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INTERSTATE POWER AND LIGHT COMPANY

EMISSIONS BUDGET UPDATE: 2015 – 2019

A. Background and Budget Summary Information

Interstate Power and Light Company's (IPL) Budget Update, as found within this Section II, provides the specific actions to be taken at IPL's coal-fired generation facilities and related costs and timing for each action during this EPB Update period. Please note that IPL is not proposing any new, significant emission control projects or changes to previously approved projects. IPL is implementing its projects as previously identified in its strategic plan.

In the development of this budget in concert with its strategic plan, IPL considered not just the environmentally sound characteristics of these various emissions controls, but also the prudence of their implementation. In other words, IPL carefully considered the environmentally beneficial nature of the projects in light of the impact on the safety and reliability of the system, and whether IPL's customers could reasonably be asked to bear the costs.

The Budget Update also provides costs associated with actions taken after the noted EPB Update period that IPL incurs during the Budget Update period. The EPB Update identifies compliance strategies in accordance with IPL's fleet operational strategy. IPL's coal-fired generation facilities are designated within a tiered structure that corresponds to various planning assumptions. The Tier I planning assumptions include, but are not limited to, the expectation to get full controls for nitrogen oxides, (NO_x), sulfur dioxide (SO_2), Mercury (Hg) and particulate matter (PM), as well as consideration for efficiency upgrades to improve heat rate and lower emissions. Tier I Units are Ottumwa Generating Station (Ottumwa) and Lansing Generating Station (Lansing) Unit 4. The Tier II planning assumptions include, but are not limited to, low-cost emissions control options, or fuel switching to natural gas, for Units which are smaller and generally less efficient than Tier I Units, given the economic considerations involved compared to the full controls anticipated for the Tier I Units. Tier II Units are Burlington Generating Station (Burlington), M.L. Kapp Generating Station (M.L. Kapp) Unit 2, and Prairie Creek Generating Station (Prairie Creek) Units 3 and 4. IPL no longer has any coal-fired Tier III Units remaining in its generating fleet that are covered within this EPB Update.

The Budget Update includes a summary of the specific types, amounts, vintages and values of allowances for which IPL has consummated transactions as of the date of this filing. This Budget Update also includes estimates of allowances that IPL plans to enter into purchase, sale, swap or other contracts for between the date of this filing and the end of the noted EPB Update period.

For purposes of this Budget Update, IPL is targeting the 2015-2019 time period for review of its environmental compliance activities, although the detail provided and approval requested is for the 2015-2016 time period. IPL is also providing a status report on activities and budget associated with the previous 2013-2014 Budget Update. This Budget Update demonstrates how IPL will comply with the environmental requirements that IPL currently knows will be applicable to its operations during the 2015-2019 Update period. This Budget Update will also demonstrate the planning considerations IPL is utilizing to identify compliance options, as well as develop cost estimates associated with forthcoming, not yet final, environmental requirements. These requirements will be dictated by rules and regulations that may or may not have compliance dates within the EPB Update period.

Scope of Budget Coverage: This Budget Update covers known and prospective compliance requirements during the 2015-2019 period, including the Clean Air Interstate Rule (CAIR), the Utility Mercury and Air Toxics Standards (Utility MATS), the Clean Water Act (CWA) Section 316(b) Phase II Water Intake Structure regulations and final Effluent Limitations Guidelines (ELG), as well as expected final Coal Combustion Residuals (CCR) rule. In addition, this Budget Update explains how IPL's plant investments appropriately anticipate potential transport rule scenarios, including the currently vacated Cross State Air Pollution Rule (CSAPR) should it be reinstated after U.S. Supreme Court review.

The Budget Update outlines approximately $123 million in environmental capital investments to existing coal-fired generating units during the Budget Update period from January 1, 2015, through December 31, 2019. IPL's share of these capital investments is approximately $100 million, with the other joint owner of the Ottumwa Unit 1, MidAmerican Energy Company (MidAmerican), responsible for the remaining investments.

IPL's share of investments included in the 2015-2019 Budget Update for the units it operates are shown in Table 1 below, as well as actual expenditures incurred during 2013. The Budget Update includes neither the budgets associated with MidAmerican's Neal Generating Station (Neal) and Louisa Generating Stations (units in which IPL has an ownership interest but MidAmerican operates) nor IPL's ownership share of those budgets. A more detailed breakdown of IPL's Budget Update cost figures can be found in Appendix C. The estimated costs in Appendix C include labor and material loadings (burden).

B. Status of 2013-2014 Budget Update

On April 2, 2012, IPL filed with the Iowa Utilities Board (Board) its EPB for the period 2013 through 2014. The 2013-2014 Budget Update, including the emissions control projects contained within it, reflected IPL's continued approach for compliance with the CAIR or CSAPR (or any successor rule), and Utility MATS Rule for mercury and other hazardous air pollutants (HAPs). IPL also detailed its approach on emerging water and ash rules. On February 26, 2013, Docket No. EPB-2012-150, the Board approved IPL's 2013-2014 Budget Update.

Since the submission of the 2013-2014 Budget Update in April 2012, IPL has made additional progress in implementing various projects included therein. The following summaries provide an update of the status of specific activities at various IPL coal-fired generating stations. Please see Section II, Subsection C, for a description of the technologies referenced.

Burlington Unit 1

- *Mercury Control*

An Activated Carbon Injection (ACI) system is being installed in 2014 as a result of the preliminary work and testing associated with Utility MATS compliance. The ACI system will be supplied by ADA-ES, Inc. (ADA-Es). When combined with Calcium Bromide and liquid flue gas conditioning, this system will obtain the mercury removal levels required by Utility MATS. Graycor Industrial Constructors, Inc., in partnership with Sargent & Lundy, LLC (collectively, "GSL") has contracted with IPL for the engineering and equipment installation of the Hg control equipment on this unit. Installation and refinement of the process will start in 2014 and be completed prior to the April 2015 compliance date. Additionally, new cold end air heater baskets will be installed in 2014 to maximize heat efficiency and mercury collection.

In advance of the ACI, upgrades to the existing precipitator were completed in late 2013. This was necessary to accommodate the increased particle loading from the planned ACI as well as lower the particulate matter emission rate to achieve compliance with Utility MATS.

Lansing Unit 4

- *Selective Catalytic Reduction*

The Selective Catalytic Reduction (SCR) project at IPL's Lansing Unit 4 went into service in July 2010, and the project was closed in May 2011. The original SCR installation consisted of two layers of catalyst. The plant plans to add a third layer of catalyst in 2014 and replace an existing layer of catalyst in 2015. After evaluating SCR performance / NO_X reduction, IPL may replace additional catalyst layers between 2016 and 2019. The estimated costs associated with catalyst addition and replacements are included in Appendix C.

- *SO_2 Control- Dry Scrubber (Circulating Fluidized Bed)*

IPL received an Air Quality Prevention of Significant Deterioration (PSD) Construction Permit from the Iowa Department of Natural Resources (IDNR) on May 13, 2013, for construction of a Circulating Fluidized Bed (CFB) flue gas desulfurization technology to reduce SO_2 emissions. Following an appeal by IPL, a new PSD permit was issued on December 2, 2013. In June 2013, IPL selected Burns & McDonnell Engineering Company, Inc. (Burns & McDonnell) to perform engineering, procurement and construction of the Lansing CFB Scrubber. Babcock & Wilcox Power Generation Group, Inc. (Babcock and Wilcox Power Generation) was selected as the scrubber equipment supplier. Detailed engineering and procurement activities have commenced and are on schedule. Construction is scheduled to start during the summer of 2014 and the project is expected to go into service in 2015.

- *Energy Efficiency Project*

Although it is not including costs for these projects in this EPB, IPL continues to evaluate efficiency projects at Lansing Unit 4 to offset the negative impact to efficiency of the emission controls. Projects being evaluated include a turbine steam path redesign, which could provide a more efficient energy production cycle. This would result in a reduction in the quantity of greenhouse gases (GHG) emitted per kWh generated, or at a minimum, not increase GHG emissions from pre-emission control conditions.

Ottumwa Unit 1[1]

- *Mercury Control*

IPL received a PSD Construction Permit from the IDNR on January 12, 2012, for construction of new Air Quality Control Systems (AQCS). These ACQS include an ACI system and pulse jet fabric filter (PJFF) baghouse that will reduce mercury emissions. IPL engaged Burns & McDonnell to complete preliminary engineering, estimating, scheduling, and evaluation of bids. IPL has contracted with BWM Ottumwa Environmental Partners, a joint venture of Burns & McDonnell and Babcock & Wilcox Construction Co., Inc., (Babcock & Wilcox Construction) for the engineering, procurement, and construction of the ACI system and baghouse.

[1] Although IPL's share of Ottumwa is only 48%, the information and numbers presented in this EPB Update represent the total (100%) plant.

Detailed engineering, fabrication and construction of the ACI system and PJFF baghouse began in 2012 and continued, as scheduled, in 2013 and 2014. Following substantial completion of the AQCS engineering design, IPL received a modified PSD Construction Permit from the IDNR on December 27, 2013, with modified emissions and stack characteristics for construction of new AQCS. Fabrication and construction of the ACI system and PJFF baghouse will continue until November 2014. Start-up and commissioning will begin following the tie-in outage completion in November 2014 consistent with the April 2012 EPB target date.

- *SO_2 Control- Spray Dryer Absorber*

IPL received a PSD Construction Permit from the IDNR on January 12, 2012, for construction of new AQCS that includes a spray dryer absorber (SDA) flue gas desulfurization technology to reduce SO_2 emissions. IPL engaged Burns & McDonnell to complete preliminary engineering, estimating, scheduling and evaluation of bids for the SDA. IPL has contracted with BWM Ottumwa Environmental Partners for the engineering, procurement, and construction of the SDA scrubber.

Detailed engineering, fabrication and construction of the SDA scrubber began in 2012 and continued, as scheduled, in 2013 and 2014. Following substantial completion of the AQCS engineering design, IPL received a modified PSD Construction Permit from the IDNR on December 27, 2013, with modified emissions and stack characteristics for construction of new AQCS. Fabrication and construction of the SDA will continue until November 2014. Start-up and commissioning will begin following the tie-in outage completion in November 2014, consistent with the target date established in IPL's April 2012 EPB.

- *Energy Efficiency Projects*

IPL received a PSD Construction Permit from the IDNR on January 12, 2012, for construction of plant efficiency improvement projects, referred to as the Comprehensive Asset Management Program (CAMP). The CAMP includes the Steam Turbine/Generator Upgrade Project that will improve plant heat rate, plant output, and steam turbine/generator reliability. IPL has contracted with BWM Ottumwa Environmental Partners for the engineering, procurement, and construction of the Steam Turbine/Generator Upgrade Project. In 2012, BWM Ottumwa Environmental Partners awarded a subcontract to Toshiba International Corporation to furnish the Steam Turbine/Generator Upgrade Project design, engineering, material, and installation. This project will replace the existing steam turbine high pressure (HP), intermediate pressure (IP) and low pressure (LP) rotors and inner shells, and rewind the generator stator. Following substantial completion of the CAMP engineering design, IPL received a modified PSD Construction Permit from the IDNR on December 27, 2013, with a modified flow rate. Installation of the Steam Turbine/Generator Upgrade Project will be performed during the tie-in outage that completes in November 2014. Start-up and commissioning will begin following the tie-in outage completion in November 2014, consistent with the target date established in IPL's April 2012 EPB.

M.L. Kapp Unit 2

In the 2012 EPB Update, IPL indicated, that for certain units, it would undertake an evaluation of precipitator improvements for PM emission reductions and install Hg emission reduction technologies or retire or fuel switch. The basis for decision on which compliance path to take would be based on the cost-effectiveness of a given solution or set of solutions. For M.L. Kapp, it was determined that fuel switching was the best path forward.

- *Utility MATS Compliance*

In order to attain Utility MATS compliance, M.L. Kapp will be fuel switching to 100% natural gas in Q2 2015. The unit currently has a capacity of 200 MW when running on coal, and is also equipped to burn natural gas. After the switch to natural gas, the unit will be limited to approximately 95 MW because of limited fuel availability.

Prairie Creek Unit 3

- *Mercury Control*

ACI is being installed in 2014 as a result of the preliminary work and testing associated with Utility MATS compliance. The ACI system will be supplied by ADA-ES, and, when combined with Calcium Bromide and liquid flue gas conditioning, will obtain the mercury removal levels required by Utility MATS. IPL has executed an agreement with GSL for the engineering and equipment installation of the Hg control equipment on this unit. Installation and refinement of the process will start in 2014 and be completed prior to the April 2015 compliance date.

In advance of the ACI, upgrades to the existing precipitator were completed in late 2013. This was necessary to accommodate the increased particle loading from the planned ACI as well as lower the particulate matter emission rate to achieve compliance with Utility MATS.

Prairie Creek Unit 4

- *Mercury Control*

ACI is being installed in 2014 as a result of the preliminary work and testing associated with Utility MATS compliance. The ACI system will be supplied by ADA-ES, and, when combined with Calcium Bromide, will obtain the mercury removal levels required by Utility MATS. IPL has executed an agreement with GSL for the engineering and equipment installation of the Hg control equipment on this unit. Installation and refinement of the process will start in 2014 and be completed prior to the April 2015 compliance date.

In advance of the ACI, upgrades to the existing precipitator were completed in late 2013. This was necessary to accommodate the increased particle loading from the planned ACI as well as lower the particulate matter emission rate to achieve compliance with Utility MATS.

C. Air Emission Rule Compliance Implementation

IPL based its current air emission rules compliance implementation plans primarily on the requirements of CAIR, its potential successor rule (the now vacated CSAPR) and Utility MATS. CAIR uses a market-based approach to achieve the required reductions of NO_x and SO_2 emissions in a flexible and cost-effective manner. IPL's plan is to meet the emission reduction requirements through a combination of emission controls, fuel switching and emission allowances, as needed. CSAPR, which was written to replace CAIR to address pollutant transport issues and also utilizes a market-based approach, was vacated by the U.S. Court of Appeals for the D.C. Circuit in August 2012. The EPA is currently appealing the CSAPR decision to the U.S. Supreme Court. IPL will continue to monitor and evaluate the CSAPR legal proceedings and the potential for another proposed CAIR replacement rule. In the interim, IPL will continue to comply with CAIR requirements.

As a result of Utility MATS, IPL is required to control and reduce emissions of Hg, as well as other pollutants, including filterable PM and hydrochloric acid (HCl), at its coal-fired electric generating units (EGUs) larger than 25 MW. Utility MATS requires unit-by-unit compliance with reduction requirements for Hg emissions from existing units of at least [redacted] with an option to average emissions from units located at a common site. Utility MATS also establishes limitations on HCl and PM emissions on a unit-by-unit basis, with an option to average emissions from units located at a common site. IPL has included emission control projects in this EPB that are responsive to the impact of Utility MATS. Section I further discusses CAIR and CSAPR, Utility MATS and other environmental-related regulatory requirements.

IPL continues to seek a better understanding of the impacts of future GHG rules on its coal-fired electric generating units. IPL understands these impacts could be significant and has attempted to consider these impacts, even though they are very uncertain, as it developed this EPB. IPL has generally incorporated risks resulting from potential future GHG rules into the approach it used for selecting non-GHG emission control projects that reduce emissions, including HCl, Hg, NO_x, PM and SO_2. IPL has also included other initiatives in this EPB that will assist in reducing GHG emissions, including plant efficiency improvement projects planned at Ottumwa and the conversion of M.L. Kapp to operate exclusively on natural gas.

Air emission rules compliance implementation entails, to a large extent, the continued undertaking of emission control projects at various IPL coal-fired generating units. To a lesser extent, other compliance options and alternatives may be useful and desirable. These options include unit retirement and fuel switching. IPL routinely reviews compliance options and alternatives as it undertakes air emission rules compliance implementation.

The estimated capital expenditures for emission control projects with expenditures incurred during 2015 through 2019, as well as expenditures and revenues associated with emissions allowance contracts, both consummated and planned, are shown in Appendix C. Estimated expenditures are based on current costs of technologies and emissions allowance prices. These estimated expenditures may change, depending on many factors including:

- material cost and availability;
- labor and allowance market conditions;
- changes to detailed scope resulting from preliminary and detailed engineering design and analysis;
- changes to the environmental rules and regulations applicable to IPL; and

- changes in timing of emission control projects necessary to maintain grid reliability.

In addition, there will also be recurring costs for operating and maintaining installed emission control equipment associated with these capital expenditures, particularly chemical costs for the operation of various emission controls.

1. Description of Emission Control Technologies and Alternatives

Technologies for the control of many emissions, including $NO_{x,}$ SO_2 and acid gases, particulate matter, and Hg are fairly mature. IPL has installed or is in the process of engineering and installing systems and processes to address these emissions, as described elsewhere in the document. For the benefit of the reader, descriptions of the emission control technologies for the above described pollutants are presented in Appendix B.

Since physical control technologies for reducing GHG emissions are maturing, and there has been recent attention in GHG regulation, IPL is providing a discussion of current known CO_2 control technologies below.

a. Description of CO_2 Emission Control Technologies

Several approaches and technologies exist to reduce or remove CO_2 emissions from coal-fired generating units. These technologies can be grouped into the following categories:

i. Increased plant thermal efficiency approach;

ii. Post-combustion CO_2 capture technologies; and

iii. Alternative fuel combustion processes.

The subsections that follow will provide a high level review of the status of these technologies.

Increased plant thermal efficiency – Optimizing plant design and operational procedures to increase thermal efficiency reduces the amount of fuel combusted to produce a given quantity of electricity. This reduced amount of fuel combusted results in a corresponding decrease in CO_2 emission rate intensity. Thermal efficiency improvements typically involve four areas of plant design: Combustion optimization; turbine steam path redesign; heat recovery improvements; and auxiliary power reduction. Many of the techniques and tools used to control NO_x through improved combustion (as described in Appendix B) can also be used to increase and sustain increased plant efficiency. A turbine steam path redesign replaces a combination of the existing low pressure, intermediate pressure, or high pressure steam turbine components with a design providing higher efficiency. Heat recovery improvements, such as upgraded air preheater baskets or condenser modifications to improve heat transfer, increase efficiency by capturing more heat from the flue gas and condensate. Installing variable frequency drives on large motors to improve control and reduce the energy requirement at low loads is an example of an improvement that can reduce auxiliary power usage. Improvements to increase plant thermal efficiency must be evaluated on a case by case basis.

Post-combustion CO_2 capture – The component technologies used for CO_2 capture and storage are well understood and have been employed in industrial processes for many years, even decades. The key technical challenge for widespread deployment within the power generation industry is the integration of component technologies into successful large–scale demonstration projects.

Pilot and demonstration projects continue in the U.S.; however, economic pressures and regulatory/legislative uncertainty have slowed progress, driving several projects to be cancelled or postponed. More commercially scalable capture facilities need to enter development planning to support the technological advancement and cost reductions needed for deployment.

Post-combustion CO_2 capture (PCC) technologies focus on removing CO_2 from the flue gas after the fuel is burned, but prior to the flue gas exiting the plant through the stack. Post-combustion CO_2 technologies use amine or ammonia solvents to remove CO_2 from the flue gas. Challenges encountered when using post-combustion technologies include degradation of the absorption solvent due to the presence of oxygen in the flue gas, loss of efficiency and power output from the plant, and the transportation and sequestration of the captured CO_2 emissions. Current PCC research and development focuses on improved sorbents that require less energy for sorbent regeneration and/or that could be regenerated at pressure, thereby reducing the CO_2 compression energy required.

Absorption of CO_2 using solvents is also affected by the need to have low pressure of the incoming flue gas stream. However, large volumes of flue gas would need to be treated to remove the CO_2. Both amine and ammonia absorption systems have been demonstrated in small scale demonstration or pilot projects. Small-scale demonstrations of amine-based systems have been carried out by several manufacturers, removing less than 500 tons per day and are becoming commercially available. To put this in perspective, a typical coal-fired generating unit produces one ton of CO_2 per hour for each megawatt (MW) of generation. Considerable scale-up and further demonstration of utility scale systems is still required. Ammonia-based systems have only been demonstrated in pilot projects.

Amine-Based System: The amine-based, post-combustion CO_2 removal process uses an amine solvent, typically monoethanolamine (MEA), to absorb CO_2 from the flue gas. This process first requires that the flue gas be treated to reduce NO_x, SO_x, particulate matter, and Hg concentrations. The flue gas is then cooled (to approximately 78ºF) prior to being directed into an absorber column where the MEA solvent is brought into contact with the flue gas. The scrubbed flue gas is vented to the atmosphere through the stack. The MEA solvent containing CO_2 is then separated from the CO_2 using steam. The MEA solvent is then re-circulated to the absorber column to be re-used.

A significant challenge to using an MEA-based system is the impact on the overall cycle efficiency. The flue gas must be cooled for the MEA solvent to absorb the CO_2 and then later the CO_2 is separated from the MEA solvent using steam. The CO_2 can then be compressed for transportation or sequestration. Additional challenges include the cost to filter impurities from the MEA solvent or make up lost solvent. The potential to increase volatile organic compound (VOC) emissions also exists.

An amine based CO_2 capture project is currently in the planning stages at NRG Energy's W.A.Parish plant (Texas). Plans are to capture CO_2 from a 250 MW unit. Two other utility-scale projects are being developed in Canada. The

SaskPower Boundary Dam project in Saskatchewan is under construction and is expected to remove CO_2 from a 110 MW plant. Another 1,000 MW system is being planned in conjunction with the construction of a new coal-fired power plant located in Bow City, Alberta.

Ammonia-Based Systems: The process equipment for the ammonia-based systems is similar to the amine-based system. The flue gas must be cooled to a lower temperature (32ºF to 50ºF) prior to coming into contact with the ammonia. The lower operating temperatures reduce the amount of ammonia emitted during the absorption process and reduce the flue gas volume and mass flow, decreasing the size of the downstream equipment. The CO_2 is removed from the ammonia in a pressurized process, reducing the energy needed to compress the CO_2 for transportation or sequestration.

The ammonia supply for CO_2 capture can be integrated into the ammonia supply for other plant processes, such as SCR. Ammonia is also more resistant to degradation than the MEA solvent. Ammonia-based systems have not progressed beyond the pilot project testing stage. Alternative fuel combustion processes – Alternative processes to combust coal including oxy-fuel combustion and chemical-looping combustion (CLC) -- can provide a more concentrated CO_2 emissions source, enabling more efficient subsequent emissions capture.

Oxy-fuel combustion: Oxy-fuel combustion is an alternative combustion process that can be used in a pulverized coal (PC) plant. Instead of burning the fuel in air, it burns the fuel in nearly pure oxygen. This results in a higher concentration of CO_2, approximately 80% to 90%, in the flue gas. Because air is not used for combustion, the flue gas consists of primarily CO_2 and water, with very little nitrogen. The CO_2 can then be more readily separated from the remaining flue gas and prepared for transportation or sequestration. Oxy-combustion technology has taken large steps forward with operating pilots in the U.S., Europe, and Australia. The FutureGen 2.0 project (cooperative project with the FutureGen Alliance, the U.S. Department of Energy, the State of Illinois, Babcock & Wilcox, American Air Liquide Holdings, Inc. and Ameren Energy Resources Company, LLC (Ameren Energy Resources)) intends to conduct large-scale testing to accelerate the deployment of a set of advanced oxy-combustion power production technologies integrated with Carbon Capture and Storage (CCS). This project will be the first advanced repowering oxy-combustion project to store CO_2 in a deep saline geologic formation. The plan is to repower a recently idled Ameren Energy Resources' plant with advanced oxy-combustion technologies. Plans slowed when Ameren Energy Resources announced in late 2011 that it was closing the plant and dropping out of the project. The project was restructured and is currently in the engineering phase, with construction expected to begin in 2014. The greatest remaining technical challenge for oxy-combustion technology is integrating these systems into a complete steam-electric power plant. There is a need to demonstrate an oxyfuel power generation facility with carbon capture at commercial scale, however no other demonstrations are currently being planned within the U.S. Two projects are in preliminary planning stages in Europe.

Chemical-looping combustion (CLC): CLC is an indirect combustion process that makes use of a metal oxide (MyOx) or calcium oxide as an oxygen carrier to transfer oxygen from air to the fuel. The CLC process is conducted in two reactors (air and fuel reactor). In the first step, carbon in the coal will bond with oxygen in the MyOx to form CO_2 which then is vented, cooled and collected from the first vessel. The second step takes place in the air reactor whereby oxygen-deprived MyOx is oxidized with air, creating a gas containing mostly nitrogen (N_2). Heat is extracted from both steps to create steam for the turbine. The CLC process is expected to have very low energy usage requirements with very high CO_2 removal efficiencies. CLC is in the research and bench-scale testing stage.

b. Other Compliance Options & Alternatives

Fuel Switching Alternatives – Fuel switching can reduce fuel-related emissions, such as SO_2, Hg, CO_2, and the fuel-related component of NO_x emissions. Switching from coal to natural gas would greatly reduce a unit's SO_2, NO_x and Hg emissions, and reduce CO_2 emissions by approximately 50%. Switching from coal to biomass would eliminate combustion-related life-cycle CO_2 emissions and greatly reduce SO_2 and Hg emissions. However, NO_x and other emissions, including those of various HAPs, might not be reduced or could even potentially increase. Emissions from biomass combustion will vary depending on the type of and manner in which the biomass is combusted.

While a dedicated large natural gas-fired generating facility may be economic, the same cannot necessarily be said for a large converted facility. Due to the possibility of added fuel cost, and impact on efficiency, currently associated with switching from coal to natural gas or biomass, especially at larger, base load coal-fired generating units, installing emission controls to reduce emissions instead of fuel switching is typically a more economic alternative.

However, for smaller, intermediate-load, coal-fired generating units, IPL has and will continue to consider converting coal-fired boilers to burn alternative fuels, such as natural gas, instead of installing emission controls. For example, in 2012, IPL switched the Sutherland Generating Station (Units 1 and 3) to a natural gas-fired facility and no longer operates the site as a coal-fired facility. In 2013, IPL announced plans to switch M.L. Kapp Unit 2 from a coal-fired to a natural gas-fired facility.

At the current time, IPL is not planning to co-fire biomass at any of its coal fired units due to the high cost of the biomass fuel and issues associated with acquiring sufficient quantities. IPL will continue to evaluate options for co-firing of natural gas with coal, however, may provide an economic alternative to installing emission controls.

<u>Environmental Dispatch</u> - IPL has the ability to manage the dispatch of its generating units through the power market administered by the Midcontinent Independent System Operator, Inc. (MISO) to achieve a specified amount of one or more types of emissions. Unlike traditional unit dispatch methods,[2] environmental dispatch adds additional constraint(s) to direct the outcome of the dispatch to

[2] Traditional dispatch methods determine a unit output that attempts to minimize the overall variable financial cost of producing energy, which already includes a variable cost associated with each emission based upon the emission rates and avoided costs of the emissions.

achieve a specified amount of emission(s). As a result of the additional constraint(s), the overall cost of the dispatch will rise as measured by the variable cost of producing energy. In practice, environmental dispatch increases the use of lower-emitting units and decreases the use of higher-emitting units for energy production, in spite of the possible increased financial cost of doing so. Thus, IPL does not regard environmental dispatch as a long-term, least-cost compliance alternative and would use it only on a short-term basis to compensate for other specific operational constraints which may hamper IPL's ability to meet its emission compliance requirements. On a longer-term basis, installing emission controls, purchasing emission allowances or fuel switching would provide lower cost compliance alternatives.

Replace Existing Generating Units with New Generating Units – One option for avoiding the costs of retrofitting emission control projects into existing generating facilities would be to construct new generating units. For larger, base-load coal-fired generating units, retrofitting the units by installing emission controls will typically be a more practical, lower-cost alternative versus replacing the capacity and energy with capacity and energy from newly-constructed units. For smaller, intermediate-load coal-fired generating units, IPL will continue to consider fuel switching or replacement with capacity and energy from new generating units or other resources in the course of conducting its integrated resource planning process. Keeping generating units in service allows IPL to maintain a balanced generation fleet and fuels portfolio for the benefit of its customers.

c. Use of Emission Allowance Markets

To comply with CAIR (or anticipated CAIR successor rule directives), purchasing SO_2 and NO_x (annual and ozone season) allowances from the emission allowance markets is a viable compliance alternative. To the extent necessary and allowable, IPL can purchase allowances and use them for compliance instead of installing emission controls or making other changes to unit operations to reduce emissions at its owned generating units. The need or desirability of using allowance purchases for compliance instead of installing emission controls is driven by a number of technological, economic, and allowance management administrative factors. Further discussion regarding emission allowance use and management practices within IPL, and the role of banked or purchased allowances in CAIR compliance, is available in the section entitled, "Emission Allowance Management – IPL" which is found in Section II.C.2.g. Please note, however, that the use of emission allowances is not a compliance alternative for Hg and other HAPs, which are regulated by Utility MATS.

2. IPL's Specific Emission Reduction Activities and Budgets

The following discussion presents IPL's 2014 EPB approach, activities and budget to meet its CAIR NO_x and SO_2, Utility MATS Hg, PM, HCl and other HAPs, as well as possible future GHG emissions requirements. Appendix A contains a summary of expected emissions changes associated with the ongoing implementation of IPL's compliance plan. As previously noted, IPL is not proposing any new, significant emission control projects in this EPB.

a. NO_x Emission Reductions – Approach and Budget

No additional NO_x emission reductions are required for IPL to meet CAIR requirements at this time. IPL has significantly reduced NO_x emissions through NO_x emission controls, unit retirements and fuel switching.

Operation of IPL's generating units as currently planned is reasonably expected to achieve cost-effective compliance with CAIR NO_x emission reduction requirements at this time. While it is possible that additional NO_x emission reductions may be needed in the future, IPL is not proposing any additional NO_x emission control projects in this 2015 - 2016 EPB.

NO_x Implementation Approach: IPL will continue to operate its existing NO_x emission controls to achieve high levels of NO_x emission reductions while considering operating costs.

NO_x Emissions Changes - Post-Project Control Installations: The ongoing implementation of IPL's strategic plan has already resulted in a 62% reduction in annual NO_x emissions from 20,255 tons, as documented in IPL's approved 2008 EPB, to the 2012 annual NO_x emissions of 7,657 tons, as shown in Appendix A. IPL anticipates some additional changes in NO_x emissions through 2016 due to the SCR catalyst bed being added at Lansing Unit 4, the fuel switch to natural gas at M.L. Kapp Unit 2, the SNCR coming online at George Neal Unit 3 in 2014 and a projected minimal heat input increase at Ottumwa Unit 1. Annual NO_x emissions are projected to decrease compared to the 2012 baseline NO_x emissions for IPL's coal-fired generating units as a result of these

changes. Appendix A contains a summary of expected NO_x emissions changes associated with the implementation of IPL's compliance plan.

Budget - Capital (NO_x): IPL will incur limited capital expenditures associated with the operation of existing NO_x reduction technologies in the 2015 - 2019 budget time period. These capital costs include replacement of SCR catalyst layers at Lansing Unit 4. IPL's projected capital costs can be found in Appendix C.

Budget - Expense (O&M, NO_x): IPL's projected O&M costs can be found in Appendix C. The O&M costs include the cost for operating the Lansing Unit 4 SCR, which includes the chemical reagent and the cost to operate and maintain the equipment, including auxiliary power.

b. SO_2 Emission Reductions – Approach and Budget

IPL anticipates having to comply with Phase II of CAIR, an updated CSAPR (pending the outcome of the U.S. Supreme Court appeal), or potentially a new federal rule to address interstate transport of SO_2 emissions. As a result, IPL continues to pursue the SO_2 compliance activities laid out in its previous EPB, as approved by the Board. IPL is not proposing any new SO_2 emission control projects in this Update.

IPL's strategy to comply with CAIR SO_2 emissions requirements can be summarized as follows:

1) operating scrubbers on the two larger (Tier I) IPL units, which provide the largest SO_2 emissions reduction;
2) fuel switching coal-fired units to natural gas-fired; and

3) using allocated, purchased and banked emission allowances, as needed.

The final aspect of IPL's SO_2 emission reduction plan is the completion and commissioning of the following projects:

- Ottumwa Unit 1: Dry Scrubber (SDA) (2014); and
- Lansing Unit 4: Dry Scrubber (CFB) (2015).

Additional SO_2 emission reductions will be realized through planned fuel switching to exclusively burn natural gas at M.L. Kapp Unit 2, although this project is primarily intended to comply with Utility MATS, and a dry scrubber coming online at George Neal Unit 3 in 2014.

SO_2 Project Implementation Approach: An air permit for the Lansing CFB scrubber was secured in late 2013 allowing IPL to move forward with pre-construction activities associated with this SO_2 emission reduction project. Construction is anticipated to begin in the summer of 2014 and completed in mid-2015. A description of the CFB scrubber technology is presented in Appendix B. The Ottumwa dry scrubber operational start-up and commissioning period will carry over from late 2014 to early 2015. Cost information regarding these projects can be found in Appendix C.

SO_2 Emission Changes - Post Project Control Installations: The ongoing implementation of IPL's strategic plan has already resulted in a 45% reduction in annual SO_2 emissions from 48,830 tons, as documented in IPL's approved 2008 EPB, to the 2012 annual SO_2 emissions of 26,714 tons, as shown in Appendix A. IPL anticipates additional significant changes in SO_2 emissions through 2016. Annual SO_2 emissions are projected to decrease [redacted] compared to

the 2012 baseline SO_2 emissions for IPL's coal-fired generating units as a result of ongoing projects. Appendix A contains a summary of expected SO_2 emissions changes associated with the implementation of IPL's compliance plan.

Budget - Capital (SO_2): IPL presents capital expenditures associated with the SO_2 reduction technologies in the 2015 - 2019 budget time period. IPL's projected capital costs may be found in Appendix C.

The SO_2 reduction technology project costs include the installation of the Lansing Unit 4 scrubber, the Ottumwa Unit 1 scrubber start-up and commissioning, and the M.L. Kapp fuel switch from coal to natural gas.

Budget - Expense (O&M, SO_2): For SO_2 reduction technology projects, the plant-specific incremental O&M after project completion is primarily related to the cost of lime reagent used as a consumable in the scrubbing process and the cost to dispose of the scrubbing by-products. Other costs that will be added to O&M are related to the addition of staff to support the operation of the scrubbers and the additional auxiliary power associated with the installation of the scrubber equipment. Plant-specific O&M costs can be found in Appendix C.

c. Hg Emission Reductions – Approach and Budget

The Utility MATS requires unit-by-unit Hg emission rate reductions from existing units, or possible emission averaging of units at a common site. For IPL, this means its coal-fired EGUs will need to achieve at least [redacted] reduction in baseline Hg emission rates. While unit retirements and fuel switching contribute to the Hg emission reductions (in terms of mass) for the IPL fleet as a whole, each unit or facility will need to comply with the Utility MATS requirements regardless of actions taken at another unit or facility. However, unit retirement or fuel switching may minimize the expense needed to comply with the Utility MATS at a specific unit or facility.

As discussed in the 2012 Update, IPL's general compliance approach to address Hg emission reduction requirements under the Utility MATS continues to include the following:

1) operate powder activated carbon (PAC) at Lansing Unit 4 and Ottumwa Unit 1;
2) operate ACI at Burlington and Prairie Creek Units 3 and 4; and
3) fuel switch at M.L. Kapp Unit 2 (2015) to exclusive natural gas use, and, as a result, eliminate the Utility MATS compliance requirements from this unit.

IPL will implement its compliance approach in order to achieve Hg reductions by the Utility MATS April 2015 compliance deadline. IPL is not proposing any new Hg emission control projects in this Update.

Hg Project Implementation Approach: IPL secured an air permit for the Ottumwa PAC project in January 2012. Construction has been underway on this project since early spring 2012 with completion targeted for Q4 2014. The PAC technology discussion is presented in Appendix B. Current cost information on this project can be found in Appendix C.

IPL will operate ACI, with calcium bromide injection, along with liquid flue gas conditioning at [redacted] The ACI and calcium bromide injection technology discussion is presented in Appendix B under the heading "Description of Mercury (Hg) Emission Control Technologies."

IPL will also complete a fuel switch at M.L. Kapp from coal-fired to exclusively natural gas-fired. This approach is reasonably expected to contribute to cost-effective compliance with the Utility MATS requirements.

Hg Emissions Changes - Post Project Control Installations: The ongoing implementation of IPL's strategic plan has already resulted in a 27% reduction in annual Hg emissions from 812 pounds, as documented in IPL's approved 2008 EPB, to the 2012 annual Hg emissions of 590 pounds, as shown in Appendix A. IPL anticipates additional significant changes in Hg emissions through 2016. Annual Hg emissions are projected to decrease compared to the 2012 baseline Hg emissions for IPL's coal-fired generating units as a result of ongoing projects. Appendix A contains a summary of expected Hg emissions changes associated with the implementation of IPL's compliance plan.

Budget - Capital (Hg): IPL will incur capital expenditures associated with the startup and commissioning of Hg reduction technologies in the 2015 - 2019 budget time period, which includes requisite Hg monitoring and testing at Ottumwa Unit 1. These projected capital costs can be found in Appendix C.

All cost estimates and schedules may be subject to change due to a variety of reasons, including: changing outage schedules beyond the control of IPL; the application of lessons learned at other generating stations; changing plant requirements; unidentified design issues; market conditions; changing technologies; inflation; and changing regulatory requirements.

Budget - Expense (O&M, Hg): For the Hg control technologies, incremental plant O&M costs will, in general, include the cost for the sorbent, the cost to operate and maintain the equipment including auxiliary power, compliance monitoring costs, and the cost to dispose of the by-products. Plant specific incremental O&M costs have been estimated. These O&M costs may be refined as more specific operating conditions are known at plants where Hg control technology installation is occurring. IPL's projected O&M costs are presented in more detail in Appendix C.

d. PM Emission Reductions – Approach and Budget

The Utility MATS requires unit-by-unit PM emission rate reductions from existing units, or possible emission averaging of units at a common site. While unit retirements and fuel switching contribute to the PM emission reductions (in terms of mass) for the IPL fleet as a whole, each unit or facility will need to comply with the Utility MATS requirements regardless of actions taken at another unit or facility. However, unit retirement or fuel switching may minimize the expense needed to comply with the Utility MATS at a specific unit or facility.

IPL's general compliance approach to address PM emission reduction requirements under the Utility MATS can be summarized as follows:

1) operate the existing baghouse(BH) at Lansing Unit 4;
2) operate the BH at Ottumwa Unit 1 (2014) in concert with the SDA/PAC project;
3) fuel switch at M.L. Kapp Unit 2 (2015) to exclusive natural gas use; and
4) evaluate PM emission reductions as a result of recent ESP upgrades at the following

IPL will implement its compliance approach in order to achieve PM reductions by the Utility MATS April 2015 compliance deadline. IPL is not proposing any new PM emission control projects in this Update.

PM Project Implementation Approach: IPL secured an air permit for the Ottumwa BH project in January 2012. Construction has been underway on this project since early spring 2012 with completion scheduled for Q4 2014. The BH technology discussion is presented Appendix B under the heading "Description of Particulate Matter (PM) Control Technologies".

IPL identified cost-effective ways to comply with the Utility MATS PM limit at its Tier II coal-fired power plants – [redacted] and reduce the resulting customer rate impact associated with achieving compliance. Sectionalization of the ESP was determined to be the most effective option for compliance with the PM requirements of the Utility MATS for [redacted] units. This work was completed in late 2013. M.L. Kapp will fuel switch to exclusive natural gas use in 2015 and will no longer be subject to the Utility MATS.

PM Emissions Changes - Post Project Control Installations: Appendix A contains a summary of expected reductions in PM emissions as a result of implementing the IPL compliance approach described at the beginning of this section.

Budget - Capital (PM): IPL will incur capital expenditures associated with the PM reduction technologies in the 2015 - 2019 budget time period, including requisite PM monitoring and testing. This includes the completion of the

Ottumwa Unit 1 baghouse. Also included in the capital budgets are PM CEMS installation, certification and replacement expenditures necessary to implement and monitor future compliance requirements. IPL's projected capital costs can be found in Appendix C.

All cost estimates and schedules are subject to change due to a variety of reasons, including: changing outage schedules beyond the control of IPL; the application of lessons learned elsewhere; changing plant requirements; unidentified design issues; market conditions; changing technologies; inflation; and changing regulatory requirements.

Budget - Expense (O&M, PM): For the PM control technologies, incremental plant O&M costs will, in general, include the cost for the flue gas conditioning agent, the cost to operate and maintain the equipment including auxiliary power, and compliance monitoring costs. Plant-specific incremental O&M costs have been estimated. These O&M costs will be refined as more specific operating conditions are known at plants where PM control technology installation occurs. IPL's projected O&M costs are presented in more detail in Appendix C.

e. HCl Emission Reductions – Approach and Budget

The Utility MATS requires unit-by-unit HCl emission reductions from existing units, or possible emission averaging of units at a common site. Through testing performed by IPL, it appears that all IPL coal-fired units can meet the Utility MATS limit for HCl with existing operating fuels and equipment. It appears that the primary reason for these lower HCl emissions is the chlorine concentration present in coal, with sub-bituminous coal having lower chlorine concentration than bituminous coal. IPL's coal-fired EGUs currently combust primarily sub-bituminous coal.

Data collected during testing also indicates that ACI used to lower Hg emissions has the effect of lowering HCl emissions. In short, HCl emissions should further decrease as other emission controls, such as those to control Hg emissions, are installed. Appendix A summarizes the Hg controls existing and planned for IPL's coal-fired units.

Utility MATS allows units with a wet or dry flue gas desulfurization (FGD) system (i.e., a scrubber) to meet alternative SO_2 limits in lieu of the HCl limits. Lansing Unit 4 and Ottumwa Unit 1 are anticipated to comply via the SO_2 limits.

IPL's general compliance approach to address HCl emission reduction requirements under the Utility MATS can be summarized as follows:

1) continue to combust primarily sub-bituminous coal;
2) utilize ACI or switch fuel from coal to natural gas; and
3) evaluate HCl emissions after completion of emission control projects.

HCl Project Implementation Approach: IPL is not proposing specific projects related to reduction in HCl emissions as part of this EPB.

HCl Emissions Changes - Post Project Control Installations: Based on data collected during testing, IPL's coal-fired units already comply with the Utility MATS HCl limit. While HCl emissions may decrease as a secondary impact of other emission reduction projects, IPL is not proposing specific reductions in HCl emissions.

Budget - Capital (HCl): IPL will not incur capital expenditures associated specifically with HCl emission reduction activities in the 2015 - 2019 budget time period. However, projects discussed previously that are aimed at reducing other pollutants may be beneficial in the reduction of HCl emissions. Costs related to other pollutant reduction efforts may also relate to the reduction of HCl emissions despite this not being the focus. IPL's projected capital costs can be found in Appendix C.

Budget - Expense (O&M, HCl): IPL will incur O&M expenditures associated with HCl quarterly stack testing necessary to implement the Utility MATS compliance requirements at units not complying via the Utility MATS SO_2 limits during the 2015 – 2019 budget time period.

f. GHG Emission Reductions – Approach and Budget

IPL expects that future rules and regulations will require it to reduce GHG emissions. However, a high degree of uncertainty exists regarding the amount, timing and means of reducing GHG emissions that will be required or allowed to meet future GHG emissions compliance requirements. This high degree of uncertainty heavily influences IPL's strategy and approach regarding future GHG emission reductions.

IPL recognizes the need to incorporate the impact of future GHG emissions compliance requirements into the process it uses to select emission controls, compliance approaches and investments that it makes in its coal-fired generating units. At this time, the majority of these emission controls, compliance approaches, and investments are not directly focused on GHG emissions compliance requirements. IPL realizes that efficiency improvement projects, which can be incorporated with other emission control projects, will reduce plant GHG emissions intensity. IPL also realizes that many emission control projects involve the installation of equipment which increases GHG emissions intensity, including increased parasitic load and reduced unit performance.

In conjunction with the large Hg and SO_2 control projects at Ottumwa, IPL is executing projects that will improve the overall efficiency, replacing capacity lost due to the parasitic load of the new emission control equipment. With limited exception for turbine upgrades at its Ottumwa facility as settled in Docket No. EPB-2012-0150, IPL is not including the costs of these projects in this EPB Update. Additionally, IPL is not proposing any new GHG-related efficiency projects in this Update.

Appendix A summarizes the anticipated CO_2 emissions and emission rates as a result of the energy efficiency projects at Ottumwa and the planned switch to exclusive natural gas usage at M.L. Kapp.

GHG Emission Changes – Energy Efficiency Projects:

Ottumwa Unit 1: Projects for Ottumwa Unit 1 will increase efficiency, with a secondary benefit of reducing GHG emissions intensity. The economic benefits of these projects are realized in terms of a reduced heat rate. A life cycle cost/benefit analysis was performed on each project and only projects with a positive net benefit will be implemented. The projects for Ottumwa Unit 1 are anticipated to deliver a benefit to the customer of approximately $190 million over their life cycle, for a net benefit of $100 million.

IPL received an air permit for the plant efficiency improvement projects referred to as the CAMP, and which were approved in the 2012 EPB Update. Primarily, the CAMP includes projects that improve the efficiency of the steam cycle. The CAMP includes a steam turbine/generator upgrade project that will improve plant heat rate, plant output and steam turbine/generator reliability. This project will replace the existing steam turbine high pressure (HP), intermediate pressure (IP) and low pressure (LP) rotors and inner shells and the generator stator will be rewound. Start-up and commissioning will begin following the tie-in outage completion in November 2014.

The CAMP projects are expected to improve the efficiency of the energy production cycle so that the quantity of GHGs emitted per kWh generated is reduced. Preliminary estimates indicate that GHG emissions will be reduced by approximately 5% per kWh, with the majority of improvements attributed to turbine steam path redesign. Cost information on the OGS CAMP projects can be found in Appendix C.

Lansing Unit 4: Although a preliminary budget and schedule for a turbine steam path upgrade at Lansing Unit 4 have been prepared, IPL is not including such costs in Appendix C. IPL continues to evaluate efficiency improvement projects at Lansing Unit 4 to offset the negative impact to efficiency due to the operation of the emission controls. A turbine steam path redesign, which could provide a more efficient energy production cycle, would result in a reduction in the quantity of greenhouse gases (GHG) emitted per kWh generated, or at a minimum, not increase GHG emissions from pre-emission control conditions.

These projects are predominantly capital projects in which all costs will be accumulated in discrete projects associated with the respective generating stations.

Budget - Expense (O&M-GHG): For GHG emission reduction projects, the plant-specific incremental O&M after project completion is primarily related to the cost to maintain the equipment. Plant-specific O&M costs for Ottumwa Unit 1 can be found in Appendix C.

g. Emission Allowance Management – IPL

CAIR emission allowance markets are a viable and useful compliance option to meet the SO_2 and NO_x emissions requirements of CAIR, as currently effective. IPL will utilize the emission allowance markets to satisfy CAIR compliance requirements as necessary and appropriate. CSAPR is currently under appeal at the U.S. Supreme Court and, depending on the outcome; IPL may need to manage its emissions allowances under the CSAPR requirements. It is also possible that the EPA will introduce an altogether new rule to replace CAIR. IPL will continue to evaluate the impact of any potential revisions the emissions rules, and in the interim will continue to comply with CAIR requirements. Key factors that drive IPL's use and transactions of emission allowances include:

1) Uncertain emissions based upon varying unit capacity factors, higher or lower than predicted overall loads, or shifts in the amount of generation produced from one unit to another;

2) Economics regarding the purchase of allowances versus the installation of controls;

3) Relevance of the specific vintage year of allowances;

4) Treatment of excess allowances in a vintage year; and

5) Ability to swap excess allowances from one type of emission for shortfalls of allowances of another emission.

IPL will actively manage its CAIR allowances to ensure adequate allowances are available to support its ongoing generation operations. As needed, current year allowance shortfalls will be covered by purchasing allowances in the spot market. Any excess allowances will be banked and carried forward to the following year or swapped for future vintage year allowances, especially if a premium exists for the vintage year in which IPL has excess allowances. This applies to the NO_x ozone season as well as the NO_x annual and SO_2 compliance requirements. In addition, IPL is utilizing banked SO_2 Acid Rain Program (ARP) emission allowances for CAIR SO_2 compliance requirements, as needed.

Allowances are issued for a specific type and vintage of emissions. The need to manage a variety of different types and vintages of allowances as a portfolio will drive the need for periodic allowance transactions as well. The general rule is that an allowance of a specific vintage can be used for compliance corresponding to the vintage year or banked and carried forward to a later year. The vintage cannot be used for compliance in an earlier year. Since current vintage allowances have more flexibility for use, they are usually more valuable than allowances with a later vintage.

Budget – NO_x Allowances

IPL is not requesting approval of any additional expenditure associated with the purchase of NO_x allowances at this time. IPL has sufficient allowances to meet compliance under CAIR while IPL continues to be subject to CAIR. Based on allowance allocations in the current version of CSAPR, IPL would receive sufficient NO_x allowances in its allocation from EPA to comply with CSAPR requirements.

Budget – SO_2 Allowances

IPL is not requesting approval of any additional expenditure associated with the purchase of SO_2 allowances at this time. IPL has sufficient SO_2 allowances to meet compliance under CAIR while IPL continues to be subject to CAIR. Based on allowance allocations in the current version of CSAPR, IPL would receive sufficient SO_2 allowances in its allocation from EPA to comply with CSAPR requirements.

D. Federal Clean Water Act Compliance Implementation

IPL has based its water compliance implementation plans around the requirements contained in the Federal Clean Water Act, specifically Section 316(a), Section 316(b), and the Effluent Limitation Guidelines. As discussed in Section I of the EPB Update, several of these rules will continue to evolve during the next year, and IPL will continue to evaluate the impact of rule outcomes on its generating plants, both coal and gas-fired. IPL has included water intake and wastewater discharge compliance projects in the Budget Update that are responsive to the impact of the aforementioned proposed or anticipated water rule changes. In addition, IPL has included compliance projects required by recently issued NPDES permits.

IPL continues to seek a better understanding of the impacts of future water rules on its generating units. IPL understands these impacts could be significant and has attempted to consider these impacts, although very uncertain, as it developed the Budget Update.

Water rule compliance implementation entails, to a large extent, the undertaking of studies and projects at various IPL coal-fired, as well as gas-fired, generating units. To a lesser extent, other compliance options and alternatives may be useful and desirable. IPL routinely reviews compliance options and alternatives as it undertakes water rule compliance implementation.

The estimated capital expenditures for water-related control projects with expenditures incurred during 2015 through 2019 are shown in Appendix C. Estimated expenditures are based on current costs of technologies as well as studies and plans that are required under current rule or expected to be part of a future rule. These estimated expenditures may change, depending on many factors including:

- material cost and availability;
- labor and market conditions;
- changes to detailed scope resulting from preliminary and detailed engineering design and analysis; and
- changes to the environmental rules and regulations with which IPL needs to comply.

In addition, there will also be recurring costs for operating and maintaining installed control equipment associated with these capital expenditures.

In the following sections, a description of potential control technologies is presented for 316(a), 316(b), and anticipated Effluent Limitation Guidelines pollutants. Descriptions of compliance options and alternatives other than direct controls are also presented. Following these descriptions, IPL's specific water compliance activities and budgets for each water program are presented.

1. IPL's Specific Water Compliance Activities and Budgets

The following discussion presents IPL's approach, activities and budget to meet its wastewater discharge and water intake requirements.

a. Thermal Water Quality Standards (Section 316(a)) – Approach and Budget

As discussed in Section I of the EPB, IPL's generating plants are receiving renewal wastewater discharge permits from the IDNR which contain new thermal discharge water quality limits under Clean Water Act Section 316(a). Typically, each permit includes a compliance schedule through which the affected facility is expected to achieve compliance with the thermal limit. In certain cases, a facility can perform site specific thermal modeling to obtain a higher thermal limit or apply for a variance requesting an exemption from the new limit. Compliance planning activities required under Section 316(a) include performing thermal studies, possible variance application preparation, compliance monitoring, and, if required, the installation of control equipment to minimize the impacts of the plant's thermal discharge on the receiving stream.

Section 316(a) – Project Implementation Approach: IPL has planned a series of studies to be performed at its generating facilities to gather information needed to determine compliance with thermal discharge limits and satisfy compliance schedule requirements contained in facility wastewater permits. This data will be used to determine if IPL can apply for a variance or if controls, such as cooling towers, will be needed. The following studies (and timing) are planned during the term of this Budget Update:

Section 316(a) - Post Project Installation: IPL has based its 316(a) compliance plan on the assumption that thermal variances can be obtained for each affected facility because of the cost compared to the benefits of installing and operating cooling towers. It is possible that the IDNR would not grant a thermal variance for a given facility. IPL will evaluate the potential outcomes of such decisions after completing studies, and submitting thermal limit variance applications to and engaging in discussions with the IDNR. IPL will then revise its compliance plan accordingly. Potential outcomes could include the installation of cooling towers, relocation of discharge piping to allow for improved thermal discharge mixing, or unit retirement. However, IPL is not planning to install physical thermal discharge controls (i.e., cooling towers) at any of its facilities; therefore expenditures associated with those controls are not included in this Budget Update

Budget – Capital (Section 316(a)): IPL is not requesting approval for capital expenditures associated specifically with Section 316(a) activities, in the 2015-2019 budget time period.

Budget – Expense (O&M, Section 316(a)): IPL is seeking approval for O&M expenses related to compliance studies and variance applications discussed above. IPL's projected O&M costs are presented in more detail in Appendix C.

b. Cooling Water Intake Standards (Section 316(b)) – Approach and Budget

Section 316(b) of the Federal CWA requires the EPA to regulate cooling water intake structures to assure that these structures reflect the "best technology available" for minimizing adverse environmental impacts to fish and other aquatic life. As discussed in Section I, the EPA published a proposed Section 316(b) rule in April 2011, and is expected to publish a final rule in April 2014. The proposed rule requires existing generating stations that withdraw greater than 2 million gallons of cooling water per day to demonstrate how they currently meet or will meet national performance standards to reduce impingement mortality and entrainment of fish and shellfish.

Cooling water intake can adversely impact aquatic organisms in two basic ways. The first is entrainment, which is the taking in of organisms with the cooling water. As these entrained organisms pass through the plant, they are subjected to numerous sources of damage. The second way is through impingement. This is the trapping of organisms that enter the cooling water intake within a physical part of the intake structure. Most electric generating plants have screening equipment installed at the cooling water intake to protect downstream equipment, such as pumps and condensers, from damage or clogging caused by debris. Larger organisms, such as fish, which enter the system and cannot pass through the screening equipment, are trapped at the intake structure. Eventually, if a fish cannot escape or is not removed, it will tire and become impinged on the screening equipment. If impingement continues for a long time period, the fish may suffocate because the water current prevents gill covers from opening. If the fish is impinged for a short time period and removed, it may survive; however, it may still suffer from delayed mortality due to the resulting stress.

IPL evaluated potential impingement and entrainment control technologies to prepare for compliance with a previous version of the Section 316(b) regulations. Installing wedge-wire screens will reduce velocity of cooling intake water withdrawals at a power plant resulting in less entrainment and impingement of fish and other aquatic life. Wedge-wire screens are bullet-shaped devices placed on the bottom of a river that allows water to be withdrawn from a river, lake or stream through small diameter holes (or slots) in the screen. Other control options include retrofitting existing travelling screen equipment at the plant water intake structure with fine mesh screens equipped with wash and fish return systems. Barrier nets (which are basically large mesh nets located up and downstream of the plant's water intake structure) provide reduced velocity across the net, thereby limiting impingement and entrainment. Due to debris present in nearly all water sources, barrier nets are prone to high maintenance.

Section 316(b) – Project Implementation Approach: IPL anticipates that the final Section 316(b) rule will require initial actions for data collection studies, report preparation, and plan development for plants affected by the rule. IPL expects the final rule will allow for pre-approved impingement control technologies to be installed to meet compliance requirements, while entrainment control technology needs will be based on determinations made by IDNR based on information submitted by IPL. Actions that IPL is taking to support what is needed to comply with Section 316(b) are discussed below. IPL's planning for Section 316(b) compliance is subject to change pending the EPA's issuance of the final rule.

Based upon a preliminary technology assessment, and subject to further evaluation, IPL has identified the following work to be performed at generating stations at which one or more coal-fired generating units are potentially impacted by Section 316(b). The timing of this work is based on the proposed Section 316(b) rule. Impingement and entrainment projects listed below are technologies that would likely provide compliance with the proposed rule requirements:

It is possible that the IDNR could require cooling towers as the best technology available to comply with Section 316(b) entrainment requirements, although, according to the proposed rule, the IDNR is not obligated to do so. IPL has not included cooling towers in its Section 316(b) compliance plan. Instead, IPL will evaluate the potential outcomes of such decisions after completing studies and submitting compliance reports to, and engaging in discussions with, the IDNR. IPL will then revise its Section 316(b) compliance plan accordingly.

Section 316(b) - Post Project Installation: Implementation of IPL's Section 316(b) project plan will provide the necessary protection to aquatic life found in the source waters used by its facilities, including the Mississippi River, the Cedar River and the Des Moines River.

Budget – Capital (Section 316(b)): IPL is providing estimated capital costs associated with projects that would likely be required for affected facilities under Section 316(b) in the 2015 - 2019 budget time period. These capital costs can be found in Appendix C and are a ROM estimate within a ± 30% accuracy. Please note that IPL has plans for control installation projects beyond the 2015 through 2019 time period, and these project costs are therefore not included.

Budget – Expense (O&M, Section 316(b)): IPL is seeking approval for O&M expenses related to compliance studies and applications discussed above. In addition, O&M costs required as part of maintaining impingement and entrainment controls are also provided. IPL's projected O&M costs are presented in more detail in Appendix C.

c. Effluent Limitation Guidelines – Approach and Budget

As discussed in Section I of this report, the EPA is charged with establishing the new ELGs based on best available technology to control the discharge of pollutants in wastewater streams. In June 2013, EPA signed the proposed revisions to the Effluent Limitation Guidelines (ELG) for steam electric generating units. IPL anticipates EPA to publish the final revisions in May 2014. The final ELG rules will have varying impacts at all IPL generating facilities.

For this report, IPL's focus is on managing water discharges from facilities with ash ponds, and investigating options to treat waters that are co-managed in the ash ponds. These waters can include boiler wash down, chemical and non-chemical cleaning wash waters, water treatment system discharges, floor sumps, and coal pile runoff. Control technology options include water reuse, primary and secondary treatment, conversion to alternate ash handling systems, and closing ash ponds. IPL continues to evaluate options for off-site management of chemical and non-chemical cleaning wastewaters.

Effluent Limitation Guidelines – Project Implementation Approach: While there is still some uncertainty around the yet-to-be published final ELGs, IPL has begun initial planning activities to understand potential ELG impacts at IPL generating facilities. Potential outcomes for IPL plants may include closing ash ponds, converting ash handling systems to dry or recirculating systems, and re-designing the balance of plant wastewater discharge streams. As part of its initial planning, IPL identified the following work that may be performed during this Budget Update period at generating stations at which one or more coal-fired generating units are potentially impacted. These plans are based on preliminary information provided by EPA and industry groups, and therefore are subject to change upon issuance of the final ELG revisions. IPL's Dubuque Generating Station (Dubuque) does not have ash ponds, so there is no planned project related to ash pond closure for that location. Since Dubuque and Sutherland are being converted to operate on natural gas and Fox Lake does not burn coal, there are no planned projects for ash handling conversion at those locations.

Effluent Limitation Guidelines - Post Project Installation: IPL believes that implementation of its plan will likely meet provisions that are expected to be included in the final ELG. As previously mentioned, IPL will evaluate the final ELG when it is published and adjust its compliance plan accordingly.

Budget – Capital (Effluent Limitation Guidelines): IPL is providing estimated capital costs associated with projects that could likely be required for affected facilities under the ELG in the 2015 - 2019 budget time period. These capital costs can be found in Appendix C and are a ROM estimate within a ± 30% accuracy.

Budget – Expense (O&M, Effluent Limitation Guidelines): IPL is not seeking approval for O&M expenses related to compliance with the ELG because IPL cannot reasonably estimate these costs at this time.

d. Water Quality Standards Compliance – Approach and Budget

As authorized by the Clean Water Act, the National Pollutant Discharge Elimination System (NPDES) permit program controls water pollution by regulating point sources that discharge pollutants into waters of the United States. Point sources are discrete conveyances such as pipes or man-made ditches. Water quality standards are established by an authorized state, for a water body within its jurisdiction, as required by the Clean Water Act. Water quality standards include designated uses for a water body, water quality criteria necessary to support the designated uses; and a policy for preventing degradation of the quality of water bodies. Water quality criteria are incorporated into NPDES permits and can include numeric criteria for specific parameters (e.g., copper, chlorine, temperature, pH); toxicity criteria to protect against pollutants; and narrative criteria that describe the desired condition of the water body. Point source effluent monitoring allows the NPDES authority to assess compliance with the permit limits and take enforcement actions where necessary.

Updated changes to water quality standards are incorporated into NPDES permits when they come due for renewal, which typically occurs on a five-year cycle. A facility could minimize or eliminate risks associated with certain water quality standards by eliminating wastewater discharges, changing its operations, or installing wastewater treatment systems.

IPL has identified four facilities that will submit NPDES renewal applications and four facilities that are awaiting NPDES permit reissuance during the 2015 - 2019 budget time period. In addition, one facility, the Prairie Creek

Generating Station, received its renewal NPDES permit which requires the facility meet revised water quality standards, specifically for aluminum and zinc.

Water Quality Standards – Project Implementation Approach: IPL evaluates new permit conditions as NPDES permits are renewed. Such work includes collection and analysis of wastewater discharge samples compared to permit limits, and review of options for treatment or elimination of the discharge stream. The evaluation of discharge information is combined with the evaluation of emerging water regulation requirements in order to determine an effective compliance approach to meet new water quality standards.

The following project (and timing) is planned during the term of this Budget Update:

The conversion of the Prairie Creek ash handling system was included in the ELG discussion above, and is being listed again in this section of the Budget Update because it offers a solution to current and long-term compliance with wastewater discharge requirements associated with the wet ash handling process. However, IPL has only accounted for these project costs once in Appendix C.

Water Quality Standards - Post Project Installation: IPL will be required to monitor and maintain any systems after they are installed in order to continue to meet permit discharge limits.

Budget – Capital (Section Water Quality Standards): IPL is providing estimated capital costs associated with the aforementioned project. These capital costs can be found in Appendix C and are a ROM estimate within a ± 30% accuracy.

Budget – Expense (O&M, Section Water Quality Standards): IPL is seeking approval for O&M expenses related to the project identified above. IPL's projected O&M costs are presented in more detail in Appendix C.

E. Coal Combustion Residue Compliance – Approach and Budget

IPL has developed a compliance implementation plan based on the requirements contained in the proposed Coal Combustion Residuals (CCR) rule, which was published by EPA in June 2010. The EPA has indicated that a final CCR rule may be issued in late 2014. As discussed in Section I of this EPB Update, the proposed rule contained two compliance options for managing residues (ash) remaining after the combustion of coal; however, IPL's compliance plan is designed to comply with the option which treats CCR as a non-hazardous solid waste. IPL's planning assumption is based in large part on information provided by EPA and industry groups, as well as Congressional activity, which appears to be focused on developing state-based regulatory programs that do not treat CCR as a hazardous waste. IPL has included compliance projects in the Budget Update that are responsive to this assumed compliance need. IPL will continue to seek a better understanding of the impacts of future CCR rules on its coal-fired generating units. Should the final CCR rule address coal ash as a hazardous waste, then IPL will adjust its plan accordingly.

The estimated capital expenditures for CCR-related projects with expenditures incurred from 2015 - 2019 are shown in Appendix C. Estimated expenditures are based on current costs of compliance as well as requirements contained in the proposed rule or expected to be part of a future rule. These estimated expenditures may change, depending on many factors including:

- Material cost and availability;
- labor and market conditions;
- changes to detailed scope resulting from preliminary and detailed engineering design and analysis; and
- changes to the environmental rules and regulations with which IPL needs to comply.

In the following section, a description of potential compliance projects for the CCR rule changes is presented. Descriptions of compliance options and alternatives other than direct controls are also presented. Following these descriptions, IPL's specific CCR compliance activities and budgets are presented.

1. IPL's Specific Coal Combustion Residue Compliance Activities and Budgets

The following discussion presents IPL's approach, activities, and budget to meet compliance requirements which may be required under a final CCR rule.

a. Coal Combustion Residue – Approach and Budget

IPL is anticipating the release of final CCR rule for utilities that combust coal. EPA has indicated that a final rule could be published by late 2014. The EPA is addressing the management of CCR and discharges from CCR management units, namely ash ponds and landfills, across multiple regulatory media programs. IPL believes that the EPA is also interested in enabling CCRs to be beneficially used following sound engineering practices.

IPL's coal-fired facilities have ash ponds for managing CCR generated at these plants. These ponds will likely be affected by the CCR rule and, as discussed above, the changes to the ELGs. IPL has included discussion of project work that would bring ash ponds into compliance with these requirements. Please note that ash pond closure projects were included in the ELG discussion, and are being listed again in this section of the Budget Update. However, IPL has only accounted for these project costs once in Appendix C.

IPL operates two active CCR landfills. One of these CCR landfills is located at Lansing, and the other, the Ottumwa-Midland Landfill (OML), is located near Ottumwa. These landfills will likely be affected by the CCR rule and IPL has also accounted for landfill-related compliance projects and their costs in its plan.

CCR – Project Implementation Approach: While there is some uncertainty regarding what requirements will be contained in a final CCR rule, if a final rule is issued that is similar to the proposed rule, IPL may be required to close active ash ponds and bring all CCR landfills up to minimum engineering design and operating criteria. IPL's plan includes closing all ash ponds, converting ash handling systems to dry or recirculating ash systems, and re-designing the balance of plant wastewater discharge streams. As part of its initial planning, IPL has identified the following work which may be performed during this Budget Update period at generating stations at which one or more coal-fired generating units are potentially impacted. These plans are based on preliminary information provided by EPA and industry groups, and therefore are subject to change upon issuance of the final CCR rule. Dubuque does not have ash ponds, so there is no planned project related to ash pond closure for that location. Since Dubuque and Sutherland are being converted to operate on natural gas and Fox Lake does not burn coal, there are no planned projects for ash handling conversion at those locations.

CCR - Post Project Installation: IPL believes that implementation of its plan will meet provisions that are expected to be included in the final CCR rule. As previously mentioned, IPL will monitor the final CCR rule when it is published and adjust its compliance plan accordingly.

Budget – Capital (CCR): IPL is providing estimated capital costs associated with projects that it expects will be required for affected facilities under the CCR rule in the 2015-2019 budget time period. These capital costs can be found in Appendix C and are a ROM estimate within a ± 30% accuracy. Please note that IPL has plans for projects beyond the 2015 through 2019 time period, and these project costs are therefore not included.

Budget – Expense (O&M, CCR): IPL is only seeking approval for O&M expenses related to interim landfill closure at OML at this time. IPL is not seeking approval for other O&M expenses related to compliance with the CCR rule at this time because IPL cannot reasonably estimate these costs at this time.

F. Plant Decommissioning – Approach and Budget

Generating plants that have been retired by IPL will be subject to decommissioning. At the present time, work is underway on the decommissioning of the Sixth Street Generating Station, and planning has begun related to the future retirement and decommissioning of Dubuque. Additional planning may occur at other IPL facilities during the 2015-2019 time period if all units at a location will be retired.

The actual steps to decommission a facility will depend on many factors including but not limited to: end use evaluation of the facility and site; environmental site assessments; and site location issues such as safety and security.

G. List of Acronyms

Acronyms Used in Section II

ACQS – Air Quality Control Systems

AEP – American Electric Power

ARP – Acid Rain Program

BH – Baghouse

BACT – Best achievable control technology

CAIR – Clean Air Interstate Rule

CCR – Coal Combustion Residue

CSAPR – Cross-State Air Pollution Rule

CEMS – Continuous Emission Monitoring System

CFB – Circulating Fluidized Bed

CFD – Computational Fluid Dynamics

CLC – Chemical-looping Combustion

CO – Carbon Monoxide

CO_2 – Carbon Dioxide

CWA - Clean Water Act

DCS – Distributed Control System

DSI – Duct Sorbent Injection

ELG – Effluent Limitation Guidelines

EPA – US Environmental Protection Agency

EPB – Emissions Plan and Budget

ESP – Electrostatic precipitator

FGD – Flue Gas Desulfurization

GHG – Greenhouse Gas

HAPs – Hazardous air pollutants

HCl – Hydrogen chloride

Hg – Mercury

ID – Induced Draft fans

IDNR – Iowa Department of Natural Resources

IPL – Interstate Power and Light Company

LNB – Low NO_x Burners

MACT – Maximum achievable control technology

MATS – Mercury and Air Toxics Standards

MEA - Monoethanolamine

MISO – Midcontinent Independent System Operator, Inc.

MW – MegaWatt

$MyOx_{TM}$ - Metal oxide product

NO_x - Nitrogen oxides

OFA – Over-fire Air

PAC – Powder activated carbon

PSD - Prevention of Significant Deterioration

PJFF – Pulse jet fabric filter

PCC – Post-combustion capture

PRB – Powder River Basin

PM – Particulate Matter

ROM – Rough Order of Magnitude

RRI – Rich Reagent Injection

SCR – Selective Catalytic Reduction

SO_2 – Sulfur dioxide

SO_3 – Sulfur trioxide

SDA – Spray Dryer Absorber

SNCR – Selective Non-Catalytic Reduction

VOC – Volatile Organic Compounds

WPL – Wisconsin Power and Light Company

H. Appendices

Appendix A
Pages 1 – 5

Emissions Plan and Budget
Section II

Public notice of additional confidential document included in this filing

APPENDIX B

Description of Emission Control Technologies and Alternatives

a. Description of NO_x Emission Control Technologies

Combustion and post-combustion NO_x emissions controls have developed into mature technologies. Combustion control technologies include combustion optimization initiatives (CI), low NO_x burners (LNB) or burner modifications, and over fire air (OFA) systems. Post-combustion control technologies commercially available include Rich Reagent Injection (RRI), Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR). Each of these technologies has varying degrees of NO_x emissions reduction effectiveness, balance-of-plant requirements, plant operations impacts, capital costs, and recurring operating and maintenance costs. The technologies that have the potential of providing NO_x emissions reductions are described briefly below.

SmartBurn® / CI

CI seeks to manage combustion stoichiometry, the relative proportions of the inputs to combustion including fuel and air, to maximize energy release while minimizing the creation of NO_x and other emissions. CI has been successfully installed on many of IPL's boilers. It encompasses many technologies that are utilized together to optimize the combustion process. Technologies include: modeling; modifications to burner, boiler and duct redesign; upgrades to coal flow processes; instrumentation and control upgrades; and use of statistical processes.

CFD modeling, a typical first step when implementing CI, is done for combustion components such as wind boxes, burners, cyclones, furnaces, heat transfer, and ash slagging and fouling. The models are used to guide testing activities to improve combustion, lower emissions and predict the impact of the combustion changes on furnace operation and efficiency.

Boiler design changes include OFA and LNB's. OFA is a technology that controls the formation of NO_x through modification of the combustion process in the boiler. This process diverts a portion of the secondary air to new ports located higher in the furnace. The technology can provide NO_x reductions in the 20% to 50% range, depending on the specific boiler application.

LNBs control the mixing of fuel and air in a pattern designed to minimize flame temperatures and quickly dissipate heat. These burners typically reduce the NO_x generated by maintaining a reducing atmosphere (a condition in which oxidation is prevented by removal of oxygen) at the coal nozzle and diverting additional combustion air to secondary air registers. This minimizes the reaction time in the oxygen-rich, high temperature zones. Duct, windbox and heat transfer surfaces may be modified to accommodate required changes to airflow and heat transfer patterns.

Additional instrumentation is needed to monitor the combustion process more precisely. Carbon Monoxide (CO) monitors measure CO, a byproduct of combustion at the lower stoichiometries required to reduce NO_x emissions. Feedback from the CO monitors is used to target OFA system nozzles at regions in the combustion path containing higher amounts of CO. Airflow instrumentation ensures the accurate measurement and distribution of combustion air.

Coal flow and condition are important components of the combustion process. Upgrades to pulverizers, feeders, and other coal distribution components may be required, as well as improvements to the coal flow measurement system. Upgrades are followed by coal flow balancing to determine the optimum balancing of coal and airflow at various load points.

Distributed Control Systems (DCS) are needed as control loops become more complex with new combustion concepts designed to lower NO_x emissions. Operators need better information to control more variables for optimal results. Optimization of the technologies and controlled automation of existing and new equipment is required to maintain reduced NO_x emission levels. Neural networks can be used in conjunction with a DCS. Neural networks use process modeling to allow real-time combustion process optimization.

Significant additions of probes, detection devices, monitors and instruments are required to monitor the inputs and outputs of the combustion process. As an example, IPL, in collaboration with the Electric Power Research Institute (EPRI), recently successfully demonstrated the effectiveness of a diagnostic laser system to assist in optimizing and maintaining combustion performance at Ottumwa Unit 1. This diagnostic laser system, ZoloBOSS, uses laser beams to create a map of emissions concentrations including oxygen (O_2) and CO within the boiler. Better information regarding concentrations of these emissions within the boiler is then provided to the neural network or DCS, enabling more accurate and timely adjustments to the combustion process. Efforts continue to fully integrate the use of the diagnostic laser information into the automatic control system.

Data mining is a term for extracting operating data from the data historian and performing statistical analysis to identify significant operating characteristics during periods of optimal operation. The information is then used to modify control parameters so that optimal combustion can be achieved more consistently over longer periods of time. Data mining is an iterative process, but has been demonstrated to be an effective method for tuning the combustion process. Data mining can be used to tune the DCS or can be used to “prime” the neural network to support further tuning of the DCS in real time.

Post Combustion NO_x Emission Control Technologies

RRI - This technology uses urea as a reducing agent to convert NO_x to nitrogen and water without the use of a catalyst. Urea is injected near the cyclone burners where gas temperatures range from 2400ºF to 3100ºF. The urea converts to ammonia within the boiler which then reacts with the NO_x. The key to the success of this process is injecting in high NO_x, low oxygen regions of the boiler. This can be accomplished most effectively in a cyclone boiler right outside the exit from the cyclone burner. RRI results in all measurable ammonia reacting with NO_x, reducing the ammonia that ultimately enters the atmosphere through the stack, known as ammonia slip. RRI is also less sensitive to load and temperature changes than SNCR. RRI can provide NO_x emission reductions from 20% to 40%, depending on boiler size and design.

SNCR - This post-combustion technology uses a reagent, such as urea, as a reducing agent, to convert NO_x to nitrogen and water without the use of a catalyst. Without a catalyst, this chemical process must occur at temperatures of 1700ºF to 2100ºF and is accomplished by injecting the reagent into the boiler downstream of the fireball or combustion zone. SNCR is sensitive to temperature and load changes and can produce ammonia slip. Fouling of the economizer section of the boiler can sometimes result from ammonia-based compounds forming on the heat transfer surfaces. SNCR can provide NO_x emission reductions from 20% to 50%, depending on boiler size and design. The technology is less effective on large boilers because of difficulty distributing the reagent into large boiler cross-sections and achieving proper mixing of NO_x and reagent for the proper amount of time at the proper temperatures.

SCR is a post-combustion process technology that uses a reagent, such as urea or ammonia, as a reducing agent, to convert NO_x to nitrogen and water *with* the use of a catalyst. This conversion is performed downstream of the boiler where gas temperatures range from 600ºF to 800ºF. The reagent is injected into the boiler exhaust gas duct downstream from the economizer section of the boiler, but upstream of multiple layers of a ceramic-based catalyst. This technology can provide NO_x emission reductions of up to 90% with effectiveness essentially independent of boiler design and size.

This technology is a proven, commercially available NO_x emission control system. Operating procedures are available to maintain low levels of ammonia slip which minimize air heater plugging and eliminate problems with fly ash beneficial reuse that would occur if higher concentrations of ammonia were present in the fly ash. The SCR catalyst will increase the pressure drop across the boiler draft system. In most cases, installing SCR will require converting the boiler draft system to a balanced draft system by adding induced draft (ID) fans or upgrading the existing ID fans along with associated boiler, ESP and related ductwork reinforcing or adding draft capacity for an existing balanced draft system.

In some applications, a variation on SCR called In-Duct SCR can be used. In-Duct SCR locates the catalyst within the boiler exhaust gas duct, downstream of the economizer rather than within a separate structure. Similar reagents are utilized. The performance and benefit of using In-Duct SCR must be evaluated on a case by case basis. Potential advantages of this technology may be lower capital cost because the catalyst is installed within the ductwork. In-Duct SCR may not be able to offer the same level of NOx removal as SCR or may require additional O&M costs because of the impact smaller geometries may have on the performance. In-Duct SCR may also require a prolonged outage for installation as compared to SCR which can be built as a stand-alone vessel then connected during a relatively short outage. In-Duct SCR may also be used in conjunction with SCR.

b. Hydrochloric Acid (HCl) Control Technologies

Hydrochloric acid is formed when chlorine from the coal is combined with hydrogen during the combustion process. The Western sub-bituminous coals in use at the IPL plants are naturally low in chlorine, resulting in HCl emissions that are below current standards. If it becomes necessary to remove HCl emissions, the same technologies used to remove SO_2, described below, will also remove HCl.

c. Description of SO_2 and Acid Gas Emission Control Technologies

A variety of control technologies are in use to remove SO_2. The same systems effectively remove HCl, and most other acid gases. The most commercialized processes for removal of these gases include the semi-dry absorber scrubber (SDA), circulating fluidized bed (CFB) or circulating dry scruber (CDS), and wet flue gas desulfurization (FGD) systems. Recently, duct sorbent injection (DSI) has seen increased interest as an SO_2 removal technology and DSI has been successfully tested within the Alliant Energy Corporation's utility subsidiary systems (i.e., Wisconsin Power and Light Company (WPL)).

FGD systems are also effective for removing other HAPs such as heavy metals and inorganic acid gases. Heavy metals (inorganic solid phase HAPs) can be removed when FGD systems are installed in conjunction with a baghouse. FGD systems and baghouses have been installed recently on new units, such as MidAmerican Energy Company's Walter Scott Jr. Unit 4, to meet Maximum Achievable Control Technology (MACT) requirements for HAPs, established at new units on a case-by-case basis.

Semi-Dry Flue Gas Desulfurization (Semi-Dry Scrubber) - This technology is a post-combustion process that uses a lime slurry injected into a SDA located in the boiler exhaust duct downstream from the air pre-heater and upstream of the baghouse. The lime slurry and SO_2 react to form a dry mixture of reaction products, primarily calcium salts. This technology is referred to as semi-dry because the lime slurry is wet when injected but the reaction products are dry. This technology is proven, commercially available and has been installed at many utility power plants. It can remove more than 90% of the SO_2 with effectiveness essentially independent of boiler design and size. Proven control systems and procedures exist to maintain efficient absorption by proper atomization and flue gas distribution and mixing.

Circulating Dry Scrubber (CDS) or Circulating Fluidized Bed Flue Gas Desulfurization – This type of scrubber operates on the same principle as the semi-dry scrubber, except that a CDS absorber uses lime, introduced into it as a dry, free flowing powder, to react with the SO_2 to form a dry mixture of reaction products. Although a limited amount of water is introduced directly into the absorber, it is completely absorbed before reaching the baghouse. Fewer moving parts and more efficient use of the lime result in higher reliability and lower operating costs, in addition to greater SO_2 removal, than is typically achieved using the semi-dry scrubber. The turbulent mixing of the lime and flue gas as well as long residence times in the absorber enable dry scrubbing technology to remove 95% or more of the SO_2. Both this and the semi-dry scrubbing technologies will produce a dry waste product required to be disposed of in a landfill or beneficially used.

This technology is newer than the SDA; however, CDS scrubbers have been used on coal-fired boilers in Europe and Asia since the early 1990s. CDS absorber vessels are typically limited to 150-400 MW. Recently, vessels large enough for 500 MW of flue gas have been proposed but little information is available concerning operation of vessels this large. CFB requires a minimum gas flow rate to maintain the reactor bed. While dry scrubbers are becoming a well-accepted SO_2 control technology in North America, the scalability and minimum flow rates introduce design challenges that may limit the use of this technology.

Wet Flue Gas Desulfurization (Wet Scrubber) - This technology is a post-combustion process that uses a lime or limestone-based slurry solution re-circulated through an absorber tower where it is placed in contact with the flue gas. The contact between the flue gas and the slurry cools and saturates the flue gas. SO_2 and other acid gases are absorbed into the slurry droplets. Gypsum (calcium sulfate) and calcium sulfite are formed in the chemical reaction in the slurry. The slurry can be dewatered creating a solid waste by-product. The by-product may be sold or placed in a landfill. Wet scrubber systems may also be designed to produce ammonium sulfate fertilizer as a by-product instead of gypsum. This technology can remove more than 95% of the SO_2 with effectiveness essentially independent of boiler design and size. Wet scrubbers are proven, commercially available and have been installed at many utility power plants. Proven control systems and procedures exist to maintain efficient flue gas distribution and mixing.

In a wet scrubber, the outlet duct from the absorber tower through the stack requires high alloy metals due to the low flue gas temperature leaving the absorber tower that creates a corrosive environment. Sulfur trioxide (SO_3) is also formed if bituminous coal is burned and the plume out of the stack will appear slightly blue (referred to as blue haze). Additional retrofits including a wet ESP downstream of the absorber tower may be necessary to address these needs or issues.

Duct Sorbent Injection - DSI removes SO_2 through the injection of a powdered sorbent material directly into the system ductwork. The injection point is typically located between the air heater and the particulate control device, but may vary depending on the flue gas temperatures in the particular system. Typical sorbents used are hydrated lime, Trona – a naturally occurring form of sodium sesquicarbonate; or sodium bicarbonate. A DSI system typically consists of storage silos designed to hold 5 to 10 days' worth of sorbent material, feeders, a pneumatic conveying system, an injection grid, injection lances, and controls to automate the system. A dust collection system is also necessary to control nuisance dust. A mill may be included in the system to improve the effectiveness of the sorbent. DSI systems can achieve 70% - 90% SO_2 removal rates on a consistent basis, depending on the type and quantity of sorbent used. Depending on the type of sorbent, DSI may also capture HCl, other acid gases and Hg.

The capital cost for DSI is significantly lower than wet or dry scrubbers. The volume of sorbent required causes significant O&M expenditures and may render ash unsuitable for sale, thus increasing disposal costs. As noted in its prior EPB filing (Docket No. EPB-2012-0150, DSI has been successfully tested at WPL's Edgewater Generating Station Unit 4, in Sheboygan, Wisconsin. During that testing, which occurred in 2011, the short duration tests at full load and stable SO_2 emissions produced the following results:[1]

- With trona, the maximum SO_2 removal was approximately 67%; and
- With sodium bicarbonate, the SO2 removal was approximately78%.

[1] Hydrated lime was not tested.

In both tests the sorbent injection rate was based on the vendor's estimates for 70% - 90% removal. Higher injection rates were not tested. A DSI system can be installed in a shorter time period than other scrubber technologies. Depending on the emission reduction requirements and the evaluated life cycle cost, DSI can be a viable option for near term compliance requirements or for smaller units unable to bear the capital burden of a scrubber system. DSI may prove uneconomical for large units over the long term because of the required volumes and costs of the sorbent. Further, the use of DSI may require additional controls for reducing particulate matter emissions. Both Trona and sodium bicarbonate are water soluble. When dissolved, some of the collected metals can be transported into the water. Additional controls may be required when landfilling or disposing the sorbent to prevent leaching of HAPS into the environment.

d. Description of Particulate Matter (PM) Control Technologies

PM can be controlled through the use of electrostatic precipitators or fabric filters (baghouses). Electrostatic precipitators have been used by utility boilers for decades. The Utility MACT requires PM to be controlled to lower limits, challenging the performance of existing precipitators. Precipitator performance often can be improved by installing upgraded or redesigned components such as power supplies, plates, rappers, wires, and controls. In some cases, the existing precipitator is large enough to allow additional fields to be installed, increasing the surface area and collection ability. Precipitators can also be enlarged to add additional collection fields. Upgrading or expanding existing precipitators is generally lower cost than retrofitting a baghouse.

Precipitators capture solid particles that respond to static charge, they are able to capture very minimal amounts of condensable emissions.

Fabric filters or baghouses are another established method for capturing particulates. They are often installed in conjunction with SO_2 removal technologies, such as FGD and are often considered BACT. Baghouses have a higher initial capital cost than precipitators, O&M costs also tend to be higher because of additional auxiliary power usage and the need to replace the fabric bags every few years. The fabric filter bags can be designed to capture emissions that consist of condensible PM, as well as very fine solid particles.

e. Description of Mercury (Hg) Emission Control Technologies

It has been demonstrated that existing and new air pollution control devices designed primarily for removing NO_x, SO_2, and particulate matter can help remove Hg from coal-fired power plant emissions. However, based upon coal characteristics, fly ash properties, and specific air pollution control equipment configurations and operations, the capture of Hg can vary substantially. Extensive research and testing have been utilized to develop the next generation of Hg control technologies. Several of these technologies have recently completed full scale field testing or have been put into continuous operation. Hg emission control technologies are described below:

Powdered Activated Carbon (PAC) Injection - PAC injection is an effective, mature technology in the control of Hg in municipal waste, medical waste combustors and utility boilers. PAC injection typically involves injecting a powder activated carbon compound into the flue gas upstream of a particulate control device such as an ESP or baghouse. Oxidized forms of Hg are adsorbed into the carbon and are collected with the fly ash in the particulate control device. The mercury removal capabilities of PAC injection can be increased with the use of a halogenated carbon (e.g., iodine or bromine), react with Hg to form iodine, bromine or fuel additives such as calcium bromide that assist in oxidizing greater amounts of Hg during combustion.

In ESPs, Hg in the flue gas is removed as it passes over the surface of the collecting plates. PAC injection systems can achieve Hg removal as high as 90%. Testing conducted on various IPL plants in 2011 achieved Hg removal rates of greater than 90%. The addition of PAC does not directly affect the function of the ash handling system, but can impact PM remission rates.

The additional PAC in the fly ash does, however, affect the quality of the ash produced. For units that currently sell fly ash, this has the potential to negatively affect their ability to continue to sell the ash. To guarantee the ash quality required for sale is maintained, the ash must be removed upstream of the PAC injection; however, in some cases it may be possible to selectively re-use the ash even if it is removed downstream of the PAC injection. Testing at IPL coal-fired generating units has shown that adding calcium bromide (CaBr) to the coal stream prior to combustion in conjunction with PAC injection reduces the amount of PAC needed to remove a comparable amount of Hg by approximately 75%. The resulting carbon content of the ash appears to be within acceptable limits for some ash uses. The fly ash vendor for WPL has accepted the ash with its small amounts of PAC and CaBr for re-sale to its customers, but testing must be done on each unit and certified by each vendor.

For an IPL unit with an ESP but no baghouse installed, the PAC injection grid would be located within the inlet ductwork of the ESP or further upstream such as within the inlet ductwork to the air heater. A normal PAC storage silo and feeder system provides the PAC to the injection grid. However, removal will vary depending on the type of coal, coal consumption, combustion technology, temperature at which the PAC is injected, use and type of flue gas conditioners, and installed particulate control equipment. Testing must be conducted on each unit to determine the optimum injection rates.

Specific examples of PAC injection are discussed in further detail in the sections that discuss the TOXECON™ Hg emission control technologies.

Non-carbon based Sorbent Injection - Non-carbon based sorbents, such as sodium tetrasulfide or amended silicates have not demonstrated sufficient Hg removal on Powder River Basin (PRB) coal to meet Utility MATS requirements. At this time, the sorbents are not available in sufficient quantities to be deemed commercial. The original suppliers ceased operations but have now restructured. Vendor testing has resumed, but current results indicate that these sorbents would only be a supplement to PAC injection and require additional capital expense. Usage of these sorbents must be tested and evaluated on a case by case basis.

Addition of Halogens - As a result of research and testing, a loose link has been established between chlorine content in coal and mercury speciation.

Reports indicate that bituminous coal with typical chlorine content greater than 1,000 parts per million (ppm) convert approximately 80% of its total mercury to the oxidized form which is more readily removed. Sub-bituminous coals, burned in all IPL coal-fired units, have a chlorine content of approximately 100 ppm and convert a maximum of only 30% of its total Hg to the oxidized form making Hg removal more difficult. Injecting a chemical additive (a halogen solution of chlorine, bromine, iodine) into the boiler can increase the amount of oxidized Hg available downstream for removal. Bromine has shown to be more effective at oxidation of Hg than chlorine.

The chemical additive (a salt solution containing bromine) can be sprayed on the coal as the fuel is transported on the conveyor belt into the coal storage silos or on the coal stream as it is discharged from the gravimetric feeders. A gaseous bromine-containing compound could also be injected into or downstream of the boiler through injection ports. The chemical additive reacts with the Hg in the coal to oxidize the Hg molecule. The Hg can be removed by injecting small amounts of PAC and collecting it in the ESP or other pollution control devices, such as a scrubber.

Using calcium bromide or other chemical additives to enhance the performance of PAC may increase corrosion in the existing materials of construction, particularly air preheaters and back end components. More frequent replacement of components or use of higher grade materials, such as enamel coated air preheater elements may be required.

Sorbent Injection Upstream of a Fabric Filter (TOXECON™) - TOXECON™ is a patented process by EPRI , which injects PAC into the flue gas downstream of an ESP and upstream of a fabric filter (a.k.a. baghouse). The baghouse provides an effective mechanism for the PAC to have intimate contact with vapor-phase mercury, resulting in high levels of mercury capture at relatively low PAC injection rates.

Using TOXECON™ at a unit would allow IPL to continue to collect fly ash in the unit's existing ESP and sell it. Collecting the fly ash without commingling it with the PAC would remove any potential issues regarding ash quality that may impact IPL's ability to continue selling it. The residual fly ash and Hg-containing sorbent collected in the baghouse will, however, have to be disposed of in a landfill. There is some evidence that the baghouse may also capture other HAPs.

The major pieces of equipment required for the TOXECON™ process include:

- a baghouse, including the interconnecting ductwork and support steel;
- a PAC storage and injection system;
- foundations;
- ash-handling system modifications; and
- the associated new and upgraded instrumentation and controls.

In addition to this equipment, a major review and possible modification of balance of plant equipment will be required. This includes a detailed investigation into the available capacity and design margins for the ID fans and motors, the ash handling system, compressed air system, ductwork, and auxiliary electrical system. Because of the higher pressure drop from the baghouse and associated ductwork, upgraded or new ID fans and motors and significant modifications to the auxiliary power system are typical for TOXECON™ installations. In addition, new ash-handling equipment for the residual fly ash and Hg-containing sorbent captured in the baghouse would be needed. Therefore, the capital cost to install TOXECON™ will be significantly higher than for the other Hg emissions control technologies.

TOXECON™ was first commercially installed at a coal-fired unit in Michigan and has been in operation for approximately six years. This unit has achieved total Hg removal ranging from 85% to 90%, with a PAC injection rate of approximately two pounds per million actual cubic feet of flue gas flow per minute. TOXECON™ is considered to be a mature, commercially available technology that is marketed by several major air pollution control vendors with performance guarantees to achieve 90% mercury removal routinely provided. A TOXECON™ system was put into operation at IPL's Lansing 4 unit in 2010 and has demonstrated 90% Hg removal rates.

It should be noted that TOXECON™ is not sorbent-specific. In fact, Hg removal may increase by using a halogenated-activated carbon sorbent, the most common of which is brominated PAC. Halogenated sorbents are especially effective when burning low-chlorine coals, such as the PRB coals burned in IPL's units. Coals with lower chlorine content tend to have higher elemental mercury content which makes Hg capture more difficult. Although brominated PAC is typically more expensive than conventional PAC, the lower injection rates required or higher removal efficiencies achieved may make it more economical.

The addition of halogens through fuel additives such as calcium bromide (as currently deployed at several WPL generating units) may also reduce the PAC injection rates required or increase the removal efficiencies from a given PAC injection rate. The addition of halogens through fuel additives in conjunction with PAC injection may be more economical or result in greater total removal efficiencies than using only one or the other technology.

f. Multi-pollutant control systems

Multi-emission control technologies are defined as options which integrate pre-combustion, in-situ or post-combustion controls of at least two of the SOx, NOx, and mercury pollutants either into one process, or a combination of coordinated or complementary (synergistic) processes. SDAs and CDSs, described above, can be referred to as multi-pollutant control systems because with adjustments to the contents of the slurry used additional pollutants can be removed; for example, by adding activated carbon to the lime slurry Hg can be removed along with the SOx.

ReACT is a multi-emission control technology offered through license by Hamon Research Cottrell that has recently become commercially available in the United States. A moving bed adsorber provides contact between flue gas and activated coke pellets, where SOx, NOx and Hg are adsorbed onto the carbon surfaces. Ammonia is injected into the process to promote the SO2 and NOx reactions. The cleaned flue gas leaves the stack with little or no plume. The activated coke is then processed in a regenerator vessel which completes the reduction of NOx to N2 and drives off SOx in a concentrated sulfur rich gas stream. Adsorbed mercury is retained in the activated coke. When the activated coke becomes saturated with mercury, it is removed during a scheduled outage and disposed of as hazardous waste. The volume of contaminated coke created will vary by size of the unit and the Hg content of the fuel, one source estimates 70 tons of contaminated coke must be removed every 18 months for a 425 MW unit burning PRB coal. The sulfur rich gas is then processed to produce a salable sulfuric acid. Impurities collected in the processing of the sulfur rich gas are neutralized and then captured in the unit's fabric filter or are otherwise disposed of as hazardous waste.

The ReAct process was introduced in Japan, where it has been successfully operated on coal-fired boilers as large as 600 MW. The first U.S. installation is currently under construction at the 425 MW Wisconsin Public Service (WPS) Weston 3 plant located in Marathon County, Wisconsin. The process is expected to reduce SO_2 and Hg emissions by 90% or greater, and reduce NO_x emissions by 20%. Overall costs for the technology are expected to be competitive with the SCR and scrubber combination that would otherwise need to be installed to control the SO_2, NO_x, and Hg.

Appendix C
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Emissions Plan and Budget
Section II

Public notice of additional confidential document included in this filing