) that can be used to address leakage: (1) the Clean Energy Incentive Program, (2) an output-based set-aside for natural gas combined cycle (NGCC) plants that increase generation from a baseline, and 3) a set-aside encouraging new renewable energy development (Jackson & Knight, 2015).

A mass-based plan may be preferable for states planning to retire coal plants (Anderson, 2015). Retired plants may receive allowances even after going offline, and if new sources come online to replace the lost generation, they will not be covered by the CPP if the state plan does not include the New Source Complement. Mass-based plans are also more familiar to state agencies and generators, and allowances are more easily tradable and should give states access to a larger market. High economic growth would present challenges, however, as the allowance limit remains the same regardless of changes in the demand for electricity.

Energy efficiency works differently in mass- and rate-based plans, but its use may actually be less expensive in a mass-based plan. Fundamentally, energy efficiency projects reduce electricity demand, thereby requiring generators to run less often. Under a mass-based plan, this means generators need fewer allowances to remain in compliance. Under a rate-based plan however, energy efficiency projects require evaluation, measurement, and verification steps to generate ERCs--a process which could prove to be costly (Knight, 2015; ASE, n.d.).

Paul Sotkiewicz of PJM Interconnection suggests that states with a high dependence on coal will prefer mass-based plans (Anderson, 2015). Other states struggling to decide between the two plans may opt for mass-based plans strictly to have access to a larger trading market. Even in southeastern states--in which planned new nuclear plants may make rate-based plans more favorable--regulators may opt for mass-based plans in order to gain access to a larger trading network (Tomich, 2015). Cost-effective trading requires a certain number of market participants, so states that choose plans against the majority may be disadvantaged.

Pam Kiely, of the Environmental Defense Fund, maintains that economic development will still be feasible under a mass-based plan; utilities have historically been able to meet increasing demand while reducing air emissions, and this should remain true for reducing CO_2 emissions (Tomich, 2015). This downplays one of the main listed advantages of a rate-based plan, and if state regulators agree, they will be even more likely to choose a mass-based plan. Finally, state regulators also express a preference for the simplicity and familiarity of mass-based plans; generators and regulators have already managed under similar regulations and would prefer to not switch to a more complicated system.

Indiana reflects many of these sentiments and will most likely choose a mass-based plan because it is more well-known, permits trading with a larger market, and is presumably more cost-effective than the alternative. Indiana and other states are already familiar with mass-based plans through the context of sulfur dioxide regulations. As a result, mass-based CO_2 standards would be easier to implement. Indiana may also favor a mass-based plan because it is more likely to provide an effective trading regime. In their comments on the Proposed Federal Plan, IDEM argues that more states are likely to select mass-based plans and that following suit would create a larger and more successful trading market (IDEM, 2016). Given that Indiana sources 85% of its electricity from coal and plans to retire about 5% of 2012 emissions from affected EGUs ("Indiana State Profile," n.d.; Maassel, 2016), Indiana will want to trade because it will have more carbon to reduce than other states (Anderson, 2015). Finally, Indiana is most likely to choose a mass-based plan because it is expected to be more cost-effective, which is the state's primary concern. In their comments on the Proposed Federal Plan, IDEM states that, "[f]rom an administrative perspective, a mass-based plan is … less resource intensive on states [and] US EPA to administer because aspects that would need to be in place under a rate-based plan, like an emissions rate credit (ERC) desk, wouldn't be necessary" (IDEM, 2016).

A mass-based plan will also benefit Hoosier Energy. It is not likely that the large Merom plant will achieve an assigned rate-based goal. As a result, the cooperative will need to rely heavily on the open market, and a mass-based plan, with its larger market, would likely be best. Depending on the market price difference between ERCs and allowances, this decision has the potential to be very important for Hoosier Energy's ability to comply in a cost-effective manner.

Decision 3: Trading-ready plan?

Under a trading-ready plan, EGUs can freely trade allowances or ERCs within and between states without requiring a joint plan (Monast & Adair, 2015). To be considered trading-ready, a state must use a mass-based plan or the subcategorized rate-based plan (R1), submit the state plan as trading-ready to the EPA, and use a common tracking system such as the EPA's Allowance Tracking and Compliance System (ATCS) (Monast & Adair, 2015). Thus, any mass-based plan can submit as trading-ready, whereas only one of the three rate-based plans can do so. The ability to trade between states is generally preferable, since the state would have access to a larger market and thus lower prices. In fact, in an analysis of nine southeastern states, costs of compliance are found to be 30% higher when states did not engage in interstate trade ("Research improves state-level," n.d.).

Many states around Indiana are also likely to choose a mass-based plan because they have a heavy reliance on coal, making a mass-based plan more advantageous. Illinois is one neighbor likely to choose a trading ready mass-based plan (PJM, 2015). Illinois has an aggressive renewable portfolio standard (RPS) designed to make renewables 25% of electricity production by 2025, and has established a lot of funding for home solar systems (PJM, 2015). Given the current and expected future state of renewables in the state, it is expected that Illinois might be able to sell allowances to other states like Indiana.

The Midcontinent Independent Service Operator (MISO) will be an important part of this process. MISO covers at least part of 15 states, each with different portfolios and energy needs. A lot of this area is heavily vertically integrated, which necessitates a lot of coordination between these states (Tierney et al., 2015). There is a lot of infrastructure within MISO to facilitate this coordination. Because states have different energy portfolios and thus different targets under the CPP, coordination will be a challenge. MISO states use more coal on average, but natural gas prices are incentivising investments in natural gas and renewables, such as wind (Tierney et al., 2015).

Based on comments made to the EPA, The Regional Greenhouse Gas Initiative (RGGI) states generally seem willing to let other states join, but are concerned about this affecting the market for allowances (Silverman, 2015). It is unlikely that other states will try to join RGGI due to political reasons and the fact that the CPP allows for trading-ready plans that do not require states to formally join and work out the details of joining a group like RGGI. It is likely states will become trading ready and figure out the details of potential trading agreements with the states around them. Indiana will almost certainly submit as trading-ready in order to gain access to a larger market of allowances. Likewise, Hoosier Energy will benefit from a trading-ready plan and a regional trading system, particularly with Illinois, because credits from the Holland plant might be used internally for emissions from the Merom plant. This decision has a very large impact on Hoosier Energy due to its impact on allowance prices in the open market.

Decision 4: Mass-based allowance allocation method

Under a mass-based plan, the EPA has set a cap on CO_2 emissions in each compliance period for every state. These emissions limits for each compliance period are equivalent to the total number of allowances that will be distributed to all EGUs within a state. It is up to the state to decide how it will allocate allowances to EGUs, and this decision can produce vastly different outcomes for Hoosier Energy. It is important to note that these are simply *initial* allocation schemes. If a state is trading-ready, there will be secondary allowance trading markets between EGUs both within-state and with other states that also adopt a trading-ready mass-based plan. These secondary markets are out of the scope of initial allowance distribution, as well a even more uncertain, and are therefore are not discussed here.

There are three likely methods for the allocation of allowances. The first is direct, or free, allocation. In its support documents, EPA proposes using direct allocation in order to resolve equity issues that may arise with a market-based auction approach. Direct allocation would be based on average historical generation from 2010-2012. The EPA chose these years because they represent the most recently available comprehensive data set on EGUs from the Emissions & Generation Resource Integrated Database (eGRID), released on October 8, 2015, and the use of several years serves to adjust for any anomalies in generation in any particular year.. Under this allocation methodology, the generation (in MWh) by each EGU will be compared to the state total electric generation to determine what percent of the state's total generation portfolio each unit makes up. Each EGU will receive a proportional amount of allowances to this historical generation, after set-asides have been taken out of the pool of allowances (should set-aside programs be used in the state plan). The Acid Rain Program of the 1990's distributed allowances via direct allocation based on rates of SO_2 emissions from affected units (EPA n.d.b).

The second allocation method is to distribute allowances via an auction. An auction would simply open the market up to EGUs to purchase allowances once set-asides have been made. The Regional Greenhouse Gas Initiative (RGGI) coalition currently uses this approach for allowance allocation (RGGI n.d.a).

A likely third allocation method might be a hybrid approach combining both direct allocation and an auction. California's cap-and-trade program, California AB-32 Global Warming Solutions Act of 2006, as well as the European Union Emissions Trading System (EU ETS) utilize this approach (California Air Resources Board 2016a, European Commission 2016a). For the CPP, this method could help ensure equity since smaller generators or rural cooperatives would likely struggle in a competitive market with other for-profit, large utilities. The nature of how this type of allocation process would roll out, however, is purely speculative. It is up to state regulators to decide what proportion of the total allowances should be auctioned or directly allocated, as well as which EGUs would receive the direct allocations.

Evaluating the auction-clearing prices of current cap-and-trade programs that employ a full or partial auction, such as RGGI and California's AB-32, and the EU ETS, provides a sense of the magnitude of allowance prices that could arise in the CPP. Consulting firms and Independent Systems Operators, such as PJM, have also performed economic analyses of allowance prices. This information is used to inform allowance prices in our financial analysis and this methodology is described explicitly in section C of the Appendix of this report.

Direct allocation provides regulated entities with a form of compensation. Giving EGUs allowances that they can then sell or trade with an associated value can decrease compliance costs. In reference to the California cap-and-trade program, the Economic and Allocation Advisory Committee (EAAC) of the California Environmental Protection Agency writes in its allocation report that "for firms with exceptionally limited cash reserves or ability to borrow in order to finance the purchase of auctioned allowances, receiving free allowances is much more attractive than receiving auction proceeds after having to purchase allowances" (EAAC, 2010). Thus, it seems likely that Hoosier Energy, a member-owned cooperative, would be best situated under this allocation scheme.

The most discussed advantage of an auction is realizing that there is an opportunity cost to direct allocation. If the regulating entity can price allowances and generate revenue, then by definition, freely allocating them represents a loss in revenue to the state. The ability to utilize auction revenues, especially if they are put towards demand suppression and energy efficiency, is an attractive prospect. Indiana could benefit significantly from generating auction revenues and putting them towards compliance with the CPP. In addition, revenues would likely be put towards demand-side energy efficiency to support ratepayers and limit the economic impact on customers. If this decision was made and revenues from auctions went to benefitting low-income families, then Hoosier Energy may be better off as a REMC.

It is hard to say which allocation scheme would be chosen by Indiana. On one hand, a heavy reliance on coal power means that compliance costs will be high for all EGUs. Thus, direct allocation would provide free compensation and perhaps lessen the burden on generators. On the other hand, an auction would raise significant revenue, and depending on how the state choose to spend this revenue, compliance costs could be just as low as with direct allocation. EPA encourages states to put auction revenues towards compliance by means of energy efficiency to decrease consumption, and thereby decrease generation and emissions overall. Another way revenues could be spent is compensating small generators and rural cooperatives, who will likely see the worst of compliance burdens.

It is important to note that Duke Energy, the largest utility in the state of Indiana, is pushing for direct allocation in its service territory states. This past January, in a panel discussion on allowance allocation methodologies organized by the Bipartisan Policy Center, Duke Energy's Federal Environmental and Energy Policy Director, Venu Ghanta, advocated on behalf of Duke Energy for direct allocation over auctions. He argues that auctions would significantly raise retail electricity prices as well as suffer from the issue of how to prioritize the use of the revenue. Duke Energy is certainly the largest stakeholder for the state of Indiana, so the task force assigned to create the state plan is likely to pay close attention to these lobbying efforts, which makes direct allocation based on historical generation a slightly more likely plan for Indiana.

It seems likely that direct allocation would also be most preferable for Hoosier Energy, since competing in an auction would be very costly, and perhaps infeasible, for a membership cooperative. If Hoosier Energy were to buy the same number of allowances it would receive under direct allocation per historical generation in an auction, the cooperative would have to spend a significant amount of money upfront, placing great stress on its finances. Hoosier Energy should also advocate for it to receive a relatively higher number of allowances than major utilities like Duke Energy compared to the 2012 baseline, arguing that its position as a rural electric membership cooperative makes compliance more costly.

The decision to initially allocate or auction allowances is extremely important to Hoosier Energy's path towards compliance. Perhaps more than any other key variable or decision at the state level, allocation methodologies will significantly impact cost of compliance.

Decision 5: New Source Complement

For states that adopt a mass-based plan, the CPP requires state plans to address the problem of leakage--the loophole in which utilities could replace decreased generation from existing plants with increased generation from new fossil-fueled plants which do not face the state-wide CO_2 emissions cap. Leakage reduces the overall effectiveness of the CPP's goal to lower emissions, and hence any state plan must address leakage concerns in order to receive approval by the EPA. The New Source Complement (NSC) is one way the EPA has identified to address leakage. The NSC simply incorporates all new sources of CO_2 emissions under the emissions cap and expands the cap by a state's expected increased load growth from 2012 to 2030.

To calculate the NSC for Indiana, the EPA assumes an increase in net energy load growth of 12.7% above 2012 levels for the entire Eastern Interconnection by 2030. The EPA then assigns 5.5% of this load growth to Indiana based on its share of 2012 generation in the Eastern Interconnection. The EPA assumes that NGCC will cover the entirety of this load growth, so the emissions rate of all new generation is assumed to be 1,030 lbs. of CO_2 per MWh. Using these assumptions, Indiana's mass-based emissions targets with the NSC increase as shown in the right-most column of Table C1, included in the appendix.

Whether or not it would be advantageous for a state to adopt the NSC depends on the difference in the state's actual and projected load growth through 2030 and how much of this growth will be met with NGCC. If actual load growth is greater than the EPA's projections, the CO_2 emissions cap with the NSC will be tighter/more stringent than a plan without the NSC, raising the price of allowances in the market. However, if load growth is lower than the EPA has assumed, or if it is cheaper to meet some of the increased load with zero-emissions renewable energy than with NGCC, the emissions cap will be less stringent with the NSC, lowering the price of allowances. Without knowing how actual load growth will compare to estimated load growth, the NSC can be incorporated into our model by increasing the uncertainty of the price of allowances.

If a state plan does not use the NSC to prevent leakage, the state can use the three set-asides (CEIP, Renewable Energy, and Output-Based) to meet the EPA's leakage-prevention requirement. We may expect that IDEM is modeling the plan with and without the NSC to determine which is less costly and, therefore, preferable for the state of Indiana. Of note, the EPA's model rule for mass-based plans does not use the NSC. Thus, without more information about how Indiana's actual load growth might compare to the EPA's projections, we think Indiana is slightly more likely to opt for the default, which is to follow the model rule and not use the NSC.

It is similarly difficult to know whether or not the NSC would play in Hoosier Energy's favor. If Hoosier Energy's demand grew more slowly than as predicted by the EPA, then the cooperative would benefit from the extra allowances it would receive through the NSC. Also, as we will see in the next decision, Hoosier Energy likely would not benefit from the set-aside programs--a different method of addressing leakage. Therefore, it is our initial hypothesis that Hoosier Energy would prefer the NSC, but this will be better informed by our financial analysis and depend on Hoosier Energy's actual load growth. This decision is significant to Hoosier Energy to the extent that actual and predicted load growth differ and to the degree that the NSC changes allowance costs relative to using set-asides to address leakage.

We note separately that the NSC plays an entirely different role if Hoosier Energy opts to retire Merom in favor of building a new NGCC plant. In this case, under the NSC, the NGCC plant would have to comply with the CPP. Without the NSC, the NGCC plant would be subject to 1.11(b) of the Clean Air Act--a separate set of standards that would relieve all of Hoosier Energy's generation in Indiana from having to comply with the CPP, but that may have additional expenses associated with it.

Decision 6: Set Asides: Clean Energy Incentive Program, Output-based, and Renewable Energy Set Asides

Should states adopting a mass-based plan choose not to use the NSC to address leakage, they may turn to the set-aside programs offered by the EPA, as is done in the EPA's model rule. States that opt into set-aside programs remove a set percentage of allowances from their initial distribution before they allocate these allowances to EGUs. These allowances are placed into three set-aside pools: CEIP, Output-based, and Renewable set-asides. EGUs can then take certain actions to earn allowances from these pools. A state can choose all or a combination of these set-asides but must address leakage in other ways if forgoing the set-asides entirely.

The CEIP is a voluntary program that Indiana can elect to participate in by designating a portion of allowances from the first compliance period to the national CEIP pool. It incentivizes early action for renewable energy and demand-side low-income energy efficiency (EE), as projects of these types implemented between 9/6/2018 and the first compliance period generate credits per MWh generated or saved in 2020 and 2021, in a 1:2 ratio (EPA, Oct. 21, 2015). The CEIP does not increase the total number of allowances available in Indiana as the state must relinquish allowances to the federal pool and is then eligible for matching allowances up to that amount (Clean Energy Incentive, 2015). Additional uncertainty exists because the EPA has yet to finalize the conversion factor for MWh to tons of CO_2 (EPA, Oct 21, 2015b). However, it appears that Indiana would elect to participate in the CEIP because it has the potential to reduce compliance costs in the first period and the time constraint burden for utilities, unless political resistance from non-renewable interests prevail. If Indiana does not participate in the federal program, it cannot incentivize early action on its own (Jackson, Sept. 22, 2015). The benefit to Hoosier Energy is that the CEIP makes it possible to reach compliance in the first period by purchasing or generating allowances from previously constructed projects while other long-term investments or changes are being made. However, given statements from MISO, utilities may see the set-asides as an equity issue and oppose them on those grounds if allowances are allocated freely but set-asides effectively have costs attached to them (e.g. a utility must build a renewable energy facility to earn set-aside allowances).

The renewable energy set-aside is a percentage reserved from the total state allowances. The EPA recommended 5%. A large set-aside would be controversial because fewer allowances are then distributed to existing coal and natural gas plants. Hoosier Energy currently has 10 MW solar under construction which unfortunately will be completed well before the qualifying date of the CEIP (Hoosier Energy REC, Inc., n.d.a). However, these projects will receive credits for energy produced during all compliance periods from the renewable energy set-aside because they will be installed after the January 1, 2013 qualifying date. The small-scale pilot wind projects that Hoosier Energy owns will not be eligible. Hoosier Energy has been obtaining renewable energy through Power Purchasing Agreements (PPA) from wind farms in Illinois and Iowa (Hoosier Energy, 2014b). Generating units located in other states that send power directly to Hoosier Energy can receive credits (EPA, Oct. 21, 2015). Given the limited MW of planned renewable installations, Hoosier Energy will not benefit significantly from generated credits and is likely to oppose the set-aside as it decreases direct allocations.

Under the output-based set-aside, credits are earned for generation at NGCC plants above a 50% net summer capacity factor if there has been an increase in capacity factor from the first compliance period baseline (EPA, Oct 21, 2015b). The size of the set-aside is dependent on Indiana's assessment of the expected increase in NGCC generation. Secondly, the state must decide how to distribute allowances that are not earned. Currently, Hoosier Energy does not have plans to build a NGCC plant and would therefore not be eligible to earn credits. We expect that Hoosier Energy would not favor the creation of the output-based set-aside because the number of allowances they would receive under direct allocation would decrease as a result.

Hoosier Energy's compliance costs will be affected by the percentage of set-asides made available by Indiana and the decisions of other utilities and independent power producers to generate and keep allowances, generate and sell allowances, or buy from others (EPA, Oct 21, 2015b). We expect a high level of uncertainty in the cost of compliance if Hoosier Energy relies heavily on either generated allowances or purchased allowances generated by others in the state to reach compliance. The risk of using generated allowances is that credits are distributed proportionally, meaning that if there are more eligible MWh generated in the state than there are set-asides, then each MWh will receive fewer allowances than expected. Hoosier Energy could choose financially attractive renewable projects only to discover that only a fraction of the expected credits will be awarded. Hoosier Energy could choose to purchase allowances as well, but in that case uncertainty about availability remains. The impact of set-asides on allowance pricing is difficult to determine. Previous experience with allowance markets has demonstrated that allowance markets are volatile without a price floor or cap (Goulder and Schein, 2013). If many utilities expect to purchase allowances to reach compliance, the price may increase to such a degree that it may be cost effective to take other actions to reach compliance.

Indiana's power grid is heavily coal-based, so it is unlikely that many allowances will be sold by other utilities from emissions reductions within EGUs alone. This is evidence that allowance prices may be relatively high without the flexibility that set-asides provide. Similarly, Hoosier Energy's coal-based portfolio suggests that if compliance cannot be reached with a combination of given allowances and changes at Merom, then Hoosier Energy may favor set-asides if they result in lower compliance costs relative to other options. However, the effect on prices is highly uncertain.

As discussed above, we think that Indiana is slightly more likely to choose the set-aside program over the NSC to address leakage, as this method is the default set by the model rule. It is our hypothesis that Hoosier Energy would not prefer the use of set-aside programs. Under the use of the set-aside programs, Hoosier Energy would receive fewer allowances upfront since the total pool of allowances would be smaller for Indiana. Furthermore, Hoosier Energy's relatively light emphasis on renewable resources and lack of a NGCC plant keep the cooperative from earning a significant amount of set-asides, especially compared to utilities with more financial power and wider ranges of assets like Duke Energy.

Decision 7: State Measures Plan

States can also choose to meet mass-based goals through a state measures plan. A state measures plan allows a state to use a mix of other kinds of policies in order to help meet the federally required targets set by the CPP. In a state measure plan, the target is federally enforceable, but the policies used to meet those targets are enforced at the state level. These policies could include a renewable portfolio standard and energy efficiency standards, and they could act as a way for a state's participation in an existing regional cap-and-trade program (e.g. RGGI) to satisfy the requirements for its state plan (California Air Resources Board, 2015). If states choose a state measures plan, they must prove that the policies implemented will not result in leakage and will meet the emissions reductions mandated by the CPP. They must also agree to a federally enforced backstop if they fail to come within 10% their targets (California Air Resources Board, 2015).

This option seems unlikely for the state of Indiana. Indiana is not a party in any regional trading program, and the state's renewable portfolio standard is voluntary. Indiana would need to develop these programs and then prove to the EPA that the result of the programs would be sufficient to meet CPP standards and prevent leakage. This would add additional work and administrative costs for the state. Since the possible policies brought in under a state measures plan are difficult to predict, the ultimate effect of a state measures plan to Hoosier Energy is unclear. A state measures plan could subject Hoosier Energy to a renewable portfolio standard or other programs which could place constraints on how the cooperative chooses to comply, thereby raising costs. Thus, it is likely in Hoosier Energy's best interest to oppose a state measures plan unless the additional policies specifically play to the cooperative's advantage.

Decision 8: Statewide energy efficiency program

The emission reductions associated with energy efficiency programs allow Hoosier Energy to comply with CPP standards while simultaneously maintaining a reliable and cost-effective energy supply. By increasing their energy efficiency program, Hoosier Energy can lower their emissions, decrease customer demand for electricity, and reduce compliance costs. Regardless of whether Indiana adopts a statewide standard, Hoosier Energy should continue to incentivize industrial and residential customers to incorporate unique energy efficiency programs.

A. Energy Efficiency's role within the CPP

While the final version of the CPP removed the energy efficiency building block, the EPA anticipates that the relative low cost and high potential of energy efficiency programs will lower electricity demand by 7%. (EPA: *The Clean Power Fact Sheet*). Energy efficiency also contributes to compliance regardless of whether Indiana adopts a mass-based or rate-based approach.

Under the assumed mass-based approach, energy efficiency automatically contributes to Indiana's compliance plan by reducing fossil fuel electricity generation and emissions. (EPA: *The Clean Power Fact Sheet*). Indiana can use the saved emission credits to trade for future emission allowances or auction the allowances to create additional revenue for demand-side efficiency programs.

Under a rate-based approach, states receive credit for energy efficiency projects built after 2012. These energy efficiency projects receive ERCs for verified MWh savings that continue to occur in 2022 and beyond. (EPA: *The Clean Power Fact Sheet*). Individual rate-based state plans can provide for the interstate transfer of ERCs, allowing one state's ERC for energy efficiency to count towards compliance in another state. (EPA: *The Clean Power Fact Sheet*). Additionally, the CPP allows states to meet emission guidelines within energy efficiency programs and policies that state, not federal laws can enforce.(EPA: *The Clean Power Plan Fact Sheet*). The Clean Energy Incentive Program, within the CPP, also provides additional incentives for energy efficiency efforts in low-income communities. (EPA: *The Clean Power Plan Sheet*).

B. Energy Efficiency Program Background

While energy efficiency programs vary across each utility and each state, most programs include a combination of Integrated Resource Planning, Statewide Energy Efficiency Requirements, Rate Structures and Incentives, Stakeholder Collaboration, Evaluation, and Smart Grid capacities. (Midwest Energy Efficiency Alliance 2014). The specifics of Hoosier Energy's program depend on whether Indiana establishes a statewide energy efficiency standard through ratepayer funded programs. Regardless of the outcome however, Hoosier Energy has the flexibility to continue their most effective energy efficiency programs, while also providing additional programs recommended in this plan.

C. Indiana Statewide Energy Efficiency Program

Both Democratic and Republican controlled state legislators, in similarly situated, coal-dependent Midwestern states, have adopted energy efficiency standards for specific energy saving targets. Illinois, Michigan, Minnesota, and Ohio all have legislature-established, ratepayer funded programs that have achieved considerable success. (Midwest Energy Efficiency Alliance 2014). Indiana also had a program issued by the state commission, before the state legislature overturned it in 2014. (Midwest Energy Efficiency Alliance 2016). Advocating for the reinstatement of a proven program, like Indiana's ratepayer funded Energy Efficiency Portfolio Standard, would provide Hoosier Energy with a stable funding base for increased investments in energy efficiency.

Hoosier Energy can also encourage Indiana state legislatures and commissions to provide shared saving mechanisms and shareholder bonuses for energy efficiency. Successful cost recovery programs ensure reasonable capital and non-capital costs associated with utility energy efficiency programs.(Midwest Energy Efficiency Alliance 2014). The programs also limit the recovery time to the length of the program.

Ordinarily, Hoosier Energy can only increase revenue by selling more energy. Therefore, investing in energy efficiency technology that decreases the amount of their product used typically only makes sense to lower emissions. "Decoupling" Hoosier Energy's total energy sales from its revenue however, allows energy commissions to adjust rates up and down to reach the authorized revenue requirements. Hoosier Energy should advocate for Indiana to reinstate a statewide program that will help Hoosier Energy reduce emissions while not sacrificing profit.

D. Industrial Efficiency Programs for Hoosier Energy

According to the Energy Information Administration, Industrial customers account for over 30% of the nation's energy use. (Midwest Energy Efficiency Alliance 2014). Despite their heavy energy use, industrial customers offer the lowest cost and the highest total of achieved national energy savings. Backed by the National Association of Manufacturers and the Alliance to Save Energy, industrial energy efficiency programs allow businesses to use less energy in processing, ultimately reducing energy bills and increasing competitiveness.

Hoosier Energy can direct their industrial customers, which account for 60% of Hoosier Energy's total usage, to incorporate a portfolio of utility energy efficiency programs as well as financing options and opt-out/self-direct policies. Hoosier Energy already utilizes a variety of energy efficiency programs, for both industrial and residential customers, that will help comply with the CPP.

By using the demand-side management programs in the following table, Hoosier Energy hopes to reduce system peak demand and total energy sales by 5% in 2018. (Hoosier Energy: *Lighting the Way to Energy Efficiency Savings*).

TeamUpToSave.com	Online tool promoting high-performance CFL and LED lighting for residential and agricultural customers, commercial and industrial incentives to help purchase energy-efficient equipment
Touchstone Energy® Home	Encourages construction of energy-efficiency house that meet high performance standards
Attic Insulation/Duct Sealing	Residential customers offered a free energy assessment to determine the benefit of attic insulation and duct sealing
HVAC Rebates	Residential heating, ventilation, and air conditioning (HVAC), heat pump water heater, Geothermal heat pump
Appliance Recycling	Remove outdated appliances like refrigerators and freezers from the grid
Energy Management Savings Switch	Switches control both water heating and air conditioning units during high demand periods
Commercial and Industrial	Occupancy sensors, direct install, small and large motor replacement, variable speed drive replacement, programmable thermostat, heat pump, and air conditioner
Load Control Program	Water heater, air conditioner, geothermal, heat pump

Overall, the results of Hoosier Energy's current programs compare favorably with other state and regional programs. The energy efficiency programs help reduce base load demand and overall energy consumption and also play a vital role in Hoosier Energy's generation and transmission power supply strategy. To build on the success, Hoosier Energy should expand their energy efficiency program to play an even larger role in the CPP compliance strategy.

E. Suggested Energy Efficiency Programs

Energy Audits

Hoosier Energy should expand their energy efficiency audits to help industrial customers identify potential energy savings. Hoosier Energy can explore a variety of options including online surveys, do-it-yourself audits, along with in-depth walk-throughs of the customer's facility. (Duke Energy).

Expanded Load Curtailment Program

Hoosier Energy should expand their Load Curtailment Program to further incentivize businesses to adjust their energy consumption during peak time periods. Other utilities in Indiana, including Duke Energy, structure their programs to reward customers for shifting a pre-allotted amount of kW in exchange for a monthly incentive. The Duke Energy program uses three different options to maximize customer participation. The *Emergency Options* requires customers to agree to shift a pre-allotted amount of kW in exchange for a monthly incentive. (Duke Energy 2016). The *Call Option* requires a load shift during the specified event. (Duke Energy 2016). Customers can select a desired amount of events to participate in each year. The *Quote Option* allows businesses to participate in curtailment periods by a designated load reduction amount. (Duke Energy 2016). Under a similar design to Duke Energy, Hoosier Energy would notify businesses before initiating the curtailment period and the distribute credits for each event.

Programs like this allow businesses to profit from effective energy management and lock in an incentive credit. The programs would help Hoosier Energy reduce the need to run expensive generation plants during high demand periods. This can lead to lower wholesale market prices as well as additional customer savings. Overall, the program lowers incidents of electrical emergencies, increases system reliability, and reduces customer's inconvenience.

Other load curtailment programs offered by comparable utilities includes Indiana Michigan Power's Emergency Demand Response Rider that allows customers to reduce usage during periods of high demand. The program allows customers to monitor the use of nonessential equipment and operate with reduced lighting and air conditioning. (Indiana Michigan Power 2016).

<u>Retro-Commissioning Incentive Program</u>

Hoosier Energy should also explore a Retro-Commissioning Incentive Program to help their customers gauge the energy performance of their facilities and optimize their existing systems. NIPSO offers a similar program that allows customers to identify and remove operational inefficiencies to yield energy savings. (NIPSO 2016). NIPSCO's particular program uses a third party implementation specialist to administer the program. (NIPSCO 2016).

Retro-commissioning programs help make energy efficiency upgrades possible for businesses where it does not make sense to completely overhaul their systems. The retro-commissioning program allows companies to take advantage of energy efficiency upgrades on a smaller scale before committing to even larger projects.

Figure 5-1. Summary of Policy Decisions

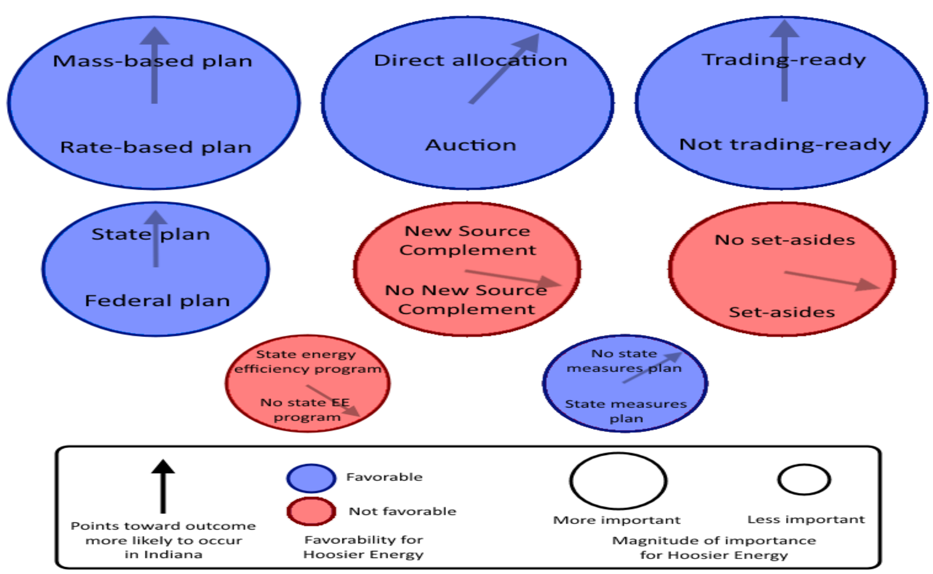


Figure 5-1 provides an illustrative summary of the eight decisions discussed in this section. Each bubble represents a decision, with the size of the bubble representing the magnitude of the importance of the decision for Hoosier Energy. The arrow points toward which decision is more likely for Indiana; the angle of the arrow gives some degree of our confidence in each case. The color of the bubble indicates whether the decision that is more likely for Indiana is also favorable for Hoosier Energy. Red bubbles represent likely decisions to occur in Indiana that do not appear to be favorable for Hoosier Energy. Therefore, it is in Hoosier Energy's interests to consider more closely those policy decisions that are the most significant of these decisions (the largest bubbles). The financial analysis provides more insight into whether this qualitative policy analysis is properly represented, given a select set of assumptions.

A.3. Construction of Frameworks

We use the results of the decision analysis to construct two key policy frameworks. The first describes the most likely framework for Indiana (denoted IND). The second describes our hypothesis for the framework that would be Hoosier Energy's preference (denoted HEP). These frameworks are listed in Table 5-1 below:

Table 5-1. Comparison of IND and HEP

Decision	**IND**	**HEP**
State or federal	State	State
Mass or rate	Mass	Mass
Trading ready	Yes	Yes
Allocation method	Direct (historical)	Direct (preferential)
New Source Complement	No	Yes
Set asides	All three	None
State measures plan	No	No
Statewide energy efficiency program	No	Yes

Notably, the two frameworks differ in four of the eight decisions. First, Hoosier Energy would benefit from being allocated a greater proportion of allowances than that determined by historical generation. As a rural electric membership cooperative with a widely distributed network of consumers, Hoosier Energy may be able to advocate to receive additional allowances upfront. Second, it appears that Hoosier Energy may stand to benefit more from the NSC than from the set-aside programs. This depends on Hoosier Energy's demand growth and the cooperative's decision about whether it will build a new power plant. Finally, we think that Hoosier Energy would benefit from a statewide energy efficiency program, although this decision depends on the relative costs and benefits specific to the design of such a program.

In Section VIII, we operationalize these frameworks for use in our financial model. Namely, we describe how differences in these frameworks correspond to changes in constraints that compliance plans must satisfy. We also construct a five alternative frameworks for use in the model, each of which toggles a specific decision starting from IND as a baseline.

We note that the EPA's proposed federal plan appears to have a framework that is actually identical to IND. However, we would encourage Indiana to still pursue a state plan as Indiana would then have control over more nuanced details that are not modeled or explicitly accounted for in this report.

A.4. Conclusions from Policy Analysis

A state plan is preferred to a federal plan for Hoosier Energy, and it is Indiana's likely choice. The federal plan looks similar to the most likely state plan for Indiana, but a state plan gives Indiana more flexibility and control with regard to the plan's finer details and nuances. If Indiana refuses or fails to develop a state plan and defaults to a federal plan, the loss of flexibility in the design of the plan will likely raise Hoosier Energy's compliance costs.

A mass-based plan is preferred to a rate-based plan for Hoosier Energy, and it is Indiana's likely choice. Mass-based plans are better suited for coal-heavy states, will likely have access to larger trading markets, and are more familiar to state regulators and EGUs. If Indiana opts for a rate-based plan, Hoosier Energy's compliance costs will likely skyrocket. Hoosier Energy would either need to buy a large number of ERCs--likely more expensive than allowances due to tighter markets and the less-familiar trading scheme--or shutter Merom, which probably will not be able to undergo the necessary changes to bring it under its emission limit.

A trading-ready plan is preferable for Hoosier Energy, and Indiana will likely submit its plan as such. Trading-ready plans allow for access to larger markets; this results in lower prices for allowances, which is significant since Hoosier Energy will likely be a net purchaser of allowances. If Indiana fails to submit as trading-ready, the restricted access to larger markets will raise allowance prices, thereby increasing compliance costs for Hoosier Energy.

Direct allocation of allowances is preferred to selling allowances in an auction for Hoosier Energy, and it is Indiana's likely choice (IDEM, 2016). Direct allocation is more simple and preferred by utilities; auctions result in high costs for utilities, and states must decide how to equitably spend the revenue they generate. Allocation may be more nuanced--for instance, states could adopt a hybrid of direct allocation and an auction. States can choose to allocate allowances based on historical generation or through some other method (e.g. giving preference to smaller utilities). If Indiana decides to distribute allowances via an auction, Hoosier Energy will likely suffer high costs. The extent of the financial loss will depend on how Indiana redistributes the revenue of the auction; in theory, Hoosier Energy could stand to benefit, but only if it receives a cash payment or other benefits (e.g. very significant efficiency upgrades) greater than its outlay of purchasing allowances. Hoosier Energy should push for an allocation method that gives set-asides or other preferential treatment to rural cooperatives and other providers that serve smaller or disadvantaged communities.

The decisions to adopt the NSC and set-aside provisions are not mutually exclusive, but they are related. Both of these decisions are meant to address leakage concerns in a mass-based plan, so a state plan would likely adopt only one of these. Use of the NSC appears to be preferable for Hoosier Energy, but Indiana's decision is uncertain, potentially leaning toward set-asides. The NSC would give Hoosier Energy more allowances, but it may not be in the cooperative's best interest if it faces growth in demand greater than the EPA's projections or if plans to build new generation. If set-asides were adopted, however, Hoosier Energy likely would not stand to benefit unless its plan for compliance included a sharp increase in renewable energy capacity and natural gas power generation. We predict that utilities with more buying power (e.g. Duke) would benefit more from set-asides. Ultimately, whether or not Hoosier Energy should advocate for the NSC or set-asides depends on whether the cooperative plans on building new natural gas capacity and the estimated cost differences between the new capacity complying with 1.11(b) and the NSC under the CPP. The magnitude and variability of allowance prices under these two schemes will also greatly affect which decision is more favorable for Hoosier Energy.

A state measures plan does not appear to be preferable for Hoosier Energy, and Indiana does not seem likely to make this a part of its state plan. A state measures plan could subject Hoosier Energy to a renewable portfolio standard or another program that could place constraints on how the cooperative chooses to comply. Therefore, if Indiana opts for a state measures plan, there is a chance Hoosier Energy's compliance costs would increase. There is a great deal of uncertainty surrounding what Indiana would include in a state measures plan however, so its potential impact on Hoosier Energy cannot be easily determined.

A statewide energy efficiency program would likely be preferable for Hoosier Energy, but it seems less likely that Indiana would adopt such a program. Indiana had a program in place several years ago, but it has since been cancelled; for political reasons, such a program will likely not return as part of Indiana's state plan. We assume that a statewide energy efficiency program would lead to demand-side and transmission line efficiency improvements. Since Hoosier Energy's transmission network is extensive given the scattered, rural nature of its consumers, the cooperative would likely stand to benefit from a statewide energy efficiency program more than other utilities in the state. This implies that the benefits of the program would exceed the costs of buying into the program. A lack of such a program would increase the demand facing Hoosier Energy relative to the inclusion of the program.

Based on our analysis, we predict that Indiana will adopt a trading-ready mass-based state plan, distributing allowances directly based on historical generation, and employing set-asides to address leakage. We do not think Indiana will adopt the NSC, state measures, or a statewide energy efficiency program. Our hypothesis states that Hoosier Energy would stand to benefit from a preferential allocation of allowances (i.e., receiving extra allowances as a rural electric membership cooperative), the use of the NSC rather than set-asides, and a statewide energy efficiency plan. The modeling section of the report explores how cost estimates change between these two policy frameworks and several alternatives; these estimates provide further insight into our hypothesis, given a list of significant assumptions.

VI. Technical Analysis

In addition to identifying which policy decisions are most likely and most beneficial to Hoosier Energy, it is important to consider the compliance options, technological and otherwise, that can be utilized to meet the Clean Power Plan's requirements. The Merom plant is the client's only generator under Indiana CPP emission limits. As such, it is important to have a menu of options to specifically address Merom's emissions. Technically and economically viable options were analyzed based on several criteria:

- Technical maturity (whether available for current or future use)
- Capital cost (to keep options considerate of Hoosier Energy's budget)
- Emissions reduction potential (maximum CO_2 reductions possible)
- Cost effectiveness of emissions reductions (dollars per reduced ton of CO_2)
- Implementation constraints (including infrastructure needs and input availability)
- Lead time to implementation (from initiation to completion of option implementation)

B.1 Energy Efficiency - Demand Side Management

Demand side management is a cost-effective option available to decrease generation needs and/or shift load through actions at the end-user level (NACAA, 2015). Since Hoosier Energy recently had a consultant evaluate how much energy could be saved, these issues are not further analyzed and instead it is assumed that the client will continue to pursue the energy savings programs and incur the costs described in the Integrated Resource Plan.

B.2 Thermal Efficiency Improvements at Merom

Technology Overview

Optimizing power plant operations through thermal efficiency improvements is an effective way to reduce power plant emissions. More thermally efficient plants produce less CO_2 per MWh of generation (Henderson, 2013). A power plant that improves its thermal efficiency by 1-2% can expect to see a nearly equivalent 1-2% reduction in CO_2 as well (NACAA, 2015). The thermal efficiency of a plant will always decline with use, but steps can be taken to both slow down and recoup much of this loss. These steps can range from a small increase in preventative maintenance schedules to large system overhauls and equipment upgrades. It should be noted though that once a plant has been in operation for an extended period of time maintenance becomes less effective as the equipment begins to suffer the effects of persistent degradation (DOE, 2013). This threshold is generally about 30 years for plants built in the United States (DOE, 2008). The EPA purportes that by employing a mix of onsite boiler optimization and equipment maintenance projects a coal fired power plant can expect to improve its thermal efficiency by 4-7% (NACAA, 2015). The potential efficiency gains achieved at a given plant will vary depending on three factors: project feasibility, past optimization projects, and the capital cost of projects. Hoosier Energy has already invested a considerable amount of capital in optimizing operations at Merom. As such, it is not feasible to expect operators to reduce the heat rate at Merom by an additional 4%. By employing a mix of onsite boiler optimization and equipment maintenance projects Hoosier Energy can expect to achieve a 2% increase in thermal efficiency at the Merom plant at an annual cost of $1,000,000 (Hoosier Energy).

Regulatory Backdrop

Hoosier Energy will need to obtain revised operating permits that reflect new emissions levels. The modifications should not be significant enough to trigger Prevention of Significant Deterioration, New Source Review, or New Source Performance Standards regulatory provisions (NACAA, 2015).

Capital, Operations, and Maintenance Cost

The costs associated with this option will depend heavily on the type of optimization projects that are implemented. Hoosier Energy is willing to invest an additional $1,000,000 annually to fund optimization projects. Hoosier Energy's operations will benefit the most from investing these funds in projects to enhance the recovery of waste heat from cooling systems and flue gas, reduce auxiliary power consumption, optimize soot blower operation, and optimize fuel combustion (DOE, 2008). Improving the quality of the coal combusted is also an effective way to increase boiler efficiency. However, for the purpose of this analysis such processes are covered in a separate section.

Implementation Benefits

CO_2 emissions reductions have been found to be proportional to heat rate improvements (NACAA, 2015). With an annual investment of $1,000,000 Hoosier Energy will be able to increase the thermal efficiency of the Merom plant by 2%. As such, Hoosier Energy should expect to see an approximately 2% reduction in Merom's CO_2 emissions as well. Emissions of criteria pollutants SO_2, NO_x, Hg, and particulate matter (PM) will be reduced as well. This is due to the direct relationships between thermal efficiency and fuel consumption. More efficient boilers are able to generate the same amount of energy using less fuel. Reducing these emissions could lead to savings in operation and maintenance costs due to the reduced load placed on the plant's pollution control technologies (DOE, 2014a). A portion of production energy cost, production capacity cost, future and existing environmental regulation costs, and coal ash disposal cost may also be avoided.

Implementation Challenges

Certain components of the Merom plant may have to be temporarily taken offline depending on the type of optimization projects Hoosier Energy chooses to implement. Such actions will need to be planned out well in advance to maintain grid reliability and ensure Hoosier Energy continues to meet its consumers' generation needs.

B.3 Cofiring Merom with Natural Gas

Technology Overview

One option to reduce the rate of CO_2 emissions (lbs/MWh) from power generation is to cofire coal with natural gas simultaneously within the existing boiler units, using any proportion of natural gas up to 100%. This may be a preferred option for complying with CO_2 limits, as 31% of the CO_2 emissions decrease under the Regional Greenhouse Gas Initiative program between 2005-2009 was accomplished by fuel switching (NACAA, 2015). Cofiring with natural gas decreases the efficiency of the boiler, but it may not significantly affect the overall plant net output efficiency (heat rate) because auxiliary load is reduced by the decreased demand for energy used internally to crush and move coal, pump ash, and control non-CO_2 pollutants. The net heat rate (BTU/kWh generated) is expected to increase by 3% for a transition to 100% gas (EPA, 2014a).

Regulatory Backdrop

A cofired plant would likely need a revised operating permit. However, the modifications would not likely trigger Prevention of Significant Deterioration, New Source Review, or New Source Performance Standards regulatory provisions because natural gas combustion releases less of regulated air pollutants (SO_2, NO_x, PM) than coal (NACAA, 2015).

Capital, Operations, and Maintenance Costs

For a 500 MW pulverized coal boiler, similar to the 540 MW units at Merom, capital costs for boiler modifications to fire up to 100% gas would be $137/kW. Adding an assumed 50-mile new gas pipeline, at $50 million, the total capital cost for modifications to the 500 MW boiler unit would be $237/kW. Assuming a 75% capacity factor and a capital charge rate at 14.3% over a 15-year retrofit book life, annualized costs for the capital improvements would be $5/MWh (EPA, 2014a). The cost per MWh at Merom could be greater, as it is estimated that each of its boiler units would require new pipeline infrastructure, at a cost of $81 million each. Typically, each unit requires two lateral gas spur lines to ensure supply reliability (EPA, 2013). Gas line costs include tying into an existing major gas pipeline, construction of the new line, associated rights-of-way, and installation of a new revenue metering station (Reinhart et al., 2012).

Projected 2020 delivered fuel costs are $2.62/MMBTU for coal and $5.36/MMBTU for natural gas. Factoring in the decreased boiler efficiency and the decreased auxiliary power consumption due to cofiring, fuel costs would be $27/MWh for coal and $57/MWh for natural gas. Thus, fuel price difference is a much more important driver of project economics than the capital improvement costs. Additionally, this price difference could increase even more if increased demand for natural gas drives the price up (EPA, 2014a). Additionally, the client estimates that reservation costs for firm natural gas capacity would be $1 million per year for enough gas to run a NGCC plant at 50% capacity.

One other consideration is operations and maintenance (O&M) costs. Cofiring is expected to decrease fixed O&M costs by 33% for a transition to 100% gas due to decreased need for coal yard and emissions control staff and decrease variable O&M costs by 25% due to decreased need for waste disposal (ash and gypsum) and demand for auxiliary power (EPA, 2014a). There would be reduced corrosion in the steam generator and other system components (Nowling, 2013).

Implementation Benefits

Cofiring preserves the option to change the proportion of the two fuels as needed due to interruptions in supply, fuel price changes, or other contingencies such as problems with coal handling systems (EPA, 2014a). Additionally, cofiring adds flexibility to unit operation, allowing it to operate more like a peaking power unit (Overton, 2014). Table 6-1 describes how the emissions reduction potential of cofiring directly depends on the fuel ratio.

Table 6-1: Cofiring CO_2 Emissions Reductions

Case	**Heat Rate (BTU/kWh)**	**CO_2 Rate (lbs/MWh net)**	**Reduction in CO_2 Rate from 100% Coal (lbs/MWh net)**
100% Coal	10,340	2,108	N/A
10% Gas	10,370	2,021	4%
50% Gas	10,490	1,673	21%
100% Gas	10,640	1,239	41%

(reproduced from EPA, 2014a)

Putting together the capital, O&M, and fuel costs, the average cost of avoided CO_2 is $83/metric tonne for burning 100% natural gas, $91/metric tonne for 50% natural gas, and $150/metric tonne for 10% natural gas (EPA, 2014a).

Implementation Challenges

Infrastructure changes needed to implement cofiring include modifications to the piping, burner, and ductwork systems and construction of a new gas pipeline to the plant (EPA, 2014a). Modifications can range from simply installing gas nozzles on the existing boiler to installing new natural gas burners. Simply replacing oil-fired igniters and warm-up guns can allow cofiring of 30-50% gas. Greater gas incorporation percentages would require burner system changes, such as adding gas rings around existing coal burners, putting gas spuds in the center of the burners, or adding full-sized natural gas burners. System modification requirements are greater if trying to maintain existing unit capacity. For example, potential implementation challenges include fans failing to supply enough combustion air to the boiler, the lack of ash fouling leading to boiler heat transfer problems, and poor natural gas burner placement leading to incomplete combustion in some areas (Reinhart et al., 2012). Heat transfer imbalances could be managed with operational efforts when firing less than 50% gas, but heat transfer surface modifications or increased flue gas recirculation would be needed to stabilize furnace temperatures when cofiring a higher proportion of gas (Nowling, 2013). Lead time for projects installing new gas burners can be short, only 14 months between stopping coal operations and beginning service on natural gas (Overton, 2014).

Potential constraints on cofiring with natural gas include the availability of pipeline capacity and the financial feasibility of arranging firm capacity agreements. There may be seasonal limits on natural gas supply to ensure there is enough for home heating demand (Nowling, 2013). Hoosier Energy maintains firm pipeline capacity at the Holland plant but due to economics has opted for interruptible capacity at the Lawrence and Worthington stations (Hoosier Energy, 2014). Other risks include volatility in natural gas pricing and a significant amount of time during which the plant is offline for the infrastructure modifications (NACAA, 2015).

B.4 Improving Coal Quality

Technology Overview

One option to reduce the rate of CO_2 emissions from a coal-fired power plant is to improve the quality of the coal used. The quality of coal is determined by a number of properties, but the heat value, sulfur content, and ash content are the most critical (Schweinfurth, 2009). The heat value of coal refers to the ratio of energy that can be generated per pound of fuel. Switching to a coal with a higher heat rate can allow a plant to reduce its fuel consumption without reducing its generation (Skorupska, 1993). Benefits to using coal with lower ash and sulfur contents are three fold. First, high sulfur and ash contents impair the thermal performance of boilers. Second, lowering the ash content reduces the auxiliary power consumption of a plant by reducing the load placed on virtually every piece of equipment that is involved in the auxiliary boiler system or handles and processes coal (DOE, 2010) .

Regulatory Backdrop

Revised operating permits reflecting the change in the quality of the coal would have to be obtained as well. Coal quality specifications laying out the minimum BTU/lb ratio, maximum ash percentage, maximum moisture content, minimum percentage of volatile matter, and grindability are established between coal suppliers and purchasers (NACAA, 2015). New contracts specifying stricter ash and sulfur limits would have to be obtained.

Capital, Operations, and Maintenance Cost

The coal utilized at the Merom plant is already of a relatively high quality with an ash content of 10% and a sulfur content of 6% (Hoosier Energy). All coal is purchased from Indiana and, as Hoosier Energy does not intend to transport fuel from out of state, it is unlikely that they will be able to purchase a higher quality of coal. Any improvements in quality would have to happen via coal washing after the fuel has been mined (Schweinfurth, 2009). Purchasing washed coal will undoubtedly increase annual fuel cost, but much of this loss would likely be recouped through savings in reduced operating and maintenance costs (Asian Development Bank, 1998). For a 500 MW pulverized coal boiler with a heat rate of 10,000 BTU per kWh, similar to the 540 MW units at Merom, coal washing increased fuel cost by $200,000 but also produced $450,000 in savings due to improved boiler efficiency and $230,000 in savings from both reduced ash disposal and improved coal handling (Asian Development Bank, 1998). The coal washing produced a 10% decrease in ash content which resulted in about a 20% reduction in operating and maintenance cost and a 5% reduction in the overall capital investment of the plant (Asian Development Bank, 1998).

As Hoosier Energy is already using a relatively low ash coal, they should expect to achieve ash reductions closer to the range of .3%-1%. Barring a dramatic drop in coal prices, it would be difficult to reduce the ash content below 9.5% in a cost effective manner (Gerhard & James, 2013). There is a significant gap in the literature concerning studies on the effect of such a small improvement in coal quality. Collating data from multiple studies, we can make a general estimate that the Merom power plant could achieve about a 1% reduction in yearly operating and maintenance by reducing their ash content by .5% (Hatt, R. & Waymel, E., 1987; Skorupska, N., 1992; Asian Development Bank, 1998). Expected increases in fuel cost cannot be constrained specifically to Hoosier Energy without knowledge of the current contracts. The USGS provides a general estimate that a switch to washed coal will increase fuel cost by about ¢.04 per ton (Bhagwat, S.B., 2009).

Implementation Benefits

For a 500 MW pulverized coal boiler with a heat rate of 10,000 BTU per kWh, similar to the 540 MW units at Merom, coal washing improved the thermal efficiency of the boiler by 1%. A 1% increase in boiler efficiency could reduce CO_2 emissions at Merom by 2-3% (NACAA, 2015). Additional benefits to improving coal quality are many. The IEA surveyed power plants and found that about 60% of forced power plant outages can be attributed to coal quality factors (Skorupska, 1992). Lower quality coal is more abrasive and therefore corrodes ductwork and other plant equipment faster (Hatt, R. & Waymel, E., 1987). Corrosion is a primary factor in reducing the life expectancy of a plant and equipment. Operating and maintenance savings will also come from the reduced auxiliary power consumption. The ash content of coal is directly related to the auxiliary load placed on ducts, conveyors, pulverizers, crushers, storage containers, forced and induced draft systems, steam temperature controls, bottom and fly ash removal systems, primary and secondary air burners, combustion controls, and virtually every piece of equipment that is involved in the auxiliary boiler system or handles and processes coal (Hatt, R. & Waymel, E., 1987).

Implementation Challenges

The greatest challenge to upgrading the coal used to fuel Merom will be obtaining a higher quality coal. All of Hoosier Energy's coal is sourced from Indiana. The Indiana Geological Survey reports the average ash content for Indiana coal as somewhere between 14.9% to 9.0% with the majority of production (~70%) extracting coals with <10% ash (Mastalerz et al., 2008a

& 2008b). So while it is possible to purchase coal with an ash content <10%, it may prove to be too arduous, either in terms of logistics or increased fuel cost. Due to these supply uncertainties, logistical challenges, and the relatively small CO_2 emissions reduction potential, upgrading the coal quality was not analyzed as part of a modeled compliance plan.

B.5 Battery Storage Technology

Technology Overview:

Grid level battery storage is, more or less, a scaled up version of modern portable battery technology, and viable iterations of this technology are available today. While the designs and somewhat limited performance of these batteries have led to prohibitively high prices in the past, current units are reaching as low as $750 per kW of capacity. While this is not competitive with baseline power costs, such as the Merom plant, it does breach the range of capital costs for peaking plants. This is the ideal range for battery technology to reach, as it does not produce energy but rather evens out the variability of demand and potentially the intermittency of renewable sources.

Regulatory Backdrop

While battery storage can be considered a renewable source complement, it does not in and of itself reduce emissions--it rather regulates energy transmission and increases the internal efficiency of a system. Meaning, batteries charged with coal energy would not reduce emissions over a gas-fired peaking plant, even though the cost efficiency may be altered. Additionally, battery technologies are comprised of a varying range of acidic, toxic, and otherwise hazardous heavy elements. The acquisition, handling, and disposal of these materials poses a concern to environmental policy makers that renewable sources do not generally have.

Capital, Operations, and Maintenance Costs

To fully replace the capacities of the two peaking plants, Worthington and Lawrence, using current battery storage technology, Hoosier Energy would need to spend up to $167 million for each. However, using estimates that Tesla (and other competitors) have made for 2020, the same capacity could be purchased for up to $44 million each--a significant decrease, and potentially a fraction of the price of a new peaking plant, which only reach as low as $110 million.

Operations and maintenance costs for battery storage are relatively low, dealing primarily with transportation of the units and checking them for temperature anomalies or leaks of the electrolyte. Longevity of batteries is among their greatest limiting factors, as it varies wildly between designs and operation conditions--ranging from less than 1 year to almost 25. Because the turbines used at the Hoosier Energy peaking plants are gas fired (as opposed to thermally driven), their life expectancy falls within the higher end of the range of batteries--at about 20 years. This means the rate of technological replacement is, potentially, not dramatically different.

Implementation Benefits and Challenges

A full battery replacement of the Worthington and Lawrence peaking plants has the potential to reduce emissions by more than 65 million tons of CO_2. However, if the energy charging the battery banks were to come primarily from the Merom plant, emissions could increase over the peaking plants by up to 50%.

While this technology was not considered viable as a compliance option for the plans detailed in the later portion of this report, the appropriateness of battery storage technology for Hoosier Energy in the future will be primarily dependent on the levels of short term variability in their energy supply or demand. Particularly, a battery storage system will be best utilized in a market that experiences both peaks and valleys of demand and/or supply, making it the natural complement to renewables and their inherent intermittency.

In summary, we find that battery storage technology is unsuitable for Hoosier Energy to comply with the CPP without a large expansion in renewable generation.

B.6 Repowering Merom with Natural Gas (Replace or Retrofit)

Technology Overview

Replacing Merom's output with higher efficiency NGCC power could be accomplished by various means. Option 1 is building a new NGCC unit on the Merom property or another property. For example, one company took advantage of their existing land by building a new NGCC unit in their plant's former coal yard (Xcel, 2011). Option 2 is replacing existing boiler units with new combustion turbines and heat recovery steam generators and steam turbines to repower the site as a NGCC plant while reusing the plant supporting infrastructure like the cooling water system, wastewater treatment, water supply, and switchyard (Reinhart et al., 2012). Option 3 is replacing the boiler units with combustion turbines and heat recovery steam generators to make a NGCC unit while reusing the existing steam turbine and cooling system. This would be done if the steam turbine useful life were deemed to be longer than that of the boilers (EPRI, 1997).

Regulatory Backdrop

If the modification capital improvement costs exceeded 50% of the cost to build a comparable new plant, New Source Performance Standards would have to be met (NACAA, 2015). The plant would fall under the CAA Section 111(b) instead of the CPP emissions cap unless the New Source Complement option was in effect.

Capital, Operations, and Maintenance Costs

Option 1, constructing a new NGCC unit in Indiana, would cost around $1067/kW (EPA, 2013). For Option 2, capital costs are estimated at $600-$1,200/kW capacity (in 2016 dollars). For Option 3, capital costs are estimated at $400-$1,500/kW capacity (in 2016 dollars), depending on many factors such as whether reused components need to be refurbished. NGCC unit blocks typically range from 300-1,200 MW capacity (EPRI, 1997). Costs of demolishing old coal plants, if needed, vary and depend on the value of the salvaged materials (Reinhart et al., 2012).
NGCC plant O&M costs are lower than at coal plants (EPA, 2013).
Natural gas fuel costs and gas line construction and reservation costs, as described in the "Cofiring with Natural Gas" section, would apply to these options as well.

Implementation Benefits

Using the Merom site for a NGCC unit would avoid the need for acquiring and permitting a new plant site and acquiring right-of-way for and constructing new transmission infrastructure. Additionally, using the same site would reduce the risk of negative transmission system balance impacts due to bringing a large generator offline (EPRI, 1997).

Replacing a 500 MW coal boiler unit with a higher efficiency new NGCC unit could reduce the net CO_2 emissions rate (of the generating capacity) by 62% (relative to burning 100% coal) for \$50/metric tonne (EPA, 2014a).

Implementation Challenges

For all of the options, the combustion turbine interface would require a higher natural gas pressure than firing gas in the existing boiler, so a high-pressure pipeline or natural gas compressors would be needed (Reinhart et al., 2012).

For turbine additions in Options 2 and 3, it is best if there is enough space at the plant to retire the boilers in place, as demolition adds expense and outage time to the construction project (Reinhart et al., 2012).

For Option 3, the new equipment would need to be compatible with the reused plant components, or the system might not run as efficiently as a new NGCC unit (EPRI, 1997). Steam mass flow patterns from combustion turbines are different than what existing coal plant steam turbines are designed to use (Reinhart et al., 2012). Turbine steam path components can be upgraded to help the new unit run more efficiently and reliably (Mashek et al., 2013). There may be modest life cycle cost savings associated with this option as compared to not reusing the existing steam turbine (Reinhart et al., 2012). According to recent analysis, though, reconfiguring coal steam plants to create NGCC units with existing equipment is not recommended, as savings do not outweigh project risks (Nowling, 2013).

The lead time for building a new NGCC unit, from permitting to site preparation to commercial operation, is 3 - 4 years (Xcel, 2011; Peltier, 2008). Demolition and removal of the old coal plant can then last another 1.5 years (Peltier, 2008). Construction time to combined cycle operation for plant retrofits, retiring the boilers in place, is around 2 years (Mashek et al., 2013).

The constraints discussed in the "Cofiring with Natural Gas" section, regarding natural gas infrastructure and fuel availability, gas pricing volatility, and risks from plant modification apply to these options as well.

B.7 Convert Natural Gas Peaking Plants to Combined Cycle

Technology Overview

Hoosier Energy's generation portfolio consists of two natural gas-fueled plants, the 174 MW Worthington Generating Station and the 258 MW Lawrence Generating Station. Converting these plants from natural gas simple cycle (NGSC) units to natural gas combined cycle (NGCC) units would greatly reduce the rate of CO_2 emissions from these plants. On average, a NGCC plant can generate the same amount of power as a NGSC plant using almost a 3rd less fuel (NACAA 2015). The main challenge with this option is that combined-cycle units have a longer startup time than simple-cycle units. Both the Worthington and Lawrence stations must be able to dispatch power quickly. As peaking plants, a quick startup time is essential to their ability to supply power during unanticipated increases in demand. Currently, both stations take approximately 15 minutes to start up and begin producing power. Full capacity can be reached in approximately 30 minutes. A typical NGCC unit takes anywhere from 1.5-3 hours to reach full capacity (Omatick 2012). While there are technologies and processes that can be used to significantly curtail this start up time, the majority has only been tested in pilot projects and much of the life cycle analysis has yet to be constrained.

If converted, the plants would have to be operated on a base or intermediate load basis. Given the moderate capacity of both, operating them as intermediate load plants would be the most appropriate. The plants could supply supplemental power if generation at Merom has to be scaled down, or if there is a large increase in demand. However, it is unlikely that Hoosier Energy will experience a large enough increase in its customer base to necessitate that additional capacity. It is important to note that while the conversion from NGSC to NGCC will reduce the plant's emissions, it will not reduce Hoosier Energy's emissions under the CPP. Emissions from peaking plants are not counted under the CPP. This compliance option is therefor more geared towards addressing Hoosier Energy's capacity needs under the CPP than its emission requirements.

Regulatory Backdrop

Converting a simple cycle plant to combined cycle will require obtaining revised air and water permits. The revised air permits will likely not be difficult to obtain as NGCC units have lower emission rates for regulated air pollutants than NGSC units. The water permits may prove more challenging, combined-cycle plants require more water than simple-cycle plants. The modifications may trigger the Prevention of Significant Deterioration, New Source Review, or New Source Performance Standards regulatory provisions (NACAA, 2015).

Capital, Operations, and Maintenance Cost

Converting a simple cycle plant to combined cycle will require the purchase of additional specialized equipment. At minimum, both the Worthington and Lawrence generating stations would be required to install a heat recovery steam generator, a steam turbine generator, condensers, a cooling tower, and additional water treatment systems and generator step-up transformers (Omatick, 2012). It is expected that both of the plants would be able to accommodate the additional equipment without the need for expansion. The client estimates the capital cost of converting the plants to NGCC be $2,500 per kW ($2,500,000/MW) (Hoosier Energy). Capital costs of conversion would be approximately $645,000,000 for the Lawrence plant and $435,000,000 for the Worthington plant. Because another company owns 1/3rd of Lawrence, however, we assume Hoosier Energy will only be responsible for 2/3 of capital cost.

Operating costs for NGCC plants vary greatly depending on the amount of time the plant is left offline, and whether or not the unit is subjected to significant load following (NREL, 2012). This analysis uses the startup and load following classifications as set forth by the National Renewable Energy Lab (NREL). A unit is considered to have undergone a warm start if time spent offline ranges between 5-40 hours. Restarting a unit below this range is considered a hot start, and any time above is considered a cold start. Load following refers to when the power output of unit is changed mid cycle (NREL, 2012). Only changes greater than 20% of the gross dependable capacity are considered significant enough to affect operating and maintenance (NREL, 2012). Operating and maintenance of NGCC plants depends on conditions, as illustrated in Table 6-2:

Table 6-2: Operating and Maintenance Cost for NGCC Plants Under Varying Startup Conditions.

Operating Condition	**Average Operating & Maintenance Cost ($/MW of Capacity)**
Hot Start	35
Warm Start	55
Cold Start	79
*Significant Load Following	+ 0.64*

*cost is additive to the conditional startup cost; (Reproduced from NREL, 2012)

Our analysis is run based on the assumption that the Lawrence and Worthington Generating Stations are typically operated under warm start conditions.

Implementation Benefits

Converting the Lawrence and Worthington Generating Stations to combined cycle plants would give Hoosier Energy the option to increase the generation of their peaking plants without increasing their CO_2 emissions. On average, a NGCC plant can generate almost a 3rd more power using the same amount of fuel (NACAA, 2015).

Implementation Challenges

The greatest challenges to converting the Lawrence and Worthington Generating Stations to NGCC plants will be obtaining financing and ensuring proper integration into the electrical grid.

B.8 Renewables: Wind and Solar Farm

Technology Overview

Wind turbines and photovoltaic (PV) solar panels are readily available for commercial-sized power generation. Wind farms have an average output of 2.4 MW, and solar farms of 1MW/4.8 acres. The capacity and output of either farm is dependent upon the reliability of the energy source and available land (for either turbines or solar panels).

Regulatory Backdrop

There are both state and federal incentives, whether in the form of tax breaks or emissions credits, to invest in wind and solar generation. Current legislation is pushing towards renewable energy as an alternative to fossil fuels in an effort to limit GHG emissions.

Capital, Operations, and Maintenance Costs

Table 6-3. Plant Characteristics and Associated Costs*

	Normal Capacity MW	Heat Rate Btu/kWh	Capital Costs $/MWh	Fixed O&M $/Kw*yr	Variable O&M $/MWh	National Energy Modeling System (NEMS) output
Wind Onshore	100	N/A	$2,213	$39.55	$0.00	Yes
Solar PV	150	N/A	$3,873	$24.69	$0.00	Yes

*EIA. (2014b). *Renewable Energy.* Retrieved from http://iea.net/renewable-energy5/

Implementation Benefits

While there are integration costs associated with switching to wind or solar energy, the fuel cost, as compared with coal, remains zero throughout its lifetime. Although wind energy has an average capacity of 30-40%, the energy source is steady from year to year, varying only on short-term scales (AWEA, 2014). Within the average rating, wind turbines can provide power for roughly 332 residential homes per year (AWEA, 2014). A solar farm spanning 12 acres (roughly 3600 MW capacity) can provide power for nearly 325 residential homes (EIA, 2012). With geographical advantages in the northern Indiana for wind, large-scale wind utility networks have already been established. According to the EIA, the total cost for wind energy (without federal taxes or incentives) is 9.7 cents/kilowatt-hour and 12 cents/kilowatt-hour for solar, comparable to coal's total cost of 9.4 cents/kilowatt-hour, adding to Hoosier Energy's profit margin.

Implementation Challenges

The payback period for a commercial wind farm varies between 20-30 years, and 7-10 years for a solar farm. The geographic location of Hoosier Energy in southern Indiana limits the availability of wind and solar resources, reducing the reliability of the energy source as well as the cost-effectiveness of the system. With median capacity ratings, the overall cost-effectiveness is reduced, explicit from the availability of the source.

B.9 Distribution and Transmission Improvements

Technology Overview

As energy is lost during the distribution and transmission of electricity, one method of limiting CO_2 emissions is improved efficiency in both areas. While high efficiency transformers, high temperature superconductors, and superconducting transformers can all improve step-up conversion efficiencies, the largest loss of electricity occurs between step-down substations and end users through transformers and cables (EIA, 2014). Improvements to transformer size, as well as installing 3-4 transformer banks at substations, can aid in loss reduction. By de-energizing these banks during low load periods and switching them on during high or peak periods, Hoosier Energy could limit both core and resistive losses at the substation (NACAA, 2015). Upgrading transmission lines from aboveground to underground single-circuit lines can raise the voltage capacity, limiting the amount of energy lost in transit.

Regulatory Backdrop

Transmission lines and distribution lines are subject to federal and state regulations, respectively. While FERC oversees costs of electricity transmission, RTOs, ISOs, and power pools aid in the creation of regional joint pricings for distribution costs. Line upgrades under 100 kV are to be reviewed for permitting by the Indiana Public Service Commission. Upgrades to distribution centers and/or power lines would trigger the Electric Power Generation, Transmission, and Distribution Standard set by OSHA.

Capital, Operations, and Maintenance Costs

Upgrading transformers within the distribution center vary in cost between $2 and $7 million depending on the voltage supported (EPA, 2011). While the factory cost per transformer remains reasonable, it does not include the taxes, installation or transportation expenses of the transformer, which can account for 25-30% of the capital costs. Transformers vary in cost, with nearly half of the cost associated with raw materials (copper and electric steel). Upgrading existing transformers to a thinner steel can improve conductor quality, resulting in lower energy losses. Table 6-4 reflects the varying costs associated with different steel thickness levels (EPA, 2011). With online monitoring of transformer performance, maintenance is either conducted on a risk-based or time-based system, greatly limiting the O&M costs, if the monitoring system is implemented.

Table 6-4 Typical Capital Costs for Electric Transmission Lines, by Voltage

Transmission Facility	**Typical Capital Cost**
New 345 kilovolt (kV) single circuit line	$915,000 per mile
New 345 kV double circuit line	$1.171 million per mile
New 138 kV single circuit line	$390,000 per mile
New 138 kV double circuit line	$540,000 per mile
New 69 kV single circuit line	$285,000 per mile
New 69 kV double circuit line	$380,000 per mile
Single circuit underground line	Approximately four times the cost of above-ground single circuit lines
Rebuild/Upgrade 69 kV to 138 kV line	$400,000 per mile

(Reproduced from American Transmission Company, 2003)

To upgrade transmission lines to underground single-circuit lines is 4 to 14 times more expensive. A new 69 kV underground line costs approximately $1.5 million per mile, mostly due to the extensive excavation necessary. The higher voltage 138 kV line costs nearly $2 million per mile for underground (without the terminals). Table 6-4 provides an accurate ratio of transmission line costs at 2003 pricings (EIA, 2003). The excavation process itself is dependent upon the land type being excavated and how much, also a large, yet variable cost. Maintenance costs for underground lines are difficult to predict, yet high variability and high expense has been associated with the main categories of repair: cable repairs, line outage durations, and line modification.

Implementation Benefits

Improving substation efficiency and building underground transmission lines allow greater grid reliability while decreasing energy losses. Reducing line losses also makes it less likely that system loads will surpass system capacity, therefore enhancing reliability as well. The overall payback period for improved transmission efficiency is 2.4 years for smaller transformers, and can account for an overall reduction between 2 and 4% of greenhouse gas emissions from reduced generation (EIA, 2014).

Outside of transformer upgrades to distribution centers, implementing energy efficient standards within the distribution center will aid in lowering emissions from the center. Better insulation and weatherization of the building will increase efficiency, and high efficiency HVAC systems will increase the efficiency of necessary units while keeping the battery system and protective relaying at normal temperatures.

Implementation Challenges

Transformer updates require substantial capital and long lead-time (greater than six months) to manufacture, with large crane requirements, ample floor space, and adequate testing and drying equipment to install.

Removing overhead lines may require circuit breaker maintenance and potential decreased liability, as well as costly maintenance for underground repairs. While underground lines provide the highest voltage (therefore reducing losses), they are expensive and only meant for short distances on relatively flat terrain; with a significant portion of Hoosier's portfolio being rural, the best method for reducing line losses would be to incorporate higher voltage lines, which can also be relatively expensive.

B.10 Cofiring with Biomass

Technology Overview

One option to reduce the rate of CO_2 emissions (lbs/MWh) from power generation is to cofire coal with biomass within the existing boiler units. The major caveat is that the CO_2 emitted at the stack when cofiring with biomass could be greater than that emitted when burning coal alone, depending on the properties of the specific biomass burned (NACAA, 2015). The emissions advantage to burning biomass depends on the extent to which regulators treat it as a carbon-neutral fuel after taking into consideration the balance between the CO_2 taken up during plant growth and released during combustion, along with other landscape impacts. The EPA has released a framework that could be used to determine how biomass emissions will be treated by regulators, but the agency has not yet committed to applying the framework in practice because the document is still in the process of scientific and public review (EPA, 2014b). Thus, the potential for a future biomass burning regulatory advantage is currently uncertain. However, EPA is willing to work with states to clarify this issue and evaluate state implementation plans that include biogenic (including agricultural) feedstock burning (McCabe, 2014).

Regulatory Backdrop

In general, biomass combustion results in less SO_2, NO_x, and Hg emissions than coal but more than natural gas when comparing pounds pollution per MMBTU input. A revised operating permit would be needed for the modified plant (NACAA, 2015).

Capital, Operations, and Maintenance Costs

It is estimated that the practical maximum amount of biomass cofiring that could be achieved is 10% of a boiler's output and 50 MW at a single site. Under this scenario, one of the units at Merom could theoretically cofire 10% biomass. The costs of infrastructure modifications allowing this arrangement would be at least $10 million, or $20/(boiler kW). Fixed O&M costs would increase by 10%, and heat rate (BTU/kWh) would increase by 1% due to decreased boiler efficiency (EPA, 2014a). Costs could be higher, as some modeling lists the capital cost of cofiring 50 MW biomass as $293/(biomass kW) (EPA, 2013). However, the main driver of project economics is the cost of the delivered biomass fuel. Biomass costs vary a lot regionally and by biomass type, but costs can be 4x that of coal on a BTU basis (NACAA, 2015). Indiana average delivered biomass costs 2016-2050 are expected to be $8.25/MMBTU, plus another $20/dry ton storage cost for agricultural residues (EPA, 2013).

Implementation Benefits

Assuming a delivered biomass cost of $4-6/MMBTU, a biomass heating value of 5000 BTU/lb, a starting (100% coal) net heat rate of 10,340 BTU/kWh, and a carbon neutral accounting policy (no biomass CO_2 stack emissions counted), biomass cofiring would reduce Merom CO_2 emissions by 5% at a cost of $30-80/metric tonne (EPA, 2014a).

Implementation Challenges

Importantly, the above analysis assumed that the biomass would be treated as completely carbon neutral. In the EPA's latest accounting framework iteration, Corn Belt corn stover (a likely crop residue fuel option for Merom) was projected to have a Biogenic Assessment Factor of 0.17. This means that 17% of biomass stack emissions would be counted as regulated CO_2 emissions, decreasing the potential for CO_2 emission avoidance and increasing the cost of CO_2 avoided by cofiring. Furthermore, the agency notes that this value could increase if increased demand for crops led to the conversion of forests to agricultural land. Thus, the carbon neutral status of crop residues is far from settled (EPA, 2014b).

Since biomass has a lower heating value/unit weight and a lower density than coal, the biomass used for 10% of the electricity output would likely be 2x heavier and 4-8x larger in volume than the coal replaced. Also, biomass can spontaneously combust if piled too high. Finally, if agricultural residues were used, they would only be delivered during certain seasons instead of steadily over time. Thus, storage space limitations could be a constraint (EPA, 2014a).

Each boiler at Merom fires around 30 TBTU (trillion BTU) per year (EPA, 2015a). In the state of Indiana, after aggregating the available urban and mill wood waste, forest residues, and agricultural residues, the estimated 2016 biomass availability is 0.69 TBTU/year (EPA, 2013).

Thus, supplying 10% biomass at one of Merom's units, or an input of 3 TBTU/year, would not be feasible, let alone after accounting for non-electric sector feedstock demand such as for cellulosic ethanol production. Even with projected increases in supply availability in the future, supply agreements and logistics could be a challenge. The plant would need a 20-ton truck delivery of biomass every 10 minutes, 5 days a week, 10 hours a day. Another drawback is that biomass ash might corrode the furnace (EPA, 2014a).

B.11 Cogeneration

Broad Overview

Cogeneration utilizes the heat which normally escapes or dissipates in a power plant after use in a turbine generator and collects it for extended use or to be sold as a commodity. Combined heat and power systems like this can be designed from the ground up, or they can retrofit existing power generators. The one plant which would be able to produce a significant amount of usable heat from a cogeneration system would be the Merom plant. However, Merom is geographically isolated from any large industry, school, recreation, government, or apartment buildings--all of which would be ideal buyers for the produced heat.

Without a market to sell the heat, Merom would only be able to use the produced heat onsite. While this would increase internal efficiency of the facility, which is quite large, the cost of performing the retrofit and maintaining the added equipment would outweigh the increased efficiency, though it would likely reduce emissions from parasitic loads.

Technological Overview

Cogeneration works by capturing “escaped” and “spent” energy and reutilizing it as low-grade heat. Cogeneration systems generally maintain two distinct levels of heat, a “high” and “low.” The high ranked heat is functional for energy production and spinning turbines--it is concentrated and very hot in temperature. Low level heat is the exhausted heat captured on the other side--it is more diffuse and cooler in temperature. While this lower heat is not useful for energy production, it is perfectly suited for heating buildings via steam radiators or central heating.

To sell and deliver this heat, the most efficient means of transporting it is through a closed loop thermal coil, not unlike the coils of a refrigerating unit.

Capital, Operations, and Maintenance Costs

Like most other energy production systems, larger cogeneration plants are less expensive per kW of capacity than a series of smaller ones. However, the larger a cogeneration plant is, the more heat there is to sell in a geographically narrow area, potentially creating an excess of heat supply to heat demand. This has led most adopters of cogeneration technology to keep their plants small to match the expected heat demand. Estimates for 50 MW plants range around $45 million, with a 1 MW system being about $1.6 million, for comparison.

Regulatory Backdrop and Implementation Benefits / Constraints

Under optimal conditions, a cogeneration plant can achieve 40% increased fuel productivity over a non-cogeneration counterpart. However, to make use of so much excess heat, the plant must find a buyer within relatively close proximity -- commonly schools, apartment complexes, large office buildings, or industrial manufacturing warehouses. Many forms of energy production are either not permitted to be in such close proximity due to safety concerns -- like nuclear -- or are otherwise undesirable in close proximity due to smoke and/or smog -- like coal.

We find that a cogeneration retrofit is not ideal for Hoosier Energy because the Merom plant does not have any potential buyers for large volumes of steam within a two mile radius. A new cogeneration plant in a location similar to Merom's would not be appropriate for similar reasons. Even under the scenario where Hoosier Energy builds a new power plant to replace Merom in an ideal location for cogeneration to market heat, the volume of steam that plant would produce would far outweigh the likely demand in that area. This would prevent the plant from reaching the touted 40% increased efficiency.

B.12 Switching to a Wholesale Trading Portfolio

One compliance option available to Hoosier Energy is to stop operations at the Merom plant and buy that power from others instead. A portfolio could be structured, with reliability in mind, in which some power was purchased on the spot market and some was procured through short- and long-term power purchase agreements. These would be bilateral structured contracts with firm transmission so that the client would have the same access rights to the power as the generators, akin to purchasing a portion of the generation. It would probably be best for the client to pursue this option quickly if they wish to use it, since there is a large amount of wind power coming online in the MISO area in the next few years so supply is high and purchase agreements may be cheaper than they will be later when others are trying to shut their coal plants as well and competing for the available alternative power. The debt on Merom would still need to be integrated into overall company operations costs, and capacity payments could be lost. However, Hoosier Energy may be able to purchase power cheaper than they are able to generate it themselves, making this an attractive economic option.

Pursuing this option would greatly change the client's generation and transmission cooperative identity, and there would need to be large shifts in employment. Instead of plant engineers, Hoosier Energy would need to hire wholesale electricity trading staff to ensure that generation needs were always covered, and at the lowest cost possible.

This option was not evaluated in depth due to the high risk involved, including uncertainty around the feasibility of such a dramatic change to the client's business model and questions about whether reliability could be maintained if this option were pursued.

Conclusions from Technical Analysis

Conclusions from the literature review of compliance options, summarized by viability in Table 6-5, are as follows.

Table 6-5. Compliance Options Categorized by Viability

Viability of Compliance Options for Hoosier Energy		
High	**Moderate**	**Low**
Thermal Efficiency Improvements at Merom	Repowering Merom With NG	Cofiring Merom with Biomass
Cofiring Merom with Natural Gas	Improving Coal Quality Through Washing	Increased Wind Energy Generation
	Converting Natural Gas Peaking Plants to Combined Cycle	Increased Solar Energy Generation
	Battery Storage	Distribution and Transmission Efficiency Improvements

Thermal Efficiency Improvements at Merom: Due to relatively low capital cost and the potential to curtail CO_2 emissions from Hoosier Energy's largest emissions source through only relatively minimal modification to plant operations, this option is included in several modeled compliance plan analyses.

Cofiring Merom with Natural Gas: Due to relatively low infrastructure modification needs and capital cost, low projected future natural gas costs, and the potential for significant CO_2 emissions reductions, this option is included in several modeled compliance plan analyses.
Improving Coal Quality: Hoosier Energy should consider switching to a coal with a lower ash and sulfur content if the additional cost incurred from increased fuel prices or the potential cost of reevaluating purchase contracts does not exceed operational and maintenance savings.
Battery Storage: Due to the current costs of battery technology, it is not recommended as a technology to revamp or replace currently productive peaking plants. In an instance where Hoosier Energy would seek to expand current peaking capacity, battery storage technology could provide the necessary value at a reasonable price while also maintaining compliance with the Clean Power Plan. Looking toward 2020 and beyond, battery technology is expected to make a phenomenal leap toward expanded economic viability. In this instance, battery technology could become a useful option for Hoosier Energy if circumstances ever require them to reduce or retire the capacity of the Worthington or Lawrence peaking plants.

Repowering Merom with Natural Gas (Replacement or Retrofit): This option is included in several modeled compliance plan analyses, as the fuel and O&M savings (compared to gas cofiring) and potential allowance sale revenues may outweigh the high upfront capital investment over the long run.

Converting Peaking Plants to NGCC: Due to the high capital cost we recommend that Hoosier Energy only pursue this option if generation at the Merom Plant is reduced so significantly that an additional base load generation source is required.

Increased Wind and Solar Generation: As Hoosier Energy moves toward renewable energy to aid in the reduction of emissions, it will benefit Hoosier Energy to invest in purchase agreements for renewables from other areas instead of investing in the development of their own solar and wind farms.

Distribution and Transmission Efficiency Improvements: It is not cost-effective for Hoosier Energy to invest in this option for the sole purpose of emissions reductions. However, long-term infrastructure upgrades will include line upgrades in the future, as well as transformer replacements.

Cofiring Merom with Biomass: Due to regulatory and feedstock supply uncertainties, logistical challenges, and the relatively small CO_2 emissions reduction potential, this option was not analyzed as part of a modeled compliance plan.

VII. Consumer Analysis

To comprehensively review the considerations important to public and consumer interests, information was gathered for a number of topic areas. After reviewing this information, we compiled the considerations deemed most important to consumers to rate public importance and consumer desirability. We gathered information via case studies, research, and consumer survey information for the following topic areas:

1. Community and Education,
2. The Environment,
3. Economic Development,
4. Service Delivery.

C.1 Community and Education

C.1.1 Community Outreach:

Hoosier Energy has a newsletter available online called *EnergyLines*. This newsletter is published monthly and offered to Hoosier Energy's past and present employees as well as cooperative boards and their employees. *EnergyLines* discusses current educational opportunities such as the co-operative (co-op) Accelerated Leadership Development program, outlines methods to increase safety within the workplace, and presents other cooperative communication topics. This is an excellent opportunity for Hoosier Energy to communicate with its cooperative members. While these issues are available online for the public to find, it may be beneficial to keep the public consumer in mind when writing in the future. The implementation of the Clean Power Plan will impact consumers and by notifying them of the various impacts, Hoosier Energy and its cooperative members may improve public support and further public their public outreach (Hoosier Energy, 2016b).

Hoosier Energy established small-scale pilot renewable energy projects in the form of wind and solar to educate distributors on the logistics of renewable energy technologies and open the conversation about renewable technology. These pilot programs also assist in demonstrating possible avenues for reducing electric bills in residential homes. Enhancing public knowledge on renewable alternatives may encourage further residential applications. Furthering knowledge of available resources such as the Alternative Power and Energy grant and the understanding of what generation and distribution involves is likely to promote decreased energy consumption. (Hoosier Energy, 2016g)

Hoosier Energy's commitment to long-term environmental stewardship extends beyond their cooperative members. Hoosier Energy also offers environmental educational outreach opportunities through their Environmental Education Center. This center allows educators of all age groups to take advantage of the educational resources, including curriculum created with the help of Indiana University's School of Public and Environmental Affairs, and laboratory setting to increase hands-on learning about environmental science. (Hoosier Energy, 2016d)

C.1.2 Education Initiatives:

Currently, Hoosier Energy has a variety of educational initiatives for youth and adults to promote environmental awareness and stewardship. Hoosier Energy has operated the Environmental Education Center since 1996, which serves as a learning center for science and environmental studies and includes both indoor and outdoor labs, audio-visual equipment, and educational materials. Educators, Boy and Girl Scout Troops, youth groups, and many others interested in learning hands-on about science and the environment have used the facility. Also housed in the center is the renewable energy system that powers the facility and serves as a venue for educating interested parties about renewable energy in southern Indiana. Near the Education Center, there is a floating dock that provides access to Turtle Creek Reservoir, where participants can collect water and sediment samples. In addition to the education center, Hoosier Energy has an educational resource program housed within Freshwater Fred's Lending Library. The lending library contains approximately 1800 educational videos, software programs and curriculum on a variety of subjects including biology, environmental science, and others (Hoosier Energy, 2016c).

The materials within the library are available for use at no charge to educators in Indiana, Illinois, Kentucky, Michigan, Ohio, and Wisconsin. Hoosier Energy also provides several helpful resources for environmental education, natural science studies, and environmental organizations on the website under the community and education tab. The community and education tab also includes links to webpages on energy issues, safety tips, and a kids zone that has interactive games for kids to learn about energy. (Hoosier Energy, 2016e)

C.1.3 Cooperative and Electric Industry Relationships:

As a regional electric entity, Hoosier Energy is involved and cooperates with a number of external, regional, and national organizations to fulfill its mission. These groups include the MISO, the North American Energy Reliability Council (NERC), the NRECA, Indiana Electric Cooperatives (IEC), the Energy-Producing States Coalition (EPSC) and other groups. Hoosier Energy's relationship with each of these groups varies in relation to purpose and how the Clean Power Plan will affect this relationship. For instance, the NRECA is the main political vehicle for electric cooperatives and is a part of the groups currently opposing the Clean Power Plan in court. At the same time, the NRECA provides resources to cooperatives, such as planning documents and development services. Along with other NRECA and IEC members, Hoosier Energy worries about the disproportionate impact of the CPP on rural communities because of increased energy prices and stranded assets. As a member of the EPSC, Hoosier Energy is using another platform to establish their interests, such as the discrepancy in impact they view from increasing regulatory burdens and reduced flexibility because of this (Energy-Producing States Coalition, 2014). Hoosier Energy coordinates with NERC on safety and reliability, and participates in tests of these measures as well as grid security with NERC. A recent audit by NERC's regional partner, ReliabilityFirst, indicated that Hoosier Energy received no violations for its reliability standards and preparedness (ReliabilityFirst, 2012).

On top of Hoosier Energy's external relationships, it is important to identify the role of internal relationships within Hoosier Energy, which includes its individual members as well as member cooperatives. Research on membership cooperatives indicates that it is crucial to appeal to members in decision-making. In the long-term, membership cooperatives need active members and loyalty to the organization (Virgil, 2010). Therefore, it is important that cooperative leadership to maintain the trust and legitimacy in a cooperative, such as Hoosier Energy, receives the values and input of members. To connect with its members, Hoosier Energy uses communications such as *EnergyLines* and Electric Consumer magazine as well as surveys, annual meetings, and leadership elections. These forums allow Hoosier Energy to receive feedback from community and cooperative members.

C.2 The Environment

C.2.1 Renewable Energy

There has been minimal research on public response to wind turbines and the associated impacts in the Midwest. However, one researcher characterized public feelings towards wind as a renewable energy by stating, "attitudes towards wind power are fundamentally different from attitudes towards wind farms" (Wolsink, 2007). Due to this separation in opinion, efforts need to be made to converge public support towards wind power and wind farms. To begin increasing public acceptance, the negative impacts that the residents perceive should be identified and discussed. A study performed in Benton County, Indiana (Mulvaney et al., 2013) came to the conclusion that the residents were not bothered by the presence of wind turbines. The research paper equated that acceptance to both personal esthetic preferences and/or the comfort that comes with the Midwest “working landscape” idea. Further, Mulvaney et al. associated the approval of renewable energy technologies in Benton County with the economic benefits displayed instead of environmental impacts. The boost in the job market played a vital role in increasing public acceptance in Benton County as the average household income is below that of the state of Indiana as a whole at $42,994 (Mulvaney et al., 2013).

Common concerns that the residents voice when discussing wind farms are: leasing and subsequently losing valuable agricultural land to wind farms, concerns that wind turbines won’t add to property value, visual appeal, and safety (ranging from noise pollution to physical injury from displaced ice) (Mulvaney et al., 2013). The most common concern however when it comes to consumers and renewable energy in general is the price of installation and maintenance (Mulvaney et al., 2013). One solution to mitigating some of these concerns is to schedule periodic public meetings and address these common concerns while actively listening to any additional issues. Another possible solution would be to engage with environmental and consumer groups such as the Citizens Action Coalition or the Sierra Club to further consumer and public knowledge of Hoosiers present and future advances in renewable energy and compliance.

While the cases above are not direct customers of Hoosier Energy, both cases have Indiana residents that are likely representative of clientele. Hoosier Energy can conduct their own survey of consumers to further understand their feelings towards wind energy and renewable energy as a whole. The questions asked by Mulvaney et al. (2013) for the Benton County case study included topics on social benefits and concerns as well as general demographic questions.

According to survey information that was collected by Hoosier Energy, their consumers somewhat agree that renewable energy technologies are of importance. Over half (55.7%) of the consumers that responded to the survey understand that it is important to use renewable energy sources for electricity generation and renewable energy generation had the highest percentage of respondents (40.6%) when asked about prefered generation techniques as compared to coal, nuclear power, and natural gas. (Strategic Marketing and Research, 2014)

Hoosier Energy runs a program called EnviroWatts that its cooperative members can opt into. If a consumer chooses to enroll in this program, Hoosier Energy secures a block of renewable energy for the consumer to utilize through their distributor (Hoosier Energy, 2016f). This allows both the cooperative members and their residential and commercial members to opt in to green energy if they wish. Currently, the renewable energy is produced from methane, gas-fired generators at an Indiana landfill (Bartholomew County REMC). It appears that nine out of Hoosier Energy’s 18 cooperative members mention the EnviroWatts program to their customers via their websites, and 169 consumers enrolled in the EnviroWatts program in 2015.

Public survey information was examined in regards to renewables. According to a survey on preferences for U.S. energy policy, conducted in 2014, Americans prefer renewable forms of energy over traditional forms of energy like oil and coal (Moore and Nichols, 2014).

C.2.2. Climate Change

Hoosier Energy has made major environmental investments within their power plants that has resulted in a 91% reduction in sulfur dioxide and nitrogen oxide emissions since 1983. By 2019, Hoosier Energy is on track to reduce these emissions by another 27% for an overall reduction in SO2 and NOx emissions of 93% since the first full year of Merom's operations.

Water quality and availability is essential to electricity production. In 2014, Hoosier Energy began a major renovation of the 30-year-old industrial wastewater treatment plant at the Merom Station to improve water flow capacity as well as better control iron, pH and total suspended solids. The new system is designed to meet current needs and future requirements while respecting environmental stewardship. The new plant can treat up to 1,050 gallons of water per minute and this was completed by the summer of 2015. Hoosier Energy will continue to monitor state and federal regulatory developments as water quality, availability and temperature regulations take on a higher profile (Hoosier Energy, 2014).

In the Midwest, more than 90% of the region's electricity is generated by coal-fired and other thermoelectric power plants, which are susceptible to increasing temperatures (DOE, 2013; EIA, 2013). Warmer temperatures reduce the generation capacity of power plants and the transmission capacity of power lines, while simultaneously increasing electricity demand for cooling (DOE 2013; USGCRP 2014). Energy-related infrastructure such as roads, railroads, and electric grid equipment may also be at increased risk of damage due to flooding, as heavy precipitation events are projected to occur more frequently (DOE, 2013; NOAA, 2013; USGCRP, 2014). Increased risk of floods and droughts may disrupt fuel transport on inlands waterways. Changing water availability and increasing temperatures may also affect biofuel production and refining capacity in the Midwest (NOAA, 2013; USGCRP, 2014).

New generation capacity can help address falling capacity due to decreased plant efficiency. Capacity expansion with low water requirements (e.g., thermoelectric power plants with dry cooling or wet–dry hybrid cooling technology) or no water requirements (e.g., wind and solar photovoltaics) would help make the region's power sector more resilient to climate change. Hoosier Energy can develop programs that reduce total and peak electricity demand and the water needs of thermoelectric generators. Wind energy technologies that are more resilient to climate change impacts can play an important role in future capacity additions. The region is enriched in wind resources, and new generation is likely to include expanded wind capacity (NREL, 2014a). Policy measures such as the Clean Power Plan can play an important role in encouraging wind energy development. In addition, innovation in wind turbine technology can enhance resilience to more extreme wind events. For example, because utilities cannot predict the availability of wind, it has been challenging integrating wind power into the electricity grid, but innovative battery designs and other grid-scale storage technologies designed to store energy produced by wind could enhance the use of wind turbine technology. Climate change affects weather; it will affect consumer demand for electricity, which will indirectly frame energy supply. Climate change policy is already exerting a major impact on energy supply portfolios and the delivery infrastructure, especially for electricity. If energy demand grows, so will production capacity needs. In the Midwest region, increased demand associated with climate change could potentially exceed 10 GW, which would require more than $6 billion in infrastructure investments (Gotham et al., 2012).

According to the survey information that was evaluated for Hoosier Energy, their consumers somewhat agree that climate change is of utmost importance (Strategic Marketing and Research, 2014). Consequently, a Gallup poll results, estimated how public perceptions about climate change has changed significantly over the years, In the 1980s to early 1990s, public awareness and concern about climate change rose dramatically. In the mid 1990s to mid 2000s, concern about climate change increased, partly due to media attention connected to increasing scientific data and political consideration. In the mid 2000s to late 2000s, there was growing uncertainty about the reality of climate change and the influence people have, regardless of the scientific data that proved otherwise. In the late 2000s to early 2010s, public concern about climate change is diverse across countries, with results revealing that climate change may be recurring to the public agenda (Capstick et al., 2015) . In addition, a 2014 study by the Global Commission on the Economy and Climate found that mitigating climate change globally would cost only 5% more than the amount that is invested in upgrading infrastructure (Public Citizen, 2015).

C.2.3 Vegetation Management

Hoosier Energy developed a vegetation management plan they use to ensure that they provide "safe, reliable, competitively priced and environmentally acceptable electric transmission" (Hoosier Energy, 2014d). Hoosier Energy's management plan is a combination of clearing trees from electrical transmission line paths, following recognized pruning standards, and working with property owners and cooperative members. To ensure that trees are clear of transmission lines, Hoosier Energy follows the right of way maintenance and outer zone maintenance approaches. Under right of way maintenance, they will remove trees and other woody-stemmed vegetation to the edge of the transmission line right of way. Under the outer zone maintenance, they will remove or trim dead, dying, diseased, or leaning trees that threaten the operation of the transmission lines.

Hoosier follows recognized pruning standards, which are:

- Branches are removed at a parent branch or at a lateral branch large enough to assume the terminal role.
- Branches growing into a utility line space are removed and those branches growing way from or parallel to the conductors remain.
- Trees are allowed to achieve their normal mature height with crown development away from the conductors (Hoosier Energy, 2014d).

Hoosier Energy maintains communication with property owners and members by notifying them of scheduled vegetation maintenance via telephone or notifications left on doors or gates. In the case that a maintenance crew cannot contact the property owner before maintenance and a dispute occurs with Hoosier Energy, they will work with property owners and members to ensure that a mutually agreeable resolution is reached (Hoosier Energy, 2014d).

Common concerns that the general public voice in regards to vegetation management include: removal of trees and other woody-stemmed vegetation to the edge of the transmission line right of way, increased soil erosion because of vegetation removal and construction equipment, and water quality impacts (Public Service Commission of Wisconsin, 1998).

There are a number of concerns associated with the addition of transmission lines specifically. These issues include: aesthetics, agricultural impacts, cultural impacts, and safety. In general, there tends to be a negative perception associated with the addition of new transmission lines in some rural areas; specifically, residents complain that transmission lines degrade the view of the landscape and change a rural landscape into a working one (Public Service Commission of Wisconsin, 1998). In addition, members of the public residing in rural communities are concerned that there is limited cultivable land, hindered spraying or seeding, increased spread of non-target species, and inhibited farm operation on agricultural lands. Lastly, there are concerns associated with property impacts and "fairness". There is an idea that one owner "bears the burden" of the new transmission line so that other community members can use the electricity (Public Service Commission of Wisconsin, 1998).

Some concerns with natural gas pipeline construction include: risk of accidents, spills, and explosions, and land destruction and associated impacts, which are the same concerns mentioned above (Food and Water Watch, 2013).

C.3 Economic Development

C.3.1 Employment

Hoosier Energy operates as a membership corporation and is a major taxpayer in 48 counties in Indiana and 11 in Illinois. Hoosier Energy is a cooperative business with nearly 500 employees that provides reliable and affordable electric power in an environmentally sound manner and carries a commitment to improve the quality of life in the region's communities. (Hoosier Energy, 2014b) Each of the power supply cooperative members elects a representative for the Hoosier Energy Board of Directors, which develops policies and reviews the cooperative's operations. The chief executive officer and his staff carry out day-to-day management of the organization, directing a workforce of more than 475 employees.

Value-Added Services:

Hoosier Energy provided training in new employee selection and hiring processes for six members, assisted four members with a CEO search and selection process, and piloted an Executive Leadership Development program for members with assistance from Indiana University's Kelley School of Business.

The communications department provided support to members through more than 45 projects. These projects include producing annual meeting video programs, writing articles and news releases, and providing event sponsorships. A new monthly communications toolbox provides members with customizable articles, graphics and videos for use in local communication programs.

The Hoosier Energy Apprenticeship Training and Safety program, commonly called HEATS, was started in 1975 with the goal of offering Hoosier Energy and member cooperatives training for line specialist and meter technician apprentices. In 2003, the Franklin Training Center was built to better educate and train member and G&T employees (Hoosier Energy, 2014c).

Overall, for every $1 billion investment in electricity generation, transmission, and distribution, electric cooperatives approximately create 14,000 jobs (Tucker, Schloss, Leitman, and Olivier, 2014).

Clean Power Plan & Employment:

As the proposed Clean Power Plan comes into place, it will be important for Hoosier Energy to provide assistance and support to employees who would otherwise be displaced during the commencement of this plan. The government can provide financial assistance through revenues generated from the auction of carbon allowances or credits. In addition, transitioning into the energy efficiency and renewable energy programs could counteract future employment losses and this can be done by training their workforces into transitioning to these new fields. For example, with electric sector reforming, some existing utilities and suppliers could shift toward developing energy-efficiency services and renewable energy (Bailie et al., 2010).

The Midwest has the best wind power resources in the United States, it is suitable for wind energy implementation. According to the Environmental Law and Policy Center estimates, a renewable energy portfolio standard of 22% can create 36,800 jobs by 2020 in the ten midwestern states, of which over 52% will be in the wind energy industry. Also, the Worldwatch Institute states that, jobs in extractive industries are plummeting, as mechanization and mergers result in continuous displacement of workers. The fossil fuel industry creates negative externalities which become visible in the loss of productive work days caused by illness due to pollution exposure, costs borne by industry (and eventually consumers) to clean up pollution, or costs borne directly by taxpayers for clean-up. Hoosier Energy will need to retrain their workforce to develop the new skills needed for Clean Power Plan compliance. Implementing relevant programs will be pertinent for retooling and retraining, and for attracting new industries.

C.3.2 Rural Development

Historically, cooperatives are well-placed for rural development because of the linkages between membership and community. This is based on the role of the Rural Utilities Service (RUS) to provide assistance to cooperatives to increase development in regions where cooperatives exist. Currently, the USDA is involved in expanding economic development in rural communities, and working with rural electric cooperatives is a key part of this initiative (Johnson, 2016). Economic development by rural cooperatives is an example of community-based collaborative development structure, which emphasizes public-private partnerships to coordinate and spur growth, especially in more challenging, rural areas (Virgil, 2010). Based on another study extending systematic public-private stimulation of economic development to rural areas, the authors Heriot and Campbell (2006) identified that rural electric cooperatives in three separate case studies acted as catalysts to development. In each case, the cooperative employed efforts to increase economic development cooperation and achieved some level of increased development, despite differences in approach and size. Hoosier Energy itself provides a number of resources and services for economic development.

Today, cooperatives must explore new opportunities to drive economic development while also contending with losing traditional generation sources that drive their development. Specifically, purchasing electricity from outside the cooperative will not support their local economy or lead to value-added (Farrell, Grimley, and Stumo-Langer, 2016)

Overall, from 2000 through today, Hoosier Energy invested approximately $6 billion in their communities and created or sustained at least 29,000 jobs (Hoosier Energy, 2015a). Recent investments focused on solar energy, efficiency, and modernization projects. For individual projects, Hoosier Energy invested in considerable projects for economic development. An example of this is recent investment in solar energy that both brings to stability to the grid and highlights that Hoosier is “a progressive community” (Green, 2015). Hoosier Energy updates the public on its economic development projects and initiatives through its communications as well as its economic development website, *Hoosiersites.com*, which is coordinated by their Hoosier Energy Economic Development platform. Through this platform, Hoosier Energy provides a number of economic development services, including assistance with project analyses and studies, site mapping and development, electric rate analysis, marketing, and other functions. Additionally, the site highlights previous economic development projects Hoosier Energy supported.

Recent trends suggested that most people prioritize economic development over the environment. However, one of the most recent Gallup polls on the environment found that the environment was considered more important than economic development (Swift, 2014). In contrast to this, when considering all issues that are important to the public, the economy and unemployment/jobs consistently rank as the most important issues or problems (Jones, 2016).

C.4. Service Delivery

C.4.1 Safety and Reliability

Hoosier Energy provides wholesale electric power and services to 18 member distribution cooperatives in central and southern IN and southeastern IL. It operates coal, natural gas, and renewable energy power plants and delivers power through nearly 1700 miles of the transmission network (Hoosier Energy, 2014b).

Hoosier Energy has a “robust” safety program and was one of the first generation and transmission cooperatives to achieve Rural Electric Safety Accreditation Program certification from the National Rural Electric Cooperative Association in the United States. Hoosier Energy also has also been able to maintain a high standard with high scores consistently. Hoosier Energy provides safe and reliable power to its members through a transmission network of 1,724 miles of high-voltage lines, 41 large power transformers, 24 primary substations and more than 350 substations and delivery points (Hoosier Energy, 2014).

Hoosier Energy has demand side management programs, which include energy efficiency and demand side response. These programs assist in reducing demand at a lower cost in comparison to building new power plants. Hoosier Energy launched an energy efficiency program in 2009. This program was created to help consumers manage their energy usage more efficiently or effectively; and to decrease the ramifications that the rising power prices may have on consumers. Currently, Hoosier Energy has a goal to reduce system peak demand and total energy sales by 5% from forecasted levels by 2018. Hoosier Energy offers its 18 member distribution cooperatives some demand-side management programs, which include: Appliance Recycling Program, Commercial & Industrial Prescriptive Rebate Program, Energy Management program, Residential HVAC Program, Residential Lighting Program, and the Touchstone Energy Home Program. (Hoosier Energy, 2016a).

The Clean Power Plan leads to changes in the cost of operating different types of power plants which in turn will affect the dispatch of electricity. States can implement some tools that can partially or entirely mitigate the impact of program costs on the consumers and the public in general. In some cases, these devices can generate consumer and broader net economic benefits. With regards to public concerns, a recent CNN/USA Today/Gallup poll shows that, while relatively few Americans view the current energy situation as a "crisis," seven in 10 believe the availability and high cost of energy are at least a major problem for the country. Americans are most likely to blame oil and electric companies for the current energy problems, rather than politicians or consumers. Still, two-thirds of the public believes that Americans must make real changes to their lifestyle to help resolve the energy problems. An Indiana SIP could include a variety of elements that could lower the demand for power, thereby reducing the average cost of electricity supply. These elements include encouraging cost-effective energy efficiency, demand response, and renewable projects on customers’ premises (Hibbard, Okie, and Tierney, 2014).

C.4.2 Consumer Cost for Electricity

The Clean Power Plan will have positive and negative effects on consumers in Indiana. This mandate will have a significant impact on the average price of electricity in the table above. Members and consumers have some general concerns about the Clean Power Plan, which include changing the price of power passed to electricity customers and changing the amount of power consumed by customers as a result of energy efficiency compliance investments. EPA’s analysis indicates that consumers will see slightly higher electricity rates in the short-run but lower electricity bills in the future with the Clean Power Plan in place. As a result of the increase in the cost of electricity, consumers will tend to have less disposable income. Compliance will increase the cost of doing business for affected plant owners in ways determined by a state's plan. For instance, in states where electric utilities own affected power plants, such costs will tend to be passed along to those utility's consumers. through regulated rates as a pass-through of a variable expense, or as recovery of and a return on compliance capital investments Power producers will attempt to pass along such costs in the prices they charge for generating electricity. If Indiana goes with a SIP, it can be designed in such a way that flow revenues back to electricity customers can mitigate the impact of power supply price increases (Hibbard et al., 2014).

It is vital to keep in mind that the impact of the Clean Power Plan on electricity prices, through increased costs at some power plants, is incomplete because it examines and over-emphasizes only one part of the electricity cost structure. A typical electricity bill includes other elements apart from the costs relating to electricity supply such as the costs to transmit and distribute electricity to the end user, and costs to manage power system operations and markets. Of the all-in price of electricity approximately 40% of the costs relate to the distribution and transmission of electricity, and 60% relate to power production. Therefore, for a 1% change in the price of electricity generation, there will be a smaller change in the bottom-line price of electricity. (Hibbard et al., 2014).

C.5 Consumer Analysis Inputs and Other Considerations

After reviewing the topic areas outlined above in the perspective of public opinion and Hoosier Energy's customers, we determined that consumer concerns primarily existed under renewable energy, climate change, vegetation management, rural development, employment, and cost of electricity. We determined these topic areas based on the associated issues being most prescient for consumers in how they receive electricity.

After examining reliability and safety, it was found that consumers are generally more concerned about these topics after-the-fact. Therefore, while Hoosier Energy needs to consider reliability and safety, because of the difficulty gauging prior public reactions to disruptions of service, it is not considered through the public and consumer interest lens. Community and education describe why Hoosier Energy should consider consumer concerns and how to potentially address those concerns after implementation.

In addition to reviewing the key topic areas as outlined above, we also considered reviewing the compliance tools and the public and consumer considerations for each to provide a second layer of review. However, we could not ascertain a clear public and consumer review at the level of possible interventions to comply with the Clean Power Plan because of changing scope and cost for each of the interventions that depended on each framework. Therefore, we focused on analyzing individual compliance plans over interventions.

VIII. Model Methodology

A. Policy Methodology

In Section V, we identify eight policy decisions which a state would have to make in designing its policy framework. For each decision, we give our best estimate of which is more likely for Indiana, which appears to be preferable for Hoosier Energy, and how important the decision is with regard to Hoosier Energy's compliance costs. This analysis informs two fundamental policy frameworks: the framework most likely for Indiana (Framework 1: IND) and our hypothesis for which framework would be most preferable for Hoosier Energy (Framework 2: HEP), both detailed earlier in Section V.

We consider five additional frameworks for use in the financial model in order to examine the effects of toggling individual decisions that vary from IND, using this framework as a baseline.

Three of these frameworks toggle different decisions between IND and HEP in order to isolate their effects. One framework turns on the statewide energy efficiency program (Framework 3: SEE). Another switches on the NSC and removes all three set-asides (Framework 4: NSC). The last changes the allocation method from historical to preferential treatment for Hoosier Energy (PTH). The final two frameworks also start with IND as a baseline but test other outcomes not present in HEP that we think are important enough to analyze. One framework changes the historical allocation of allowances to an auction (Framework 6: AUC). The other assumes that Hoosier Energy's Ratts plant will not receive allowances in the historical allocation method (Framework 7: NAR). We lay out these frameworks in Table 8-1 below, highlighting decisions that differ from IND in each case.

Table 8-1. Summary of Seven Policy Frameworks

IND	**HEP**	**SEE**	**NSC**	**PTH**	**AUC**	**NAR**
State	State	State	State	State	State	State
Mass	Mass	Mass	Mass	Mass	Mass	Mass
Trading	Trading	Trading	Trading	Trading	Trading	Trading
Direct (Historic)	Direct (Extra for Hoosier Energy)	Direct (Historic)	Direct (Historic)	Direct (Extra for Hoosier Energy)	Auction	Direct (None to Ratts)
No NSC	NSC	No NSC	NSC	No NSC	No NSC	No NSC
Set-asides	No set-asides	Set-asides	No set-asides	Set-asides	Set-asides	Set-asides
No state measures	No state measures	No state measures	No state measures	No state measures	No state measures	No state measures
No state energy efficiency plan	State energy efficiency plan	State energy efficiency plan	No state energy efficiency plan	No state energy efficiency plan	No state energy efficiency plan	No state energy efficiency plan

*Highlighted cells represent decisions that differ from IND

We next operationalize the seven policy frameworks by translating decisions into numbers for our financial analysis. Policy frameworks influence crucial parameters affecting Hoosier Energy's strategy for complying in a least-cost manner, including the number of allowances the cooperative receives, the price of allowances in the open market, and other costs and benefits (e.g. paying into a statewide energy efficiency program but reducing their electricity demand by some percentage). We first develop baseline assumptions for the IND framework. From there, we operationalize the differences between frameworks by altering these assumptions based on our research. We give full details about our assumptions and numbers--as well as how we arrive at them--in Appendix C.

B. Technical Methodology

Based on the designated policy frameworks, we develop a system for evaluating the viability of technologies and processes that Hoosier Energy can implement to satisfy the requirements of the CPP. First, we use a combination of literature review and case study research to determine a menu of available options. Options that are based on unproven technologies or shown to be technically and/or economically unfeasible are excluded from this list and all subsequent analysis. The final menu, shown in Table 8-2, includes ten options: cofire Merom with natural gas, repower Merom with natural gas, cofire Merom with biomass, improve the quality of coal used at Merom, thermal efficiency improvements at Merom, convert the simple cycle natural gas peaking plants to combined cycle, improve transmission and distribution efficiencies, battery storage, solar energy generation, and wind energy generation.

Table 8-2. Compliance Option Categorization

Viability of Compliance Options for Hoosier Energy		
High	**Moderate**	**Low**
Thermal Efficiency Improvements at Merom	Repowering Merom With NG	Cofiring Merom with Biomass
Cofiring Merom with Natural Gas	Improving Coal Quality Through Washing	Increased Wind Energy Generation
	Converting Natural Gas Peaking Plants to Combined Cycle	Increased Solar Energy Generation
	Battery Storage	Distribution and Transmission Efficiency Improvements

We present these options ranked as high, moderate, or low viability. Rankings are determined through a scoring system that assesses each option in six categories: technical maturity, capital cost, emission reduction potential, cost effectiveness of emission reductions, implementation constraints, and lead time to implementation. A mix of qualitative and quantitative data is used to evaluate each category for each option on a scale of -1 to 1. All scores are specific to Hoosier Energy and determined in light of the company's resource constraints and needs. The scales are as follows:

Technical Maturity

-1: Technology is still in the research and development phase, is difficult to scale up, and/or has only been tested in pilot projects. The full life cycle has yet to be constrained.
0: Technology is readily available but is likely to be outmoded by increases in efficiency and/or reductions in costs due to technological improvements before the full lifespan of the technology.
1: Technology is readily available.

Capital Cost

-1: > $500 million
0: $100 million to $500 million
1: < $100 million

Emissions Reduction Potential

-1: no CO_2 reduction
0: up to 5% CO_2 reduction
1: > 5% CO_2 reduction

Cost Effectiveness of Emissions Reductions

-1: relatively lower compared to other options
0: neutral
1: relatively higher compared to other options

Implementation Constraints

-1: geographic, infrastructure, input, regulatory, and/or permitting challenges severe enough to halt project implementation
0: project requires obtaining revised permit, and/or moderate infrastructure changes
1: relatively few geographic, infrastructure, input, regulatory, and/or permitting challenges hindering implementation

Lead Time to Implementation

-1: > 2 years
0: 1 - 2 years
1: < 1 year

The categorical scores are then summed to produce the final ranking score for that option. Table 8-3 provides summary explanations for each option's given scores. Cumulative scores ranged from 5 to -1 and are ranked as follows:

High Viability: 5 to 3
Moderate Viability: 2 to 1
Low Viability: 0 to -1

High viability options are recommended for Hoosier Energy to pursue in compliance plans under all policy frameworks. Moderately viable options are recommended under some specific frameworks. Low viability options are not recommended. Scores were assigned to each compliance option as a follows:

Table 8-3. Compliance Option Rankings Broken Down by Analysis Category

Technology Option	Impact	Score	Justification/Explanation
Battery Storage	Technology Maturity	-1	Battery storage technology has been predicted to surpass peaking plants in the next 1 to 5 years--making it non-useful for a present day solution
	Emissions Reduction Potential	1	In settings where production and/or demand are highly variable, battery storage is among the most effective technologies in increasing efficiency. In the case of replacing the Worthington and Lawrence peaking plants, 100% or 960 thousand tons/year of CO2 emissions would be reduced. This is assuming all energy is produced by renewables.
	Capital Cost	0.5	Even at current prices, battery storage can compete directly with peak power plants in terms of $/kW of capacity ($750-$950/kW). Claimed to fall as low as $250 per kw of capacity in 2020. This means, with today's technology, replacing a peaking plant would cost more than $126 million, but could reach as low as $40 million in the near future.
	Cost Effectiveness of Emissions Reductions	0	Considering that batteries are charged with energy from wind farms, solar panels, or other intermittent sources, the peaking energy provided would involve a zero or nearly zero level of CO2 emissions
	Implementation Constraints	0.5	The technology is most effective when combined with highly intermittent supply or demand of power, ie renewable sources.
	Implementation Lead Time	1	Aside from manufacture and technological development, battery systems are self contained systems and, upon arrival, can be grid-ready in less than a month
Cogeneration	Technology Maturity	1	Cogeneration, while not common, is a generally well understood technology with high market viability.
	Emissions Reduction Potential	1	Cogeneration can increase the productive energy output of a plant by 40%--assuming the produced heat is fully utilized.
	Capital Cost	0	New cogeneration plants are between $900 and $1500 per Kw of capacity. Retrofit projects vary too greatly to provide an effective recommendation for Hoosier Energy.
	Cost Effectiveness of Emissions Reductions	0	Dependent on capital costs and use
	Implementation Constraints	-1	For cogeneration to be fully effective, it requires a nearby buyer for the produced heat--like a hospital, apartment complex, or university campus. Since Merom is intentionally remote, this becomes a significant limitation.

	Implementation Lead Time	0	Construction of a new plant would take between 3 and 4 years. Retrofit of Merom is estimated to take between 2 and 3 years.
Cofiring with NG	Technology Maturity	1	readily available technology
	Emissions Reduction Potential	1	4% reduction for 10% gas, 41% reduction for 100% gas
	Capital Cost	0	around $290/kW including pipeline construction
	Cost Effectiveness of Emissions Reductions	0	$83/metric tonne for 100% gas firing, maybe cheaper because of low natural gas prices
	Implementation Constraints	1	burner modifications to maintain full capacity, pipeline construction, gas capacity availability and price, natural gas price volatility
	Implementation Lead Time	1	14 months plant shutdown for modifications
Repowering with NG	Technology Maturity	1	readily available technology
	Emissions Reduction Potential	1	62% reduction from a coal plant on a per capacity basis, assuming the efficiency of a new NGCC plant
	Capital Cost	-1	around $1,000/kW
	Cost Effectiveness of Emissions Reductions	1	$50/metric tonne
	Implementation Constraints	0	New Source regulatory hurdles, need space for plant and gas compressor, same gas constraints as cofiring option
	Implementation Lead Time	-1	3 - 4 years to build a new NGCC plant on the Merom property
Cofiring with Biomass	Technology Maturity	1	Readily available technology
	Emissions Reduction Potential	0	Practical maximum 5% reduction at Merom, and could be lower depending on pending carbon neutrality policy
	Capital Cost	1	$20 - $30/kW
	Cost Effectiveness of Emissions Reductions	-1	$30 - $80/metric tonne assuming carbon neutral policy, likely higher for Merom because of high feedstock costs
	Implementation Constraints	-1	Carbon neutrality policy still uncertain, biomass storage needs, questionable nearby feedstock availability, difficult to set up supply chain
	Implementation	0	Plant modification needs low, but coordinating

	Lead Time		logistics could take longer
Improving Coal Quality	Technology Maturity	1	Readily available technology
	Emissions Reduction Potential	0	2-3%
	Capital Cost	0	Estimated fuel cost increase of $0.04 per ton
	Cost Effectiveness of Emissions Reductions	-1	Highly dependent on the contract established between Hoosier Energy and their coal suppliers
	Implementation Constraints	1	Current fuel contracts would have to be re-negotiated
	Implementation Lead Time	1	6 months
Converting NG Peaking Plants to Combined Cycle	Technology Maturity	0	The basic technology is readily available, but newer systems designed to reduce startup times are still under development
	Emissions Reduction Potential	1	An approximate 33% reduction at each plant
	Capital Cost	0	$645,000,000 for the Lawrence Plant and $435,000,000 for the Worthington Plant based on capital cost of $2,500 per kW
	Cost Effectiveness of Emissions Reductions	0	High capital cost is greatest impediment, once converted however the plants will not require any additional modifications to control emissions
	Implementation Constraints	-1	Integrating converted plants into the grid could prove extremely difficult due to their increased generation
	Implementation Lead Time	-1	3 - 4 years
Thermal Efficiency Improvements at Merom	Technology Maturity	1	Readily available technology
	Emissions Reduction Potential	0	2%
	Capital Cost	1	$1,000,000 annually
	Cost Effectiveness of Emissions Reductions	1	$500,000 per each percent decrease in emissions
	Implementation Constraints	1	Certain components may need to be temporarily taken offline during optimization projects
	Implementation Lead Time	1	Negligible lead time, improvements could begin to be implemented within a few weeks

Distribution and Transmission	Technology Maturity	1	Readily available technology
	Emissions Reduction Potential	1	8% reduction due to efficient energy transport
	Capital Cost	-1	Replacing ~1700 miles with only single circuit, 69 kV line costs near $484 million; underground upgrades are four times this amount
	Cost Effectiveness of Emissions Reductions	0	High capital costs create improved energy transport and long-term infrastructure upgrades
	Implementation Constraints	0	Determined by the land and length of the line in question
	Implementation Lead Time	0	Determined by the land and length of the line in question
Renewables: Purchase Agreements	Technology Maturity	1	Readily available technology
	Emissions Reduction Potential	1	Purchasing renewable energy will limit the generation of Merom and other fossil-fueled plants
	Capital Cost	0	Dependent upon the agreement (Duke, Dayton, etc.) and MW market price
	Cost Effectiveness of Emissions Reductions	1	Dependent upon the MW purchased, yet directly offsets emissions while limiting generating costs to plants
	Implementation Constraints	1	Hoosier Energy already has 20 year agreements in place with multiple renewable power generators in the Midwest
	Implementation Lead Time	1	Energy transfer infrastructure is already present, as Hoosier Energy already has renewable agreements in place
Renewables: Solar & Wind Generation	Technology Maturity	1	Technology is readily available
	Emissions Reduction Potential	1	Wind & solar farms produce no GHG emissions
	Capital Cost	-1	$2,213/MW for 100 MW of wind; $3,873/MW for 150 MW of solar
	Cost Effectiveness of Emissions Reductions	0	Dependent upon the size and output of the farm, whether wind or solar
	Implementation Constraints	-1	Capital costs are high with a poor geographic location for either solar or wind (southern Indiana)
	Implementation Lead Time	-1	Dependent on size, some farms could take 4-10 years to complete

Table 8-3 represents the relative compliance options as ranked by five separate analysis categories. Each compliance option was ranked on a scale of -1 to 1 based on the individual analysis category, with a ranking of 1 being the most beneficial.

To create baseline inputs for the compliance plans, we used the coal, gas, renewable, and purchased MWh projected in Hoosier Energy's IRP for 2016-2018. We then assumed that the coal, gas, and renewable MWh would remain the same from 2018-2046 and that purchased power would increase to cover projected increases in energy demand. Total MWh needed was scaled from projected demand using the client's projected savings based on a previous consultant's demand side management report, assumed to continue at 3.8% of total demand from 2018 onward. The cost of each MWh saved in the demand side management program was assumed to remain the same from 2018 on. Short tons of coal needed annually were calculated from the client's provided coal specification and Merom heat rate. Natural gas needed annually was calculated using IRP estimates for the Worthington, Lawrence, and Holland heat rates. Total CO_2 emissions from Merom, Hoosier Energy's only facility under Indiana CPP caps, were based on the client's estimated ratio of 1 ton of CO_2 for every MWh generated. We then implemented changes to this baseline model input to account for changes made in each compliance plan.

In the Merom thermal efficiency improvement scenarios, we decreased coal needs and emissions by 2% while keeping the amount of power generated from coal stable. Annual costs, per client estimate, were added to account for these improvements.

In the cofiring with natural gas at Merom scenarios, we changed the amount of coal and gas needed each year based on the proportion of each fuel fired and EPA estimates for boiler efficiency at that fuel ratio. CO_2 emission rates were reduced using the EPA's estimated emissions reductions (compared to 100% coal) for the fuel ratio used. Capital costs were added for the necessary boiler modifications and pipeline construction, along with the client's estimated cost for securing firm natural gas capacity. O&M costs were also reduced when cofiring began, based on EPA estimates of cofiring impacts on coal plant O&M.

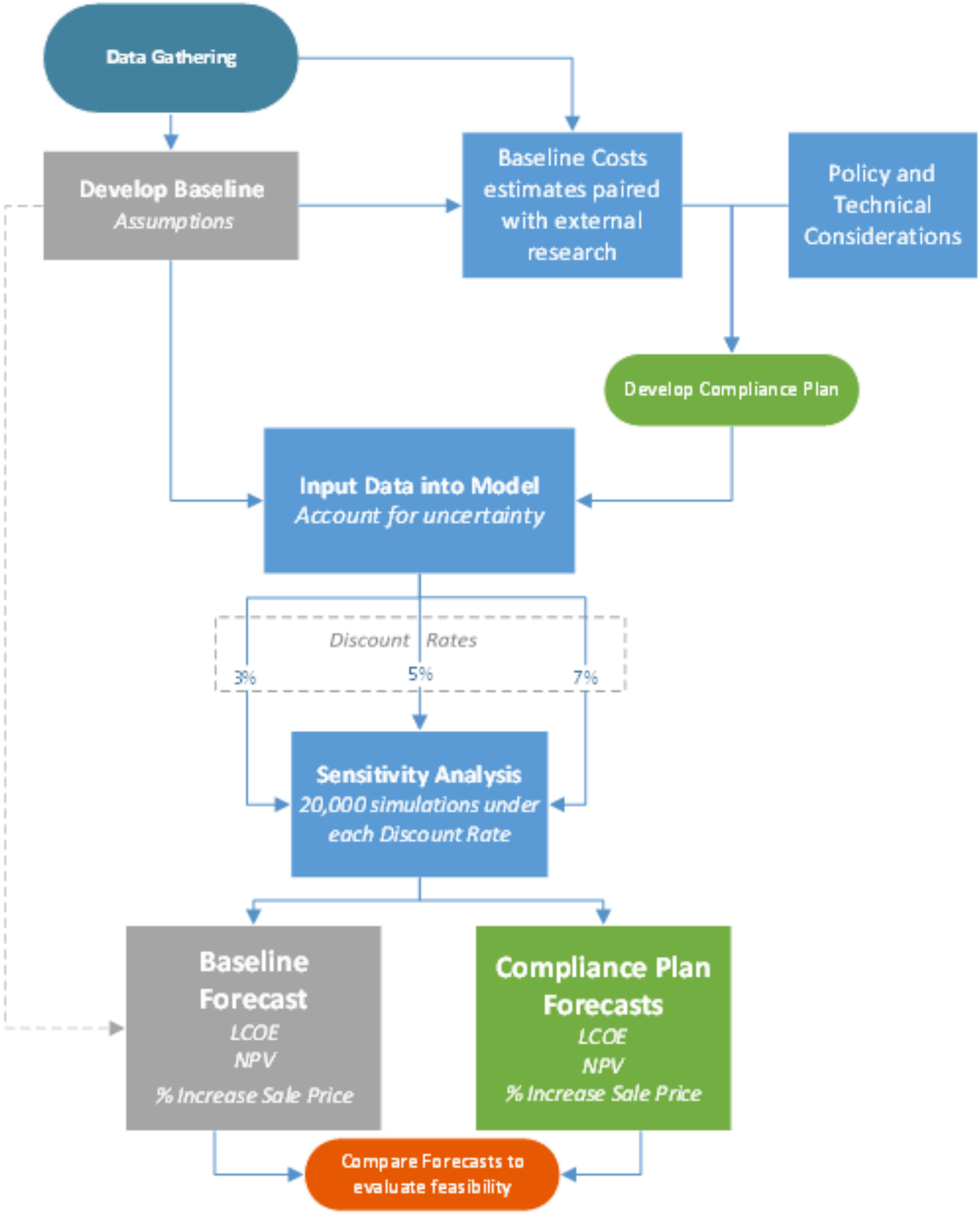
In the NGCC scenarios, we eliminated coal costs when the gas plant came online and added natural gas costs based on the EPA's heat rate estimate for a new NGCC plant and the assumption that the plant would run at a 75% capacity factor, which is the EPA's CPP goal for NGCC plant utilization. This increased the power output to greater than that provided by Merom, resulting in a decreased need for Hoosier Energy to purchase power to meet its demand. CO_2 emissions were set to zero. Although of course the NGCC plant would still emit CO_2, for the policy frameworks this compliance option was considered under the CPP emissions cap would not be applicable to these emissions. Capital costs were added for the plant and pipeline construction, along with the client's estimated cost for securing firm natural gas capacity. O&M costs were reduced when the new plant came online, based on the ratio of the EPA's estimated O&M costs for coal plants over 30 years old vs. those for new NGCC plants.

Each compliance plan's annual fuel usage, power purchased and sold, allowances purchased or sold, capital costs, and O&M costs would impact Hoosier Energy's financial performance. These changes were put into our financial model and compared to the baseline forecast after 30 years along a series of outputs including average LCOE, % change in LCOE over the baseline, NPV, and the necessary average annual % change necessary in the sale price of electricity to remain profitable. Likewise, to account for uncertainties, the financial model also used Monte Carlo simulations and three unique discount rates to make realistic predictions. These outputs and the methodology of the financial analysis are described in the financial methodology section detailed below.

C. Financial Methodology

We have constructed a financial model in order to quantify the impact on Hoosier Energy of each compliance plan. In essence, the model begins by developing a compliance plan, which considers basic financial assumptions, policy framework constraints, and the technical options to meet those constraints. Costs associated with technical compliance options (e.g. capital, operations, or fuel costs) and allowances were input into the model in the year in which they are incurred by Hoosier Energy. By aggregating and discounting all costs and benefits over a 30-year time horizon, the model produces three important numerical outputs which describe the Hoosier Energy's costs of CPP compliance. The flowchart below graphically depicts the creation and financial evaluation of each compliance plan in question.

Figure 8-1. Financial Model Creation, Inputs, Outputs, and Process



The model is designed to examine the financial impact of costs and revenues that are as granular in scale (e.g. transmission costs, distribution costs, administrative costs) as those reported in the client's 2014 Annual Report. Similarly, the financial model can incorporate costs and revenue impacts that are as aggregated as categories like O&M costs, capital costs, fuel costs, etc… Our results are based mostly on the use of the latter, as cost estimates were mostly derived from sources like EIA and EPA, which tend to estimate costs and revenues in aggregate.

The model starts with a 2016 baseline and then forecasts costs and benefits over the next thirty years. The baseline is comprised of a series of variables (e.g. fuel costs, taxes, operations and maintenance, etc...) determined using data from both the 2014 and 2010 Annual Reports. The variables used in our model match those presented in the costs and revenues given in Hoosier Energy's 2014 Annual Report. Baseline variable values in year 2016 are simply an average of the values from three most recent years, to avoid dependence on statistical outliers that may be present in any one year. We subsequently project these values forward by assuming and fitting a linear trendline to the nine years of data in the reports. The assumptions we use to create the model are listed in Appendix B. Based on these assumptions, we create a business-as-usual scenario (herein "baseline"). This scenario represents normal operation without the CPP. We then run the compliance plans through the model to determine how they compare with each other and the baseline forecast.

To generate the most robust results possible, we use multiple discount rates, multipliers, and Monte Carlo simulations. We run each compliance plan with 3%, 5%, and 7% discount rates to determine how well each plans compares at different valuations of costs incurred in the future. To account for uncertainties in the allowance market prices (a market that does not currently exist), we predict a price per allowance and a standard deviation that represents our certainty in that price. We then use these standard deviations as multipliers when forecasting the price of allowances. Finally, we run Monte Carlo simulations to account for the uncertainties in allowance prices and growth in price of electricity sold.

Our model strives for precision rather than accuracy. For example, Levelized Cost of Electricity (LCOE) does not necessarily represent what the average LCOE will be over the next 30 years. The relative values of financial outputs are much more important, and we are more confident that relative ordinal rankings are accurate. While model is fortified by using information directly from Hoosier Energy, it cannot account for many future exogenous uncertainties, like the exact mix of policies that Indiana will adopt to comply with the CPP.

Net Present Value (NPV)

Seven designated policy frameworks house two to three compliance plans for each framework, where each compliance plan is composed of a different set of compliance options. Each compliance option includes a variety of capital, fuel, and other compliance costs. We incorporate these costs into the model (in the year in which Hoosier Energy might pay these costs) by adding or subtracting them from the 2014 baseline costs. The same is done for any extra revenues associated with each compliance plan.

All costs and revenues are then totaled in each given year and summed. Each is discounted back to present value (t = 0). The formula for NPV is below:

$$NPV = \sum_{t=0}^{30} (R - C)_t * (\frac{1}{(1+r)^t})$$

NPV = Net Present Value
R = Annual Revenue
C = Annual Cost
t = time period (0 - 30)
r = discount rate

Once all costs and revenue streams are discounted to present, they are then summed. By subtracting present costs from revenues, the model then produces the NPV for a given compliance plan.

This NPV is particularly sensitive to the discount rate (r) used in the discounting equation. Recognizing this, each compliance plan is run through the model three times, using discounted rates of 3%, 5%, and 7% iteratively. This sensitivity analysis accounts for uncertainty in the tradeoff between costs (or benefits) incurred now or in the future over the 30-year time horizon.

Levelized Cost of Electricity (LCOE)

LCOE was also calculated for each compliance plan, within each policy framework, in order to provide a sense for the average price Hoosier Energy would need to sell electricity in order to recover the costs of CPP compliance. Costs for each compliance plan were, as above, aggregated in each year. These annual costs were then discounted back to present time and summed. A capital recovery factor was applied to this summed cost resulting in an annualized cost. Finally, this annualized cost was divided by the MWh sold in each year to provide an LCOE for every year over the project time horizon. These LCOEs were averaged to result in one LCOE output for each compliance plan. The formula is below. Important assumptions about the growth in demand and electricity sales are listed in Appendix B. Notably, the LCOE calculation does not utilize any possible additional revenue accrued to Hoosier Energy. It merely relates what must be charged to buyers to recover all costs of compliance and “break even”.

$$LCOE = \frac{\sum_{t=0}^{30} \frac{\sum_{t=0}^{30} (C_t * (\frac{1}{(1+r)^t}) * \frac{(r)(1+r)^t}{(1+r)^t - 1}}{MWh\ sold_t}}{30}$$

LCOE= Levelized Cost of Electricity
C_t = Annual Cost
t = time period (0 - 30)
r = discount rate
MWh $sold_t$= MWh sold in a time period

% Increase in Sales Price of Electricity

This output represents the average annual percentage increase in the price of electricity sold from Hoosier Energy to "break even." It is related to the LCOE, but describes what must happen on an annual basis, rather than LCOE's average over 30 years, in order for the client to recover all of their costs of compliance. This metric assumes that Hoosier Energy can set the sale price for electricity, that demand is highly inelastic, and that costs will be borne by consumers. Simply put, for Hoosier Energy to ensure that all costs are covered, they must plan to increase the sale price of electricity by this amount per year. It is important to keep in mind that this increase is relative to the 1.4% increase determined in the baseline. The proper interpretation of a 4% increase, therefore, is that Hoosier Energy must increase the sale price of electricity by an average of 2.6 percentage points over the baseline to remain profitable.

D. Consumer Methodology

Table 8-4. General Importance and Hoosier Energy Consumer Desirability Table

	Cost of Electricity	Economic Development	Local Environmental Issues	Renewables & Global Climate Change	Total Desirability
General Importance					
Recommendation 1					
Recommendation 2					
Recommendation 3					

__Description of Analysis__

To analyze overall public and consumer concerns, the public and consumer specialists review four key categories of concern in regards to the importance to the general public and the desirability of Hoosier Energy's consumers for the outlined top three compliance plans. This is represented by Table 8-4.

__Four Categories of Concern__

We place the six topic areas that determine the key consumer considerations into four categories of concern to evaluate each compliance plan. These categories of concern are:

- Cost of Electricity- Perceptions on cost to produce per kWh with the assumption that those costs will be borne by the consumer
- Economic Development- Employment and rural development
- Local Environmental Impact- Perception of land/vegetation, water, safety, and human health concerns.

- Renewable Energy and Global Climate Change- Perception of long term impacts of climate change and use of renewable energy in the place of conventional generation sources.

Importance

We evaluate the four categories of concern on a scale of 1 to 3 based on the importance to the general public. The scale is as follows:

1: Least Important
2: Moderately Important
3: Most Important

We assign these values after analysis of public opinion information based on nation wide survey results, research, and case studies stating public opinion and feelings regarding each of the four categories. We then evaluate this information to determine the importance to the general public.

Desirability

We evaluate the top three compliance plans on a scale of 1 to 3 based on their desirability to Hoosier Energy's consumers. The scale is as follows:

1: Least Desirable
2: Moderately Desirable
3: Most Desirable

We assign these values based on information about Hoosier Energy's consumers, including survey information, research on Hoosier Energy, research on electric cooperative consumers/members, and case studies. We then evaluate this information to determine the desirability of Hoosier Energy consumers.

We then sum the assigned values across each of the four categories of concern to get an overall level of desirability for each of the three compliance plans in regards to Hoosier Energy's consumers.

General Public-Hoosier Energy Consumer Difference

By comparing the desirability ratings for Hoosier Energy's consumers to the importance ratings for the general public in regards to the four categories of concern, Hoosier Energy can better understand how the concerns of their consumers differ from that of public opinion.

On a categorical level, it is important for Hoosier Energy to understand where their consumers stand regarding these four areas of concern. Overall, Hoosier Energy can use the sums of these categorical concerns to understand which compliance plan is most appropriate for their consumers.

IX. Financial Analysis

Considering the importance of the action that Hoosier Energy ultimately chooses, it is vital to understand the context of our recommendations. Simply comparing our recommendations to a "business as usual" approach ignores the gravity of the regulatory burden imposed by the CPP.

To account for this, our financial model makes a number of assumptions detailed in Appendix B and presumes the most conservative estimates for each of these assumptions. The calculation of a negative NPV under the baseline forecast is an expression of that sense of caution. Overall, there are a few important takeaways independent of our recommendations. Our findings reveal the following:

- The policy framework that is most likely for Indiana is a relatively desirable option for Hoosier Energy.
- There is a likely increase in Hoosier Energy's LCOE of 22-46% depending on the policy framework adopted by Indiana and the compliance plan adopted by Hoosier Energy.
- Depending on the compliance plan, Hoosier Energy will need to increase the sale price of electricity by an average of 3.9-5.6% annually compared to the 1.4% necessary under the baseline forecast.

Detailed Findings

The following table summarizes the findings of the financial analysis. All values are shown at the 5% discount rate. Additional outputs under the 3% and 7% discount rates are available in Appendix E, Table E-1.

Table 9-1. Outputs of each compliance plan by policy framework

Policy Framework	Compliance Plan	Description	LCOE*	LCOE %Δ over baseline	NPV*	%Δ Electricity Sale Price**
		Baseline	0.087	n/a	(784,156)	1.4%
Most Likely for IND	1A	cofire Merom with NG (to 100%)	0.119	37.80%	(6,518,686)	5.1%
	1B	purchase allowances	0.111	28.60%	(5,124,607)	4.4%
	1C	NGCC	0.107	23.20%	(4,296,090)	4.0%
Hoosier Energy Preference	2A	thermal efficiency + purchase allowances	0.111	27.70%	(4,884,418)	4.2%
	2B	cofire Merom with NG	0.117	34.50%	(5,926,043)	4.8%
	2C	thermal efficiency + cofire Merom with NG	0.115	32.90%	(5,682,740)	4.7%
Statewide Energy Efficiency	3A	cofire Merom with NG (to 100%)	0.120	38.70%	(6,545,228)	5.1%
	3B	purchase allowances	0.112	29.30%	(5,135,668)	4.3%
	3C	NGCC	0.110	27.00%	(4,780,764)	4.2%
New Source Compliment	4A	thermal efficiency + purchase allowances	0.110	27.50%	(4,947,530)	4.3%
	4B	cofire Merom with NG (to 100%)	0.118	36.00%	(6,253,960)	5.0%
Preferential Treatment for Hoosier	5A	cofire Merom with NG (to 100%)	0.119	37.20%	(6,436,227)	5.1%
	5B	purchase allowances	0.111	27.70%	(4,996,061)	4.3%
	5C	NGCC	0.106	22.40%	(4,177,831)	3.9%
Auction	6A	cofire Merom with NG (to 100%)	0.127	46.20%	(7,792,300)	5.6%
	6B	purchase allowances	0.118	36.50%	(6,340,128)	4.9%
No Allocation to Ratts	7A	cofire Merom with NG (at 100%)	0.121	39.40%	(6,766,095)	5.2%
	7B	cofire Merom with NG (to 100%)	0.122	40.30%	(6,917,706)	5.3%
	7C	NGCC	0.108	24.20%	(4,455,456)	4.0%

5% Discount Rate | 2014 Dollars *Average of 60,000 Simulations
** Annual Average Increase in the Sale Price of Electricity Necessary to Break Even

Green cells represent the top five optimal numbers for each output (Min: LCOE, LCOE %Δ over baseline, %Δ in the energy sale price | Max: NPV). Red cells represent the least optimal outputs.

The table below summarizes the financial outputs of three compliance plans under the first policy framework (most likely for Indiana). Baseline values represent Hoosier Energy operating under a business as usual scenario. Increases in real costs cause LCOE to increase to approximately

$0.0866 per kWh, averaged over the next 30 years, and the NPV to be about -$784,156,000. It is important to note that these figures are built on the assumptions that the demand for energy will increase by an average of 1.08% annually and the sale price of electricity will increase by approximately 1% annually. This is an expression of conservative estimates built into our model. Should Hoosier Energy choose to increase the sale price of electricity in order to maintain a positive NPV, and thus remain profitable, the sale price of electricity should be increased by at least 1.386% annually. This baseline forms the basis for considering the financial feasibility of various compliance plans.

Table 9-2. Outputs of compliance plans for the most likely framework for Indiana

Compliance Plan	LCOE*			%Δ over baseline			NPV*			%Δ Electricity Sale Price for NPV=0**		
	3%	5%	7%	3%	5%	7%	3%	5%	7%	3%	5%	7%
Baseline	0.090	0.087	0.084	n/a	n/a	n/a	(1,467,161)	(784,156)	(387,044)	1.5%	1.4%	1.3%
1A	0.122	0.119	0.118	35.9%	37.8%	39.7%	(8,684,285)	(6,518,686)	(5,068,360)	4.8%	5.1%	5.4%
1B	0.113	0.111	0.110	25.9%	28.6%	31.2%	(6,672,822)	(5,124,607)	(4,070,066)	4.1%	4.4%	4.7%
1C	0.106	0.107	0.107	18.8%	23.2%	27.6%	(5,220,804)	(4,296,090)	(3,640,026)	3.6%	4.0%	4.4%
1C ***	0.114	0.114	0.113	27%	31.06%	35%	(6,956,354)	(5,509,868)	(4,505,044)	4.2%	4.507%	4.9%

*60,000 Monte Carlo simulations each = 120,000 simulations per compliance plan
** Represents average annual increase in the sale price of electricity for NPV to equal 0
***Represents compliance plan 1C in which allowances have a market price of zero

The following is an example of how to interpret each of the outputs from each compliance plan. For a complete list of compliance plan details, see Appendices D and E. Considering the third compliance plan (1C), we anticipate a 23.21% increase in the average LCOE, to $0.1067 kWh, over the 30 years of analysis. This drives the NPV from a baseline of -$784,156,000 to -$4,296,090,000. Should Hoosier Energy choose to increase the sale price of electricity in order to maintain a positive net present value, and thus remain profitable, the cooperative should increase the sale price of electricity by at least 3.976% annually.

Within this particular policy framework, our financial model therefore identifies compliance plan 1C as the most cost-effective plan. Compliance plan 1C involves building a new NGCC plant and operates under the assumption that Merom will be retired early but will continue to receive allowances through 2047. With the new NGCC plant falling under 1.11(b) instead of the CPP, Hoosier Energy could sell these allowances to offset the new plant's high capital costs. Since the allowance market is highly uncertain, we analyze this compliance plan under a parallel scenario in which the allowance price is set to zero. Under this scenario--marked as compliance plan 1C*** in Table 9-2--all else is held constant but no revenues or costs are incurred by the sale or purchase of allowances.

Under this parallel scenario, we anticipate that compliance plan 1C will increase the average LCOE by 31.06%, to $0.114 kWh, over the 30 years of analysis. This drives the NPV from a baseline of -$784,156,000 to -$5,509,868,000. Should Hoosier Energy choose to increase the sale price of electricity in order to maintain a positive net present value, and thus remain profitable, the cooperative should increase the sale price of electricity by at least 4.507% annually. Though this is a weaker performance than the original compliance plan 1C, in which revenues can be generated through the sale of allowances, it still performs better than compliance plan 1A and almost equally as well as compliance plan 1B.

Late in our analysis however, we realized that one of our assumptions for the NGCC compliance plan is highly unlikely--rather, Merom will likely only receive allowances through the end of the compliance period after which it was retired, or through 2027. The decision of how long retired power plants will continue to receive allowances is ultimately written into a state plan, and therefore is unknown at this point. Allocating allowances to plants after they retire is a method to address leakage, serving as an incentive to retire old coal power plants. However, there is little motivation for a state to give allowances past a few years. Running the model again under the scenario where Merom receives allowances only through 2027 gives an LCOE very similar to that of assuming it did not receive allowances at all (represented as compliance plan 1C*** in Table 9-2). Therefore, our corrected financial analysis shows that compliance plan 1B is of least cost, closely followed by compliance plan 1C***.

Next, we sort compliance plans from Table 9-2 from lowest to highest LCOE across all frameworks to inform which framework is most favorable for Hoosier Energy; this is represented in Table 9-3.

Table 9-3. Compliance plans sorted by LCOE

Compliance Plan	Description	LCOE*	LCOE %Δ over baseline	NPV*	%Δ Electricity Sale Price**
	Baseline	0.087	n/a	(784,156)	1.4%
5C	NGCC	0.106	22.40%	(4,177,831)	3.9%
1C	NGCC	0.107	23.20%	(4,296,090)	4.0%
7C	NGCC	0.108	24.20%	(4,455,456)	4.0%
3C	NGCC	0.110	27.00%	(4,780,764)	4.2%
4A	thermal efficiency + purchase allowances	0.110	27.50%	(4,947,530)	4.3%
1B	purchase allowances	0.111	28.60%	(5,124,607)	4.4%
2A	thermal efficiency + purchase allowances	0.111	27.70%	(4,884,418)	4.2%
5B	purchase allowances	0.111	27.70%	(4,996,061)	4.3%
3B	purchase allowances	0.112	29.30%	(5,135,668)	4.3%
2C	thermal efficiency + cofire Merom with NG	0.115	32.90%	(5,682,740)	4.7%
2B	cofire Merom with NG	0.117	34.50%	(5,926,043)	4.8%
4B	cofire Merom with NG (to 100%)	0.118	36.00%	(6,253,960)	5.0%
6B	purchase allowances	0.118	36.50%	(6,340,128)	4.9%
1A	cofire Merom with NG (to 100%)	0.119	37.80%	(6,518,686)	5.1%
5A	cofire Merom with NG (to 100%)	0.119	37.20%	(6,436,227)	5.1%
3A	cofire Merom with NG (to 100%)	0.120	38.70%	(6,545,228)	5.1%
7A	cofire Merom with NG (at 100%)	0.121	39.40%	(6,766,095)	5.2%
7B	cofire Merom with NG (to 100%)	0.122	40.30%	(6,917,706)	5.3%
6A	cofire Merom with NG (to 100%)	0.127	46.20%	(7,792,300)	5.6%

*60,000 Monte Carlo simulations each = 120,000 simulations per compliance plan
** Represents average annual increase in the sale price of electricity for NPV to equal 0

Table 9-3 represents our original output. However, the same mistaken assumption--that a retired power plant receives allowances indefinitely--is carried through these results for all NGCC compliance plans. We therefore assume that correcting this assumption is equivalent to an increase in LCOE of $0.007/kWh (the difference between 1C and 1C*** in Table 9-2) for each NGCC compliance plan. Table 9-4 reflects the updated LCOE rankings under the more stringent assumption that Merom does not receive allowances once Hoosier Energy retires it.

Table 9-4. Corrected compliance plans sorted by LCOE

Compliance Plan	Description	LCOE*	LCOE %Δ over baseline	NPV*	%Δ Electricity Sale Price**
	Baseline	0.087	n/a	(784,156)	1.4%
4A	thermal efficiency + purchase allowances	0.110	27.50%	(4,947,530)	4.3%
2A	thermal efficiency + purchase allowances	0.111	27.70%	(4,884,418)	4.2%
5B	purchase allowances	0.111	27.70%	(4,996,061)	4.3%
1B	purchase allowances	0.111	28.60%	(5,124,607)	4.4%
3B	purchase allowances	0.112	29.30%	(5,135,668)	4.3%
5C	NGCC	0.113	30.50%	-	-
1C	NGCC	0.114	31.30%	-	-
7C	NGCC	0.115	32.30%	-	-
2C	thermal efficiency + cofire Merom with NG	0.115	32.90%	(5,682,740)	4.7%
2B	cofire Merom with NG	0.117	34.50%	(5,926,043)	4.8%
3C	NGCC	0.118	36.30%	-	-
4B	cofire Merom with NG (to 100%)	0.118	36.00%	(6,253,960)	5.0%
6B	purchase allowances	0.118	36.50%	(6,340,128)	4.9%
1A	cofire Merom with NG (to 100%)	0.119	37.80%	(6,518,686)	5.1%
5A	cofire Merom with NG (to 100%)	0.119	37.20%	(6,436,227)	5.1%
3A	cofire Merom with NG (to 100%)	0.120	38.70%	(6,545,228)	5.1%
7A	cofire Merom with NG (at 100%)	0.121	39.40%	(6,766,095)	5.2%
7B	cofire Merom with NG (to 100%)	0.122	40.30%	(6,917,706)	5.3%
6A	cofire Merom with NG (to 100%)	0.127	46.20%	(7,792,300)	5.6%

*60,000 Monte Carlo simulations each = 120,000 simulations per compliance plan

** Represents average annual increase in the sale price of electricity for NPV to equal 0

Examining Table 9-4, we see that several frameworks appear to be similarly preferable for Hoosier Energy. The lowest-cost compliance plan is 4A, in which Hoosier Energy would make thermal efficiency improvements at Merom and purchase allowances from the open market to cover the difference. This framework is similar to the most likely framework for Indiana, except it uses the NSC in place of set-aside programs. In the next section, we discuss why this may not truly be the most preferable framework for Indiana, however.

X. Recommendations and Conclusions

A. Recommendations

We make two separate recommendations based on the results of our financial analysis and supported by research from our qualitative analysis. The first recommends a least-cost compliance plan under the most likely policy framework for Indiana. The second recommends a policy framework for which Hoosier Energy should advocate in order to further reduce compliance costs. These recommendations are contingent upon Hoosier Energy's key decision of whether to continue operating Merom.

1. Recommendation 1 - Least-cost compliance plan under most likely framework for Indiana

We find that Indiana is most likely to develop a mass-based, trading-ready state plan that allocates allowances directly based on historical generation, uses set-asides to address leakage rather than the NSC, and does not use state measures or a statewide energy efficiency program.

If Indiana designs its state plan in this way, Table 9-2 suggests that compliance plan 1B (with an LCOE of $0.111/kWh) represents the least-cost way of reaching compliance. Under this plan, Hoosier Energy takes no action other than to purchase allowances from the open market. However, allowance prices are our most uncertain input in the model. Further, if all utilities come to this conclusion and opt to purchase allowances, prices are likely to increase dramatically. Therefore, compliance plan 1B is very risky.

We see from Table 9-2 that compliance plan 1C*** (with an LCOE of $0.114/kWh) represents the next lowest-cost way of reaching compliance. Under this plan, Hoosier Energy builds an NGCC plant, with construction beginning in 2021 and the plant coming online in 2024. This plant replaces Merom's capacity and--since the NGCC plant runs at a 75% capacity factor--increases power output from the plant by 2.7% compared to projected 2018 output. This decreases the amount of power Hoosier Energy needs to purchase by 7% compared to projected business-as-usual operations. While this compliance plan involves retiring Merom in favor of building a new NGCC plant--or repowering Merom with natural gas, which designates Merom a new source and requires a similar investment--it represents significantly less risk by avoiding the uncertain allowance market. This plan does require Hoosier Energy to make a big commitment however by switching from coal to natural gas and subjecting the cooperative to fluctuations in the natural gas market.

We recommend that Hoosier Energy follow compliance plan 1C***. With this plan, Hoosier Energy avoids heavy reliance on the highly uncertain allowance market, bringing the cooperative greater independence, certainty, and control relative to compliance plan 1B. If Hoosier Energy decides it does not want to retire Merom however, the cooperative will have to choose between relying on the allowance market or making costly investments in the facility, as represented by compliance plan 1A--choosing to co-fire Merom with natural gas at an LCOE of $0.119/kWh.

2. Recommendation 2 - Policy framework in Hoosier Energy's best interest

We next turn to our financial outputs in Table 9-4 to inform our recommendation of the policy framework in the best interest of Hoosier Energy. We note that the five compliance plans with lowest LCOEs rely heavily on purchasing allowances. Even the first two compliance plans--which call for thermal efficiency improvements--require the purchase of a very large number of allowances. As discussed in Recommendation 1, any plan advising the purchase of a large number of allowances is highly risky for Hoosier Energy.

We see that compliance plan 5C represents the next best option at an LCOE of $0.113/kWh. Again, this plan involves the construction of an NGCC plant, offering the lowest risk and greatest control for the cooperative. This suggests that Hoosier Energy should advocate for framework 5, which only differs from framework 1 by having the cooperative receive extra allowances beyond historical generation. Hoosier Energy should argue that it should receive more allowances relative to what it would receive under historical generation since the cooperative serves a more distributed network of users with fewer financial resources than the state's major utilities.

We briefly note that our assumptions concerning the statewide energy efficiency program's effect on Hoosier Energy are uncertain. In operationalizing this policy decision, we estimate that Hoosier Energy's electricity demand is reduced by some percent at some cost paid to the state. Our financial model suggests that Hoosier Energy pays more as part of the program than it would receive in the form of facing reduced demand. However, if our predictions are wrong and Hoosier Energy does benefit from the program, then Hoosier Energy should advocate for a framework inclusive of extra allowances and the statewide energy efficiency program. This is represented as a hybrid of frameworks 3 and 5.

Our analysis changes once more if Hoosier Energy decides it does not want to close Merom. When we designed framework 2--our original hypothesis of the most preferable framework for Hoosier Energy--we assumed that it would not be in Hoosier Energy's interest to close Merom. Our first recommendation shows that it is actually cost-effective and significantly less risky to build an NGCC plant. If we are underestimating the cost and feasibility challenges of closing Merom however, we want to provide a recommendation for the next most cost-effective plan.

Looking to Table 9-4, if we remove all compliance plans that only purchase allowances or that comply by building an NGCC plant, we are left with the top four being 4A, 2A, 2C, and 2B. In other words, three of the least-cost compliance plans fall under framework 2. Compliance plans 4A and 2A also rely heavily on purchasing allowances, leaving 2B and 2C as less risky (albeit more expensive) plans.

Therefore, if Hoosier Energy chooses to not retire Merom, it can comply at least cost under framework 2. In particular, Hoosier Energy should advocate for the plan most likely for Indiana, but with an allocation scheme that favors them as a rural electric membership cooperative, the NSC in favor of set-asides, and a statewide energy efficiency program (if this appears to benefit Hoosier Energy relative to the costs of the program). Under this framework, Hoosier Energy can achieve least-cost compliance with thermal efficiency improvements and purchasing allowances (high risk) or thermal efficiency improvements and co-firing Merom with natural gas (low risk). As the common factor in frameworks 2 and 4, we see that the NSC is most important in this case. This makes intuitive sense--if Hoosier Energy does not build a new NGCC plant, then it benefits from the extra allowances it receives under the NSC.

B. Consumer Desirability

Table 10-1 shows the complete, assigned ratings for each compliance plan based on the four primary categories of concern: cost of electricity, economic development, local environmental issues, and renewables & global climate change. The general importance ratings are a reflection of how the general public views these concerns. The consumer desirability ratings are a reflection of how Hoosier Energy's consumers will respond to intended changes. The total desirability scores are the the sum of these individual ratings for each category. In this section, we review the considerations behind these ratings, the most desirable compliance plan for Hoosier Energy's consumers, and a comparison of concerns between the general public and Hoosier Energy's consumers. A comprehensive discussion of our ratings is found in Appendix G. We also discuss possible strategies for outreach with consumers to mitigate their concerns associated with CPP compliance.

Table 10-1. Consumer Desirability Conclusions

	Cost of Electricity	Economic Development	Local Environmental Issues	Renewables & Global Climate Change	Total Desirability
General Importance	3	3	2	1	
Recommendation 1	2	1	1	2	**6**

(1C)					
Recommendation 2 without closing Merom (2A)	1	3	3	1	**8**
Recommendation 2 with closing Merom (5C)	3	1	1	2	**7**

For **compliance plan 1C**, we considered a number of aspects that might affect Hoosier Energy's consumers upon implementation. These considerations include: the change in the cost of electricity, the amount of staff required to operate a NGCC plant, the effects of retiring Merom in regards to job loss, the impacts that the construction of new gas pipelines will have on the local environment, and the impact that the plan will have on greenhouse gas emissions. We compared the results of these considerations for this compliance plan to the other two recommendations and gave a rating for each of the four areas of concern accordingly. Based on that analysis, compliance plan 1C was given a total rating of 6.

For **compliance plan 2A**, we considered two major factors that might affect Hoosier Energy's consumers upon implementation. These considerations include both the overall change in the cost of electricity and the impact that the proposed compliance plan will have on greenhouse gas emissions. We compared the results of these considerations for this compliance plan to the other two recommendations and gave a rating for each of the four areas of concern accordingly. Based on that analysis, compliance plan 2A was given a total rating of 8.

For **compliance plan 5C**, we considered a number of aspects that might affect Hoosier Energy's consumers upon implementation. These considerations include: the change in the cost of electricity, the amount of staff required to operate a NGCC plant, the effects on retiring Merom in regards to job loss, the impacts that construction of new gas pipelines will have on the local environment, and the impact that the plan will have on greenhouse gas emissions. We compared the results of these considerations for this compliance plan to the other two recommendations and gave a rating for each of the four areas of concern accordingly. Based on that analysis, compliance plan 5C was given a total rating of 7.

1. Most Desirable Plan for Consumers

Based on our analysis, the most desirable compliance plan for consumers is 2A. This is largely because of the economic development impacts from not closing Merom and the more desirable local environmental impacts resulting from less land development. Additionally, there is less potential for accidents through new construction, operation, and maintenance of a Natural Gas Combined Cycle Plant. The compliance plan with the least consumer desirability is 1C and compliance plan 5C falls between the most and the least desirable. The only key difference between these two plans is the price of electricity will increase more in 1C, which is less desirable for consumers. Overall, the difference between the lowest desirability score is two points. This signals that consumers despite different areas of concerns, no one plan is likely to raise significant concerns for consumers.

2. Hoosier Energy Consumer Concerns Compared with Public Concerns

Compared with the concerns of the general public, the most desirable compliance plan has the lowest desirability in terms of cost, despite this being one of the most important concerns to the general public. In terms of economic development, which is also one of the most important concerns, Hoosier Energy consumers would find this plan to be most desirable. This is likely because this plan will not shut down Merom, which means there should be no significant disruptions in employment, the operation portfolio of Hoosier Energy, and its business structure. There appears to be tradeoff for Hoosier Energy's consumers on the two most important public concerns of economic development and cost of electricity.

The general public views local environmental issues as somewhat important, and the most desirable overall plan for consumers is also the most desirable in terms of local environmental issues. Therefore, this plan will provide desirable economic and environmental impacts in line with issues the public finds to be at least somewhat important. Lastly, the general public views climate change and renewable energy as the least important concern, but the most desirable compliance plan for Hoosier Energy's consumers is least desirable for this category. This is likely because this plan will not advance renewable energy production or significantly mitigate carbon production. Because this is a concern to Hoosier Energy's consumers based on survey information, this is not desirable to them, despite the low importance to the general importance (Strategic Marketing and Research, 2014).

3. Suggested Community Outreach Strategies

In order to further promote the public image of Hoosier Energy in regards to the chosen CPP compliance strategy, we offer two suggestions. The first suggestion revolves around Hoosier Energy's electronic newsletter *EnergyLines*. To further enhance community outreach Hoosier Energy could create a similar online publication designed for consumers specifically. This might manifest itself via a section on public education and engagement or a separate newsletter like *EnergyLines* from the public or consumer point of view. This addition may act as an additional educational outreach component for Hoosier Energy both by increasing knowledge of the electric generation processes and the benefits the compliance plan has on the four primary consumer concerns.

Another option that may further increase public relations would be for Hoosier Energy to host open annual meetings to try and mitigate consumer concerns through facilitated discussion. This meeting could be backed up by online agendas and meeting minutes to try and engage as many people into the discussion as possible. One way other rural energy cooperatives work in a meeting of this sort is by opening the existing monthly board of directors meeting to the public and adding a segment for the community to openly discuss any concerns (La Plata Electric Association Inc., 2010).

C. Conclusions

In 2014, Hoosier Energy produced 6.4 million MWh of energy from coal at Merom, or about 88% of their net generation. Now, Hoosier Energy faces a pivotal question about who they are as a company. The cooperative can continue to generate with coal and open themselves up to uncertainty in the CPP's allowance market, or it can build an NGCC plant and face the uncertainty of fundamentally changing its generation strategy. Despite all the financial modeling we do, it comes down to a question of what Hoosier Energy wants to be and which risks they decide to assume.

Our analysis suggests that building an NGCC plant would be the strongest option for Hoosier Energy. Making thermal efficiency improvements on Merom and buying allowances off the market is a more conservative alternative. The numbers that we used to determine the price of allowances in the market are inherently uncertain. This market does not yet exist so it is possible that allowances will be much higher or potentially lower than is shown in our model. By continuing to operate the Merom facility, Hoosier Energy would be opening itself up to this uncertainty every time the allowance market shrinks. Alternatively, if Hoosier Energy builds a new NGCC plant, it will be dependent on the fluctuations of natural gas prices.

XI. Appendix

A. Glossary

State plan - an implementation plan for the Clean Power Plan developed by a state; an alternative to the federal plan

Federal plan - an implementation plan for the Clean Power Plan developed by the EPA; if a state fails to propose a state plan, the federal plan will become the default

Emission Rate Credits (ERCs) - represent 1 MWh of emissions-free electricity generated, added to the denominator of the equation determining performance rates. Under a rate-based plan, utilities must obtain enough ERCs to reach their assigned emission rate

Allowances - represent one short ton of CO_2. Under a mass-based plan, utilities must obtain enough allowances to cover their emissions by the end of each compliance period

Credits - under CEIP, EPA awards credits for MWh renewable energy and EE. Has not decided on equivalency between MWh and CO_2 to convert to allowances

BTU	British Thermal Unit
CAA	Clean Air Act
CO_2	carbon dioxide
CPP	Clean Power Plan
EPA	US Environmental Protection Agency
EPRI	Electric Power Research Institute
Hg	mercury
kW	kilowatt
kWh	kilowatt hour
lb	pound
MMBTU	million British Thermal Units
MWh	megawatt hour
MW	megawatt

NACAA	National Association of Clean Air Agencies
NEMS	National Energy Modeling System
NGCC	natural gas combined cycle
NO_x	nitrogen oxides
O&M	operations and maintenance
PM	particulate matter
SO_2	sulfur dioxide
TBTU	trillion British Thermal Units

B. Financial Assumptions

Here, we present important assumptions used in the creation of the financial model. All assumptions below are held constant in the analysis of each compliance plan. The majority of our assumptions are based on information in the client's 2014 Annual Report or from other information provided by Hoosier Energy.

Table B.1 - Financial Assumptions Holding for all Compliance Plans

Figures from Hoosier Energy's 2014 Annual Report or other data Hoosier Energy provided	Figures defined in 2014 US Dollars ($)	Figures defined and projected based on NYMEX and other market trends	Internal methodology and modeling decisions
Growth in energy demand over the next 20 years will be 24% (annual 1.08% over 20 years).	Net Present Value (NPV), as calculated by subtracting discounted costs from discounted and accrued benefits for the first 30 years of the plan's implementation. timeline	Price of coal will increase at rates derived by the New York Mercantile Exchange (NYMEX) Futures quotes available via the U.S. Energy Information Administration (EIA).	2016 will serve as the "year zero"or present time, for all compliance plans.
Discount rates of 3%, 5%, and 7% will serve to model increasing degrees of uncertainty in our analysis.	Benefit / Cost ratio, weighing the same figures used to calculate NPV.	Price of gas will increase at rates derived by the New York Mercantile Exchange (NYMEX) Futures quotes available via the U.S. Energy Information Administration (EIA).	Each compliance plan will be evaluated 30 years into the future.

Tax levels (owed and, when negative, serving as income) listed in Hoosier Energy's 2014 annual report will continue to be reported at 2014 levels, unless by virtue of a specific compliance plan should be altered available exemptions and deductions.	Percentage Annual Energy Sale Price Increase, as a hypothetical figure denoting the needed annual increase in the price of electricity Hoosier Energy to offset potential losses in revenue unique to a specific compliance plan.	Changes in demand, supply, and prices of allowances will follow smooth trend-lines reflective of overall trends in respective commodities' markets. These linear trends were projected from NYMEX data provided by the client.	Annual energy sale price of electricity will increase at an average of 1.39% per year over our 30 year period of interest.
	Levelized Cost of Electricity (LCOE) as determined by the annual generation and costs necessitated by each specific plan's options.		
	Average revenue, cost, and profit per MWh sold.		

C. Assumptions

C.1. Framework-Specific Assumptions

Table C.1-1 indicates Indiana's historic CO_2 emissions in 2012 that are the basis for calculating the state's rate- and mass-based goals, which are also included in the table. The rate- and mass-based goals are shown for each compliance period: the Interim Period (2022-2029), which has been broken down further into three separate interim step periods, and the Final Goal (2030). Two mass-based goals are shown below, one excluding the NSC and one including the NSC.

Table C.1-1. Rate- and Mass-Based Goals for Indiana

INDIANA			
	CO_2 Rate (lbs/Net MWh)	CO_2 Emissions (short tons)	
2012 Historic [1]	2,021	107,299,591	
2020 Projections (without CPP)	1,882	104,669,332	
	Rate-based Goal	Mass-based Goal (annual average CO_2 emissions in short tons)	Mass Goal (Existing) & New Source Complement
Interim Period 2022-2029	1,451	85,617,065	86,556,407
Interim Step 1 Period 2022-2024 [2]	1,578	92,010,787	92,396,252
Interim Step 2 Period 2025-2027 [3]	1,419	83,700,336	85,000,711
Interim Step 3 Period 2028-2029 [4]	1,309	78,901,574	80,130,184
Final Goal 2030 and Beyond	1,242	76,113,835	76,942,604

Source: (EPA, 2015c)

The below table provides the allowance prices (in dollars), standard deviations, and lower and upper bounds (in dollars, given in brackets) used in the financial analysis for each policy framework and compliance period.

Table C.1-2. Assumptions of Allowance Prices, Standard Deviations, and Upper and Lower Bounds

Period	IND	HEP	SEE	NSC	PTH	AUC	NAR
1st	5 (0.3) [1, 10]	5 (0.5) [1, 10]	5 (0.3) [1, 10]	5 (0.5) [1, 10]	5 (0.3) [1, 10]	5 (0.3) [1, 10]	5 (0.3) [1, 10]
2nd	15 (0.5) [7.5, 25]	15 (0.7) [7.5, 25]	15 (0.5) [7.5, 25]	15 (0.7) [7.5, 25]	15 (0.5) [7.5, 25]	15 (0.5) [7.5, 25]	15 (0.5) [7.5, 25]
3rd	25 (0.7) [15, 40]	25 (0.9) [15, 40]	25 (0.7) [15, 40]	25 (0.9) [15, 40]	25 (0.7) [15, 40]	25 (0.7) [15, 40]	25 (0.7) [15, 40]
Final	30 (0.8) [20, 50]	30 (1.0) [20, 50]	30 (0.8) [20, 50]	30 (1.0) [20, 50]	30 (0.8) [20, 50]	30 (0.8) [20, 50]	30 (0.8) [20, 50]

*Mean allowance prices; standard deviation given in parentheses; lower and upper bounds given in brackets

The CPP is an extremely complex piece of legislation with five root causes of uncertainty: (1) the first compliance period will not begin for at least six years, (2) utilities and state legislators are having difficulty interpreting the rule, (3) each state has flexibility in designing a state plan, making it challenging to anticipate the structure of the final market, (4) a carbon market of this kind (including allowances and ERCs) has never existed, and (5) the stay on the CPP adds an additional layer of uncertainty. Even so, predicting the cost of allowances over the course of the CPP's four compliance periods is crucial in deciding the extent to which a utility should allocate its money to technological improvements and the purchase of allowances. Therefore, we provide our best estimate of allowance prices and variabilities across all four compliance periods and subject to seven different policy frameworks. To do so, we make reasonable order-of-magnitude estimates based on current cap-and-trade programs and economic analyses of expected impacts of the CPP.

California's Assembly Bill 32 (CA AB-32) of 2006 implemented a cap-and-trade program for CO_2 covering the electricity sector, large industrial consumers, and distributors of transportation, natural gas, and other fuels (California Air Resources Board 2011). In 2013, Quebec joined this emissions trading system as well. This scheme utilizes both direct allocation as well as an auction. Auction clearing prices for both the CA-only--as well as the CA-QC auctions--have ranged from a minimum of $10.09 to a maximum of $14.00 per allowance, with prices generally rising over time (California Air Resources Board 2016b). These clearing prices contribute to our estimations of auctioned allowance prices.

The Regional Greenhouse Gas Initiative (RGGI) is another emissions trading scheme involving nine northeastern states, which began compliance in 2009. RGGI uses an auction-style format, the clearing prices of which inform our price estimation of CPP allowances. Auctioned allowance prices from RGGI range from the price floors of $1.86 in the early years of the program to $7.50 per allowance in recent auctions (RGGI n.d.b). The upward trend in auction prices is much more noticeable in RGGI than CA-AB32, but both support the hypothesis that auction prices will likely rise in later compliance periods for the CPP as the number of available allowances is ratcheted down.

The European Commission's EU Emissions Trading System (EU ETS) also uses a hybrid approach, distributing allowances directly to certain entities, while auctioning the majority of the allowances under the program. Evaluating monthly auction information since January 2013 (European Commission 2016b), accounting for monthly exchange rate differences throughout 2013-2015 (www.x-rates.com), auction prices for this program have ranged from $2.62-7.24. Auction information was pulled from individual monthly auction reports from EU ETS and compiled into the following table, with the appropriate exchange rates from the above website. Similar to other programs, prices have generally risen over time.

Table C.1-3. Compiled Average Clearing Prices from Monthly EU ETS Auctions

European Union Emissions Trading System			
Auction	**Avg Clearing Price (EUR)**	**Exchange Rate**	**Ave Clearing Price ($)**
Aug-15	8.06	0.898446	7.24
Jul-15	7.73	0.908698	7.02
Jun-15	7.42	0.890998	6.61
May-15	7.43	0.896047	6.66
Apr-15	7.06	0.924432	6.53
Mar-15	6.76	0.924815	6.25
Feb-15	7.24	0.881461	6.38
Jan-15	6.89	0.860294	5.93
Dec-14	6.76	0.81232	5.49
Nov-14	6.77	0.801875	5.43
Oct-14	6.04	0.789418	4.77
Sep-14	6.01	0.775966	4.66
Aug-14	6.24	0.750935	4.69
Jul-14	5.91	0.738765	4.37
Jun-14	5.53	0.735341	4.07
May-14	5.02	0.728241	3.66
Apr-14	5.19	0.724163	3.76
Mar-14	6.42	0.723186	4.64

Feb-14	6.39	0.73218	4.68
Jan-14	4.96	0.734198	3.64
Dec-13	4.61	0.72962	3.36
Nov-13	4.49	0.741259	3.33
Oct-13	4.85	0.732967	3.55
Sep-13	5.18	0.748762	3.88
Aug-13	4.39	0.751037	3.30
Jul-13	4.19	0.764668	3.20
Jun-13	4.2	0.758973	3.19
May-13	3.4	0.770547	2.62
Apr-13	3.93	0.767746	3.02
Mar-13	3.93	0.771468	3.03
Feb-13	5.52	0.748673	4.13
Jan-13	5.52	0.751635	4.15
		Min	**2.62**
		Max	**7.24**
		Average	**4.60**

Finally, PJM Interconnection released an economic analysis of the CPP proposed rule on its service territory, titled *PJM Interconnection Economic Analysis of the EPA Clean Power Plan Proposal* (PJM Interconnection 2015) . This report has not been updated for the final rule, but we think it is still useful in providing a reasonable range of price estimates to include in our model. At the request of the Organization of PJM States, PJM evaluates five assumption scenarios for a regional mass-based plan, as well as eight other scenarios that they chose to analyze. These scenarios are comprised of varying assumptions, including differing amounts of renewable energy generation, energy efficiency adoption, and natural gas utilization. It is not wise or within the scope of this project to determine which of these scenarios is most likely. Included in PJM's analysis is an estimation of allowance prices throughout the interim compliance periods. The estimates are detailed in *Table 19. Clean Power Plan Regional Mass-Based Compliance-Related Costs* in the report, which can be found on page 102. While the allowance price estimates vary widely across all of the scenarios, they generally fall within a range of \$0 to \$40 per allowance from 2020 to 2029. Many of these estimates fall in line with what we observe from California and RGGI clearing prices with prices rising over time.

These four sources of information form the basis on which we estimate allowance auction prices for our analysis. We think our increasing estimates of \$5, \$15, \$25, and \$30 throughout each compliance period follow both the range of prices from these sources as well as the trend of price increases in later compliance periods. We acknowledge, however, that the CPP market will be significantly different in design and scale from the RGGI, California AB-32, and EU ETS markets, and that PJM's analysis is limited in both its application to PJM's territory and the proposed rather than the final rule. Regardless, we think these are reasonable order-of-magnitude estimates in predicting a complex, future market; they should serve their purpose in informing Hoosier Energy's decision-making until better estimates can be provided.

We opt to keep allowance prices the same between policy frameworks since we cannot justify significant changes in prices under any of the chosen frameworks. The standard deviations are chosen to provide reasonable distributions; they increase over time to reflect greater uncertainty in allowance prices over time. Since the market with the New Source Complement is even more unpredictable--for example, one must consider projections of future capacity additions and how they will affect allowance prices--we opt to increase the standard deviations in these policy frameworks. Upper and lower bounds are chosen to reflect reasonable ranges in prices for each compliance framework, and these ranges are also held constant across policy frameworks.

Table C.1-4. Assumptions of Allowance Allocations to Hoosier Energy

Period	**IND**	**HEP**	**SEE**	**NSC**	**PTH**	**AUC**	**NAR**
	Direct (Historical)	**Direct (Preferential)**	**Direct (Historical)**	**Direct (Historical)**	**Direct (Preferential)**	**Auction**	**Direct (Historical w/o Ratts)**
1st	5,129,864	6,385,044	5,129,864	5,804,585	5,642,850	5,129,864	4,503,135
2nd	4,925,878	5,873,975	4,925,878	5,339,977	5,418,466	4,925,878	4,324,071
3rd	4,639,481	5,537,397	4,639,481	5,033,997	5,103,429	4,639,480	4,072,663
Final	4,473,104	5,317,119	4,473,104	4,833,745	4,920,414	4,473,104	3,926,613

Predicting the number of allowances that will be allocated to Hoosier Energy under each framework we identify is critical for both the technological and financial considerations for compliance. Under the CPP, Hoosier Energy must surrender at the end of each compliance period one allowance for each ton of carbon emissions generated during that same period. Depending on the number of allowances that Hoosier Energy can be expected to receive at the outset of each compliance period, a target is set for compliance, above which allowances must be purchased from other EGUs. As described in section IV.A.2 *Decision 4* of this report there are several options for the initial distribution of allowances, and we apply different allocation formats across our identified policy frameworks.

Framework 1: IND

For this framework, we decide that initial allocation will likely be direct (free) allocation based on historical generation from 2010-2012. This allocation methodology falls in-line with EPA's own proposed federal plan. In a memorandum titled *Allowance Allocation Proposed Rule Technical Support Document (TSD)* that is included with the supporting documents of the docket folder for the final version of the Clean Power Plan (Docket EPA-HQ-OAR-2015-0199), the EPA details the direct allocation methodology it is considering using for allowance allocation under the proposed mass-based federal plan (EPA 2015d). Attached to this document are several Excel file appendices detailing the data EPA used for calculating both allocations for all EGUs as well as set asides for each state. Specifically, in *Appendix A- Allocations and Underlying Data*, EPA provides the number of allowances it expects will be awarded at the boiler level under a mass-based historical generation approach. These calculations are made by taking the generation from each boiler averaged over 2010-2012 and determining what fraction of the statewide average total electric generation over that same time frame these boilers contributed. These calculations can be found both in the aforementioned document appendix as well as in the following table.

Table C.1-5. Fraction of Historical Generation at the Boiler Level

Affected EGU Boiler	*2010-2012 Boiler Generation Average* (MWh)*	*2010-2012 State Generation Average** (MWh)*	*Generator's Fraction of State Generation*
Ratts 1	455,339	116,601,868	0.3905072%
Ratts 2	439,606	116,601,868	0.3770145%
Merom 1	3,294,392	116,601,868	2.8253335%
Merom 2	3,135,912	116,601,868	2.6894180%

*Excludes zero generation years and year of commencement
**Excludes zero generation years, year of commencement, and those excluded in 2012

From there, EPA provides the total emissions caps for each compliance period, which constitute the number of allowances that will be available to all EGUs in the state. This information can be found under Indiana's state-specific fact sheet. EPA provides the number of allowances budgeted for each compliance period both before and after removing the expected number of set asides, should a state choose to utilize them. Again, the following table details these statewide allowance budgets, which can also be found in the EPA documents.

Using the fraction of historical generation for each boiler and applying it to the total emissions budget for the state in each compliance period, we calculate the expected number of allowances that each EGU boiler will receive under historical generation for this three-year period.

Table C.1-6. Indiana Mass-Based Goals, Set Asides, and New Source Complement

Compliance Period	*Indiana's Affected Source Mass Goals (Short Tons)*	*Indiana's Affected Source Mass Goals w/ New Source Complement (Short Tons)**	*Renewable Energy Set Aside (5% of Total Emissions Budget) (Short Tons)*	*Indiana's Clean Energy Incentive Program Set Aside (Short Tons)*	*Indiana Output-Based Allocation Set Aside (Short Tons)*	*Indiana's Affected Source Mass Goals After Set Asides (Short Tons)*
First Period (2022-2024)	92,010,787	92,396,252	4,600,539.35	5,754,076	n/a	81,656,171
Second Period (2025-2027)	83,700,336	85,000,711	4,185,016.80	n/a	1,106,150	78,409,169
Third Period (2027-2029)	78,901,574	80,130,184	3,945,078.70	n/a	1,106,150	73,850,345
Final Period	76,113,835	76,942,604	3,805,691.75	n/a	1,106,150	71,201,993

*Inclusion of an NSC in the state plan accomplishes the requirement of addressing leakage and so Set Asides are not used or removed from the total available pool. Now that we know Indiana's mass goals (or the number of available allowances) both with and without set asides, as well as a fraction of historical generation from each of Hoosier Energy's boilers at Merom and Ratts, we calculate how many of these allowances these boilers might receive under historical allocation.

Table C.1-7. Boiler Level Allowance Allocation Calculations

	Historical Generation (2010-2012) Allowance Allocations w/o Set Asides				Historical Generation (2010-2012) Allowance Allocations w/ Set Asides			
Affected EGU Boiler	First Period	Second Period	Second Period	Final Period	First Period	Second Period	Third Period	Final Period
Ratts 1	359,309	326,856	308,116	297,230	318,873	306,193	288,391	278,049
Ratts 2	346,894	315,562	297,470	286,960	307,856	295,614	278,427	268,442
Total (Ratts)	**706,203**	**642,418**	**605,586**	**584,190**	**626,729**	**601,807**	**566,818**	**546,491**
Merom 1	2,599,612	2,364,814	2,229,233	2,150,470	2,307,059	2,215,321	2,086,519	2,011,694
Merom 2	2,474,555	2,251,052	2,121,993	2,047,019	2,196,076	2,108,750	1,986,144	1,914,919
Total (Merom)	**5,074,167**	**4,615,866**	**4,351,226**	**4,197,489**	**4,503,135**	**4,324,071**	**4,072,663**	**3,926,613**
Total (Merom & Ratts)	**5,780,370**	**5,258,284**	**4,956,812**	**4,781,679**	**5,129,864**	**4,925,878**	**4,639,481**	**4,473,104**

As you can see in the above table, the calculated allowance allocations for direct allocation based on historical generation, highlighted in yellow, now match with those included in Framework 1 (IND) in Table C.1-4.

These above underlying calculations form the basis for the rest of the allowance allocation calculations for the rest of the frameworks. For the rest of the frameworks, we will describe how to replicate the calculations to determine the final numbers included in Table C.1-4.

Framework 2 (HEP)

This framework is different from Framework 1 in three ways: (1) it uses a New Source Complement, which sets slightly higher mass goals for the state, (2) because it has the NSC, set asides are not needed to address leakage so they are not included, and (3) we assume preferential treatment for Hoosier Energy in that we expect rural electric cooperatives to receive some additional allowances from the state since they are the most compliance-burdened utilities. In this case, we assume that Hoosier Energy will receive an additional 10% of allowances on top of historical generation after accounting for the first two differences. We choose this value because it gives Hoosier Energy a significant number of extra allowances, roughly half a million, to provide a stark difference from Framework 1 without being too unrealistic. The limitation here is that this number was picked out of thin air. We do not know if the state would consider providing extra support to rural cooperatives. However, if Hoosier Energy can argue that they are in a uniquely difficult position, as rural cooperatives are without significant borrowing power or liquid cash as described in section IV.A.2 *Decision 4* of this report, then they will be in a better position to comply with the CPP.

To replicate the calculation for the number of allowances under this framework, take the statewide mass goals including the NSC from Table C.1-6 without set asides, multiply by the boiler generation fractions from Table C.1-5, sum all boiler allocation calculations for Merom and Ratts similar to as was done in Table C.1-7, and then multiply by a 1.10x multiplier. This should yield the results under Framework 2 (HEP) in Table C.1-4.

Framework 3 (SEE)

This framework only differs from Framework 1 in that it includes a statewide energy efficiency program. However, this change does not affect allowance allocation, so the numbers are the same as for Framework 1 in Table C.1-4.

Framework 4 (NSC)

This framework is almost identical to Framework 2, only that we do not consider preferential treatment via an additional 10% of allowances. To replicate our calculated allowance allocation for this framework, follow the same steps outlined under Framework 2 (HEP) above but skip the last step of using the multiplier.

Framework 5 (PTH)

This framework differs from Framework 1 (IND) only in that it includes again some preferential treatment for Hoosier Energy in the form of 10% extra allowances. To replicate this calculation, simply apply a 1.10x multiplier to the number of allowances listed under Framework 1 (IND) in Table C.1-4.

Framework 6 (AUC)

This framework uses an auction style format for the initial allocation of allowances. Here, we have listed the same number of allowances as Hoosier Energy would receive based on historical generation under Framework 1 conditions because this is the only number that we could reasonably estimate that Hoosier Energy would purchase in an auction. It should be noted that these are not freely allocated allowances, just a placeholder showing how many allowances we would expect Hoosier Energy to purchase in each compliance period.

Framework 7 (NAR)

This framework only differs from Framework 1 (IND) in that we assume that Hoosier Energy would no longer receive allowances for Ratts' historical generation. Thus, this calculation is easily replicated by summing only the Merom boilers in Table C.1-7 for each compliance period.

C.2 General Compliance Plan Assumptions and Notes

Thermal efficiency can be increased at Merom by 2% at a cost of $1 million/year.

The Energy Efficiency/Demand Side Management program described in the client's Integrated Resource Plan will be continued through 2046. Since estimated energy savings were not projected past 2018, a stable 3.8% was assumed from then on. The price per MWh saved was assumed stable from 2018 on to project out annual costs of the program. This analysis also assumes that same price per MWh saved would be the amount that Hoosier Energy would have to pay in under a statewide energy efficiency program, estimated to add another 2% of energy savings starting in 2022.

Firm natural gas capacity at Merom can be procured for $1 million/year for “enough gas to run a typical NGCC plant at 50% capacity.” Assumed a typical plant to be 600 MW. Scaled capacity costs up from there proportionally based on additional gas needed.

Assumed that generation levels at Merom, Worthington and Lawrence, Holland, and Hoosier’s owned renewable assets stayed stable at IRP projected 2018 levels from 2019 – 2046 unless otherwise specified. Additional power needs due to increasing demand were met by additional power purchased.

Assumed that allowance banking and carry-over from one compliance period to the next would be allowed under the state plan.

No calculations took Holland’s allowances into account. If Holland generated less emissions than it was allocated and Indiana and Illinois had compatible trading-ready plans, Hoosier could reduce the amount of allowances bought for Merom or sell the extra allowances, depending on needs.

Hoosier Energy can meet its bought power needs through various sources: renewable energy purchase agreements, other long-term purchase agreements (such as from Duke), and market purchases. This analysis did not differentiate between them. However, they have different prices. Renewable power purchases cost more, but that difference could be outweighed if Hoosier were awarded allowances from renewable set-asides and could then sell them. Hoosier Energy will need to increase its level of purchased renewable power per year in order to meet the company’s stated goal of 10% renewable power by 2025.

The MWh listed under “Produced Renewable MWh” includes HE’s landfill gas facilities and new 10 MW of solar.

D. Compliance Plan Descriptions

D.1 General Compliance Plan Rationale

The compliance plans used can be broadly categorized as cofiring at Merom with natural gas, continuing business as usual and buying any allowances needed, and replacing Merom with a NGCC plant. Thermal efficiency improvements at Merom were included across those three major plan types.

Variations on the cofiring theme between plans included the year cofiring was implemented and the proportion of gas fired over time, depending on each Framework’s applicable allowance limits. Implementation dates and gas proportion increases were pushed back when possible in order to put off making major changes to Merom until legal and political issues were decided, to transition away from coal gradually, and to allow time to resolve any operational or equipment changes needed to fire 100% gas.

Although the capital cost of a new NGCC plant is high, the plant would not be included under CPP emissions caps*, so Hoosier Energy could sell its allocated allowances**. Also, the plant would need less fuel/MWh generated than firing gas in coal plant boilers and operations and maintenance costs would be lower. Thus, revenue from selling allowances and savings on fuel and O&M could make this option work out economically in the long run better than cofiring.

The new NGCC plant would be built on the Merom property to take advantage of existing land assets and transmission infrastructure. It would not be built on the exact site of the coal plant, though, to allow for the coal plant to continue running during NGCC construction.

*Replacing Merom with a NGCC plant was not included under Frameworks with the New Source Complement, as in that case the new plant would be under CPP emission caps so the allowances allocated to Hoosier Energy could not all be sold. Since the allowance sale revenue stream would be a key incentive to building the NGCC plant, without it this compliance option was not used.

**Replacing Merom with a NGCC plant was also not considered in any compliance plan under the Framework with an allowance auction instead of direct allocation, for the same reason (lack of an allowance sale revenue stream) as described above. Also, even under a direct allocation system, allowances would likely only be given to Hoosier Energy for 2-3 years after shutting down coal plant operations.

D.2 Detailed Compliance Plans

The following section provides detailed description for every compliance plan. Plans are organized by the policy framework under which they were designed.

Policy Framework 1

1A

- 2016 – 2031: Implement 2% thermal efficiency improvements at Merom
- 2024 – 2025: Take Merom offline for the year to modify both boilers to allow natural gas cofiring. Supplement lost generation with power purchases
- 2025 – 2027: Fire both Merom boilers with 50% coal, 50% gas
- 2028 – 2030: Fire one Merom boiler with 50% gas 50% coal, fire the other boiler with 100% gas
- 2031 – 2046: Fire both Merom boilers with 100% gas

1B

- 2016 – 2046: Continue all generating operations as “business as usual”

1C

- 2016 – 2024: Implement 2% thermal efficiency improvements at Merom
- 2024 – 2046: Take the Merom coal plant offline and replace with a 1070 MW new NGCC plant onsite. Run the NGCC plant at 75% capacity factor. Run the NGCC plant at 75% capacity factor.

Policy Framework 2

2A

- 2016 – 2046: Implement 2% thermal efficiency improvements at Merom

2B

- 2027 – 2028: Take Merom offline for the year to modify both boilers to allow natural gas cofiring. Supplement lost generation with power purchases
- 2028 – 2046: Fire both Merom boilers with 50% coal, 50% gas

2C

- 2016 – 2046: Implement 2% thermal efficiency improvements at Merom
- 2027 – 2028: Take Merom offline for the year to modify both boilers to allow for natural gas cofiring. Supplement lost generation with power purchases
- 2028 – 2046: Fire both Merom boilers with 50% coal, 50% gas

Policy Framework 3

3A

- 2016 – 2023: Implement 2% thermal efficiency improvements at Merom
- 2024 – 2025: Take Merom offline for the year to modify both boilers to allow natural gas cofiring. Supplement lost generation with power purchases
- 2025 – 2027: Fire both Merom boilers with 50% coal, 50% gas
- 2028 – 2030: Fire one Merom boiler with 50% gas 50% coal, fire the other boiler with 100% gas
- 2031 – 2046: Fire both Merom boilers with 100% gas

3B

- 2016 – 2046: Continue all generating operations as "business as usual"

3C

- 2016 – 2023: Implement 2% thermal efficiency improvements at Merom
- 2024 – 2046: Take the Merom coal plant offline and replace with a 1070 MW new NGCC plant onsite. Run the NGCC plant at 75% capacity factor.

Policy Framework 4

4A

- 2016 – 2046: Implement 2% thermal efficiency improvements at Merom

4B

- 2027 – 2028: Take Merom offline for the year to modify both boilers to allow natural gas cofiring. Supplement lost generation with power purchases
- 2028 – 2030: Fire both Merom boilers with 50% coal, 50% gas
- 2031 – 2033: Fire one Merom boiler with 50% gas 50% coal, fire the other boiler with 100% gas
- 2034 – 2046: Fire both Merom boilers with 100% gas

Policy Framework 5

5A

- 2024 – 2025 : Take Merom offline for the year to modify both boilers to allow natural gas cofiring. Supplement lost generation with power purchases
- 2025 – 2027: Fire both Merom boilers with 50% coal, 50% gas
- 2028 – 2030: Fire one Merom boiler with 50% gas 50% coal, fire the other boiler with 100% gas
- 2031 – 2046: Fire both Merom boilers with 100% gas

5B

- 2016 – 2046: Continue all generating operations as "business as usual"

5C

- 2016 – 2023: Implement 2% thermal efficiency improvements at Merom
- 2024 – 2046: Take the Merom coal plant offline and replace with a 1070 MW new NGCC plant onsite. Run the NGCC plant at 75% capacity factor.

Policy Framework 6

6A

- 2016 – 2030: Implement 2% thermal efficiency improvements at Merom
- 2024 – 2026 : Take Merom offline for the year to modify both boilers to allow natural gas cofiring. Supplement lost generation with power purchases
- 2025 – 2027: Fire both Merom boilers with 50% coal, 50% gas
- 2028 – 2030: Fire one Merom boiler with 50% gas 50% coal, fire the other boiler with 100% gas
- 2031 – 2046: Fire both Merom boilers with 100% gas

6B

- 2016 – 2046: Continue all generating operations as "business as usual"

Policy Framework 7

7A

- 2016 – 2023: Implement 2% thermal efficiency improvements at Merom
- 2024 – 2025: Take Merom offline for the year to modify both boilers to allow natural gas cofiring. Supplement lost generation with power purchases
- 2025 – 2046: Fire both Merom boilers with 100% gas

7B

- 2016 – 2025: Implement 2% thermal efficiency improvements at Merom
- 2021 – 2022: Take Merom offline for the year to modify both boilers to allow natural gas cofiring. Supplement lost generation with power purchases
- 2022 – 2023: Fire both Merom boilers with 50% coal, 50% gas
- 2024– 2025: Fire one Merom boiler with 50% gas 50% coal, fire the other boiler with 100% gas
- 2026 – 2046: Fire both Merom boilers with 100% gas

7C

- 2016 – 2023: Implement 2% thermal efficiency improvements at Merom
- 2024 – 2046: Take the Merom coal plant offline and replace with a 1070 MW new NGCC plant onsite. Run the NGCC plant at 75% capacity factor.

D3. Compliance Plan Clean Air Act Permit

The following section offers a brief summary of the relevant CAA provisions that also affect Hoosier Energy's EGUs. While the applicability of each provision depends on the specific situation at each EGU, Hoosier Energy must consider these compliance issues before completing any modifications or creating any new EGUs. Below the summary of each compliance issue, a table highlights the various "triggers" and "questions" to help Hoosier Energy decide whether the CAA provision applies to a particular EGU. The questions provide a conceptual guideline for each permit requirement and can work in conjunction with a separate analysis from Hoosier Energy's legal department.

I. Title V Permits

Title V permits allow Hoosier Energy to consolidate emission requirements and monitoring plans into a single document. Title V permits can cover major sources of criteria pollutants, sources subject to NSPS when constructed or modified, sources required to go through NSR in nonattainment areas, major sources of hazardous air pollutants, as well as boilers subject to acid rain provisions. Regardless of whether Hoosier Energy builds or modifies any EGUs, Hoosier Energy can combine the various CAA requirements into Title V permits.

A. State Implementation Plan

To comply with the National Ambient Air Quality Standards (NAAQS), Indiana must submit a state implementation plan (SIP) with control strategies to obtain certain air quality levels. To meet these designated air quality levels, the Indiana SIP places emission limits on specific emitting facilities including Hoosier Energy's EGUs. (40 C.F.R. § 51.1- 51.205). Hoosier Energy must ensure that each EGU meets the requirements in Indiana's SIP. (40 C.F.R. § 51.1- 51.205).

Guidelines for Permit Requirements	(1) Does the EGU emit one or more of the six criteria pollutants? - Carbon Monoxide, Sulfur Dioxide, Nitrogen Oxide, Particulate Matter, and Lead (2) Has Indiana placed emission limits on the EGU in the SIP? - Emission standards include primary air quality levels to protect human

	health as well as secondary levels to protect public welfare. (3) What are the limits placed on the EGU by the SIP?

B. New Source Review/Non-Attainment

To comply with New Source Review/Non-Attainment provisions, *existing* major EGUs must meet emission controls based on reasonably available control technology (RACT). If Hoosier Energy decides to build any *new* EGUs or modify any existing EGUs, the EGU must go through new source review (NSR) and meet the nonattainment emission limits based on lowest achievable emission rate (LAER). (Nonattainment New Source Review (NA NSR) Program).

Guidelines for Permit Requirements	(1) Is the area in non-attainment? - Nonattainment areas do not meet either the national primary or secondary air quality standards and require certain pollution thresholds to prevent the air quality from getting worse (2) What pollutant is the area considered in nonattainment? (3) Is the EGU emitting the pollutant for area in non-attainment? (4) Is the EGU a major source of the non-attainment pollutant? - Existing major EGUs must operate *at the time of nonattainment* and have the potential to emit more than 100 tons per year of the non-attainment pollutant. (5) Is the EGU new or did it exist at the time of attainment? - New or modified EGU's include facilities built or modified *after time of attainment* that have the potential to emit more than 100 tons per year of a criteria pollutant
Current Hoosier Energy EGU Project	Clark-Floyd Landfill Methane Generation Project- Clark County Annual PM 2.5- "Unclassifiable" due to uncertainties with monitoring data within Louisville's monitoring network. The EPA was unable to determine whether air quality in the entire Louisville KY-IN area was meeting the 2012 PM2.5 NAAQS or whether the area was contributing to a potential violation in Jefferson County, Kentucky

C. New Source Review/Attainment/Prevention of Significant Deterioration

Existing EGUs in attainment areas, which do not increase annual emissions, do not have to comply with prevention of significant deterioration (PSD) and attainment provisions. If Hoosier Energy plans to construct a *new* EGU unit or undergo *modification*, however, the EGU must meet emission standards based on best available control technology (BACT) along with an increment to cover potential new emissions. If the EGU exceeds the increment, the facility must meet emission standards based on BACT as well as offset the increased emissions with a 1:1 ratio. Hoosier Energy can purchase "offsets" from another entity, who will reduce its emissions to equalize the emission of the EGU. Offsets must be real, permanent, quantifiable, and legally enforcement. (Trinity Consultants).

Guidelines for Permit Requirements	(1) Is the EGU located in an attainment area? - For areas designated as in attainment, Hoosier Energy must prevent significant deterioration (PSD) of the area by monitoring EGU emissions (2) Is the EGU a major emitting source?

	- Does it fall into one of 28 specified categories and have the potential to emit 100 tons per year of any pollutant. - Major facilities include fossil fuel boilers and fossil fuel fired stream electric plants with more than 250 MMbtu/hr heat input. (3) Was the EGU built or modified after 1977? - Modification includes any physical change that causes a significant net increase in annual emissions. - Modifications usually involve more capital expenditure, reach a larger scope, involve outside contractors, increase the value of the unit, and do not occur with regularity. - Modification exemptions include routine maintenance, repair, or replacements that occurs regularly, involves no permanent improvements

New Source Performance Standards

Hoosier Energy's EGUs also face technology based New Source Performance Standards (NSPS). Developed and implemented by the EPA, NSPS enforcement falls on the states to conduct initial performance tests followed by continuous monitoring of the regulated emissions. NSPS regulate emissions of acid mist, carbon monoxide, particulate matter, fluorides, hydrogen sulfide in acid gas, lead, nitrogen oxides, sulfur oxides, total reduced sulfur, and VOCs. (Chem Alliance). In general, PSD and NSR requirements supersede NSPS but the standards of performance still serve as a technology floor. NSPS do not specify the control technology used to achieve the standards, only the specific emission limits achievable by the BDT. Other considerations for Hoosier Energy's NSPS compliance include standards for visible emissions, monitoring requirements, performance test methods, compliance procedures, reporting, and records. (Chem Alliance).

Guidelines for Permit Requirements	(1) Does the EGU fit into a designated source category? - NSPS cover more than 70 source categories including industrial-commercial-institutional steam generating units like Hoosier Energy's EGUs. NSPS along with PSD and NSR always applies to new EGUs as well as certain modified ones. (2) Does the EGU have the equipment addressed by the NSPS? (3) Has the EGU been constructed, modified, or reconstructed after the NSPS were proposed? - *Modified existing sources* include any facility where a physical or operation change results in an increased emission rate. - Facility changes exempted from the modification designation include routine maintenance, repair, and replacement procedures, increases in production rate without a capital expenditure, or increases in the hours of operation. - *Reconstructed sources* undergo a replacement of components from their facility to extent that the fixed capital cost of the new component exceeds 50% of the fixed cost required to construct a comparably new facility. Under the reconstruction provision, the facility does not have to experience an increase in emission rate to need NSPS. (4) What are the emission limits required by the NSPS? - NSPS requires EGUs to control emissions to the level achievable by best demonstrated technology (BDT) considering costs and any non-air quality health and environmental impacts as well as energy requirements

Other Air Pollution Concerns

(A) Hazardous Air Pollutants

Part of the 1990 Amendments to the CAA included provisions for air pollutants reasonably anticipated to result in an increase in mortality or increase in serious irreversible or incapacitating reversible illness. (Bradstreet). MACT allows the EPA to consider costs, adverse health or environmental effects, and energy concerns. (Bradstreet). Any modified facility that starts emitting HAPS falls into the new source category. Currently, a case-by-case determination sets the MACT level for each power plant. The EPA also recently added mercury from coal fired power plants to the HAPS requirements.

Guidelines for Permit Requirements	(1) Is the pollutant on the list of 189? - EPA cannot list criteria pollutants but can list precursors to criteria pollutants including VOC's, a precursor to ozone (2) How much of the pollutant is the facility emitting? - New major sources have the potential to emit 10 tons per year or greater of one HAP or 25 tons per year of any combination of air pollutants - if less than 10 TPY → see whether it's an "area source" and what GACT standards are (3) Was the facility in existence when the EPA established these standards? - Existing major sources, operating before the regulation, must achieve MACT based on what the top 12% of the performing companies in the industry can achieve - New major s must meet maximum achievable control technology (MACT)

(B) Acid Rain Control

Hoosier Energy should also ensure compliance with the acid rain (SO2) control program, also part of the 1990 Amendments. The program allows for a cap-and-trade allowance/auction system. The program requires continuous emissions monitors (CEMs) with an EPA accounting system where sources, like Hoosier Energy's EGUs must surrender allowances equal to SO2 emissions. The EPA can issue $2,000 penalties per ton of exceeded allowances. (40 C.F.R. § 72.1- 77.6.).

E. Select Excel Sheets

Table E-1 Financial Model Output

Compliance Plan	LCOE*			%Δ over baseline			NPV*			%Δ Electricity Sale Price for NPV=0**		
	3%	5%	7%	3%	5%	7%	3%	5%	7%	3%	5%	7%
Baseline	0.090	0.087	0.084	n/a	n/a	n/a	(1,467,161)	(784,156)	(387,044)	1.5%	1.4%	1.3%
1A	0.122	0.119	0.118	35.9%	37.8%	39.7%	(8,684,285)	(6,518,686)	(5,068,360)	4.8%	5.1%	5.4%
1B	0.113	0.111	0.110	25.9%	28.6%	31.2%	(6,672,822)	(5,124,607)	(4,070,066)	4.1%	4.4%	4.7%
1C	0.106	0.107	0.107	18.8%	23.2%	27.6%	(5,220,804)	(4,296,090)	(3,640,026)	3.6%	4.0%	4.4%
2A	0.112	0.111	0.110	24.7%	27.7%	30.6%	(6,348,628)	(4,884,418)	(3,903,201)	4.0%	4.2%	4.6%
2B	0.118	0.117	0.115	32.3%	34.5%	36.7%	(7,823,349)	(5,926,043)	(4,629,250)	4.5%	4.8%	5.1%
2C	0.117	0.115	0.114	30.3%	32.9%	35.4%	(7,435,997)	(5,682,740)	(4,470,536)	4.4%	4.7%	5.1%
3A	0.122	0.120	0.118	36.6%	38.7%	40.7%	(8,717,137)	(6,545,228)	(5,096,105)	4.8%	5.1%	5.4%
3B	0.113	0.112	0.111	26.5%	29.3%	32.0%	(6,683,104)	(5,135,668)	(4,075,780)	4.1%	4.3%	4.7%
3C	0.110	0.110	0.111	22.6%	27.0%	31.4%	(5,913,907)	(4,780,764)	(3,996,012)	3.8%	4.2%	4.6%
4A	0.112	0.110	0.109	24.7%	27.5%	30.1%	(6,435,856)	(4,947,530)	(3,943,283)	4.0%	4.3%	4.6%
4B	0.120	0.118	0.116	34.2%	36.0%	37.7%	(8,352,420)	(6,253,960)	(4,843,400)	4.8%	5.0%	5.3%
5A	0.121	0.119	0.117	35.1%	37.2%	39.1%	(8,537,755)	(6,436,227)	(5,013,174)	4.8%	5.1%	5.4%
5B	0.112	0.111	0.110	24.9%	27.7%	30.3%	(6,484,259)	(4,996,061)	(3,967,170)	4.0%	4.3%	4.6%
5C	0.106	0.106	0.107	17.9%	22.4%	26.9%	(5,050,485)	(4,177,831)	(3,563,735)	3.5%	3.9%	4.4%
6A	0.130	0.127	0.124	44.7%	46.2%	47.2%	(10,486,097)	(7,792,300)	(5,988,534)	5.3%	5.6%	5.9%
6B	0.120	0.118	0.116	34.4%	36.5%	38.4%	(8,415,897)	(6,340,128)	(4,935,185)	4.6%	4.9%	5.2%
7A	0.123	0.121	0.119	37.4%	39.4%	41.1%	(9,001,728)	(6,766,095)	(5,258,376)	4.9%	5.2%	5.6%
7B	0.124	0.122	0.120	38.1%	40.3%	42.6%	(9,157,842)	(6,917,706)	(5,417,592)	5.0%	5.3%	5.6%
7C	0.107	0.108	0.108	19.9%	24.2%	28.5%	(5,462,617)	(4,455,456)	(3,758,084)	3.7%	4.0%	4.5%

Model Inputs for Compliance Plan 1C (Merom replacement example)

Energy Production and Purchase Schedule

			Produced			Purchased			
Year	Coal Mwh	**Short Tons of Coal**	Gas Mwh	**MMBTU of NG**	Renewable Mwh	**Purchased Mwh**	Total Mwh	Total Mwh after EE/DSM	Assumed EE/DSM Savings
2016	7,177,000	3,323,149	765,000	6,120,000	356,000	1,532,303	10,176,297	9,830,303	3.40%
2017	6,784,000	3,141,179	723,000	5,784,000	355,000	2,045,714	10,277,712	9,907,714	3.60%
2018	6,847,000	3,170,349	767,000	6,136,000	355,000	2,016,692	10,380,137	9,985,692	3.80%
2019	6,847,000	3,170,349	767,000	6,136,000	355,000	2,116,206	10,483,583	10,085,206	3.80%
2020	6,847,000	3,170,349	767,000	6,136,000	355,000	2,216,713	10,588,059	10,185,713	3.80%
2021	6,847,000	3,170,349	767,000	6,136,000	355,000	2,318,222	10,693,577	10,287,222	3.80%
2022	6,847,000	3,170,349	767,000	6,136,000	355,000	2,420,741	10,800,147	10,389,741	3.80%
2023	6,847,000	3,170,349	767,000	6,136,000	355,000	2,524,283	10,907,779	10,493,283	3.80%
2024	-	-	7,796,900	51,338,257	355,000	2,445,957	11,016,483	10,597,857	3.80%
2025	-	-	7,796,900	51,338,257	355,000	2,551,572	11,126,270	10,703,472	3.80%
2026	-	-	7,796,900	51,338,257	355,000	2,658,240	11,237,152	10,810,140	3.80%
2027	-	-	7,796,900	51,338,257	355,000	2,765,972	11,349,139	10,917,872	3.80%
2028	-	-	7,796,900	51,338,257	355,000	2,874,776	11,462,242	11,026,676	3.80%
2029	-	-	7,796,900	51,338,257	355,000	2,984,666	11,576,471	11,136,566	3.80%
2030	-	-	7,796,900	51,338,257	355,000	3,095,650	11,691,840	11,247,550	3.80%
2031	-	-	7,796,900	51,338,257	355,000	3,207,740	11,808,358	11,359,640	3.80%
2032	-	-	7,796,900	51,338,257	355,000	3,320,948	11,926,037	11,472,848	3.80%
2033	-	-	7,796,900	51,338,257	355,000	3,435,283	12,044,889	11,587,183	3.80%
2034	-	-	7,796,900	51,338,257	355,000	3,550,758	12,164,925	11,702,658	3.80%
2035	-	-	7,796,900	51,338,257	355,000	3,667,384	12,286,158	11,819,284	3.80%
2036	-	-	7,796,900	51,338,257	355,000	3,785,172	12,408,599	11,937,072	3.80%
2037	-	-	7,796,900	51,338,257	355,000	3,904,134	12,532,260	12,056,034	3.80%
2038	-	-	7,796,900	51,338,257	355,000	4,024,282	12,657,153	12,176,182	3.80%
2039	-	-	7,796,900	51,338,257	355,000	4,145,626	12,783,291	12,297,526	3.80%
2040	-	-	7,796,900	51,338,257	355,000	4,268,181	12,910,687	12,420,081	3.80%
2041	-	-	7,796,900	51,338,257	355,000	4,391,956	13,039,351	12,543,856	3.80%
2042	-	-	7,796,900	51,338,257	355,000	4,516,965	13,169,298	12,668,865	3.80%
2043	-	-	7,796,900	51,338,257	355,000	4,643,220	13,300,540	12,795,120	3.80%
2044	-	-	7,796,900	51,338,257	355,000	4,770,733	13,433,090	12,922,633	3.80%
2045	-	-	7,796,900	51,338,257	355,000	4,899,517	13,566,961	13,051,417	3.80%
2046	-	-	7,796,900	51,338,257	355,000	5,029,584	13,702,166	13,181,484	3.80%

Energy	Emissions Schedule				Costs	2014 Dollars			
					Fin Needs all columns with bold headers				
Year	Coal Tons of CO2	Allocated Allowances	Total Allowances Needed	**Purchased/Sold**	**O&M (thousands)**	**Capital**	**Misc Costs**	**EE/DSM costs**	**Adjusted O&M (thousands)**
2016					658,720	-	1,000,000	9,235,000	658,720
2017					662,504	-	1,000,000	9,745,000	662,504
2018					659,176	-	1,000,000	10,189,000	659,176
2019					656,543	-	1,000,000	10,290,546	656,543
2020					654,576	-	1,000,000	10,393,099	654,576
2021					652,263	1,303,690,000	1,000,000	10,496,674	652,263
2022	6,710,060	5,129,864	6,710,060	-	650,120	-	1,000,000	10,601,282	650,120
2023	6,710,060	5,129,864	6,710,060	-	650,083	-	1,000,000	10,706,931	650,083
2024	-	5,129,864	-	(1,969,472)	648,824	-	2,500,000	10,813,634	603,599
2025	-	4,925,878	-	(4,925,878)	646,735	-	2,500,000	10,921,400	601,656
2026	-	4,925,878	-	(4,925,878)	648,227	-	2,500,000	11,030,240	603,044
2027	-	4,925,878	-	(4,925,878)	649,976	-	2,500,000	11,140,165	604,671
2028	-	4,639,480	-	(4,639,480)	654,846	-	2,500,000	11,251,185	609,202
2029	-	4,639,480	-	(4,639,480)	658,630	-	2,500,000	11,363,311	612,722
2030	-	4,473,104	-	(4,473,104)	661,601	-	2,500,000	11,476,555	615,486
2031	-	4,473,104	-	(4,473,104)	665,555	-	2,500,000	11,590,928	619,164
2032	-	4,473,104	-	(4,473,104)	671,745	-	2,500,000	11,706,440	624,923
2033	-	4,473,104	-	(4,473,104)	671,440	-	2,500,000	11,823,104	624,639
2034	-	4,473,104	-	(4,473,104)	675,273	-	2,500,000	11,940,930	628,205
2035	-	4,473,104	-	(4,473,104)	679,772	-	2,500,000	12,059,930	632,390
2036	-	4,473,104	-	(4,473,104)	684,827	-	2,500,000	12,180,117	637,093
2037	-	4,473,104	-	(4,473,104)	690,514	-	2,500,000	12,301,501	642,383
2038	-	4,473,104	-	(4,473,104)	696,845	-	2,500,000	12,424,095	648,273
2039	-	4,473,104	-	(4,473,104)	703,857	-	2,500,000	12,547,910	654,797
2040	-	4,473,104	-	(4,473,104)	711,573	-	2,500,000	12,672,959	661,975
2041	-	4,473,104	-	(4,473,104)	720,079	-	2,500,000	12,799,255	669,888
2042	-	4,473,104	-	(4,473,104)	729,384	-	2,500,000	12,926,809	678,544
2043	-	4,473,104	-	(4,473,104)	739,601	-	2,500,000	13,055,635	688,049
2044	-	4,473,104	-	(4,473,104)	750,865	-	2,500,000	13,185,744	698,528
2045	-	4,473,104	-	(4,473,104)	763,084	-	2,500,000	13,317,150	709,896
2046	-	4,473,104	-	(4,473,104)	776,335	-	2,500,000	13,449,865	722,222

Model Inputs for Compliance Plan 4A (thermal efficiency and allowance purchase example)

Energy Production and Purchase Schedule									E
			Produced			Purchased			
Year	Coal Mwh	**Short Tons of Coal**	Gas Mwh	**MMBTU of NG**	Renewable Mwh	**Purchased Mwh**	Total Mwh	EE/DSM	Assumed EE/DSM Savings
2016	7,177,000	3,323,149	765,000	6,120,000	356,000	1,532,303	10,176,297	9,830,303	3.40%
2017	6,784,000	3,141,179	723,000	5,784,000	355,000	2,045,714	10,277,712	9,907,714	3.60%
2018	6,847,000	3,170,349	767,000	6,136,000	355,000	2,016,692	10,380,137	9,985,692	3.80%
2019	6,847,000	3,170,349	767,000	6,136,000	355,000	2,116,206	10,483,583	10,085,206	3.80%
2020	6,847,000	3,170,349	767,000	6,136,000	355,000	2,216,713	10,588,059	10,185,713	3.80%
2021	6,847,000	3,170,349	767,000	6,136,000	355,000	2,318,222	10,693,577	10,287,222	3.80%
2022	6,847,000	3,170,349	767,000	6,136,000	355,000	2,420,741	10,800,147	10,389,741	3.80%
2023	6,847,000	3,170,349	767,000	6,136,000	355,000	2,524,283	10,907,779	10,493,283	3.80%
2024	6,847,000	3,170,349	767,000	6,136,000	355,000	2,628,857	11,016,483	10,597,857	3.80%
2025	6,847,000	3,170,349	767,000	6,136,000	355,000	2,734,472	11,126,270	10,703,472	3.80%
2026	6,847,000	3,170,349	767,000	6,136,000	355,000	2,841,140	11,237,152	10,810,140	3.80%
2027	6,847,000	3,170,349	767,000	6,136,000	355,000	2,948,872	11,349,139	10,917,872	3.80%
2028	6,847,000	3,170,349	767,000	6,136,000	355,000	3,057,676	11,462,242	11,026,676	3.80%
2029	6,847,000	3,170,349	767,000	6,136,000	355,000	3,167,566	11,576,471	11,136,566	3.80%
2030	6,847,000	3,170,349	767,000	6,136,000	355,000	3,278,550	11,691,840	11,247,550	3.80%
2031	6,847,000	3,170,349	767,000	6,136,000	355,000	3,390,640	11,808,358	11,359,640	3.80%
2032	6,847,000	3,170,349	767,000	6,136,000	355,000	3,503,848	11,926,037	11,472,848	3.80%
2033	6,847,000	3,170,349	767,000	6,136,000	355,000	3,618,183	12,044,889	11,587,183	3.80%
2034	6,847,000	3,170,349	767,000	6,136,000	355,000	3,733,658	12,164,925	11,702,658	3.80%
2035	6,847,000	3,170,349	767,000	6,136,000	355,000	3,850,284	12,286,158	11,819,284	3.80%
2036	6,847,000	3,170,349	767,000	6,136,000	355,000	3,968,072	12,408,599	11,937,072	3.80%
2037	6,847,000	3,170,349	767,000	6,136,000	355,000	4,087,034	12,532,260	12,056,034	3.80%
2038	6,847,000	3,170,349	767,000	6,136,000	355,000	4,207,182	12,657,153	12,176,182	3.80%
2039	6,847,000	3,170,349	767,000	6,136,000	355,000	4,328,526	12,783,291	12,297,526	3.80%
2040	6,847,000	3,170,349	767,000	6,136,000	355,000	4,451,081	12,910,687	12,420,081	3.80%
2041	6,847,000	3,170,349	767,000	6,136,000	355,000	4,574,856	13,039,351	12,543,856	3.80%
2042	6,847,000	3,170,349	767,000	6,136,000	355,000	4,699,865	13,169,298	12,668,865	3.80%
2043	6,847,000	3,170,349	767,000	6,136,000	355,000	4,826,120	13,300,540	12,795,120	3.80%
2044	6,847,000	3,170,349	767,000	6,136,000	355,000	4,953,633	13,433,090	12,922,633	3.80%
2045	6,847,000	3,170,349	767,000	6,136,000	355,000	5,082,417	13,566,961	13,051,417	3.80%
2046	6,847,000	3,170,349	767,000	6,136,000	355,000	5,212,484	13,702,166	13,181,484	3.80%

Energy	Emissions Schedule				Costs	2014 Dollars		
					Fin Needs all columns with bold headers			
Year	Coal Tons of CO2	Allowances	Needed	**Purchased/Sold**	**O&M (thousands)**	**Capital**	**EE/DSM costs**	**Misc Costs**
2016					658,720	-	9,235,000	1,000,000
2017					662,504	-	9,745,000	1,000,000
2018					659,176	-	10,189,000	1,000,000
2019					656,543	-	10,189,005.06	1,000,000
2020					654,576	-	10,290,546.19	1,000,000
2021					652,263	-	10,393,099.25	1,000,000
2022	6,710,060	5,804,585	6,710,060	905,475	650,120	-	10,496,674.33	1,000,000
2023	6,710,060	5,804,585	6,710,060	905,475	650,083	-	10,601,281.62	1,000,000
2024	6,710,060	5,804,585	6,710,060	905,475	648,824	-	10,706,931.39	1,000,000
2025	6,710,060	5,339,977	6,710,060	1,370,083	646,735	-	10,813,634.05	1,000,000
2026	6,710,060	5,339,977	6,710,060	1,370,083	648,227	-	10,921,400.08	1,000,000
2027	6,710,060	5,339,977	6,710,060	1,370,083	649,976		11,030,240.08	1,000,000
2028	6,710,060	5,033,997	6,710,060	1,676,063	654,846	-	11,140,164.75	1,000,000
2029	6,710,060	5,033,997	6,710,060	1,676,063	658,630		11,251,184.90	1,000,000
2030	6,710,060	4,833,745	6,710,060	1,876,315	661,601	-	11,363,311.46	1,000,000
2031	6,710,060	4,833,745	6,710,060	1,876,315	665,555	-	11,476,555.44	1,000,000
2032	6,710,060	4,833,745	6,710,060	1,876,315	671,745	-	11,590,927.98	1,000,000
2033	6,710,060	4,833,745	6,710,060	1,876,315	671,440	-	11,706,440.33	1,000,000
2034	6,710,060	4,833,745	6,710,060	1,876,315	675,273	-	11,823,103.85	1,000,000
2035	6,710,060	4,833,745	6,710,060	1,876,315	679,772	-	11,940,930.00	1,000,000
2036	6,710,060	4,833,745	6,710,060	1,876,315	684,827	-	12,059,930.39	1,000,000
2037	6,710,060	4,833,745	6,710,060	1,876,315	690,514	-	12,180,116.70	1,000,000
2038	6,710,060	4,833,745	6,710,060	1,876,315	696,845	-	12,301,500.76	1,000,000
2039	6,710,060	4,833,745	6,710,060	1,876,315	703,857	-	12,424,094.51	1,000,000
2040	6,710,060	4,833,745	6,710,060	1,876,315	711,573	-	12,547,909.99	1,000,000
2041	6,710,060	4,833,745	6,710,060	1,876,315	720,079	-	12,672,959.39	1,000,000
2042	6,710,060	4,833,745	6,710,060	1,876,315	729,384	-	12,799,255.00	1,000,000
2043	6,710,060	4,833,745	6,710,060	1,876,315	739,601	-	12,926,809.24	1,000,000
2044	6,710,060	4,833,745	6,710,060	1,876,315	750,865	-	13,055,634.66	1,000,000
2045	6,710,060	4,833,745	6,710,060	1,876,315	763,084	-	13,185,743.91	1,000,000
2046	6,710,060	4,833,745	6,710,060	1,876,315	776,335	-	13,317,149.81	1,000,000

Model Inputs for Compliance Plan 1A (cofiring example)

Energy Production and Purchase Schedule									
			Produced			Purchased			
Year	Coal Mwh	**Short Tons of Coal**	Gas Mwh	**MMBTU of NG**	Renewable Mwh	**Purchased Mwh**	Total Mwh	Total Mwh after EE/DSM	Assumed EE/DSM Savings
2016	7,177,000	3,323,149	765,000	6,120,000	356,000	1,532,303	10,176,297	9,830,303	3.40%
2017	6,784,000	3,141,179	723,000	5,784,000	355,000	2,045,714	10,277,712	9,907,714	3.60%
2018	6,847,000	3,170,349	767,000	6,136,000	355,000	2,016,692	10,380,137	9,985,692	3.80%
2019	6,847,000	3,170,349	767,000	6,136,000	355,000	2,116,206	10,483,583	10,085,206	3.80%
2020	6,847,000	3,170,349	767,000	6,136,000	355,000	2,216,713	10,588,059	10,185,713	3.80%
2021	6,847,000	3,170,349	767,000	6,136,000	355,000	2,318,222	10,693,577	10,287,222	3.80%
2022	6,847,000	3,170,349	767,000	6,136,000	355,000	2,420,741	10,800,147	10,389,741	3.80%
2023	6,847,000	3,170,349	767,000	6,136,000	355,000	2,524,283	10,907,779	10,493,283	3.80%
2024	-	-	767,000	6,136,000	355,000	9,475,857	11,016,483	10,597,857	3.80%
2025	3,423,500	1,640,990	4,190,500	41,909,588	355,000	2,734,472	11,126,270	10,703,472	3.80%
2026	3,423,500	1,640,990	4,190,500	41,909,588	355,000	2,841,140	11,237,152	10,810,140	3.80%
2027	3,423,500	1,640,990	4,190,500	41,909,588	355,000	2,948,872	11,349,139	10,917,872	3.80%
2028	1,711,750	826,361	5,902,250	60,180,036	355,000	3,057,676	11,462,242	11,026,676	3.80%
2029	1,711,750	826,361	5,902,250	60,180,036	355,000	3,167,566	11,576,471	11,136,566	3.80%
2030	1,711,750	826,361	5,902,250	60,180,036	355,000	3,278,550	11,691,840	11,247,550	3.80%
2031	-	-	7,614,000	78,706,254	355,000	3,390,640	11,808,358	11,359,640	3.80%
2032	-	-	7,614,000	78,706,254	355,000	3,503,848	11,926,037	11,472,848	3.80%
2033	-	-	7,614,000	78,706,254	355,000	3,618,183	12,044,889	11,587,183	3.80%
2034	-	-	7,614,000	78,706,254	355,000	3,733,658	12,164,925	11,702,658	3.80%
2035	-	-	7,614,000	78,706,254	355,000	3,850,284	12,286,158	11,819,284	3.80%
2036	-	-	7,614,000	78,706,254	355,000	3,968,072	12,408,599	11,937,072	3.80%
2037	-	-	7,614,000	78,706,254	355,000	4,087,034	12,532,260	12,056,034	3.80%
2038	-	-	7,614,000	78,706,254	355,000	4,207,182	12,657,153	12,176,182	3.80%
2039	-	-	7,614,000	78,706,254	355,000	4,328,526	12,783,291	12,297,526	3.80%
2040	-	-	7,614,000	78,706,254	355,000	4,451,081	12,910,687	12,420,081	3.80%
2041	-	-	7,614,000	78,706,254	355,000	4,574,856	13,039,351	12,543,856	3.80%
2042	-	-	7,614,000	78,706,254	355,000	4,699,865	13,169,298	12,668,865	3.80%
2043	-	-	7,614,000	78,706,254	355,000	4,826,120	13,300,540	12,795,120	3.80%
2044	-	-	7,614,000	78,706,254	355,000	4,953,633	13,433,090	12,922,633	3.80%
2045	-	-	7,614,000	78,706,254	355,000	5,082,417	13,566,961	13,051,417	3.80%
2046	-	-	7,614,000	78,706,254	355,000	5,212,484	13,702,166	13,181,484	3.80%

Energy	Emissions Schedule					Costs	2014 Dollars			
						Fin Needs all columns with bold headers				
Year	Coal Tons of CO2	Gas Tons of CO2	Allocated Allowances	Total Allowances Needed	**Purchased/ Sold**	**O&M (thousands)**	**Capital**	**Misc Costs**	**EE/DSM costs**	**O&M adjusted (thousands)**
2016						658,720	-	1,000,000	9,235,000	658,720
2017						662,504	-	1,000,000	9,745,000	662,504
2018						659,176	-	1,000,000	10,189,000	659,176
2019						656,543	-	1,000,000	10,290,546.19	656,543
2020						654,576	-	1,000,000	10,393,099.25	654,576
2021						652,263	-	1,000,000	10,496,674.33	652,263
2022	6,710,060	-	5,129,864	6,710,060	-	650,120	-	1,000,000	10,601,281.62	650,120
2023	6,710,060	-	5,129,864	6,710,060	-	650,083	-	1,000,000	10,706,931.39	650,083
2024	-	-	5,129,864	-	-	648,824	309,000,000		10,813,634.05	577,453
2025	3,423,500	1,985,630	4,925,878	5,409,130	-	646,735	-	2,000,000	10,921,400.08	636,419.79
2026	3,423,500	1,985,630	4,925,878	5,409,130	-	648,227	-	2,000,000	11,030,240.08	637,887.57
2027	3,423,500	1,985,630	4,925,878	5,409,130	-	649,976	-	2,000,000	11,140,164.75	639,609.04
2028	1,711,750	3,012,680	4,639,480	4,724,430	-	654,846	-	3,000,000	11,251,184.90	639,179.03
2029	1,711,750	3,012,680	4,639,480	4,724,430	-	658,630	-	3,000,000	11,363,311.46	642,872.35
2030	1,711,750	3,012,680	4,473,104	4,724,430	-	661,601	-	3,000,000	11,476,555.44	645,772.66
2031	-	4,039,730	4,473,104	4,039,730	-	665,555	-	4,000,000	11,590,927.98	644,324
2032	-	4,039,730	4,473,104	4,039,730	(965,238)	671,745	-	4,000,000	11,706,440.33	650,316
2033	-	4,039,730	4,473,104	4,039,730	(433,374)	671,440	-	4,000,000	11,823,103.85	650,021
2034	-	4,039,730	4,473,104	4,039,730	(433,374)	675,273	-	4,000,000	11,940,930.00	653,732
2035	-	4,039,730	4,473,104	4,039,730	(433,374)	679,772	-	4,000,000	12,059,930.39	658,087
2036	-	4,039,730	4,473,104	4,039,730	(433,374)	684,827	-	4,000,000	12,180,116.70	662,981
2037	-	4,039,730	4,473,104	4,039,730	(433,374)	690,514	-	4,000,000	12,301,500.76	668,486
2038	-	4,039,730	4,473,104	4,039,730	(433,374)	696,845	-	4,000,000	12,424,094.51	674,615
2039	-	4,039,730	4,473,104	4,039,730	(433,374)	703,857	-	4,000,000	12,547,909.99	681,404
2040	-	4,039,730	4,473,104	4,039,730	(433,374)	711,573	-	4,000,000	12,672,959.39	688,874
2041	-	4,039,730	4,473,104	4,039,730	(433,374)	720,079	-	4,000,000	12,799,255.00	697,108
2042	-	4,039,730	4,473,104	4,039,730	(433,374)	729,384	-	4,000,000	12,926,809.24	706,116
2043	-	4,039,730	4,473,104	4,039,730	(433,374)	739,601	-	4,000,000	13,055,634.66	716,008
2044	-	4,039,730	4,473,104	4,039,730	(433,374)	750,865	-	4,000,000	13,185,743.91	726,912
2045	-	4,039,730	4,473,104	4,039,730	(433,374)	763,084	-	4,000,000	13,317,149.81	738,742
2046	-	4,039,730	4,473,104	4,039,730	(433,374)	776,335	-	4,000,000	13,449,865.26	751,569

F. Input Data

Fuel Switching Financial/Modeling Information from EPA IPM v.5.13

Table F-1. Fixed and Variable O&M Costs

Plant Type	FOM ($/kW-Yr)	VOM ($/mills/kWh)
Coal Steam 30-40 yrs	48.76	6.66
Coal Steam 40-50 yrs	59.27	6.66
Coal Steam over 50 yrs	60.98	6.66
NGCC	25.56	2.95 - 6.09

*does not include carried capital charges

Table F-2. New NGCC Plant Financial Parameters

Lead Time (yrs)	3
Capital ($/kW)	1,006
Heat Rate (BTU/kWh)	6,430
FOM ($/kW/yr)	15.1
VOM ($/MWh)	3.2

*Need to multiply by regional multiplier for Indiana (1.061)

G. Public Importance and Consumer Desirability Ratings

General Public Importance Rating

Cost of Electricity

Survey information from a March 2016 Gallup poll indicates that a majority of Americans care about reliability and affordability of electricity, with only 13% of Americans do not personally worry about these issues. The changing price of electricity and the expected increase in electricity prices due to the Clean Power Plan are important concerns nationally (Hibbard, Okie, and Tierney, 2014). The general public is wary of increases in electricity prices and usually protest increases in price. A recent push by Indiana electric utilities led to backlash from consumer groups (Trabish, 2015). Other interest groups such as the AARP, which represents the elderly, view affordability of electricity as the top energy concern for their members (Sanderson, 2015).

For the above reasons we give Cost of Electricity a score of 3 or **most important** from the General Public point of view.

Economic Development

Recent trends suggested that most people prioritize economic development over the environment. However, one of the most recent Gallup polls on the environment found that the environment was considered more important than economic development (Swift, 2014). In contrast to this, when considering all issues that are important to the public, the economy and unemployment/jobs consistently rank as the most important issues or problems (Jones, 2016). In relation to local environmental concerns and climate change, the prospect of jobs and a boost to the economy trumps the benefits or concerns related to these (Benton County Indiana)

For the above reasons we give Economic Development a score of 3 or **most important** from the General Public point of view.

Local Environmental Issues

Generally, when the public is most concerned about environmental issues, they are most concerned about pollution of drinking water as well as possible concerns related accidents, spills, and land destruction. Land impacts generally affect a smaller base of people than other environmental concerns, therefore, these are not as important a concern as other issues. As in the past, Americans express the greatest worry about pollution of drinking water, a primarily local issue, and the least about global warming or climate change. The results are based on Gallup's annual Environment survey, conducted March 5-8. Gallup trends on many of these items stretch back more than two decades (Moore and Nichols, 2014). This is likely related to events such as the BP Oil Spill and increased use of hydraulic fracturing, with further importance after the Flint Water Crisis.

For the above reasons we give Local Environmental Issues a score of 2 or **somewhat important** from the General Public point of view.

Renewable Energy and Climate Change

In a recent Gallup poll, global warming and climate change were the least important environmental issues (Jones, 2014). Overall, the opinion of the general public toward climate change is mixed, with existing doubts. On the other hand, Americans prefer renewable energy sources to traditional forms of energy, such as natural gas and coal (Moore and Nichols, 2014).

For the above reasons we give Renewables Energy and Climate Change a score of 1 or **least important** from the General Public point of view.

Consumer Desirability Ratings

Compliance Plan 1C

Cost of Electricity

Based on this compliance plan (1C), the price of electricity will increase 2.6% compared with the baseline as outlined in the financial model. According to a survey conducted by Hoosier Energy, consumers were torn between whether or not they agreed the least expensive energy source was the best (Strategic Marketing and Research, 2014). Therefore, these consumers were less concerned with cost of electricity.

For the above reasons, Cost of Electricity is given a score of 2 or **moderately desirable** from Hoosier Energy's consumers point of view.

Economic Development

Natural Gas Combined Cycle Plants require less staff for operation and maintenance compared with coal plants. Therefore, by closing Merom and replacing it with a NGCC plant as this compliance plan (1C) proposes, there will likely be a negative impact on employment for the Hoosier Energy service area. This change would also impact upstream employment for Merom, such as local positions that work in coordinating and transporting coal. This change in economic development (loss of jobs) is the greatest out of the two recommended plans. However, some short-term positions in construction as well as long-term jobs in natural gas supply could mitigate job losses in the service area. The expected increase in price of electricity will modestly impact disposable income of consumers, which could also negatively impact economic development. On the other hand, Hoosier Energy will not significantly change in their status as a centralized generation and transmission cooperative, meaning they will likely continue to play an active role in economic development projects in the community.

For the above reasons, Economic Development is given a score of 1 or **least desirable** from Hoosier Energy's consumers point of view.

Local Environmental Issues

Due to the fact that Hoosier Energy will be constructing a new Natural Gas Combined Cycle plant in this compliance plan (1C), there is the possibility for a more significant environmental impact. Specifically, because new pipelines must be constructed and new connections to natural gas sources must be made, there will be greater risk of spills, accidents, fires, and other potential consequences from pipeline construction (Public Service Commission of Wisconsin, 1998). Additionally, there will be land impacts such as potential tree removal, increased soil erosion, water quality impacts, and reduction in cultivable lands (Public Service Commission of Wisconsin, 1998). Additionally, there are concerns regarding social fairness. Specifically, the potential for one landowner to bear the burden of land destruction so that other community members can benefit from the newly constructed natural gas pipeline (Public Service Commission of Wisconsin, 1998).

For the above reasons, Local Environmental Impact is given a score of 1 or **least desirable** from Hoosier Energy's consumers point of view.

Renewables & Global Climate Change

According to the survey conducted by Hoosier Energy, consumers are somewhat concerned about global climate change (Strategic Marketing and Research, 2014). The initial thermal efficiency upgrades proposed by this compliance plan (1C) will lead to less CO_2 emitted for the same amount energy, meaning there will be less impacts on global climate change. By shutting down Merom, Hoosier Energy will stop generating electricity from coal, which produces the most amount of CO_2 per ton burned. Additionally, the CO_2 emissions used to deliver coal by rail to Merom will also cease. Hoosier Energy consumers are receptive to renewable energy based on the survey and somewhat agree that renewable energy is important (Strategic Marketing and Research, 2014). Actions taken by Hoosier Energy and similar electric cooperatives suggest that cooperative members are more concerned about generation from renewable sources, but this compliance plan does not expand on actions in progress.

For the above reasons, Renewables & Global Climate Change is given a score of 2 or **moderately desirable** from Hoosier Energy's consumers point of view.

Compliance Plan 2A

Cost of Electricity
Based on this compliance plan (2A), the price of electricity will increase 2.8% compared with the baseline as outlined in the financial model.This change in price is the largest out of the two recommended Frameworks. According to a survey conducted by Hoosier Energy, consumers were torn between whether or not they agreed the least expensive energy source was the best. Therefore, Hoosier Energy's consumers were less concerned with cost of electricity (Strategic Marketing and Research, 2014).

For the above reasons, Cost of Electricity is given a score of 1 or **least desirable** from Hoosier Energy's consumers point of view.

Economic Development
Improving the thermal efficiency by 2% at Merom will not have any additional negative impacts on jobs within Hoosier Energy. Therefore, there would be no impact on upstream employment for Merom, such as local positions that work in coordinating and transporting coal. Due to this lack of impact, compliance plan 2A is the most desirable of the recommended plans.

For the above reasons, Economic Development is given a score of 3 or **most desirable** from Hoosier Energy's consumers point of view.

Local Environmental Issues
There would be no additional negative impacts to the environment such as land degradation, potential tree removal, increased soil erosion, water quality impacts, and reduction in arable lands since there will be no construction of any additional plants. (Public Service Commission of Wisconsin, 1998).

For the above reasons, Local Environment Issues is given a score of 3 or **most desirable** from Hoosier Energy's consumers point of view.

Renewables & Global Climate Change
According to the survey conducted by Hoosier Energy, consumers are somewhat concerned about global climate change (Strategic Marketing and Research, 2014). While, improving thermal efficiency at Merom by 2% as proposed by this compliance plan (2A) will lead to slightly improved air pollution, this does not do enough to offset the pollutants expelled as a result from the coal-fired power plant. Therefore, this compliance plan has been ranked as the least beneficial.

For the above reasons, Renewables & Global Climate Change is given a score of 1 or **least desirable** from Hoosier Energy's consumers point of view.

Compliance Plan 5C

Cost of Electricity

Based on this Compliance Plan (5C), the price of electricity will increase by 2.5% compared with the baseline as outlined in the financial model. This change in price is the least out of the 2 recommended Frameworks. According to a survey conducted by Hoosier Energy, consumers were torn between whether or not they agreed the least expensive energy source was the best. Therefore, Hoosier Energy's consumers were less concerned with cost of electricity.

For the above reasons, Cost of Electricity is given a score of 3 or **most desirable** from Hoosier Energy's consumers point of view.

Economic Development

Natural Gas Combined Cycle Plants require less staff for operation and maintenance compared with coal plants. Therefore, by closing Merom and replacing it with a NGCC plant as this compliance plan (5C) proposes, there will likely be a negative impact on employment for the Hoosier Energy service area. This change would also impact upstream employment for Merom, such as local positions that work in coordinating and transporting coal. This change in economic development (loss of jobs) is the greatest out of the two recommended plans. However, some short-term positions in construction as well as long-term jobs in natural gas supply could mitigate some of the job losses in the service area. The expected increase in price of electricity will modestly impact disposable income of consumers, which could also negatively impact economic development. On the other hand, Hoosier Energy will not significantly change in their status as a centralized generation and transmission cooperative, meaning they will likely continue to play an active role in economic development projects in the community.

For the above reasons, Economic Development is given a score of 1 or **least desirable** from Hoosier Energy's consumers point of view.

Local Environmental Issues

Due to the fact that Hoosier Energy will be constructing a new Natural Gas Combined Cycle plant in this compliance plan (5C), there is the possibility for a more significant environmental impact. Specifically, because new pipelines must be constructed and new connections to natural gas sources must be made, there will be greater risk of spills, accidents, fires, and other potential consequences from pipeline construction (Public Service Commission of Wisconsin, 1998). Additionally, there will be land impacts such as potential tree removal, increased soil erosion, water quality impacts, and reduction in cultivable lands (Public Service Commission of Wisconsin, 1998). Additionally, there are concerns regarding social fairness. Specifically, the potential for one landowner to bear the burden of land destruction so that other community members can benefit from the newly constructed natural gas pipeline (Public Service Commission of Wisconsin, 1998). For the above reasons, Local Environmental Impact is given a score of 1 or **least desirable** from Hoosier Energy's consumers' point of view.

Renewables & Global Climate Change

According to Hoosier Energy's survey, consumers are somewhat concerned with climate change (Strategic Marketing and Research, 2014). The initial thermal efficiency upgrades proposed by this compliance plan (5C) will lead to less CO2 emitted for the same amount energy, meaning there will be less impacts on global climate change. By shutting down Merom, Hoosier Energy will stop generating electricity from coal, which produces the most amount of CO2 per ton burned. Additionally, the CO2 emissions used to deliver coal by rail to Merom will also cease. Hoosier Energy consumers are receptive to renewable energy based on the survey and somewhat agree that renewable energy is important (Strategic Marketing and Research, 2014). Actions taken by Hoosier Energy and similar electric cooperatives suggest that cooperative members are more concerned about generation from renewable sources, but this compliance plan does not expand on actions in progress. For the above reasons, Renewables & Global Climate Change is given a score of 2 or **moderately desirable** from Hoosier Energy's consumers point of view.

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