Attachment A
IPL Responses to Questions Posed by the IUB

EPA PROPOSED 111(d) RULES QUESTIONS

1. **Is the EPA list of Iowa affected facilities correct? If not, what information needs to be changed?**

   Response:
   IPL believes that the list is complete with regard to affected IPL electric generating stations.

2. **Are the numbers EPA used to calculate Iowa's baseline and reductions and goals correct? If not, what are the correct numbers and why?**

   Response:
   Based upon its review to date, IPL believes that the data EPA used to calculate Iowa's baseline, reductions, and goals is correct. IPL continues to evaluate the technical documents that EPA used in developing the proposed rule. IPL may identify necessary revisions in the data or methods used and will bring these revisions to the attention of the IUB and IDNR.

3. **Are the types of generation EPA used to calculate Iowa's baseline and reductions and goals correct? If not, what should be included and why? (For example, should all existing nuclear and hydro be used?)**

   Response:
   Based upon is review to date, IPL believes that the generation data EPA used to calculate Iowa's baseline, reductions, and goals is correct. IPL continues to evaluate the technical documents that EPA used in developing the proposed rule. IPL may identify necessary revisions in the data or methods used and will bring these revisions to the attention of the IUB and IDNR.

   IPL is concerned about the EPA's assumption that 5.8% of Iowa's nuclear power is "at risk" (resulting in the application of 5.8% of the "at risk" nuclear generation to the goal calculation). From a practical standpoint, it is difficult to determine how only a 5.8% portion of a nuclear generation facility would be "at risk", given that there is only one facility statewide. IPL encourages flexibility in the BSER blocks to properly assess and allocate nuclear generation in State Plans.

   IPL is also concerned with the EPA's compliance demonstration modeling (the Integrated Planning Model (IPM)) assumptions regarding Iowa generating facilities. Although the EPA indicates that the IPM model is an illustrative example of what compliance might look like nationally, it uses the modeling and underlying assumptions as part of its cost-benefit analysis for the proposed rule. IPL has summarized its approach to environmental controls for its Iowa coal-fired units in the recent Emissions Plan and Budget (EPB) filing. Specifically, the EPB delineates IPL's Tier philosophy to determine appropriate performance improvements and emissions controls given the age, size and expected retirement of coal-fired units. Accordingly, corrections to the following EPA IPM-derived assumptions are not currently recognized in IPL's resource planning process:

   1. *Burlington Unit 1 will install DSI and make heat rate improvements.*
      - IPL does not plan to install DSI or complete heat rate improvement projects.
   2. *ML Kapp Unit 2 will install DSI and make heat rate improvements.*
      - IPL does not plan to install DSI or complete heat rate improvement projects.

- This unit will be fueled by natural gas in 2015, and will no longer combust coal in order to meet MATS compliance.

3. *Prairie Creek Unit 3 will retire.*
   - IPL has not announced plans to retire this unit.
4. *Prairie Creek Unit 4 will install DSI and make heat rate improvements.*
   - IPL does not plan to install DSI or complete heat rate improvement projects.
5. *Sutherland Unit 3 will install mercury control and DSI, and make heat rate improvements.*
   - IPL does not plan to install mercury control or DSI or complete heat rate improvement projects.
   - This unit is fueled by natural gas.

The IUB expressed an interest in reviewing EPA's projected cost impacts for the State of Iowa. EPA developed illustrative benefit and cost projections based on IPM output. This information is available in their Regulatory Impact Analysis[1]. EPA summarized the projected impact on electricity prices on North American Electric Reliability Corporation (NERC) electricity market module regions rather than on a state-by-state basis. The following are projected changes in retail electricity prices from the Midwest Reliability Organization – West (MROW) region:

Year	2020	2025	2030
State-Only Approach	+ 7.0 %	+ 5.7 %	+ 4.3 %
Regional Approach*	+ 6.4 %	+ 5.8 %	+ 4.3 %

* Includes - ND, SD, IA, MN, WI, MO, IL, IN, MI
Data Reference: EPA-RIA, Tables 3-21, 3-22 and 3-23

Regardless of the projected electricity price increases, EPA projects that average electricity bills will decline in 2025 and 2030 due to lower electricity demand resulting from increased energy efficiency. The following are projected changes in average electricity bills:

Year	2020	2025	2030
State-Only Approach	+ 3.2 %	- 5.3 %	- 8.4 %
Regional Approach*	+ 2.7 %	- 5.4 %	- 8.7 %

* Includes - ND, SD, IA, MN, WI, MO, IL, IN, MI
Data Reference: EPA-RIA, Table 3-24

EPA only provided these estimates on a national level. IPL has not performed its own analysis of this data to verify whether it is complete or accurate, and to what level EPA's cost analysis did or did not include possible cost to improve infrastructure (ex, natural gas distribution and storage, transmission, etc.).

4. **Did EPA give Iowa appropriate credit for Iowa's early actions between 2005 and 2012?**
   a. **If not, how could and should this be remedied? (We need to be specific regarding early actions taken and what we need to be appropriately credited. Examples include such**

[1] http://www2.epa.gov/sites/production/files/2014-06/documents/20140602ria-clean-power-plan.pdf

things as early actions constructing wind, energy efficiency program savings, heat rate improvements at affected plants, plant closures, fuel switching.)

b. Is 2012 the appropriate base year? If not, please explain why not and what year, or averaging over several years, would be appropriate and why.

Response:
IPL believes that credit for early actions should be treated more equitably under the rule.

a. IPL has reduced its total CO2 emissions approximately 29% from 2005 to 2012. These reductions came in the form of plant retirements, fuel switching from coal to natural gas, energy efficiency, and the addition of wind and natural gas generation. Many of these reductions are not recognized since they occurred prior to 2012, so they are lost in the reduction goal that begins in 2012. Specific plant retirement and fuel switching CO2 emission reduction examples include:
    i. Sixth Street Generating Station – Retired in 2008, resulting in an annual reduction of approximately 582,000 tons of CO2.
    ii. Lansing Generating Station – Retirement of Units 1, 2, and 3 from 2006 to 2011, resulting in an annual reduction of approximately 184,000 tons of CO2.
    iii. Dubuque Generating Station – Fuel switched from coal to natural gas in 2011, resulting in an annual reduction of approximately 380,000 tons of CO2.
    iv. Sutherland Generating Station – Fuel switched from coal to natural gas in 2011, resulting in an annual reduction of approximately 906,000 tons of CO2.

Further, natural gas prices were extremely low in the 2012 baseline period, resulting in a spike in natural gas use which displaced other higher CO2 emitting sources, such as coal generation.

Concerning energy efficiency program savings:

> The EPA used 2012 state-level data provided in Form EIA-861 to determine each state's emission rate goal. The EPA considered using a historic-year data set, a projected year data set, or a hybrid of the two as a starting point for applying the above technology assumptions and calculating the state's emission rate goals. Ultimately the EPA chose the historic data approach as it reflected actual historic performance at the state level. EPA chose the year 2012 as it represented the most recent year for which complete data was available at the time of the analysis. The EPA also considered the possibility of using average fossil generation and emission rate values over a baseline period (e.g., 2009 – 2012), but determined that there would be little variation in results

compared to a 2012 base year data set due to the rate-based nature of the goal.[2]

The EPA's approach, therefore, looks at a historical snapshot of a single year to set the targets, giving no credit for activities in previous years. According to the EPA, because it is a rate-based target, a single year snapshot is still accurately reflective of prior year achievements. All states were set on this baseline and setting a target based on historical data reflects what was achieved by states. However, historical data does not consider the potential achievements remaining in the market. The method assumes that savings achieved in 2012 can be achieved and increased in the future. This assumption can create difficult targets for states which have already made significant savings through energy efficiency.

The largest energy savings gains are often made early in the life of energy-efficiency programs. Given that some states: (1) have had active energy-efficiency programs for years if, not decades (such as Iowa), and; (2) implement more stringent building codes (as in Iowa), a historical benchmark is not the most accurate method to determine the remaining market potential for energy-efficiency programs.

b. IPL is evaluating alternative baseline periods to the proposed 2012 period, including 2010 and 2011. One concern is that a complete historical alternative baseline year data set may not be available prior to 2010 which is of similar quality to the 2012 data set. IPL has evaluated 2010 and 2011 data and believes that these data are of similar quality to 2012. IPL believes that an alternative multi-year baseline such as 2010-2012 could be developed and supported given that the final goal is measured on a three-year rolling average basis (i.e., 2030-32, 2031-33, 2032-2034, etc.). Therefore, IPL supports this three-year average baseline even though it does not capture all of the early reductions IPL has made.

5. **For each Iowa affected coal facility: Is the 6% heat rate improvement achievable? If not, please explain specifically why not and what percent would be achievable.**

Response:
In general, heat rate improvement opportunities are dependent on the original design of the unit – for example, a sub-critical pressure coal fired Rankine cycle plant will not be able to achieve the efficiency of a natural gas combined cycle plant because of inherent physical design considerations. Heat rate and the impact of heat rate improvements will vary along the load curve for each generation unit. Production at partial loads requires the majority of plant equipment to operate below design, or most efficient levels. Improvements that result in reducing heat rate at a high load point may result in marginal or negative improvement at a lower load point. Thus the average heat rate improvement will be less than the the heat rate reported at the high load point depending on the units' capacity factor.

Almost all forms of heat rate improvement will degrade over time, requiring maintenance efforts, such as a turbine overhaul, to return the unit to near design conditions. The heat rate

[2] EPA. Technical Support Document. *Goal Computation*. June 2014. Available online: http://www2.epa.gov/sites/production/files/2014-06/documents/20140602tsd-goal-computation.pdf

improvement proposed by the EPA is an average improvement of 6%, and presumably includes all forms of heat rate improvements across the operating range and across a fleet. To attain the proposed average improvement will require cumulative heat rate improvements in excess of 6%. Yet, opportunities to incorporate improvements resulting in a total of 6% or greater heat rate improvement at one load point are rare and are even less likely to carry that level of improvement across the load curve. A significant driver of average heat rate is the capacity factor of a unit. It is further unlikely that an average heat rate improvement of 6% can be achieved and sustained on coal units that may be dispatched at reduced load points in the future in order to meet an emission reduction goal.

A discussion of heat rate opportunities that are currently available to specific IPL coal units is given below.

Burlington Generating Station: Based on information reviewed to date, an average heat rate improvement of 6% would be very difficult for Burlington Generating Station to sustainably achieve. The improvements currently being installed are expected to be 0% to less than 1%, depending on the impact of emission control systems. Over the past five years, the plant has installed many of the projects commonly identified as heat rate improvement opportunities; for example, a turbine overhaul was performed in 2010, variable frequency drives were installed on the induced draft fans, and air heater baskets and high pressure feedwater heaters have been replaced. An internally designed intelligent sootblowing control system is being installed, but the impact on heat rate is expected to be minimal because the sootblowing system is currently operating at capacity with little opportunity to expand. The primary opportunities for sustaining or further improving heat rate include increasing turbine overhaul frequency and upgrading the turbine to a higher efficiency design. More cost effective projects, like adding variable frequency drives to FD fans and feed pumps, would yield very small incremental savings as the existing hydraulic couplings provide nearly the same benefit.

Ottumwa Generating Station: Based on information reviewed to date, an average heat rate improvement of 6% would be difficult for Ottumwa Generating Station (Ottumwa) to sustainably achieve. A program of efficiency and emission control improvements began in 2012 and is currently being implemented at Ottumwa. Upon completion, total net heat rate improvement at full load may possibly achieve 6% compared to a 2011 reference point, including an offset for the impact of new emission control systems. However, an achievable average improvement is expected to be 3 – 5%. Further efficiency improvement is not currently achievable. By the completion of the program, the plant will have implemented all currently identified opportunities to significantly improve heat rate, including upgraded turbine rotors, new air preheater baskets, a new economizer section, new feedwater heaters, a neural net control system, condenser improvements, and variable frequency drives on induced draft fans. Finally, over time Ottumwa is expected to experience degradation which will require additional future investment to restore heat rate to near design conditions.

Prairie Creek Generating Station Unit 3: Based on information reviewed to date, a 6% average heat rate improvement would be very difficult to achieve at Prairie Creek Generating Station Unit 3. An achievable improvement is expected to be less than 1%. An internally developed intelligent sootblowing system has been implemented, new air heaters were installed and the electrostatic precipitators were rebuilt in 2013, improving heat rate 0.5%. The Installation of

some common heat rate improvement projects such as a condenser cleaning system are limited due to insufficient space, while a turbine upgrade would require significant system design changes, affecting the unit's dispatch and capacity positions, as well as being very costly. More cost-effective projects such as adding economizer steam sootblowers may achieve some improvement of boiler efficiency, but it is currently estimated at only 0.35%, which is not a significant heat rate improvement.

Prairie Creek Generating Station Unit 4: Based on information reviewed to date, an average heat rate improvement of 6% is very difficult to achieve at Prairie Creek Generating Station Unit 4. An achievable average heat rate improvement is likely 1% or less. New air heaters were installed in 2012. Heat rate improvements of approximately 1% may be available from miscellaneous boiler efficiency improvements such as mill classifier replacements, burner upgrades and primary air fan modifications. However, the unit does not have enough control capability for neural net inputs and there is not enough room to install a condenser cleaning system. An internally developed intelligent sootblowing system is currently being implemented, with preliminary estimate of 0.5% heat rate improvement. The electrostatic precipitators were modified and rebuilt in 2013, reducing air leakage, but this will not generate a significant decrease in heat rate. Switching fuel to high Btu, low sulfur western coal may also decrease auxiliary power for a net heat rate improvement of < 0.2% but the costs and feasibility of a fuel switch have not been evaluated.

Lansing Generating Station Unit 4: Based on information reviewed to date, an average heat rate improvement of 6% is difficult to achieve at Lansing Generating Station Unit 4 (Lansing). An achievable average heat rate improvement is expected to be 1% - 3%. Lansing is in the development stages of a program to install efficiency improvement and emission control projects. When complete, the net heat rate at full load is currently expected to improve by 2.5% - 3%, including the impact of additional environmental controls. Thus far, only two heat rate improvement projects have been identified to be cost-effective to proceed with planning and future installation – turbine steam path upgrade and water cannons with intelligent sootblowing controls. At this time, IPL cannot estimate the impact of these projects on capacity factor and heat rate at lower loads but expects the average heat rate improvement to be less than the improvement at full load.

6. **For each Iowa affected gas unit: Is the 70% capacity factor achievable? If not, please explain specifically why not and what percent would be achievable.**

Response:
IPL's combined cycle gas generating units,[3] Emery and the planned Marshalltown Generating Station, will have the ability and available natural gas supply to operate at a 70% capacity factor, and potentially higher if required. Excluding maintenance events, these units will have the capability to operate throughout the year, including the winter, and will play a critical role in meeting Iowa customers' energy needs.

Under current conditions, given the amount of wind generation in Iowa, IPL believes it is unlikely that the system would require the amount of energy produced at a 70% capacity factor from

[3] 70% capacity factor is only assumed for NGCCs and not CTs, so only NGCCs are discussed in this section.

combined cycle units. However, with future transmission system upgrades, IPL expects the combined cycle units will likely operate at a higher capacity factor than today.

7. **Is the 1.5% annual incremental savings rate due to energy efficiency from years 2020 to 2029 achievable? If not, please explain specifically why not and what percent would be achievable.**

Response:
Achieving a sustained 1.5% annual incremental savings rate from 2020 to 2029 via energy efficiency would be possible, but challenging as it would require additional substantial investments in energy efficiency programs resulting in significant cost implications for customers in comparison to benefits. Because of Iowa's long-term history and customer participation in energy efficiency, the low-hanging fruit opportunities and lower incremental cost technologies and programs have largely been implemented and those savings have been achieved. IPL believes that additional savings to achieve this higher level requirement will need to come from the commercial and industrial sector, new construction, and the turnover of current efficient technologies with more efficient ones from now through 2020 and beyond.

8. **Is the time allowed to develop the initial state plan feasible and reasonable? Is the level of detail required for the initial plan feasible and reasonable given the amount of time allowed to develop it? If not, please explain why it is not and the amount of time we need and why. This should probably include the steps required for the initial state plan and the amount of time we estimate it will take for each of the steps.**

Response:
While IPL will happily provide any recommendations and supporting information that may be needed, this is ultimately a question for the State to answer. If done simply, without the need for new regulatory or legislative tools, and with cooperation from all parties involved, the time to develop a state plan may be reasonable. Utilities may need additional time to gather and analyze data as the state plan is developed. The State should ensure it has adequate time to engage in discussion with surrounding states on the potential of entering in a regional or multi-state approach.

9. **Is the time allowed to develop the final state plan feasible and reasonable? Is the level of detail required for the final plan feasible and reasonable given the amount of time allowed to develop it? If not, please explain why it is not and the amount of time we need and why. This should probably include the steps required for the final state plan and the amount of time we estimate it will take for each of the steps.**

Response:
Please see IPL's response to question 8 above.

10. **How do you anticipate the proposed rule will impact the operation of the MISO market? Is the rule workable within the current MISO market construct?**

Response:

Implementation of CO2 emission regulations will be highly dependent on how the state implementation plans are designed and whether there are state or regional approaches to managing these emissions. MISO's primary market responsibilities are to ensure reliability with economic dispatch. In the current market, many units operate under emissions rate or cap requirements established in various air permits. Adding CO2 as another regulated emission is manageable. However, given the likelihood that electricity costs will increase as this rule is implemented, this final rule should enable the continuation of economic dispatch while adding CO2 as an additional constraint. This functionality is critical to help manage customer energy costs. As there are many unanswered questions about this implementation, it is likely some changes will need to be made to the MISO construct to ensure economic implementation.

11. **What do you believe would be the impact on Iowa's target CO2 emissions rate if the EPA were to recalculate emissions targets based on non-Iowa entities' 2012 purchases of RECs or energy from Iowa based wind units?**

Response:

If the EPA were to recalculate emissions targets considering non-Iowa entities' 2012 purchases or ownership of energy from Iowa-based wind units, preliminary evaluations suggest that the goal should not be significantly different. In calculation of the Iowa goal for Block 3, the EPA assumed that Iowa would have to achieve a level of 15% renewable energy generation, as established on a regional basis. However, Iowa's existing wind resources in 2012 were 25% of the total state energy generation. Therefore, no additional renewable growth is factored into the Iowa target for this part of the state's goal calculation.

IPL has only evaluated Iowa wind generation relative to direct ownership and purchase power agreements (PPAs). Sales of RECs were not considered because they can vary from year to year and this data was not readily available in the data that IPL reviewed. IPL's preliminary analysis shows that approximately 40% of Iowa wind generation is held, either through direct ownership or a PPA, by out-of-state entities. IPL does not believe Iowa's target CO2 emission would change significantly if this generation was removed from the state's goal calculation because of the large amount of wind generation in Iowa.

12. **If Iowa's utilities must use at least some of their wind generation to satisfy Iowa's target CO2 emissions rate instead of selling the associated RECs to other states to satisfy the other states' RPSs, will there be an impact on Iowa customers' electric rates? If yes, do you know what the impact could be? Do Iowa utilities have current multi-year contracts to sell their wind Recs that will impact when their wind generation can be used to satisfy Iowa's target CO2 emissions rate?**

Response:

IPL sells excess RECs after meeting its Renewable Portfolio Standard. IPL has not sold forward REC contracts.

In 2012 and 2013, IPL generated $0.9 million and $1.2 million from the sale of excess RECs, which was passed through the energy adjustment clause to IPL customers. In 2014, IPL forecasts $1.4 million in proceeds from REC sales. The three-year forecast (2015-2017) of REC sale refunds to IPL customers is $1.2-$1.4 million/year. If excess RECs are needed to satisfy Iowa's target CO2 emission rate, the pass-through to customers during the carbon rule period may be decreased or eliminated.

13. Have the other participants in the 111(d) collaborative identified any additional information that is needed?

Response:

Given the broad considerations for the EPA's proposed Clean Power Plan, there is much additional information that will be needed as part of the rule comment and State Plan development process. IPL recognizes that not every aspect of the EPA's proposal can or will be solved prior to the close of the public comment period. At this time, IPL recommends that review of the information being generated by other entities would be a good preliminary method to identify key issues. The remaining information gaps could then be identified to complete the assessment. Available information anticipated at this time includes EEI White Papers, and MISO's modeling as proposed June 25, 2014 for the GHG Regulation Impact Analysis. Additional information that also should be considered includes an assessment of Iowa's state natural gas pipeline capacity and potential additional gas pipeline infrastructure that could be required. Similarly, valuable information can be obtained regarding the current status and timing for potential additional infrastructure needs of transmission projects in Iowa. Additional critical information that should be considered includes an evaluation of a mass cap (versus emissions rate) approach and the potential cost differential for a state-only versus regional approach.